UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	)	**Docket No. __________________**
	)	
New York Independent System Operator, Inc.	)	
	)	
PJM Interconnection, L.L.C.	)	

PETITION OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC., NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., AND PJM INTERCONNECTION, L.L.C. FOR RULEMAKING CONCERNING ANNUAL CHARGES ASSESSED TO PUBLIC UTILITIES UNDER 18 CFR PART 382

Pursuant to Rule 207 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. §385.207, the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), the New York Independent System Operator, Inc. ("NYISO"), and PJM Interconnection, L.L.C. ("PJM") (collectively, as "Petitioners") hereby petition the Commission to initiate a rulemaking to conform the allocation of annual charges associated with the costs of the Commission's electric regulatory program to the circumstances that have changed since the issuance of Order No. 641.[1]

In support hereof, the Petitioners state as follows:

[1] *Revision of Annual Charges Assessed to Public Utilities*, Order No. 641, 65 Fed. Reg. 65,757 (November 2, 2000), FERC Stats. & Regs. Regulations Preambles July 1996-December 2000

I.

COMMUNICATIONS AND CORRESPONDENCE

Communications and correspondence concerning this matter should be directed to:

Stephen G. Kozey
Vice President and General Counsel
Lori A. Spence*
Associate General Counsel
Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400

Stephen L. Teichler*
Sheila S. Hollis
Duane Morris LLP
1667 K Street, NW, Suite 700
Washington, DC 20006
Telephone: (202) 776-7830

Robert E. Fernandez
General Counsel and Secretary
Belinda F. Thornton*
Director of Regulatory Affairs
New York Independent System Operator, Inc.
3890 Carman Road
Schenectady, NY 12303
Telephone: (518) 356-7661

Arnold H. Quint*
Ted J. Murphy
Hunton & Williams
1900 K Street, NW
Washington, DC 20006
Telephone: (202) 955-1500

Craig Glazer*
Vice President-Governmental Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, DC 20005
Phone (202) 393-7756
Fax (202) 393-7741

Barry S. Spector*
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, DC 20005
Phone (202) 393-1200
Fax (202) 393-1240

*Persons designated for official service pursuant to Rule 2010.

II.

BACKGROUND

Section 3401 of the Omnibus Budget Reconciliation Act of 1986 ("Budget Act") requires the Commission to "assess and collect fees and annual charges in any fiscal year in amounts

¶31,109 (2000), *reh'g denied*, Order No. 641-A, 66 Fed. Reg. 15793 (March 21, 2001), 94 FERC ¶ 61,290 (2001), 18 CFR Part 382 ("Order No. 641").

equal to all of the costs incurred…in that fiscal year."[2] The Budget Act further provides that the annual charges assessed by the Commission must be computed based on methods that the Commission determines to be "fair and equitable."[3] In response to this requirement, the Commission promulgated Order No. 472 in 1987.[4] The regulations established by that order assessed charges against gas and oil pipelines, electric utilities, power marketing administrations and one electric cooperative. The charges were based on the volume of energy transported and sold by the gas pipeline and the electric service provider, and on the operating revenues received by the oil pipeline.

In 2000, the Commission amended its regulations to establish a new methodology for the assessment of annual charges to public utilities, and these regulations became effective January 1, 2001. In Order No. 641, the Commission noted that the industry had undergone sweeping changes since 1987.[5] Specifically, the Commission cited its establishment of open access transmission as a foundation for competitive wholesale power markets. In addition, the Commission noted the movement towards retail competition and generation divestiture by public utilities.[6] The Commission stated that these changes had altered the nature of the work performed by the Commission and thus its cost incurrence. In light of these changes, the Commission proposed to assess annual charges to public utilities that provide transmission

---

[2] 42 U.S.C. §7178.

[3] 42 U.S.C. §7178(b).

[4] *See Annual Charges Under the Omnibus Budget Reconciliation Act of 1986*, Order No. 472, 52 Fed. Reg. 21,263 and 24,153 (June 5 and 29, 1987), FERC Stats. and Regs., Regulation Preambles 1986-1990 ¶30,746 (1987), *clarified*, Order No. 472-A, 52 Fed. Reg. 23,650 (June 24, 1987), FERC Stats. and Regs., Regulations Preambles 1986-1990 ¶30,750, *order on reh'g*, Order No. 472-B, 52 Fed. Reg. 36,013 (September 25, 1987), FERC Stats. and Regs., Regulations Preambles 1986-1990 ¶30,767 (1987), *order on reh'g*, Order No. 472-C, 53 Fed. Reg. 1,728 (Jan. 22, 1988), 42 FERC ¶61,013 (1988).

