August 12, 2002

VIA HAND DELIVERY

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Revised Lake Erie Emergency Redispatch Agreement,
Northeast Power Coordinating Council, Docket No. ER02-___-000

Dear Ms. Salas:


\(^1\) 16 U.S.C. § 791a-825r.

\(^2\) 18 C.F.R. § 35.13.

\(^3\) The IMO is one of the LEER Participants, but as a Canadian provincial entity the IMO is not subject to the Commission’s jurisdiction and is not submitting to such jurisdiction by joining this filing. However, the IMO will follow the LEER procedures. A current list of LEER participants is located at http://www.npcc.org/leer_members.htm.
Emergency Redispatch Agreement (“LEER Agreement”). NPCC coordinates Lake Erie Emergency Redispatch activities and posts all LEER-related information on the NPCC web site.

This letter and accompanying attachments provide the information required by Part 35 of the Commission’s Regulations. This filing does not involve a rate increase within the meaning of Section 35.13(a)(2)(iii) of the Commission’s Regulations. Accordingly, the information required by Section 35.13 (b) and (c) is provided herewith.

I. Introduction

The revised LEER Agreement, attached hereto, is materially the same as the LEER Agreement previously approved by the Federal Energy Regulatory Commission (“FERC” or “Commission”). This filing revises the LEER Agreement to reflect changes in the industry since the last LEER filing on July 28, 2000, Docket No. ER02-3300-000 (“July 2000 LEER Filing”). Concurrent with this filing, the LEER Participants are making corresponding changes to the LEER Operating Manual that deal with the day-to-day operating practices required to implement the revisions enumerated below. The revised LEER Operating Manual will be posted on the LEER webpage in accordance with the process previously accepted by the Commission.

The following list enumerates the primary changes to the LEER Agreement:

- A description of the LEER settlement procedure has been added;
- A description of how LEER handles constraints that may develop during the process of restoring the system to normal (unwinding a LEER transaction) has been added;
- The LEER Agreement has been amended to recognize that Phase Angle Regulator (“PAR”) adjustments are not limited to only those PARs under the control of the constrained system;

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4 Allegheny Power (“AP”) is no longer a direct participant in the LEER Agreement. Effective April 1, 2002, PJM became the independent system operator of AP’s transmission system and control area. Michigan Transco LLC will succeed Consumers Energy Co. as a signatory to the LEER Agreement. International Transmission Company will succeed Detroit Edison Company as a signatory to the LEER Agreement.


6 http://www.npcc.org/LEER.asp?Folder=CurrentYear

7 The July 2000 LEER filing set forth the process for updating the LEER Operating Manual and established that “In the future, to the extent that the LEER Agreement is amended, the Lake Erie participants anticipate filing these amendments with the Commission.” See July 2000 LEER Filing, Docket No. ER00-3300-000 at 2 (July 28, 2000).
• The term Reliability Coordinator has been substituted for Security Coordinator and the LEER definition of flowgate has been deleted to comport with the terminology changes adopted by the North American Electric Reliability Council ("NERC"); and
• The LEER participant list has been amended to include the Midwest ISO and reflect the organizational changes of several existing LEER participants.

The Lake Erie Security Process Working Group ("LESPWG") will continue to meet to enhance the procedure and identify other possible solutions to the problem of transmission congestion management. In addition, the LESPWG will continue to review the LEER procedure to ensure that it follows the Standard Market Design principles as outlined by FERC.

II. Background

The LESPWG is an industry participant group open to all market participants. The group’s objective is to facilitate emergency redispatch among participating control areas surrounding Lake Erie to avoid the shedding of firm load and to enhance the effectiveness of security coordination to address reliability and commercial concerns specific to the control areas surrounding Lake Erie.

The Commission initially approved the LEER Procedure on May 12, 1999.\(^8\) In this order the Commission commended the LEER members for establishing “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.”\(^9\)

On June 1, 1999 the LEER Participants made a compliance filing responding to questions raised by the Commission in its May 12, 1999 Order on Interim Procedures.\(^10\) The compliance filing clarified that LEER does not transform a non-firm transaction into a firm transaction, since the protecting transactions are not afforded a priority greater than the remaining Firm Point-to-Point transactions.\(^11\)

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\(^9\) Id.

\(^10\) The Commission stated in its order that “one aspect of the LEER proposal that is unclear is . . . [the] priority afforded to non-firm transmission services that are supported by . . . re-dispatch arrangements to avoid firm load shedding.” Id.

