Before Commissioners: James J. Hoecker, Chairman; Vicky A. Bailey, William L. Massey, Linda Breathitt, and Curt Hébert, Jr.

North American Electric Reliability Council ) Docket No. EL98-52-000
Northeast Power Coordinating Council ) Docket No. ER99-2012-000
Commonwealth Edison Company and Commonwealth Edison of Indiana ) Docket No. ER99-1957-000
Illinois Power Company ) Docket No. ER99-1957-000
Entergy Services, Inc. ) Docket No. ER99-1967-000
Southern Indiana Gas and Electric Company ) Docket No. ER99-1968-000
Alliant Energy Corporate Services ) Docket No. ER99-1972-000
Virginia Electric Power Company ) Docket No. ER99-1973-000
Dayton Power & Light Company ) Docket No. ER99-1974-000
American Electric Power Service Corporation ) Docket No. ER99-1984-000
Carolina Power & Light Company ) Docket No. ER99-1986-000
Madison Gas & Electric Company ) Docket No. ER99-1987-000
Cinergy Services, Inc. ) Docket No. ER99-1991-000
Western Resources, Inc. ) Docket No. ER99-1994-000
Central Illinois Light Company ) Docket No. ER99-1995-000
Southern Company Services, Inc. ) Docket No. ER99-1997-000
Ohio Valley Electric Company ) Docket No. ER99-2001-000
Allegheny Power Service Company ) Docket No. ER99-2002-000
WPS Resources Corporation ) Docket No. ER99-2004-000
East Texas Electric Cooperative, Inc. ) Docket No. ER99-2008-000
Maine Public Service Company ) Docket No. ER99-2009-000
PJM Interconnection, L.L.C. ) Docket No. ER99-2010-000
Duke Energy Corporation ) Docket No. ER99-2011-000
Detroit Edison Company and ) Docket No. ER99-2014-000
In an order issued December 16, 1998, the Commission reviewed a petition for a declaratory order filed by the North American Electric Reliability Council (NERC) regarding NERC’s proposed Transmission Loading Relief (TLR) procedures. In its order, the Commission concluded that the TLR procedures must be on file with the Commission, that they should be incorporated as a single generic amendment to the pro forma tariff, and that every transmission-operating public utility that adopted NERC’s TLR procedures must file with the Commission a notice that its tariff shall be considered so modified.

1/ North American Electric Reliability Council, 85 FERC ¶ 62,353 (1998) (December 16 Order). An order denying requests for rehearing of that order filed by several parties is being considered contemporaneously with this order.

2/ 85 FERC at 62,364. The Commission subsequently accepted
notices filed by forty transmission-operating public utilities indicating that they are adopting NERC's TLR procedures, as well as revised sheets filed by five utilities for their individual tariffs containing NERC's TLR procedures. North American Electric Reliability Council, et al., 86 FERC ¶ 61,275 (1999) (March 12 Order).
The December 16 Order also directed that by March 1, 1999, (1) transmission-operating public utilities in the Eastern Interconnection must file in a new docket revised, interim TLR procedures to address parallel flows associated with native load transactions and network service; and (2) those transmission-operating public utilities in the Eastern Interconnection not already developing regional congestion management programs through their power pools must identify and file interim redispatch solutions, with particular emphasis on solutions which could be implemented by the 1999 summer period. 1/

In this order, the Commission accepts NERC's revised, interim procedures addressing parallel flows associated with native load transactions and network service, as well as its redispatch pilot program for the 1999 summer period. We therefore accept for filing the submissions of those public utilities in the Eastern Interconnection which express an intention to subscribe to NERC's revised, interim TLR procedures and pilot redispatch program. We also find the alternative programs adopted by the Mid-America Interconnected Network (MAIN) and the Northeast Power Coordinating Council (NPCC) to be consistent with the NERC proposals subject to conditions described herein, and conditionally accept the filings of the public utilities who intend to adhere to these proposals. 1/

On April 5, 1999, NERC filed a letter with the Commission explaining that it had reviewed the comments and protests submitted in this proceeding and would take them under advisement. NERC further stated that it would continue to update the details of the pilot redispatch program. We approve NERC's efforts in this regard and will review its further submissions. We emphasize that our approval today of NERC's interim proposal is in no way meant to suggest that NERC should not continue to refine and expand its TLR and redispatch procedures. We encourage NERC to submit any further revisions so that they may be implemented as soon as possible this summer.

3/ 85 FERC at 62,364.

4/ Filings by Mid-Continent Area Power Pool (MAPP) and its members concerning its proposed Line Loading Relief procedures will be addressed in a separate order.
Background

1. The NERC Filing

On March 1, 1999, NERC filed with the Commission its response to the December 16 Order. 1/ In response to the Commission's mandate for new procedures to address parallel flows associated with native load and network service, NERC states that by summer 1999, its TLR procedures will include a calculation, the Transaction Contribution Factor (TCF), of the share of the transmission constraint that is attributable to transactions using firm point-to-point service. 1/ NERC explains that the TCF represents the pro rata share of the flow over a constrained facility which a transmission provider may request its security coordinator to curtail by employing the TLR procedures. It follows, NERC reasons, that the remaining share of the constraint results from native load and network service. 1/

According to NERC, use of the TCF will address concerns parties have expressed that the TLR procedures' limitation to interchange transactions treats network service and native load preferentially, as well as further the Commission's objective that the TLR procedure should curtail transactions using firm point-to-point transmission service only to the extent of their

5/ This filing included a "NERC Policy Statement in Response to FERC TLR Order." NERC Response at 4-5.

6/ NERC Response at 2.

7/ Id.
contribution to the constraint. In NERC's view, once the calculation of the TCF has been made, the transmission provider will have the information necessary to mitigate overloads by comparable treatment (based on how these three services contribute to the constraint) of firm point-to-point, network and native load customers. 1/

8/ Id.
NERC acknowledges that its proposal does not go a step further to identify the share of native load and network service attributable to native load parallel flows from other systems, but observes that extensive modifications of the TLR procedures "would be required in order for such curtailment to treat parallel flows from electrically adjacent transmission systems' network and native load service on a pro-rata basis as well." 1/ However, NERC is continuing efforts to develop and coordinate a workable process for determining these parallel flow effects. 1/

NERC responds to the Commission's mandate for interim redispatch solutions for the 1999 summer period by implementing a "market redispatch pilot program" to be in effect June 1 through September 30, 1999. 1/ NERC states that the pilot program will provide a redispatch option through the use of bilateral redispatch transactions arranged by the transmission customer with individual generation owners, which will set up "counterflows" to help mitigate a constraint. NERC explains that this redispatch option, which will be available at 13 common transmission constraints, will be for all transmission reservation priorities (non-firm through firm) and will not interfere with existing regional or pool congestion management programs.