[5] Order No. 641, at 31,842.

[6] *Id.*

service based solely on the volumes of electric energy transmitted, rather than on both jurisdictional power sales and transmission volumes.

The Commission also discussed the role of independent system operators ("ISOs") and regional transmission organizations ("RTOs") with respect to the assessment of annual charges. The Commission noted that such entities are public utilities and thus are required to report to the Commission the transmission volumes delivered under the ISO or RTO tariff (as opposed to the transmission owners whose assets are under ISO or RTO control). The Commission further held that, for purposes of administrative convenience, the ISO or RTO should be the entity that pays the charge, as opposed to invoicing the participating transmission owners that are public utilities directly. The Commission reasoned that the ISO or RTO would be in the best position to know whose facilities were involved in what transactions and thus could reapportion the charges among its members accurately. The Commission did not foresee any substantial burden since the charges were expected to be modest.

The new methodology was applied for the first time with respect to assessments for the 2002 fiscal year. Several entities, including the NYISO, American Transmission Company LLC ("ATCLLC") and the California Independent System Operator Corporation ("CAISO") (collectively, as "Applicants"), requested rehearing of the invoices they received reflecting their respective portions of annual electric program charges computed by the Commission for fiscal year 2002.[7] Each of those entities claimed that it was being required to bear a significant increase in the annual charges as a result of the revised regulations.

---

[7] *See* Annual Charges Billing - Fiscal Year 2002, Docket Nos. RM00-7-002, *et al*. Each of the NYISO, ATCLLC and CAISO submitted requests for rehearing on August 14, 2002. The NYISO, ATCLLC and CAISO each state that they are seeking rehearing of the bill pursuant to the instructions set forth on the bill and Rule 713 of the Commission's Rules of Practice

The Applicants cited to several problems underlying the 2002 assessments. Several Applicants alleged inconsistencies in the data reported by certain public utilities under the amended regulations.[8] Some cited changes in the legal and policy assumptions that prompted adoption of the revised regulations in 2000.[9] According to Applicants, these circumstances resulted in ISOs and members thereof shouldering a disproportionate amount of the annual charges for the Commission's electric regulatory program.

On October 11, 2002, the Commission issued an order denying rehearing.[10] The Commission rejected claims that the bills rendered should be corrected because the data reporting among utilities was faulty. Instead, the Commission expressed confidence that its audit process will detect and correct reporting errors. The Commission held that assertions concerning the new thrust of its mission constituted a collateral attack on Order No. 641. The Commission also rejected requests that the cost of the Commission's regulatory program be spread over both bundled and unbundled load as a collateral attack on Order No. 641. Finally, the Commission held that the basic focus of its Standard Market Design ("SMD") initiative[11] remains on eliminating undue discrimination in the use of the Nation's interstate transmission grid, and thus it continues to be appropriate to impose assessments on transmission providers.

---

and Procedure, 18 C.F.R. §385.713. *See* NYISO Filing at 1, ATCLLC Filing at 3, n. 6, and CAISO Filing at 2, n. 1.

8 For example, at least one utility company (Duke Power Company) and one ISO (ISO New England Inc.) reported no transmission transactions for 2002. *See, e.g.,* NYISO Filing at 5-6.

9 *See, e.g.,* NYISO Filing at 9-13.

10 Revision of Annual Charges to Public Utilities (*California Independent System Operator, et al.*), 101 FERC ¶ 61,043 (2002).

III.

PETITION

The Petitioners share the Commission's commitment to the administration of existing regulations and its dedication to appropriate procedures. However, the Petitioners also believe that the NYISO, CAISO and ATCLLC raised valid concerns in their rehearing requests, not the least of which is that the current methodology works as a penalty to RTO participation. To the extent that those concerns were considered a collateral attack on existing regulations, the appropriate procedural option is the institution of a new rulemaking pursuant to which the assumptions and policy considerations underlying Order No. 641 may be reevaluated and modified to the extent necessary. Accordingly, the Petitioners respectfully request that the Commission initiate such a rulemaking.