\(^11\) Under LEER, either the protected transaction is removed from the group of transactions appropriate for TLR by the controlling transaction’s effective nullification of the protected transaction, or the controlling transaction itself is curtailed and the protected transaction is curtailed with it. See LEER Compliance Filing, Docket Nos. EL98-52-000 and ER99-1957-001 at 2 (June 1, 1999).
On July 28, 2000, the LEER Participants filed a revision to the LEER agreement to remove the original document's appendices, information that deals with the day-to-day operating practices required to implement the procedure, along with technical and contact data, and placed them into a separate document, the LEER Operating Manual, because this information is subject to recurrent change. The LEER Agreement continued to include the principles and elements of the emergency redispatch procedure. These revisions were accepted by the Commission on September 15, 2000.12

III. Description of the Revisions

The revisions to the LEER Agreement submitted in this filing are briefly described below.

A. LEER Settlement Procedure

A Settlement Section has been added to the LEER Agreement to better describe the LEER settlement process. The paragraph describing compensation has been moved to the Settlement Section and a new paragraph describing how a LEER transaction is to be billed has been added. Additionally, an example of the settlement process has been added to Appendix B of the LEER Agreement.

The LEER Participants have agreed that in order for the service providing entities to be appropriately compensated a transaction should be billed as it is scheduled, from source to sink. The total costs, including energy and transmission service charges, incurred for the Lake Erie System redispatch service will be initially payable by the Sink (DEC) Controlling System to the Source (INC) Controlling System as if it were the purchaser of the redispatch service. The Sink Controlling System will then bill the Dependant Area(s) for full recovery of the redispatch costs.13 An additional provision has been added to clarify that billing will be conducted on the customary monthly basis with interest due at the prevailing interest rates for late payments.14

The revised LEER Agreement also clarifies that the compensation for charges incurred in acquiring replacement energy includes charges for the provision of ancillary services needed to support the controlling transaction.15 This express statement has been added to comport with the LEER Participants prior understanding that the Controlling

13 See Attachment A, Revised LEER Agreement, at 6 (2002).
14 See Id.
15 See Id.
System or PSEs operating in the Controlling System’s Control Area shall be entitled to recover all costs from the dependent system(s) incurred by redispatch under LEER.

Generator compensation under LEER for INC units has traditionally been such that payment is in accordance with local tariffs and control area agreements or at the prevailing emergency energy price. The compensation for INC generators has been modified as an incentive to promote the availability of INC generators in areas where compensation is at a cost-based emergency rate, where an INC generator may have an incentive to bid outside the area rather than making itself available to LEER when market prices are higher elsewhere. Generator compensation for INC units under the revised LEER Agreement will be in accordance with local tariffs and control area agreements or at the higher of the prevailing emergency energy price or hourly market price, or imbalance price.\(^\text{16}\)

### B. Unwinding of the LEER Transaction

Once a constraint is mitigated (i.e. the TLR canceled), the LEER Participants agree to terminate the LEER transaction. However, returning to a normal dispatch following the cancellation of a TLR event and unwinding the LEER transaction might create a constraint on some other flowgate. The LEER Participants have amended the LEER Agreement to describe how such an event would

The unwinding of a LEER transaction will be handled as follows. Any new constraints and dependencies that arise following a return to normal operation after a TLR is canceled and a LEER Protecting Transaction is unwound would be handled as a new event. If the Dependent System still has a Dependency, the Dependent System may choose to continue the LEER assistance but the LEER transaction may be adjusted as appropriate to relieve the new constraint. If there is no Dependency, then there is no reason for that System to request or continue LEER assistance.\(^\text{17}\)

### C. Preliminary Actions: PAR Adjustments

In a tightly interconnected transmission system, PAR adjustments will affect transmission line flows in external systems as well as within the constrained system. System operators must be aware of the effects of power flows in other parts of the interconnected system as well as within the constrained area and PARs must be operated in a coordinated fashion to preserve the reliability of the system and not create or aggravate emergencies in neighboring systems. Recognizing this as an operating axiom,

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\(^{16}\) See Id. Imbalance Price is the price that a Control Area or other balancing entity can charge when it incurs additional cost to make up for either the loss of generation (by purchasing power from outside the Control Area to supply load) or by the cost of increasing generation to supply load.