9/ Id. (emphasis deleted).
10/ Id. at 2-3.
11/ Id. at 3, 6.
NERC explains that the specific procedures of its pilot program "will be applied to only those schedules that are provided 3 hours prior to, but not later than 9:00 [AM] Central Daylight Savings Time (CDT) of, the day of the possible implementation of the Redispatch Tag." 1/ For the flowgates covered by the project, information as to actual flow and post-contingent flow and their respective limits for a listed flowgate will be posted, as well as Generation Shift Factors (GSFs) for approximately 100 generators for each of the flowgates. 1/ So-called Purchasing and Selling Entities (PSEs) would be responsible for identifying generators between or within control areas for a Redispatch Transaction, and would develop appropriate interchange transactions as necessary. PSEs would submit a Market Redispatch Pilot Tag containing this information by the time noticed above to security coordinators with potentially constrained flowgates, as well as to security coordinators, transmission providers and control areas on the proposed contract path whose transaction is causing the impact. 1/ These Redispatch Tags would be studied by the parties mentioned above, who will then notify the submitting PSEs whether the Redispatch Tag is approved or denied. If approved, the redispatch transaction will be implemented. 1/

NERC's March 1 filing also responded to the December 16 Order's request for proposals concerning long-term solutions to these problems. 1/ In this regard, NERC states that its Board will direct certain of its committees to develop plans "for addressing longer-term solutions for 2000 and beyond," to be presented for approval at its Board's May 1999 meeting. 1/

A number of public utilities in the Eastern Interconnection made filings with the Commission stating that they supported and

12/ Id. at 6.

13/ GSFs measure the change in power flows that can be expected if the output of one generator is increased at the same time that the output of a second generator is decreased.

14/ Id. at 7.

15/ Id. at 8.

16/ Id. at 3.

17/ Id. at 3, 4-5.
would employ the interim procedures set out in NERC's March 1 filing. 1/ They are listed in Appendix A to this order. 1/

Florida Power Corporation, Florida Power and Light Company and Tampa Electric Company (collectively Florida Power Corp), Carolina Power and Light Company (CP&L) and Virginia Electric and Power Company (VEPCO) made filings accepting the NERC proposals subject to certain qualifications.

Dayton Power and Light Company (Dayton P&L), Northern Indiana Public Service Company (NIPSCO) and South Carolina Electric and Gas Company (SCE&G) made filings adopting NERC's pilot redispatch program but making no reference to the new interim TLR procedures.

Duke Energy Corporation (Duke) made a filing adopting NERC's interim TLR procedures, but stating that it has not determined whether to participate in the redispatch pilot program pending review of NERC's filing.

18/ The December 16 Order gave transmission-operating public utilities in the Eastern Interconnection the option of having NERC make the actual filing. 85 FERC at 62,363 n.50.

19/ One of these utilities, Southern Indiana Gas and Electric Company (Southern Indiana), also filed the notice required by the December 16 Order stating that its pro forma tariff should be considered modified to reflect NERC's TLR procedures. Southern Indiana states that it missed the January 15, 1999 deadline for this filing because of management reorganization.
Entergy Services, Inc., on behalf of the Entergy Operating Companies (Entergy) filed comments stating that it had not yet determined whether to subscribe to NERC's revised TLR procedures or the pilot redispatch program.

Maine Public Service Company (Maine Public) made a filing stating that it does not need to comply with the December 16 Order because it is an isolated system without parallel flows. Maine Public also filed a motion for clarification of the March 12 Order, stating that the Commission there erroneously identified it as a member of the New England Power Pool (NEPOOL) and seeking clarification that it need not comply with the December 16 Order.

United Illuminating Company (United Illuminating) made a filing stating that it was not required to comply with the December 16 Order because it is a transmission provider within the NEPOOL.

2. The MAIN Filings

Central Illinois Light Company (CILCO) and the other public utilities listed in Appendix B to this order made individual filings stating they intended to comply with the December 16 Order by using procedures adopted by MAIN. CILCO explains that MAIN is a not-for-profit, membership corporation comprised of investor-owned, municipal and cooperative utilities, independent power producers and power marketers. Among other functions, MAIN is the NERC regional reliability council for the upper central Midwest, as well as functioning as the security coordinator for that region. 1/

20/ CILCO Notice at 1-2. For convenience, we will use CILCO's filing to describe the MAIN plans. The other utilities' filings either repeat the same information or incorporate it by reference.
MAIN and its members have adopted the Interim Firm Load Curtailment Plan to address curtailment of parallel flows arising from native load and network service. Under this plan, members will notify MAIN whenever, notwithstanding implementation of available redispatch and reconfiguration options and the curtailment of non-firm transmission, further steps must be taken to relieve a constrained facility. 1/ MAIN will then determine, using appropriate power flow models and the transmission system information available to it, the proportional flows on the constrained facility caused by firm point-to-point service, network service provided by the member and the member's native load transactions, and parallel flows on the constrained facility caused by network service and native load transactions of other systems. CILCO explains that MAIN will assign to each of the foregoing members their proportional share of the flows on the constrained facility, and inform the member of the amount of curtailment required from its network service and native load transactions. 1/

CILCO states that MAIN's Interim Regional Redispatch Plan can be implemented on a pilot basis by the summer of 1999, using historically constrained flowgates, as well as other flowgates for which experience has shown that constraints may be predicted on a day-ahead basis. 1/ The Plan employs the resources of the NERC TLR procedures, as well as a centralized calculation process it has developed for determination of available transmission capacity (ATC). When a significant transmission constraint is anticipated, MAIN will calculate and promulgate for market participants, transmission-operating public utilities and other interested parties a matrix of generation units for which a change in output would be effective in relieving the constraint, along with GSFs for each unit specific to the constrained facility. 1/

CILCO further explains that GSFs, in combination with the posted advance transmission information, will enable market participants and generation operators to determine feasible voluntary contingent redispatch arrangements. Redispatch

---

21/ Id. at 4.
22/ Id.
23/ Id. at 5.
24/ Id. at 6.
arrangements may be made using any appropriate combination of generation pairs shown on the list of GSFs. 1/

3. The LEER Filings

25/ Id. and Cl LCO Exhibit 2 at 2-3.
Another alternative to the NERC pilot redispatch program was the Lake Erie Emergency Redispatch Procedure (LEER) filed by NPCC on behalf of the certain member systems of the New York Power Pool (New York Petitioners) 1/ and other public utilities listed in Appendix C to this order. NPCC states that the LEER procedure is an emergency redispatch tool designed to relieve transmission constraints "that would otherwise require a Lake Erie participant to shed firm load" and only will be invoked when such "firm load curtailment is imminent." 1/ NPCC explains that the procedure works essentially in this manner:

The Sink [security coordinators] identify "Dependent Transactions" while all [security coordinators] identify potential flowgate constraints. The NERC TLR Procedures is followed until LEER is invoked to "protect" dependent transactions if TLR could result in firmload cuts. Should a potential TLR cut affect a "protected transaction" the constraining [security coordinator] then directs redispatch, assisted by the dependent [security coordinator] and the [security coordinator] having available generation. [1/]

26/ The New York Petitioners are comprised of Central Hudson Gas & Electric Corporation, Consolidated Edison of New York, Inc., Long Island Power Authority, New York State Electric and Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation. New York Petitioners' Filing at 1 n.1. The New York Petitioners' filing states that their current practices are "consistent with the terms" of the December 16 Order with respect to the TLR revisions and redispatch because of being parties to the LEER procedures, and because of their existing pool-to-pool agreement with PJM as well as the New York Power Pool's Security Constrained Dispatch System which "insure[s] shifting of generation prior to the termination of any bilateral transactions." Id. at 2.