A. The Commission's Assessment Methodology May Undermine RTO Formation and Participation.

In Order No. 2000, the Commission stated that its goal was to encourage the voluntary formation of RTOs. As a carrot to induce the desired voluntary conduct, the Commission provided "certain favorable ratemaking treatments for those who assume the risks of the transition to a new structure, which should, at a minimum, eliminate any rate disincentives to RTO formation."[12] In addition, the Commission recognized the need to "assure utilities that they will not be penalized for RTO participation."[13]

---

[11] Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452 (2002), FERC Stats. & Regs. ¶______(2002), 100 FERC ¶61,138 (July 31, 2002) ("SMD NOPR").

[12] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,034 (1999), 89 FERC ¶ 61,285, *order on reh'g,* Order No. 2000-A, 65 Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs ¶ 31,092 (2000), *petitions for review dismissed*, *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[13] Order No. 2000, at 31,172.

The Commission also stated that one of its objectives under Order No. 2000 was to encourage non-jurisdictional transmission owners—*e.g.*, cooperatives, Federal Power Marketing Agencies and municipal systems—to place their transmission facilities under the control of an RTO. The Commission said that "public power and cooperative participation in RTOs will enhance the reliability and economic benefits of an RTO. Furthermore, participation by public power entities and cooperatives is vital to ensure that each RTO is appropriate in size and scope."[14]

The Commission has assisted the Midwest ISO materially in creating positive incentives for RTO participation. By order dated September 23, 2002, the Commission approved a return on equity for Midwest ISO participants of 12.88 percent; an increase of 50 basis points over the mid-point figure recommended by the Administrative Law Judge.[15] With the Commission's help, the Midwest ISO has increased its footprint substantially, and thus stands in a position to reduce its administrative adder as it is spread over a greater load. In addition, the Commission has approved TRANSLink's participation as an Appendix I Independent Transmission Company ("ITC") in the Midwest ISO, which has been an essential vehicle to secure the participation of public power entities on the western border of the Midwest ISO.

Similarly, the Commission has approved transition rate proposals of transmission owners to enable the expansion of PJM to include the Allegheny Power system, enabling PJM to increase its scope substantially. *See PJM Interconnection, LLC*, 96 FERC ¶ 61,060 (2001). Most recently, American Electric Power Company, Dayton Power & Light Company, Commonwealth Edison Company, and Virginia Electric & Power Company also have agreed to join PJM, which ultimately will result in lower administrative charges to PJM customers.

---

[14] Order No. 2000, at 31,201.

These substantial gains may be jeopardized if they are offset by the imposition of disproportionate allocations of annual fees to RTO members. While an RTO is the quintessential transmission provider and hence can be the focal point for the assessment of annual charges where one exists, as alleged by CAISO, NYISO and ATCLLC, this status results in what appears to be disproportionately large assessments assigned to such entities. Efforts by the Midwest ISO and PJM to pass through these charges to their members may constitute a substantial disincentive to RTO participation notwithstanding the incentives elsewhere provided.

For example, with non-jurisdictional systems voluntarily participating within the Midwest ISO, the total transmission service provided exceeds the transmission provided over jurisdictional facilities. If the Commission assessed annual charges based on total transmission service provided by the Midwest ISO, which includes transmission provided over non-jurisdictional facilities, the Midwest ISO would have three alternatives for allocating these assessments. First, it could allocate these assessments to its members, both jurisdictional and non-jurisdictional. This alternative has the effect of the Commission assessing annual charges to non-jurisdictional entities indirectly through the Midwest ISO. Because the Commission does not have the authority to assess annual charges to non-jurisdictional entities directly, the non-jurisdictional entities that are members of the Midwest ISO have told the Midwest ISO that they do not believe that the Commission has the authority to assess charges to non-jurisdictional entities indirectly through the Midwest ISO either.[16] The non-jurisdictional entities in the NYISO raised the same argument during the rulemaking proceeding that led to Order No. 641. The Commission invited non-jurisdictional entities to participate voluntarily in RTOs and ISOs

---

[15] *See Midwest Independent Transmission System Operator, Inc.*, 100 FERC ¶ 61,292 (2002).

and many responded favorably to the Commission's invitation. If FERC asserts authority to assess annual charges to non-jurisdictional entities that may consider joining RTOs, some non-jurisdictional entities that have participated in RTOs voluntarily could decide to reevaluate their decisions.