\(^{17}\) See Id. at 4-5.
the LEER Participants have amended the Preliminary Actions section of the LEER Agreement to state that Phase Angle Regulator adjustments not be limited to only those PARs under the control of the constrained system.\textsuperscript{18} PAR adjustments are to be “balanced” in accordance with the principles agreed to by the LEER Participants.\textsuperscript{19}

\textbf{D. Terminology Change}

On November 15, 2001 the North American Electric Reliability Council (“NERC”) approved a revision to its terminology.\textsuperscript{20} Those organizations performing security coordination functions that were once called Security Coordinators are now called Reliability Authorities. This change in terminology does not affect the functional responsibilities of the organizations performing the current security coordination functions.\textsuperscript{21}

To avoid possible system operator confusion that might result from a difference in terminology between the LEER procedures and NERC Policies, the LEER Participants have revised the LEER documentation to comport with the NERC terminology. This change in terminology has no effect on the current responsibilities of the participating entities under LEER.

Additionally, the definition of flowgate in Appendix A of the LEER Agreement has been deleted. Initially, in the absence of a NERC definition of flowgate, the LESPWG believed it necessary to include a definition in the LEER Agreement. Since the last filing of the LEER Agreement, NERC has developed a reference document that now defines the term flowgate. Members of the LESPWG contributed to the creation of the NERC reference document and the definition of flowgate contained therein. In light of this development, the LEER Participants no longer believe it is necessary to include a

\textsuperscript{18} See Id. at 2.


\textsuperscript{20} See Minutes of the NERC Operating Committee, November 15, 2001 (Approval to rename Security Coordinator to Reliability Coordinator).

\textsuperscript{21} The change in terminology is to avoid the confusion arising from the use of the word “security” since the September 11 attack on the World Trade Center. The NERC Operating Committee observed that “security” now implies physical security of critical infrastructures, and many in government and the media are confusing “Security Coordinators” with those responsible for physical protection of the electric system. See Minutes of the NERC Operating Committee, July 17, 2002.
definition of flowgate in the LEER Agreement since the NERC definition of flowgate is consistent with the former LEER definition.\textsuperscript{22}

\textbf{E. Participant Changes}

The electric industry has undergone a number of changes since the last LEER re-filing and several new organizations have come into existence. One such organization, the Midwest ISO,\textsuperscript{23} could affect the operation of the LEER procedures. The Midwest ISO is a Reliability Coordinator within the LEER area and, as such, would need to approve the redispatch actions of its members under the LEER Agreement. Recognizing the integral role the Midwest ISO will play in the operation of the LEER procedures, Midwest ISO was approached by the LESPWG and has agreed to become a signatory to the LEER Agreement. The LEER participant list in the LEER Agreement has been amended to include the addition of the Midwest ISO as a participating member system.\textsuperscript{24}

Several LEER members have undergone organizational changes requiring that the successor organizations now become signatories to the LEER agreement. These organizations include Consumers Energy Company, Detroit Edison Company, and Allegheny Power.

Michigan Transco LLC\textsuperscript{25} will replace Consumers Energy Co. as a signatory to the LEER Agreement. On February 13, 2002 the Commission approved the transfer of all of Consumers Energy Company’s membership in Michigan Transco LLC to Michigan Transco Holdings LP and that Michigan Transco LLC would provide open access transmission service.\textsuperscript{26} Furthermore, the Commission approved the transfer of operational control over Michigan Transco LLC jurisdictional facilities to the Midwest

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\textsuperscript{22} NERC approved a Reference Document entitled “Flowgate Administration Reference Document” at its March 2001 Operating Committee meeting. \textsuperscript{See} Minutes of the NERC Operating Committee, March 21, 2002.

\textsuperscript{23} \textsuperscript{See} Midwest Independent System Operator, Inc, 97 FERC ¶ 61,326 (2002).

\textsuperscript{24} \textsuperscript{See} Attachment A, Revised LEER Agreement, at n.1.

\textsuperscript{25} Michigan Transco LLC is independent of market participants and is owned by Michigan Transco Holdings LP and Trans-E lect, Inc. Trans-E lect, Inc. is an independent, for-profit transmission company that focuses solely on the acquisition of transmission systems from investor-owned utilities and other transmission owners, with the goal of creating a network of independent transmission companies under the Regional Transmission Organizations (“RTO”) envisioned by the Commission.