27/ NPCC Filing at 3.

28/ Id. at 4.
NPCC states that the LEER procedures can be implemented by the 1999 summer period, and requests a waiver of the OASIS reservation posting guidelines to the extent necessary to implement the LEER procedure, and asks that the LEER procedure be considered a generic amendment to the pro forma tariff of each LEER participant which has filed an open access tariff (or reciprocity tariff) with the Commission. 1/

4. The PJM Filing

29/ Id. at 5.
PJM filed a notice stating that it is managing congestion over its multi-state region through the use of locational marginal pricing (LMP), which was approved by the Commission in November 1997. PJM explains that it permits market participants to avoid TLR curtailments by instead paying congestion charges when off-the-contract-path flows occur, and has recently extended this redispatch alternative to non-members as well as PJM members. PJM states that while it complied with the December 16 Order by filing a notice that the PJM Tariff is now considered modified by the NERC TLR procedures, because it has a regional congestion management program in place, it "is not required, and has no need, to file any further interim redispatch solution." PJM will, however, implement NERC's interim revised TLR procedures, though it does not foresee any curtailments of firm service on its system. Comments were filed by Public Service Electric and Gas Company and Potomac Electric Power Company (collectively PSE&G), supporting PJM's filing and asserting that PJM's redispatch program is superior to NERC's proposed pilot redispatch program.

5. The Southwest Power Pool Filing


31/ Id. at 3 & n.2., citing PJM Interconnection, L.L.C. 86 FERC ¶ 61,015 (1999). Additionally, PJM states that it participates in cooperative inter-regional arrangements to manage parallel flows. Id. at 4.

32/ Id. at 5 (citations omitted).

33/ Id. at 6-7 & n.9.
Southwest Power Pool (SPP) filed a response to the Commission's December 16 Order stating that its open access transmission tariff provides a partial remedy for parallel flow issues, because in its role as independent regional tariff administrator, SPP determines ATC based on all power flows within the SPP region. 1/ Thus, SPP contends that "some of the problems described in the [December 16] order relating to parallel flows affecting adjoining transmission providers are mitigated as a result of the SPP tariff." 1/ Concerning redispatch, SPP states that its currently effective tariff allows for regional redispatch of generation to relieve congestion of firm transactions, and that its new tariff effective April 1, 1999, "contains an expanded regional redispatch provision adding redispatch for non-firm transmission service." 1/ SPP’s submission is supported by filings by Oklahoma Gas and Electric Company (OG&E), Western Resources, Inc. (Western Resources), Cleco Corporation (Cleco), Public Service Company of Oklahoma and Southwestern Electric Company (collectively PSO), Empire District Electric Company (Empire District), which are members of SPP.

Interventions and Protests

34/ SPP Response at 2.

35/ Id.

All of these filings were duly noticed in the Federal Register. Timely motions to intervene were filed by Electric Clearinghouse, Inc. (ECI) and by Enron Power Marketing, Inc. (Enron) in all dockets except Docket No. ER99-2372-000; by Electricity Consumers Resource Council, the American Iron and Steel Institute and the Chemical Manufacturers Association (collectively ELCON), the American Public Power Association (APPA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), the National Energy Marketers Association (NEMA), Georgia Transmission Corporation (Georgia Transmission), the National Rural Electric Cooperative Association (NRECA), Arkansas Electric Cooperative Corporation, Golden Spread Electric Cooperative, Inc., Kansas Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation and Seminole Electric Cooperative (collectively AEEC) in Docket No. ER99-2012-000; by Northern States Power Marketing (Minnesota) and Northern States Power Marketing (Wisconsin) (collectively NSP Companies) and WPPI in Docket Nos. ER99-1967-000, ER99-1984-000, ER99-2019-000 and ER99-2004-000; by CLECO in Docket No. ER99-1969-000; by AEEC and Ralph R. Mabey, Chapter 11 Trustee for Cajun Electric Power Cooperative, Inc. (Cajun) in Docket No. ER99-1969-000; by the New York Municipal Power Agency (NYMPA) in Docket No. ER99-1973-000; by the Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia (Dalton) in Docket No. ER99-2000-000; and by Duke Energy Trading and Marketing, L.L.C. (Duke Energy) in Docket No. ER99-2010-000. On April 20, 1999, Ontario Power Generation, Inc. (Ontario Power) filed a late motion to intervene in Docket No. ER99-1957-000, stating that it could not have sought intervenor status earlier because it did not come into corporate existence until April 1, 1999.

1. Protests and Comments on NERC Filing

Those interventions raising substantive issues are discussed below. However, we note that many of the protests and comments raised issues that were decided on the merits by the December 16 Order. These include matters concerning the independence and oversight of security coordinators, e.g., ELCON Filing at 11-13, as well as the sufficiency of NERC’s data supporting its TLR procedures generally, e.g., NEMA Supplemental Protest at 5. These issues should have been on rehearing of the December 16 Order. They are not properly before the Commission in its review of these dockets and will not be addressed here.
NEMA contends that both NERC's interim TLR procedures and its pilot redispatch procedures are deficient in that neither eliminates the disproportionate impact of TLR curtailments on point-to-point transmission customers. 1/ NEMA faults NERC's interim TLR procedures as based on insufficient data, and claims that the redispatch pilot program is inequitable because, by requiring certain customers to enter into "counterflow" transactions in lieu of curtailment, NERC "merely substitutes one form of penalty for another, especially for customers using point-to-point service, and without compensation provided by those whose transactions are "saved" by the procedure. 1/

38/ NEMA Supplemental Protest at 2.