The second alternative for allocating these annual charges based on total transmission service provided by the Midwest ISO would be to attempt to pass-through its assessment solely to its public utility participants. This would result in public utilities shouldering the financial responsibility for the annual charges that the Commission has levied on non-jurisdictional entities indirectly through the Midwest ISO. This would be neither appropriate nor fair and would result in public utilities that are members of the Midwest ISO being obligated to pay sums higher than they would obtain if they were non-participants.

The third alternative for allocating these annual charges based on total transmission service provided by the Midwest ISO would be for the Midwest ISO to include the FERC assessment in its Schedule 10 Adder and recover the charge from all of its customers. By this method, however, the Midwest ISO also would be billing non-jurisdictional utilities directly for costs that the Commission could not bill to those entities. As noted above, the specter of additional cost may create a disincentive for non-jurisdictional utilities to join RTOs, a result in direct conflict with Order No. 2000. In fact, the possibility of incurring additional costs associated with the FERC's annual fee has caused Eastern Kentucky Power Cooperative to delay its membership in the Midwest ISO until its Board is informed of such liability. Public power should not be discouraged from joining an RTO through a requirement that it bear a portion of

---

[16] As transmission customers, non-jurisdictional entities may be required to pay a portion of the ISO/RTO's costs through administrative charges, including a share of the total costs associated with payments that the ISO/RTO makes to FERC for annual charges.

the cost of the Commission's operation that would not be imposed upon it if it did not participate.[17]

Petitioners respectfully request a second independent basis for the Commission's re-evaluation of the position of RTOs in the recovery of the Commission's annual assessment. Under the Commission's current methodology for determining annual assessments, public utilities that have not yet joined an RTO have received lower assessments than utilities that have joined an RTO. The annual assessment for utilities that have not joined an RTO is based on the utilities' transmission for wholesale transactions, while the annual assessment for utilities that have participated in RTOs is based on the utilities' transactions for both wholesale and retail transactions pursuant to the Commission's Opinion No. 453.[18] In practice, RTO participants should not bear a higher proportion of costs than non-participants. Yet, this appears to be the case.

Indeed, in its rulemaking, the Commission should consider whether members of an RTO should be assessed a lower portion of the Commission's costs than non-participants. In Order No. 2000, the Commission stated that RTOs would facilitate "lighter-handed governmental regulation."[20] The Commission expressly cited this consequence of RTO formation as one of the

---

[17] The non-jurisdictional transmission owners that are members of the Midwest ISO have advanced the argument that the extension of the Commission's cost recovery mechanism/charges to their load is in fact beyond the proper scope of the Commission's jurisdiction. These non-jurisdictional transmission owners have requested that the Midwest ISO file this Petition to raise this issue with the Commission.

[18] *See, e.g.* Opinion No. 453, 97 FERC ¶ 61,033 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002); and Order No. 641**,** 65 Fed. Reg. 65,757 (November 2, 2000), FERC Stats. & Regs. Regulations Preambles July 1996-December 2000 ¶ 31,109 (2000), *reh'g denied,* Order No. 641-A, 66 Fed. Reg. 15793 (March 21, 2001), 94 FERC ¶ 61,290 (2001).

[20] Order No. 2000, at 31,021.

benefits to be provided by an RTO.[21] The Commission stated that a "properly structured RTO would reduce the need for Commission oversight and scrutiny, which would benefit both the Commission and the industry."[22] The Commission concluded that formation of and participation in RTOs would enhance the benefits of competitive electricity markets, to the benefit of the public interest.[23]

In particular, the Commission noted that an RTO independent of power marketing interests would dispel the need for the Commission to monitor and enforce compliance with standards of conduct with respect to a utility unbundling its transmission and generation functions.[24] Similarly, an RTO with an impartial dispute resolution procedure could resolve disputes without resorting to the Commission's complaint process.[25] Additionally, the Commission indicated that RTOs should lead to more streamlined transmission rate proceedings.[26] Finally, the Commission stated that RTOs, by increasing market size and decreasing market concentration, would alleviate competition concerns for mergers and thereby facilitate the Commission's merger decision-making process.[27]

Since RTOs are assisting the Commission to perform many functions, the Commission no longer will incur the full burden of costs associated with performing those functions on a stand-alone basis. Accordingly, the cost burden of annual charges for transmission owners participating in RTOs should be diminished correspondingly.