\textsuperscript{26} \textsuperscript{See} Trans-E lect, Inc., et al, 98 FERC ¶ 61,142 (2002), \textsuperscript{order on reh’g}, 98 FERC ¶ 61,368 (2002).
ISO on April 12, 2002.\textsuperscript{27} Transfer of operational control was made effective as of May 1, 2002.\textsuperscript{28}

International Transmission\textsuperscript{29} will succeed Detroit Edison Company as a signatory to the LEER Agreement. On June 29, 2000 the Commission approved the transfer of substantially all of Detroit Edison Company’s integrated transmission facilities to International Transmission as part of a divestiture plan to transfer Detroit Edison Company’s transmission business to an entity qualified to join a Regional Transmission Organization (“RTO”).\textsuperscript{30} On December 20, 2001, the Commission authorized International Transmission to transfer operational control of certain of its transmission facilities to Midwest ISO and accepted an agreement to allocate certain RTO functions between the two organizations.\textsuperscript{31}

Allegheny Power (“AP”) will no longer be a direct participant in the LEER Agreement but will continue to participate in LEER development discussions. On January 30, 2002 the Commission approved the implementation of PJM-West.\textsuperscript{32} On April 1, 2002, PJM Interconnection, L.L.C. assumed the responsibility as the independent system operator of AP’s transmission system and control area. As the independent system operator of the AP transmission system, redispatch will be the responsibility of PJM. AP will no longer have direct responsibility for redispatch under the LEER Agreement in its control area and therefore need not be a signatory. From the inception of the LEER procedures, AP has been a strong supporter of the LEER Agreement and an essential member in the LEER development team. This has not changed. AP intends to continue as an active participant in the working group’s development of the LEER procedures.

\footnotesize{\textsuperscript{27} Trans-Elect, Inc., et al., 99 FERC ¶ 61,068 (2002).}

\footnotesize{\textsuperscript{28} See Trans-Elect, Inc. Michigan Transco Holdings, LP, and Michigan Electric Transmission Company, LLC, Docket No. EC02-55-000 (May 13, 2002).}

\footnotesize{\textsuperscript{29} International Transmission is a special purpose, wholly-owned subsidiary of DTE Energy created for the purpose of acquiring substantially all of Detroit Edison's transmission assets.}

\footnotesize{\textsuperscript{30} See DTE Energy Co. et al., 91 FERC ¶ 61,317 (2000).}

\footnotesize{\textsuperscript{31} See International Transmission Company et al., 97 FERC ¶ 61,328 (2001).}

\footnotesize{\textsuperscript{32} See PJM Interconnection, L.L.C and Allegheny Power, 98 FERC ¶ 61,072 (2002); see also, PJM Interconnection, L.L.C and Allegheny Power, 98 FERC ¶ 61,235 (2002) (Approval to extend PJM West startup date beyond March 1, 2002).}
IV. Additional Requirements

To the extent not already provided elsewhere in this Transmittal Letter, the following information required by sections 35.13(b) and (c), 18 C.F.R. §§ 35.13(b) (c) (2001) is hereby provided:

- The proposed changes to the LEER Agreement are provided in Attachment A.

- A copy of this Agreement is being mailed to the commissions in the states of Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia and Wisconsin.

- A description of the changes to the LEER Agreement is provided in the body of this letter.

- A statement of the reasons for the changes to the LEER procedures has been provided in the body of this letter.

- No expenses or costs in connection with this Agreement have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

- A draft notice of filing suitable for publication in the Federal Register is provided in Attachment B to this letter, and an electronic copy on a diskette has also been provided.

- This Agreement does not establish a rate schedule. Compensation for energy replacement or energy reduction shall be in accordance with local tariffs and control area agreements or at the higher of the prevailing emergency energy price as presently filed in the LEER Participants' existing tariffs or hourly market price, or imbalance price, as applicable. It is difficult to accurately predict the extent that actual implementation of the LEER procedure has revenue impact because it is not possible to forecast how often emergencies will occur that will lead to the use of the LEER procedure.

- No specifically assignable facilities will be constructed in order to effect these changes.

V. Proposed Effective Date

The applicants request that the revised LEER Agreement described in this filing be made effective October 10, 2002. All signatories to the LEER Agreement agree to
implement the revised procedure in their respective control rooms for the summer 2002 period.