39/ Id. at 6. Under NEMA's alternative proposal for the 1999 summer period, only if voluntary measures fail would a utility then curtail service within each class on a nondiscriminatory, pro rata basis, with parties whose loads were involuntarily curtailed "entitled to reasonable compensation" so that the costs of such actions would be "shared equitably, spread across the service classes of those benefitting from the actions." Id. at 2.
Enron criticizes the NERC redispatch pilot program for requiring security coordinators to offer redispatch at only one flowgate even if another flowgate included in the pilot program is located in the security coordinator's security area. 1/ Enron complains that NERC's limitation of submitting dispatch tags by 9:00 AM CDT on the day of the redispatch transaction is unjustified and arbitrary, and requests that the Commission require that security coordinators receive tags three hours in advance of the redispatch transaction. It also objects to the reporting obligation that the NERC plan imposes on the transmission customer as burdensome. 1/

Enron next contends that the NERC proposal appears to force the customer to make a second transmission payment for reserving the redispatch path, which in its view is "unlawful postage-stamp 'and' pricing." 1/ Enron also argues that the acceptance or denial of the proposed redispatch tag should have a deadline (suggesting within one hour of receipt of the tag) and that the process should be flexible enough to permit approval of redispatch transactions contributing to any offset of the impact of the transaction, rather than limited to transactions that must completely offset the impact of the transaction in question. 1/

At the same time, Enron believes that the NERC pilot program employs redispatch in excess of what is required, rather than avoiding implementation of an entire redispatch transaction when some lesser number of megawatts would be sufficient to alleviate congestion on the affected flowgate. 1/

40/ Enron Protest at 6. Enron also requests that the Commission convene a technical conference to develop a comprehensive system of economic redispatch for the Eastern Interconnection. Id. at 3-4.

41/ Id. at 6-7.

42/ Id. at 7-8, citing Inquiry Concerning the Commission's Pricing Policy for Transmission Services by Public Utilities under the Federal Power Act; Policy Statement, FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994).

43/ Id. at 8.

44/ Id. at 9. Enron submits an alternative proposal for redispatch, which it contends avoids the problems it has identified in the NERC proposal. Id. at 10 & Exhibit 1.
ELCON contends that in the event that costs incremental to those already provided for under the pro forma tariff are incurred by a transmission provider to avoid curtailments, or that compensation is paid to curtailed parties, there should be a pro rata allocation of the financial costs associated with redispatch. 1/ Hence, ELCON believes that all comparable transmission customers (including native load) whose reliability is maintained as a result of firm transmission curtailments should be required to financially compensate curtailed parties.

45/ ELCON at 10.
APPA supports NERC’s filing, but believes that there are insufficient "fixes" to deal with congestion in the Eastern Interconnection and further believes that the Commission should move promptly to issue a Notice of Proposed Rulemaking on Regional Transmission Organizations (RTOs), as only such an entity with operational control of the grid will be able to ensure redispatch that is comparable for all customers and truly nondiscriminatory curtailments. 1/ APPA recommends acceptance of NERC’s procedures subject to the establishment of a uniform set of procedures. Furthermore, APPA requests that the Commission require all transmission providers and security coordinators to submit a report to all transmission customers affected when TLR procedures are invoked. For instance, APPA notes that the filings of Commonwealth Edison Company (Docket No. ER99-1967-000) and American Electric Power Service Corporation (Docket No. ER99-1991-000) use different tariff language for the pilot redispatch program.

EPSA asserts that the Commission must require all transmission providers to participate in the NERC pilot redispatch program 1/ Additionally, EPSA expresses concern that for most transactions, the cost of utilizing out-of-dispatch generators will be financially burdensome. Further, EPSA believes NERC’s TLR procedures should address this concern.

EPSA further contends that the NERC redispatch program unreasonably requires transmission customers to pay twice for a single transaction. Also, EPSA believes that transmission payments should be allocated pro rata among transmission providers. 1/ In this context, EPSA recommends either the voluntary off-setting of transactions, or alternatively that the transmission provider responsible for ensuring the delivery of firm transmission service (by contract) pay compensation to the transmission provider supplying the redispatch service.

EPSA further recommends that the Commission emphasize that Order No. 888 already requires transmission providers to provide redispatch service. Also, EPSA believes that the customer’s choice to allow a transaction to be curtailed will relieve a congested facility and lessen the financial impact of

46/ APPA Comments at 3.
47/ EPSA Comments at 5-6.
48/ Id. at 8-9.
curtailment. Further, EPSA observes that under NERC's proposal, when redispatch is invoked, "an entire Redispatch Transaction will be implemented." 1/ EPSA asserts NERC's TLR procedures should be revised to provide only the amount of redispatch needed to relieve a congested facility.

49/ Id. at 10.
TAPS contends that NERC's filings fail to go far enough toward the goal of comparable treatment of native load and network customers. 1/ TAPS further asserts that NERC's proposed procedures emphasize the need of the Commission to require the formation of RTO to resolve the problems associated with the curtailment of firm transmission service.

ECI contends that NERC has not required tagging for native load or network service, and that incomplete data is being used to implement the program. 1/ ECI also asserts that NERC's TCF construct is problematic, because it subjects firm point-to-point customers to a disproportionate amount of curtailment.

ECI requests that if the Commission adopts NERC's TLR procedures it should require security coordinators to provide reports when NERC's TLR procedures are invoked. ECI further contends that the Commission should establish a principle that would absolve a transmission customer whose transaction has been curtailed as a result of the implementation of TLR from paying for services that were not rendered. ECI also requests that the Commission establish a principle that firm transactions should be treated as the highest priority and all options available to the transmission provider to assure their integrity should be pursued, with no extra charge levied except by mutual agreement, and then only when necessary to pay for redispatch to avoid true force majeure related curtailments. 1/

50/ TAPS Filing at 4-5.

51/ ECI Protest at 6-7.

52/ ECI proposes an alternative interim approach with pro rata allocation of the financial costs associated with redispatch. On April 5, 1999, Entergy filed a motion to intervene out of time in Docket No. ER99-2012-000 in order to file a response to the protests of Enron and ECI.
2. Protests and Comments on LEER Filing

ECI's protest concerning LEER is based on its concern that it is "unclear how the LEER procedures would fit with" NERC's redispatch pilot program. ECI contends that because the LEER procedures appear to rely on control area operators to declare a transaction "dependent," it is therefore "unclear how marketers delivering power to a participating utility would be able to protect transactions." ECI requests that the Commission require NPCC to provide an explanation of how the LEER plan comports with the NERC TLR procedures.

Enron claims that, as proposed, LEER is available only to "participants within the Lake Erie Control Areas relying on interconnection transactions to meet firm load." Also, Enron believes that all transmission customers whose transactions are threatened with curtailment should have the opportunity to receive redispatch services. Further, Enron contends that the LEER proposal is unduly discriminatory and requests that the Commission require NPCC to file a revised LEER redispatch plan.

3. Protests and Comments on MAIN Filing

NSP Companies generally support the MAIN plan but ask for clarification on certain issues. Specifically, NSP Companies protest the designation of MAIN as the regional security coordinator responsible for the Eau Claire/Arpin 345 kV flowgate, a transmission line operated by NSP and within the NSP control area. NSP Companies additionally contend that the MAIN plan permits redispatch to be curtailed in a situation where the NERC redispatch pilot program is employed "to avoid curtailment of..."
non-firm point-to-point service" which "exhaust[s] the redispatch available to curtail the impacts of network and native load." 1/ Additionally, NSP Companies contend that under MAIN's redispatch plan, MAIN does not clearly establish whether it will require pro rata shedding after redispatch options are exhausted. 1/ NSP Companies request clarification on this issue.