B. The Commission's Focus Has Changed Again.

---

[21] *Id.*
[22] *Id.* at 31,027.
[23] *Id.* at 30,993.
[24] *Id.* at 31,027.
[25] *Id.*
[26] *Id.*
[27] *Id.*

Over the years, the Commission has shown flexibility in revising its annual charge regulations to reflect its changing focus. In 1987, when Order No. 472 was issued, the bulk of the Commission's time was dedicated to reviewing the prices set forth in bulk power sales contracts pursuant to Section 205 of the Federal Power Act.[28] With the evolution of market-based sales certificates and the issuance of Order No. 888, the focus of the Commission's efforts shifted dramatically from sales to providing open access nondiscriminatory transmission access according to the strictures of Order No. 888.[29] The Commission's technical staff evaluated dozens of Open Access Transmission Tariffs and associated requests for variance. The Commission policy personnel prepared orders clarifying the requirements of Order No. 888 and its applicability to specific factual circumstances. The Commission's solicitors shepherded Order No. 888 through the courts of appeal and on to the Supreme Court. In addition, the Commissioners themselves began a push for more ISOs and ultimately RTOs, and that initiative culminated in Order No. 2000. This provided the context within which the Commission revised the basis for determining the annual charge to transmission providers by adopting Order No. 641.

While the Commission's Orders Nos. 888 and 2000 mandates resulted in a more efficient transmission regime, the Commission noted that "there remain significant impediments to the competitive market," including "inconsistent design and administration of short-term energy markets [that] has resulted in pricing inefficiencies that can cause rates to be unjust and

[28] 16 U.S.C. §824(d).

[29] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶61,046 (1998), *aff'd in relevant part, remanded in part on other grounds sub nom.* Transmission Access Policy Study Group,

unreasonable."[30] The Commission therefore issued its Notice of Proposed Rulemaking concerning SMD. The Commission stated that its "objectives in this third rulemaking initiative … are to remedy remaining undue discrimination and establish a standard transmission service and wholesale electric market design that will provide a level playing field for all entities that seek to participate in wholesale electric markets."[31]

In its order denying rehearing of its 2002 assessments, the Commission properly cited removal of the last vestiges of undue discrimination in transmission service as one SMD goal. It is also irrefutable, however, that improvements in the wholesale electric market are an equally compelling objective. Indeed, the modality chosen by the Commission to eradicate transmission impediments is largely through the creation of markets. Moreover, the Commission has stated specifically that the benefits of SMD will manifest themselves in lower average costs of power. Specifically, the Commission said:

> The proposed Standard Market Design rules are intended to have a generally positive impact on these market participants. For example, the proposed Standard Market Design rules will facilitate direct dealings between market participants who want to secure long-term bilateral power supply arrangements. The proposed Standard Market Design rules will also facilitate short-term transactions that are made in the spot market to make up for imbalances (differences) between scheduled electricity supplies that were matched to projected load levels, and the load levels that actually develop. Through these proposed Standard Market Design rules, sellers will be able to more effectively sell into the market and buyers will be able to more efficiently buy from the market because they will not need to be directly matched up at the last minute on a real-time hourly and day-ahead basis. In addition, the proposed Standard Market Design rules will bolster customers' ability to profitably participate in programs designed to encourage reductions in loads to offset electricity supply shortages. Finally, the proposed Standard Market Design rules will foster the trading of Congestion Revenue

---

et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 122 S. Ct. 1012 (2002).

30 SMD NOPR, at ¶ 2.

31 *Id.* at ¶ 3.

> Rights among transmission customers that will allow them to protect against congestion charges.[32]

There is no reason to believe that SMD implementation will be any less arduous than the implementation of Orders Nos. 888 and 2000. The Commission's staff is hosting seminars throughout the country to explain the new market structure. In record time, the Commission's technical and policy staffs reviewed and approved a Standard Market Design proposal for New England.[33] And the Commission generously has devoted resources to help the Midwest ISO and PJM form a joint and common market based on SMD. Finally, the Commission has created an entirely new group within its organizational structure with the sole mandate to monitor markets and investigate potential abuses of market power by energy suppliers. Indeed, a significant portion of the Commission's current adjudicatory resources are being devoted to the establishment and remediation of market failures in California. Similarly, the Commission recently has initiated a rulemaking on generator interconnections[34] and an interim rule and investigation of supply margin assessments,[35] functions tied to market activity as opposed to a pure transmission focus.