VI. Conclusion

The applicants believe that the revisions to the LEER Agreement presented in this filing constitute an affirmative step towards promoting the continued reliability of the Bulk Electric System in the Lake Erie region of the Eastern Interconnection. Moreover, the LEER Agreement provides one solution to the critical international seams issue concerning parallel path power flows across and between the control areas in the Lake Erie region. As such, the applicants request that the revised LEER Agreement described in this filing be approved and made effective as of October 10, 2002.

Respectfully submitted,

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/s/

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ATTACHMENT A
LAKE ERIE EMERGENCY RE-DISPATCH AGREEMENT
August 2002
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Lake Erie Emergency Re-dispatch (LEER) Agreement

Objective

The objective of the Lake Erie Emergency Re-dispatch (LEER) procedure is to facilitate emergency re-dispatch among participating Operating Authorities surrounding Lake Erie to avoid the shedding of firm load. The LEER procedure is only intended to be implemented for emergency re-dispatch to relieve transmission constraints that could otherwise require another Lake Erie Participant to shed firm load. The LEER procedure would only be fully executed when firm load curtailment is imminent. Lake Erie Participants must purchase emergency power from unconstrained directions or from other sources, if possible, before calling on the Lake Erie Emergency Re-dispatch procedure.

Lake Erie Reliability Coordinators (RCs) and Control Areas (CAs) will provide emergency aid in the form of intra-Control Area re-dispatch, inter-Control Area re-dispatch, re-configuration of the transmission system, and/or adjustment of phase angle regulating transformers to maintain Firm Load service when possible. RCs/CAs will determine emergency re-dispatch options and requirements prior to actions being needed. Attempts should be made by the Dependent System or Purchasing-Selling Entities operating in these areas, where applicable, to secure firm transmission services to support transactions that are required to supply firm load.

Definitions of terms and acronyms used in this agreement are found in Appendix A. Unless otherwise defined in this agreement, terms and acronyms used in this agreement have the meanings ascribed thereto in the NERC Operating Manual.

Provisions of the LEER procedure are not intended to conflict with applicable transmission service agreements, tariffs filed with Federal and State regulatory commissions, or NERC Policies. The terms of such agreements, tariffs, and policies take precedence over LEER.

Under the Lake Erie Emergency Re-dispatch Process, transactions with non-firm or firm transmission reservations which would otherwise be curtailed in accordance with NERC Policy 9, resulting in the shedding of firm load, may be protected from curtailment through the implementation of re-dispatch actions. Once implemented, if a controlling action and any applicable transmission service for it are curtailed by NERC Transmission Loading Relief (TLR) actions, the protected transaction will also be curtailed. In this case, either the protected transaction is removed from the group of transactions appropriate for TLR by the controlling transaction’s effective nullification of the protected transaction.

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33 The participating Operating Authorities are American Electric Power Company, Inc (AEP), FirstEnergy Corporation (FE), Independent Electricity Market Operator [of Ontario, a Canadian entity] (IMO), Michigan Electric Coordinating Systems (MECS), Midwest Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection L.L.C., The MISO may proxy active participation and control actions to other participating Operating Authorities, as deemed appropriate. For the ease of reading, we shall refer to participating Operating Authorities in the LEER agreement as the Lake Erie Participants, LEER Participants, or the Participants.
(effectively curtailing the transaction), or the controlling transaction itself is curtailed and the protected transaction is curtailed with it. In neither case is a protected transaction whose service priority was non-firm given higher priority than a transaction whose service priority was firm.

LEER is intended to make protection available for any transaction that serves firm load and is at risk of curtailment under NERC's TLR procedure, regardless of whether that transaction's transmission service priority is firm or non-firm. The choice of requesting that a particular transaction be protected under LEER depends on whether the load served is firm, and is a security decision of the Dependent Control Area. LEER is simply intended to provide an option to avoid the curtailment of firm load resulting from TLR actions. The use of non-firm transmission to serve firm load is not condoned. The Dependent Systems or Purchasing-Selling Entities operating in these areas should attempt, where applicable, to secure firm transmission services to support transactions that are required to supply firm load.

The Constrained System's RC/CA should notify all other LEER participants of any pending constraints and potential impacts such that implementation of the LEER procedure may be considered. The LEER procedure will be initiated by the Dependent System's RC/CA, but must be directed by the Constrained System's RC/CA. The relevant parameters for all transactions covered by LEER should be supplied to the IDC database and the IDC software or equivalent should be the primary tool used to identify scheduled transactions that are subject to curtailment. This procedure is intended to be as dynamic as practicable, allowing the dependent and constrained system's RC/CA to update dependent transactions and controlling actions as system conditions change.