59/ Id. at 7.

60/ Id. at 8.
WPPI seeks clarification of MAIN's use of the term "firm load curtailment" rather than "firm transmission curtailment." 1/ WPPI states since the security coordinator will be curtailing transmission service, not load, the Commission should require the transmission providers to modify the language to reflect this reality. WPPI also requests clarification that the MAIN plan should be read to mean that MAIN utilities have a mandatory obligation to redispatch generation. WPPI objects to the MAIN voluntary interim redispatch plan as impractical in that because it is to be implemented only on a day-ahead (or morning of) basis "that is, the redispatch plan would be designed in anticipation of loads and resources on the system the next day." 1/ Finally, WPPI requests the Commission to clarify that under the MAIN plan non-firm transactions, "even if enabled through redispatch," cannot obtain a higher curtailment priority than the underlying non-firm service. 1/  

4. Miscellaneous Issues

ECI asserts that PJM's locational marginal pricing (LMP) is a market-based approach which does not address the actual "cost" of relieving congested facilities. Additionally, ECI claims that PJM's redispatch procedures fail to explain how LMP will be applied for transactions where PJM is part of the contract path (LMP applies to transactions not on PJM's contract path). ECI believes that the failure of security coordinators to apply the LMP redispatch procedures may result in the curtailment of a disproportionate number of firm transmission transactions. Therefore, ECI requests that PJM be required to provide a more detailed description of how its LMP procedures comport with the TLR procedures.

ECI contends that SPP should be required to file its redispatch procedures in order to demonstrate how SPP will implement the TLR procedures on a comparable and non-discriminatory basis. While SPP states that it will evaluate

61/ WPPI Protest at 6.

62/ Id. at 7.

63/ Id. at 8. On April 1, 1999, Wisconsin Electric filed an answer to the protest of WPPI concerning the MAIN procedures. On April 5, 1999, Commonwealth Edison filed a motion for leave to answer the protests of WPPI and NSP Companies concerning the LEER procedures.
NERC's TLR protocols which are being developed as a result of the NERC Order, ECI requests that the Commission direct SPP to clarify how SPP's redispatch plan comports with NERC's TLR procedures.

NYMPA contends that the New York Petitioners must be directed to submit the NYPP's Security Constrained Dispute procedures and demonstrate that they are superior to the TLR Procedures. NYMPA also observes that the New York Petitioners' reference to the NYPP plan to restructure its operations is irrelevant because it will not be in place by the summer of 1999.

AECC requests rejection of Entergy's proposal, because Entergy has not committed to adopt the TLR procedures and amend its open access transmission tariff to include the TLR procedures.

Discussion


We also grant the unopposed motion for late intervention of Ontario Power in Docket No. ER99-1957-000.

64/ NYMPA Motion at 4.


67/ The late filings by Entergy, NPCC, Wisconsin Electric and Commonwealth Edison are answers to protests which are generally forbidden by the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (1998), and we reject them on that basis.
as it had good cause for failing to file within the prescribed period and its intervention will neither unduly disrupt the proceedings nor unduly prejudice any party.

1. NERC Proposal

We accept NERC's proposal. As some intervenors note, this is not the perfect, comprehensive solution that may be attainable some months or years down the road. However, NERC's current proposal improves on the one we accepted in the December 16 Order and complies with our directives.

(a). Native Load Flows

As we discussed in the December 16 Order, the protests had argued that the original TLR procedures' limitation to interchange transactions had the effect of sparing native load and network customers and therefore treating native load and network customers preferentially. NERC responded that, although its TLR procedures did not quantify or identify such impacts, each transmission provider was responsible for identifying native load and network customer impact on the constrained facilities and ensuring comparable curtailment of its native load transactions. NERC also stated that the tracking and identifying of parallel flows associated with native load and network customers raised complex issues. We directed an interim proposal to at least identify the impact of parallel flows associated with native load and network customers on a partial basis, so that the curtailments of interchange transactions would be further consistent with our comparability requirements. NERC's interim proposal has complied with our requirements in the December 16 Order by establishing a systematic method to identify flows that are associated with all network services (native load and network customers), including parallel flows, on all transmission lines.

68/ 85 FERC at 62,361.

69/ See supra notes 8 and 9 and accompanying text. As NERC explains, after subtracting the impact of point-to-point flows on the constraint, it follows that the residual must be associated with native loads and network uses.
However, NERC is unable to further separate native load and network customer flows into flows related to the native load and network customer flows of the transmission provider and those associated with parallel flows from another system. NERC suggests that the affected transmission provider be left with the discretion of absorbing such curtailments or taking steps to identify parallel flows and raising its concerns with the systems where the flows originate. Under NERC's proposal, the decision of a transmission provider not to pursue the issue of parallel flows resulting from network service (native load and network customer), but to instead absorb them itself has no effect on the curtailments of interchange customers, so that interchange transactions still do not shoulder a disproportionate share of curtailments.

We find this proposal to be reasonable and practical as an interim step. Indeed, NERC's proposal is a significant improvement over the TLR procedures as initially proposed because it takes the first step of quantifying the native load and network customer flows on constrained facilities. At this time, we will accept NERC's proposal that the transmission provider have the option of absorbing all such curtailments rather than asking neighboring systems to reduce parallel flows. There may be valid reasons for a transmission provider to be willing to wholly absorb such curtailments, e.g., neighboring utilities may reasonably decide that their native load impacts are offset over time or that the parallel flows may actually result from the configuration or operation of the transmission system experiencing the flows, not the actions of the neighboring system. Our goal in asking for and accepting this interim proposal is not to require the curtailment of more transactions; rather it is only to ensure that native load and network customer parallel flows do not receive a preference at the expense of interchange transactions. NERC's proposal accomplishes this.

70/ As previously discussed, some utilities already have in place procedures for handling parallel flows, such as the LEER and MAIN procedures.
The Commission rejects the complaints of NEMA, ECI and others that firm point-to-point customers bear a disproportionate share of the cost of curtailment under the TLR procedures. By the revised TLR procedures' ability to spread the impact on a pro rata basis also over native load and network customers, these respective customer groups are being treated on a comparable, non-preferential basis.

VEPCO expresses concern that NERC's procedure for identifying native load flows on constrained facilities does not explicitly recognize that curtailments apply only to transactions that have a Power Transfer Distribution Factor (PTDF) higher than five percent. VEPCO seeks clarification that NERC did not intend to treat native load and network customer transactions differently in this regard since that would result in noncomparable treatment when compared to firm point-to-point transactions. WPPI, on the other hand, is concerned that applying the five percent PTDF threshold to native load and network customer transactions if the those "transactions" are viewed as all network service on the system would result in the five percent waiver always being invoked, no matter what the size of the native load and network customer transaction.