Given these events, it appears that the Commission's prospective focus will not be exclusively on transmission. Rather, the Commission will pursue economic efficiency on a balanced basis by integrating sales and transmission into a seamless whole. In these circumstances, all who benefit from the Commission's initiatives should contribute to defraying the cost the Commission incurs to achieve them. As the Commission noted, all market participants will benefit from SMD and hence all market participants should share an equal cost

---

[32] *Id.* at ¶ 608.
[33] *New England Power Pool, et al.*, 100 FERC ¶ 61,287 (2002).
[34] *See* Docket No. RM02-1-000.
[35] *See* Docket Nos. ER96-2495-015, *et al.*

burden with respect to the implementation of the Commission's initiatives. Only by employing an assessment methodology that reflects an appropriate balance between transmission and market activities can this equality be achieved.

C. The Current Allocation Method is Unfair

The unreasonableness of the allocation under Order No. 641 may be seen from the following example. The Commission's Electric Assessment Table for FY2002 indicates the "Total Sales" to be 1,704,208,204 MWh. The "Total Sales" for the California Independent System Operator were shown to be 236,212,930 MWh. The "Total Sales" for the New York Independent System Operator were shown to be 161,943,228 MWh. By letter dated September 23, 2002, PJM advised the Commission that it was amending its transmission service to be 280,344,453 MWh. Adjustment of the national total solely to reflect the PJM amendment would result in a total base of 1,939,231,049 MWh. As may be seen on the following table, the CAISO, the NYISO and PJM alone would have borne more than one-third of the Commission's total costs. Their share of national energy sales, according to a report of the Energy Information Administration and a PJM report is, however, only 19%.

ISO	Transmission Service	Percent of Adjusted Total	Regional Energy Sales (2000) (Gwh)	Share of National Energy Sales (%)
California	236,212,930	12%	244,057[36]	7.1
NYISO	161,943,228	8%	142,027[37]	4.2
PJM	280,344,453	14%	262,084[38]	7.7

36 Electric Sales and Revenue, 2000, Energy Information Administration, Table 16.
37 *Id.*
38 PJM Annual Report of Operations 2000, at 8.

TOTAL		34%		19.0%

The billings to those three entities bear no rational relationship to the relative demands or energy usage in their regions or to the level of transmission service necessarily related to the level of demand or energy usage. Including transmission owners participating in the Midwest ISO on the same basis will compound the inequity exponentially.

D. Reform of Part 382 of the Commission's Regulations Is Required to Produce a "Fair and Equitable" Allocation of Costs.

Application of the revised regulations set forth in Order No. 641 to 2002 ISO assessments has revealed inequities that should not be overlooked by the Commission. Any method used by the Commission to compute annual charges must be "fair and equitable" in accordance with applicable law. Additionally, these annual charges should be borne by those entities that demand regulatory oversight from the Commission and are representative of the Commission's workload. Petitioners urge the Commission to remedy the problems associated with allocation of annual charges under the amended regulations to ensure that assessments for fiscal year 2003 and subsequent fiscal years meet the fairness and equity standards articulated in the Budget Act and to reflect the realities of the Commission's electric regulatory program.

When assigning annual charges to public utilities, the Commission should be guided by certain principles that will aid in promoting a fair and equitable distribution of the costs of the Commission's electric regulatory program. Specifically, the Commission must articulate, in unambiguous terms, the reporting requirements for public utilities under Order No. 641. It must be clear to all public utilities that are subject to such requirements exactly what transmission transactions must be reported to the Commission, whether such transactions occur in the context of an ISO/RTO or outside an ISO/RTO or on a bundled or unbundled basis. Since annual charges are assessed based on the percentage of total reported transmission volumes, it is critical that there be consistency among the data reported by public utilities. There should be no room for confusion or doubt on the part of these public utilities as to which transactions they are required to report to the Commission for purposes of computing annual charges. Furthermore, the annual charges must be allocated in proportion to the MWs of transmission service actually provided by the relevant entity relative to demand or energy usage in the particular region. In other words, there must be a rational and readily apparent connection between the amount of annual charges assigned to a public utility and the level of transmission service required to meet a certain level of demand or energy usage.