Preliminary Actions

Prior to implementing LEER, all Phase Angle Regulator adjustments and other “no cost” operating procedures should be utilized by Lake Erie participants to the benefit of reliability of the bulk power system. Phase Angle Regulator adjustments are not limited to only those PARs under the control of the constrained system. However, owners of PARs, etc., are not expected to incur excessive financial harm by operating PARs at a tap position that forces uneconomical operation. Phase Angle Regulator adjustments shall be consistent with the principles in the “Utility Practices in Phase Angle Regulator Operation” document.

Re-dispatch service shall be available to any participants within the Lake Erie Control Areas relying on interconnection transactions to meet firm load. Prior to resorting to re-dispatch service, the Dependent System shall curtail interruptible customers and reduce voltage, if applicable and as system conditions permit, and use their best efforts to obtain other sources of energy that do not adversely affect the Constrained System(s).

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Effective generation shifts, including generation under the control of Independent Power Producers and Power Marketers, should be used for re-dispatch, if applicable.

Coordinating Actions

RCs/CAAs who determine at any time that they are dependent on purchases and may need to implement the LEER procedure, shall provide, via the Reliability Coordinator Information System (RCIS), its expected peak dependence on covered transactions.

**Dependency** = Forecasted/Actual Load – Committed/Available Resources – MW Voltage Reduction – MW Interruptible/Curtailable Load

The Lake Erie RCs/CAAs implementing LEER shall identify those dependent transactions in the IDC that require re-dispatch service. This list of dependent transactions should be published via the RCIS “System Emergency” messaging page for participating RC/CAAs to investigate possible mitigating measures including re-dispatch.

The RCs/CAAs initiating the LEER procedure shall conduct a conference call to discuss their dependency on external transactions. At this time each Lake Erie RC/CA shall discuss expected constraints on their system and how those constraints would impact the RCs/CAAs with the dependency. The Constrained System’s RC/CA and Dependent System’s RC/CA should discuss the optimal re-dispatch solution for the expected constraint, taking into consideration generation available for re-dispatch (both reduction (**DEC**) and increase (**INC**)) in generation. The Dependent RC/CA should determine the appropriate GSF/PTDF/OTDF for use in the re-dispatch evaluation, using on-line or off-line load flows that depict current system topology. The Constrained System’s RC/CA, the one declaring TLR, must be in control of the re-dispatch process and agree with the effectiveness of all schedule/re-dispatch changes. This process may involve other RCs/CAAs who are in control of and have available the generation designated for re-dispatch.

LEER re-dispatch can be implemented as follows, to the extent that generation is available and transmission tariffs allow:

1. **Lower Controlling Generator (s) DEC Unit (s):** The Dependent System’s RCs/CAAs or Purchasing-Selling Entities (PSEs) operating in these areas, where applicable, would arrange to replace the amount of generation that was lowered by the controlling generator with an Emergency Transaction.

2. **Raise Controlling Generator (s) INC Unit (s):** The Dependent System’s RCs/CAAs or PSEs operating in these areas, where applicable, would arrange to purchase the most effective generator increase, where available, as an Emergency Transaction.

3. A combination of the above two options may be exercised to effect the re-dispatch option.
These actions will allow for continued transfers across the constrained flowgate, minimizing the need to curtail scheduled transactions supplying firm load. The generation shift factors (GSFs) for use in the re-dispatch evaluation must be based on a current system analysis, which depicts the latest system topology. Re-dispatch should be at the request of the RCs/CAs (or on behalf of PSEs in their control area where applicable) with the dependency, but under the direction of the constrained RCs/CAs.

All RCs/CAs should expedite the emergency re-dispatch schedule without regard for the formality of obtaining transmission service reservations on OASIS, and permit after-the-fact reservations, where required. Transmission reservations are secured on OASIS and the protecting counter-flow transactions are E-tagged and entered in the IDC according to NERC policies. Reservations for LEER counter-flow transactions may be entered in the OASIS after the fact, but not exceeding a delay greater than four hours. The objective is to provide information on OASIS as soon as practicable.