NERC's proposal does not disturb the five percent threshold for inclusion in the curtailment directives and, therefore, it would apply to all transactions. We also do not understand NERC's proposal to treat the native load and network customer "transactions" on the constrained facilities as the entirety of native service on the system. Such an approach would clearly be inconsistent with the intent of the proposal to ensure comparable curtailments of constrained facilities.

VEPCO also asks the Commission to clarify the distinction between curtailment of usage of constrained facilities and the shedding of firm load as a result of that curtailment. VEPCO states that all remedial measures should be exhausted before shedding firm load and suggests that among these measures should be deviations from the curtailment priorities in the pro forma tariff to favor transactions that have no options over those that are economic transactions only. In a similar vein, VEPCO expresses a concern that the use of redispatch transactions to avoid curtailment of nonfirm transmission services not transform these services into firm transactions that would no longer be subordinate to firm transactions. 71/

71/ VEPCO concedes that the counterflow transactions relieve the constraint, but contends that nonfirm transmission customers may have tied up redispatch options that may be needed to
We agree with VEPCO that we expect all remedial measures to be employed as an alternative to shedding firm load. We note that it is industry practice to pre-arrange such measures (e.g., emergency energy assistance tariffs), and below we approve LEER Participants' proposal to create more options to address such circumstances. Moreover, the reassignment provisions of the pro forma tariff and NERC's regional redispatch proposal discussed below do provide a mechanism for those customers engaged in economic transactions to release capacity to other customers without such power supply options. We have no reason to believe that any utility would be forced to shed load in circumstances where other industry participants have power to sell. Finally, we reject VEPCO's suggestion that the pro forma tariff curtailment priorities are based on the customer's options as contrary to our prior decision on the issue. 1/

We note that NSP Companies (with respect to MAIN's proposal) and Entergy raise a similar concern about tying up generation units for redispatch service which will then be unavailable should native load face a load-shedding event.

72/ Northern States Power Company, 83 FERC ¶ 61,098, clarified in part, 83 FERC ¶ 61,368, rehearing denied, 84 FERC ¶ 61,128 (1998), appeal pending, Northern States Power Company (Minnesota), et al. v. FERC, No. 98-3000 (8th Cir. August 3, 1998). We note that, unlike NSP Companies, VEPCO does not presume that all point-to-point customers have such options.
(b). **Regional Redispatch**

NERC's pilot dispatch proposal relies on counterflow transactions, i.e., transfers against the prevailing flows on the constraint, and focuses on 13 known constraints. 1/ Customers will be informed about the potential for congestion by the posting in advance by the security coordinator or transmission provider of actual flow and post-contingent flow and their respective limits for these flowgates, as well as GSFs for approximately 100 generators for each of the flowgates. 1/ Armed with this information about the power flow impact of various counterflow transactions, a transmission customer will have the opportunity to pre-arrange counterflow transactions to be executed only during a TLR event that would otherwise result in a curtailment of the customer's original transaction. Based on its assessment of the consequences and costs of curtailment, each customer will determine whether or not to engage in counterflow transactions. Public utilities generating energy for counterflow transactions will transact under existing power sale tariffs.

Although the form of the transactions that are the basis for this proposal are simple power sales and transmission transactions that are feasible on any system today, this proposal provides the key to make it a workable regional redispatch alternative to the TLR procedures -- information. Clearly, a significant impediment to regional redispatch is lack of information, i.e., while each transmission provider has information about its own redispatch options and the impact of those options on its system, it does not have information about the redispatch options available on neighboring systems or the impact of redispatch on multiple systems. And, of course,

73/ The known constraints that have been selected are governed by the following security coordinators: MAIN, Entergy, Allegheny Energy, VEPCO, Ontario Hydro, and TVA. NERC Response at 9 (Exhibit 2, Attachment A).

74/ Id. at 6.
customers currently have no information about redispatch options at all. NERC's proposal creates an information clearinghouse on regional redispatch options and thereby creates the real possibility that regional redispatch solutions can be identified in time to avoid curtailment. While this proposal certainly has its limitations (e.g., the process requires the time and effort of customers to evaluate the data and preschedule their own counterflow transactions), it is a meaningful and timely step in the right direction.

The Commission rejects the objections by Enron and others that the NERC pilot redispatch program employs forbidden "and" pricing (paying both an embedded cost transmission rate and a redispatch charge). First, the Commission's "and" pricing prohibition involves the situation when the transmission provider and the party charging the redispatch costs are one and the same. Under NERC's proposal, the party providing redispatch service will often be a utility other than a transmission provider, so that there would be no "and" pricing of the type we have prohibited. Moreover, even if the entity providing the redispatch service (the counterflow transaction) is the transmission provider, it is providing a different service (and one that is not required under the pro forma tariff). The service will be provided only when all firm customers are being comparably curtailed and an individual transmission customer is seeking (and willing to pay for) something better than the comparable curtailment which the pro forma tariff would otherwise impose. 1/ To the extent that Enron complains of a customer

75/ We specifically contrast this additional option with the requirements of the pro forma tariff involving an application for transmission service. If the transmission provider would reject the transaction for lack of ATC, it must offer to redispatch its system if cheaper than expansion, and may charge only the higher of the embedded cost transmission charge or the redispatch cost. We do not allow a transmission provider to charge -- as the price for obtaining comparable transmission service -- an embedded cost rate to some users and the sum of an embedded cost rate and incremental cost (redispatch or expansion) to other customers.

Here, all firm customers are required, on a comparable basis, to remove their loads from the constrained facilities. To the extent any such customer takes steps to arrange an alternate transaction, such as redispatch, that customer must bear the additional
having to pay for a counterflow transaction when it has already paid for the original transaction, we have previously explained that it is reasonable for the customer to compensate a transmission provider providing a counterflow for the costs the transmission provider incurs to provide this transmission service on its system. 1/

The Commission likewise denies the request by ELCON and others that costs related to the redispatch should be spread across all comparable transmission customers, including native load, whose reliability was preserved by redispatch measures taken. Under NERC’s proposal, the choice as to whether to buy through the curtailment lies with the individual transmission customer and it is reasonable for that customer to bear the cost.

---

76/ See PJM Interconnection, L.L.C., 86 FERC ¶ 61,015 at 61,036 (1999).
Certain intervenors complain that the scheduling requirements for transmission of counterflow transactions depart from the pro forma tariff and that the proposal could be designed to better match the MW of redispatch relief to the MW curtailment. 1/ For example, Enron complains that NERC's pilot program assigns insufficient duties to security coordinators and that to be effective, the program must require security coordinators and transmission providers to undertake significantly more responsibility to offer services that are more flexible and market friendly. 1/ The Commission rejects these

77/ Under NERC's proposal, the prescheduled redispatch transactions presume that the entire transaction is being curtailed. Intervenors would prefer that the security coordinator implement a partial redispatch transaction if the transaction is only partially curtailed, or accommodate a partial redispatch/partial curtailment at the customer's request.