The Commission must determine what entities are subject to the Commission's jurisdiction for purposes of assessing annual charges in connection with its electric regulatory program, particularly in light of the Commission's recent pronouncement in its SMD initiative that it intends to exercise jurisdiction over the transmission component of bundled retail transactions.[39] Will entities providing bundled retail service be considered public utilities required to pay annual charges under 18 CFR Part 382? As a general proposition, the Petitioners submit that non-FERC jurisdictional entities should not be charged costs associated with the Commission's electric regulatory program.[40] Only those entities over which the Commission has jurisdiction, and derive the benefits of FERC's regulatory oversight, should bear the costs of running the Commission's electric regulatory program.

[39] SMD NOPR, at ¶ 6.

IV.

INTERIM RELIEF

Petitioners understand that the Commission will begin to analyze data beginning in April of 2003 in order to make the necessary assessments by July of 2003. This time frame may not permit the Commission a sufficient period within which to complete the requested rulemaking and issue a final order. Nevertheless, Petitioners believe that the merits of reallocating assessments for the Commission's electric regulatory expense are sufficient to warrant interim relief if the Commission cannot finish its rulemaking initiative prior to April, 2003.

Petitioners believe that an appropriate form of interim relief may be to prepare the July 2003 bills on the basis of the Order No. 472 allocation mechanism. Additionally, as discussed, the Commission should back out transmission over facilities of non-jurisdictional entities in determining annual charges. The Commission and the industry have experience with the Order No. 472 methodology. Utilizing the Order No. 472 format will spread the Commission's cost over a much wider class of industry participants, and thereby diminish the impact on any single class of regulated entities. Moreover, it will eliminate a significant disincentive to RTO or ITP participation during a critical period in which the Commission strenuously is urging the creation or expansion of such entities.

As part of this relief, the Commission also should provide that utilities whose transmission facilities are under the operational authority of an RTO should not report transmission volumes that are also reported by RTOs or ISOs. Further, the Commission should provide that it will not assess annual charges on operators of power exchanges (such as RTO and

---

[40] As transmission customers, non-jurisdictional entities may be required to pay a portion of the ISO/RTO's costs through administrative charges, including a share of the total costs

ISO spot markets) under the Order No. 472 allocation mechanism, because power sellers already will be paying assessments for those transactions. These clarifications are consistent with the guidance under Order No. 472 that the Commission previously provided in *PJM Interconnection, LLC*, 88 FERC ¶ 61,109 (1999), where it found that Order No. 472 otherwise inappropriately would "effectively double[]" the number of assessed transactions in those parts of the country moving most rapidly towards competition.[41] Petitioners respectfully request the Commission consider a similar temporary waiver of the annual charges as an alternative interim remedy.

V.

CONCLUSION

WHEREFORE, the Petitioners respectfully request that the Commission reassess its regulations under 18 CFR Part 382 governing annual charges payable by public utilities to ensure that such charges are fair and equitable, consistent with the comments set forth herein.

Respectfully submitted,

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

By: ______________________________

Stephen L. Teichler
Sheila S. Hollis
Duane Morris LLP
1667 K Street, NW, Suite 700
Washington, DC 20006
Telephone: (202) 776-7830

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: ______________________________

Arnold H. Quint
Ted J. Murphy
Hunton & Williams
1900 K Street, NW
Washington, DC 20006
Telephone: (202) 955-1500

associated with payments that the ISO/RTO makes to FERC for annual charges.

41 *PJM Interconnection, LLC*, 88 FERC ¶ 61,109 at 61,257 (1999).

Stephen G. Kozey
Lori A. Spence
Midwest Independent Transmission
System Operator, Inc.
701 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400

Robert E. Fernandez
Belinda F. Thornton
New York Independent System
Operator, Inc.
3890 Carman Road
Schenectady, NY 12303
Telephone: (518) 356-7661

PJM INTERCONNECTION, L.L.C.

By: ____

Barry S. Spector
WRIGHT & TALISMAN, P.C.
1200 G Street N.W.
Suite 600
Washington, DC 20005
(202) 393-1200

Craig Glazer
Vice President - Governmental Policy
PJM Interconnection, L.L. C
1200 G Street, N.W.
Suite 600
Washington, DC 20005
(202) 393-7756

Dated: December 3, 2002

WSH\87778.1