The Lake Erie participants have agreed that transmission reservations for LEER emergency purchases would be reserved as non-firm hourly (Level 2 priority). All parties to a LEER transaction are responsible for entering the appropriate transmission reservations pertaining to their portion of the transaction into their OASIS nodes and the Load Control Area (area with the DEC Unit) for creating the appropriate NERC tag(s) needed to support the LEER counter-flow transaction. Since the protected transaction and the controlling transaction require each other to remove their contribution to the constraint, it is necessary to curtail both if either is curtailed. Transactions for which re-dispatch is implemented shall be protected from further curtailment on the designated flowgate. A single LEER transaction may be used to protect multiple transactions flowing in the same direction (Block Protection). Series flowgates may be protected by a single LEER transaction. Once re-dispatch begins to protect dependent transactions, they are categorized as protected transactions. Any additional loading of the flowgate should not be associated with the protected transactions so long as the re-dispatch action is current. Re-dispatch can be applied to a whole or part of a transaction, as required by the magnitude of the dependency. When the re-dispatch action covers only a portion of the transaction, the unprotected part is still subject to curtailment.

If the unit(s) designated as the controlling action in the LEER procedure were to trip or become limited or unavailable in any way (e.g., derated or not able to provide additional relief if it has already been dispatched to control an unrelated transmission constraint), the Constrained System's RCs/CAs shall immediately notify the Dependent System's RCs/CAs that the re-dispatching service has been modified or canceled. All transactions designated as replacement energy for the limited/unavailable controlling transaction shall be canceled immediately.

The Dependent System's RC shall provide periodic updates via the RCIS as the level of dependency changes and as changes occur in dependent transactions. When the transmission system is no longer constrained, the Constrained System's RC/CA shall notify all other RCs/CAs that transactions can resume and re-dispatch service can be discontinued.
The Lake Erie participants have agreed that once a constraint is mitigated (i.e. TLR canceled) then the participants would return the redispacht to the normal, or pre-LEER state. Any new constraints and dependencies that may arise would be handled as a new event. If a new flowgate becomes constraining following the resumption of normal operation with the termination of a LEER, the Dependent System may or may not still have load at risk of curtailment. If the Dependent System no longer has a Dependency, then there is no reason for that Area to request or continue redispacht assistance. If the Dependent System still has a Dependency, then the Area may choose to continue the LEER assistance. However, the amount of the redispacht may be adjusted to a different MW level or to different Controlling Systems, as may be appropriate to relieve the new constraint.

At any point in the execution of the procedure:

- The Dependent System's Reliability Coordinator must cancel the LEER procedure when it is determined that the dependency no longer exists. The Dependent System's RCs/CAs, or PSEs operating in those areas, where applicable, are responsible for canceling the emergency energy purchase that replaced the controlling action, after concurrence by the Constrained System's RCs/CAs that relief is no longer required, or that dependence no longer exists.

- The Constrained System's Reliability Coordinator must cancel LEER procedures if the system constraint is relieved when the controlling action is terminated. The Constrained System's RC/CA is responsible for notifying all parties once system constraints are relieved.

- The Controlling System's Reliability Coordinator must cancel LEER procedures if the controlling unit is no longer available for re-dispatch, has tripped off-line, or in the case an "INC" unit is derated, or has been reduced (raised in the case of a "DEC" unit) to control a separate constrained facility; unless alternative re-dispatch can be immediately implemented.

- The Reliability Coordinator supplying emergency energy to replace the controlling action can cancel LEER procedures if the replacement energy becomes unavailable.

**LEER Procedure**

1. Lake Erie RCs/CAs report dependence on transactions and request a conference call using the RCIS “System Emergency” messaging page.

2. Dependent System's RCs/CAs summarize dependency during morning conference call (LEER Hotline).

3. Lake Erie RCs/CAs discuss projected constraints and how transfers to the dependent system impact constraints.
4. Dependent System's RCs/CAs discuss **controlling actions** and identify **dependent transactions** with Constrained System's RCs/CAs. RCs/CAs with dependency should:

- Note Dependent Transaction Identification. Transaction must be entered into NERC **Interchange Distribution Calculator** (IDC) prior to becoming a candidate for LEER Procedure
- Discuss Control Area **Source** and **Sinks** of Dependent Transactions to determine **GSF/PTDF/OTDF** effect
- State MW amount of **Dependent Transaction** – list maximum when transaction MW profile varies

*This discussion does not have to be part of the initial conference call.*

5. The Constrained System's RCs/CAs will discuss available **controlling actions** and updated **GSF/PTDF/OTDF** effects based on current system topology.