78/ Enron proffers its own redispatch proposal which it claims would mandate the participation of transmission providers, not be limited to the 13 known constraints, add flexibility, and extend beyond the four month pilot. We shall not consider Enron's proposal in this compliance order. Enron
contentions and accepts the procedures of NERC’s proposed pilot program. We believe that security coordinators and transmission providers will be more than sufficiently occupied by the program’s use of counterflow transactions to avoid curtailment, which will require system operators to manage an additional layer of transactions at the very time when they are addressing reliability matters. Thus, we find NERC’s proposal to limit these schedule deadlines initially to the non-peak periods and not to require security coordinators to adjust prescheduled redispatch transactions to match partial curtailments is entirely reasonable. 1/

---

1/ is encouraged to sponsor its proposal in NERC proceedings that are considering permanent redispatch proposals, as are the other intervenors who made alternative proposals.

79/ NERC describes that the market redispatch will be applied only to those schedules that are provided 3 hours prior to, but not later than, 9:00 AM CDT on the day of the possible implementation of the redispatch procedures. NERC Response at 6.
The remaining arguments are of a general nature that NERC's pilot redispatch program is of insufficient scope (e.g., raising such claims as more flowgates should be included in the pilot program) or can be replaced by allegedly more efficient alternatives. 1/ Our answer to these various claims and proposed alternatives is that NERC's proposal complies with the December 16 Order, has broad support among transmission-operating public utilities and is ready to be implemented now. While NERC assures the Commission that it is continuing to research more comprehensive redispatch solutions to congestion management, the pilot program represents its best effort to meet the Commission's mandate for an interim program for the 1999 summer period. As NERC indicates in its April 5th letter, it and the Congestion Management Working Group are continuing to work on the details of the pilot program. The balancing of interests of all industry segments is difficult, but in the end will produce a more efficient and workable program.

VEPCO asserts that its participation in the pilot redispatch program depends on successful completion of the technical improvements (e.g., changes to the modeling programs) that are currently underway and that it is premature to develop pro forma tariff revisions to accommodate the pilot program since these details are also being finalized. Entergy raises similar concerns about the pilot program but takes the position that the pro forma tariff is flexible enough to accommodate transmission arrangements for counterflow transactions. We understand that the final technical details are still being worked through and we are confident that these efforts will be successful and timely. As to the need to make tariff revisions to accommodate this proposal, we agree with Entergy and do not believe that the pro forma tariff, as currently drafted, would in any way impede the transmission component of the pilot program. We also see no reason to require revised tariff sheets clarifying the specific procedures to be placed in each open access tariff for a program that will be in place for only four months. We therefore direct public utilities, through NERC, to develop a single, separate statement of final procedures consistent with this order and file it with the Commission. Each utility may simply post these procedures on its OASIS for the duration of the pilot program.

80/ These include alternative proposals by Enron and others, as well as suggestions that these matters should await development of RTOs.
Entergy seeks clarification that the owners of generation units identified as potential participants in counterflow transactions are not required to commit their resources to such transactions or allow the generation owners to set the rates for these transactions. That is our understanding of NERC's proposal, which facilitates redispatch transactions under the utility's filed tariffs and does not mandate participation or rate treatment.

In view of the foregoing, the filings of the public utilities which are implementing NERC's revised TLR procedures and pilot redispatch program (listed in Appendix A to this order) are accepted by the Commission. By the same token, we reject the filings of the public utilities which have not determined whether to accept either NERC's revised TLR procedures and the redispatch pilot program have accepted them subject to qualifications, or have accepted only one procedure or the other, without having submitted or subscribed to an adequate alternative proposal to NERC's, as failing to comply with the December 16 Order.

2. MAIN Proposal

The Commission also accepts MAIN's proposed procedures as complying with the requirements of the December 16 Order, as they are consistent in major essentials with NERC's proposal, with the exception that MAIN is able to add more precision to the quantification of native load flows.

We do agree with WPPI, however, that MAIN's use of the term "firm load curtailment" rather than "firm transmission curtailment" is an unexplained departure from language we have already approved in NERC's proposal. Thus, the Commission conditions its acceptance of MAIN's proposal on its member public utilities either changing this terminology to be consistent with NERC or, alternatively, explaining what it means by this terminology and demonstrating that it complies with our requirements. However, we reject WPPI's assertions that the Commission should order public reporting by MAIN participants of steps taken to redispatch in order to avoid curtailment of native load or require MAIN to attempt to adopt a regional redispatch program different from the one it proposes (which is based on the NERC model we have accepted above).

NSP Companies protest the designation of MAIN as the Security Coordinator for the Eau Claire/Arpin 345 kV flowgate because it is a transmission line operated by NSP Companies and within the NSP Companies' control area. However, nothing in
MAIN's proposal states that this is the case and we do not understand MAIN's proposal to change the responsibilities of any security coordinator from that in place today. Accordingly, NSP Companies' concerns are groundless.

3. LEER Proposal

Participants in LEER include the members of the New York Power Pool, Allegheny, Detroit Edison, Consumers Energy Company, AEP and PJM, and also include the Ontario Central Market Operations. The LEER participants distinguish curtailments that have economic consequences only (non-emergency) and those that would result in the shedding of firmload by one of the LEER participants (emergency). The LEER participants explain that their proposal differs from NERC's proposal because it implements a system redispatch (the system operators identify and implement the best redispatch options available), requires mandatory assistance from other participants, and applies only to emergency curtailments. The LEER participants state that their proposal would complement, rather than replace, NERC's market redispatch proposal. Before members of LEER may invoke LEER procedures, they must have purchased emergency power from unconstrained sources to the extent possible, curtailed interruptible load, and reduced voltage, if applicable. The LEER procedures require the participants to provide assistance through redispatch, reconfiguration of the transmission system and/or the adjustment of phase angle regulating transformers when possible. The LEER participants state that these actions are not intended to conflict with any requirements of the pro forma tariff.

We find that the LEER proposal is an additional measure that goes beyond the requirements of our December 16 Order. The LEER participants have designed an emergency assistance scheme that obligates members to assist each other not only by selling emergency power (the traditional focus of emergency assistance agreements), but also by cooperating in regional redispatch arrangements.

One aspect of the proposal that is unclear is that the proposal discusses a priority afforded to nonfirm transmission services that are supported by these redispatch arrangements to avoid firmload shedding. Because the LEER participants have committed that their proposal cannot be implemented in a manner that conflicts with the pro forma tariff, we conclude that this priority provision is not intended to change the pro forma tariff curtailment priorities. We shall therefore accept the LEER participants' proposal and direct them to make a compliance
filing providing more specificity concerning that aspect of the proposal that affects the priorities of nonfirm transmission services. Except for the matter discussed above, we do not share the intervenors' concerns that the LEER proposal is unclear.

Enron also complains that the LEER emergency assistance proposal is discriminatory and does not comply with the Commission's directives because it applies only to the LEER participants. We disagree. As noted above, the LEER procedures supplement the NERC proposal and deal only with an emergency assistance arrangement. The LEER participants also state that they welcome new participants who are willing to accept the obligation to provide emergency assistance to them as well.

4. Other Compliance Filings

PJM states that, since the Commission has accepted its regional redispatch proposal, it need not adopt NERC's proposal. VEPCO complains that the proposals of PJM and other power pools to rely on existing congestion management plans may be an adequate response as they relate to internal constraints, but are inadequate as to external constraints. VEPCO explains, for example, that a counterflow transaction in its service area may involve the participation of generators located in PJM's service area, and those generators may require transmission under the PJM tariff. VEPCO is concerned that PJM has not addressed if and how transmission services can be arranged for these counterflow transactions. We clarify that we expect power pools to support the pilot redispatch program with respect to external transactions by facilitating the necessary transmission services for the counterflow transactions. As noted above, we believe that the pro forma tariff terms will not impede these services, and we expect that the necessary transmission services will be made available under the terms of each power pool's open access tariff.

SPP suggests that it will adopt the NERC proposal once it is finalized, but also suggests that its regional tariff addresses the Commission's concerns. SPP asserts that, because its regional tariff uses a flow-based model to design rates, it reduces concerns about parallel flows and contends that the redispatch service it currently offers satisfies the Commission's requirements. We find that SPP's statements do not constitute an adequate response with respect to native load and network customer curtailments. We shall direct SPP members to either notify the Commission that it will implement NERC's proposals or to demonstrate that SPP provides pro rata curtailment of native
loads and network customers. We agree, however, that SPP's existing redispatch proposal is adequate. We observe that none of the 13 flowgates that have been identified as part of NERC's pilot redispatch program are located in the SPP region.

The Commission rejects NYMPA's protest because it goes to issues concerning the NYPP beyond the scope of this proceeding.

The Commission grants Maine Public's motion for clarification. Maine Public does appear to be an isolated system which does not experience a parallel flow problem and is not a member of NEPOOL. Thus, Maine Public need not comply with the December 16 Order.

United Illuminating's filing is rejected. United Illuminating is a NEPOOL member, and the March 12 Order rejected NEPOOL's request for a waiver from the requirements of the December 16 Order.

The Commission orders:

(A) The Commission hereby accepts for filing the submissions of the public utilities listed in Appendix A of this order, incorporating the NERC interim TLR procedure and pilot redispatch program.

(B) The Commission hereby accepts for filing the submissions of the public utilities listed in Appendix B to this order, subject to the conditions in the body of this order.

(C) The Commission hereby accepts for filing the submissions of the public utilities listed in Appendix C to this order, subject to the conditions in the body of this order.

(D) The filings of FirstEnergy, Florida Power Corp, CP&L, VEPCO, Dayton P&L, NIPSCO, SCE&G, Duke, Entergy and United Illuminating are hereby rejected, and the Commission hereby directs these parties to comply with the December 16 Order within 10 days of the date of this order.

(E) The filings by PJM and PSE&G are hereby accepted subject to clarification as discussed in the body of the order, and the Commission hereby directs these parties to comply with the December 16 Order within 10 days of the date of this order.

(F) The filings by SPP, OG&E, Western Resources, Cleco, PSO and Empire District concerning the interim TLR procedures are
hereby rejected and the Commission hereby directs these parties to comply with the December 16 Order within 10 days of the date of this order.

(G) Southern Indiana is hereby informed of the rate schedule designation in Appendix D.

By the Commission.

(SEAL)

David P. Boergers,
Secretary.

APPENDIX A

Companies that filed notices accepting NERC's revised TLR procedures and pilot redispatch program

<table>
<thead>
<tr>
<th>Utilities</th>
<th>Docket Nos.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allegheny Power Service Company</td>
<td>ER99- 2002- 000</td>
</tr>
<tr>
<td>American Electric Power Service Corporation</td>
<td>ER99- 1991- 000</td>
</tr>
<tr>
<td>Cinergy Services, Inc.</td>
<td>ER99- 1997- 000</td>
</tr>
<tr>
<td>Detroit Edison Company, et al.</td>
<td>ER99- 2014- 000</td>
</tr>
<tr>
<td>Duquesne Light Company</td>
<td>ER99- 2015- 000</td>
</tr>
<tr>
<td>East Texas Electric Cooperative, Inc.</td>
<td>ER99- 2008- 000</td>
</tr>
<tr>
<td>Company</td>
<td>Docket No.</td>
</tr>
<tr>
<td>------------------------------------------------------------------------</td>
<td>------------</td>
</tr>
<tr>
<td>Louisville Gas and Electric Company, et al.</td>
<td>ER99-2032-000</td>
</tr>
<tr>
<td>Ohio Valley Electric Company</td>
<td>ER99-2001-000</td>
</tr>
<tr>
<td>Southern Indiana Gas and Electric Company</td>
<td>ER99-1972-000</td>
</tr>
<tr>
<td>Wolverine Power Supply Cooperative, Inc.</td>
<td>ER99-2031-000</td>
</tr>
</tbody>
</table>
**APPENDIX B**

Companies that filed notices accepting the MAIN procedures.

<table>
<thead>
<tr>
<th>Utilities</th>
<th>Docket Nos:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Illinois Light Company</td>
<td>ER99-1999-000</td>
</tr>
<tr>
<td>Commonwealth Edison Company, et al.</td>
<td>ER99-1967-000</td>
</tr>
<tr>
<td>Illinois Power Company</td>
<td>ER99-1968-000</td>
</tr>
<tr>
<td>Alliant Energy Corporate Services</td>
<td>ER99-1984-000</td>
</tr>
<tr>
<td>Ameren Services Companies</td>
<td>ER99-2018-000</td>
</tr>
<tr>
<td>Madison Gas &amp; Electric Company</td>
<td>ER99-1996-000</td>
</tr>
<tr>
<td>Wisconsin Electric Power Company</td>
<td>ER99-2019-000</td>
</tr>
</tbody>
</table>
### APPENDIX C

Companies that filed notices accepting the LEER procedures.

<table>
<thead>
<tr>
<th>Utilities</th>
<th>Docket Nos:</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York Power Pool</td>
<td>ER99-1973-000</td>
</tr>
<tr>
<td>Allegheny Power Service Corporation</td>
<td>ER99-2002-000</td>
</tr>
<tr>
<td>Detroit Edison Company, et al.</td>
<td>ER99-2014-000</td>
</tr>
</tbody>
</table>
## Appendix D

**Southern Indiana Gas & Electric Company**

**Docket No. ER99-1972-000**

**Rate Schedule Designations**

<table>
<thead>
<tr>
<th>Designation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original Sheet No. 151</td>
<td>Adoption of the North American Electric Reliability Council's Transmission Line Loading Relief Procedures to Southern Indiana Gas &amp; Electric Company's Open Access Transmission Tariff</td>
</tr>
<tr>
<td>Original Volume No. 3</td>
<td></td>
</tr>
</tbody>
</table>