*This discussion does not have to be part of the initial conference call.*

6. The Constrained and Dependent System's RCs/CAs will agree on which **dependent transactions** are protected based on the **controlling action**. The net MW effect of the **controlling action** must equal the effect of the **dependent transactions**.

7. The Dependent System's RCs/CAs will arrange for emergency replacement energy in the amount of the **controlling action** when the agreed upon action is to lower generation. **Dependent transactions** become **protected transactions** once re-dispatch begins.

8. The Constrained System's RC/CA will notify other RCs/CAs via the RCIS when the LEER procedure is implemented and provide information including the **controlling action**, the **protected transactions**, and the anticipated duration of the constraint. Periodic updates by either the Constrained or Dependent System's RCs regarding system conditions are to be provided via the RCIS “System Emergency” messaging page as system conditions permit.

**Settlements**

The **Dependent System’s** RC/CA will be required to compensate the **Controlling Systems’** RC/CAs, or PSEs operating in these areas, where applicable, for all charges incurred in acquiring replacement energy, including transmission and applicable ancillary service charges, consistent with existing tariffs. Generators raised for LEER shall be paid in accordance with local tariffs and control area agreements or at the higher of the prevailing emergency energy price, hourly market price, or imbalance price, where applicable. The RCs/CAs with generators being reduced for LEER shall be compensated in accordance with local tariffs and control area agreements. Where applicable, the
**Dependent System’s** RC/CA will recover the expenses based on their current settlement practices.

The LEER participants have agreed that in order for the service providing entities to be appropriately compensated a transaction is to be billed as it’s scheduled, from source to sink. The Sink **Controlling System** will recover all costs from the **Dependent System**. The Sink **Controlling System** will initially pay all energy and transmission service charges as if it were the purchaser of the redispatch service. The Sink **Controlling System** will then send a bill for all the payments it made to the **Dependent System** for full recovery. All settlements will be conducted on a monthly basis and will satisfy all appropriate due dates, and interest rates, if applicable.
APPENDIX A: DEFINITIONS AND ABBREVIATIONS

DEFINITIONS

**Constrained System** - The Control Area (and associated Reliability Coordinator) with a transmission limitation, which may curtail Dependent System’s transactions through TLR actions.

**Controlling Action(s)** - INC/DEC generation change that creates a LEER controlling transaction.

**Controlling System** - The Control Area (and associated Reliability Coordinator) with the re-dispatch option to control a constraint (not necessarily constrained system).

**Controlling Transaction** - The counter-flow transaction that effectively nullifies the protected transaction's effect on the constrained flow gate.

**DEC Unit** - Generator (s) associated with a controlling transaction that lowers its level of generation in a re-dispatch action.

**Dependency** - Forecasted Peak Load (MW) – Committed Available Resources (MW) – Voltage Reduction MW – Interruptible/Curtailable Load (MW).

**Dependent System** - The Control Area (and associated Reliability Coordinator) that is dependent upon an import transaction for meeting internal firm load requirements and is in jeopardy of curtailing firm load.

**Dependent Transaction(s)** - Transactions required to serve firm load, which if curtailed will immediately result in load curtailment.

**Energy Management System (EMS)** – A tool used by transmission operators to monitor and control operation of their transmission systems.

**Generation Shift Factor (GSF)** - MW effect on a flowgate resulting from the change in MW output of a generator (s).

**INC Unit** - Generator (s) associated with a controlling transaction that raises its level of generation in a re-dispatch action.

**Interchange Distribution Calculator (IDC)** – A tool developed under the North American Electric Reliability Council (NERC) sponsorship for guiding the execution of TLR actions. The IDC also provides other information for operators through a variety of data viewers.

**LEER Hotline** – The pre-arranged telephone conferencing service by which the LEER participants contact one another to arrange LEER actions.
Outage Transfer Distribution Factor (OTDF) – A measure of the power flow impact on a circuit due to the loss of another circuit, and the pre-contingency loading on that circuit. The percent of the pre-outage flow which has been carried by the outaged circuit and now flows on any selected circuit remaining in service. This incremental power flow is superimposed on the pre-outage flow on this specific circuit, resulting in a net increase or decrease in the circuit’s loading.

Power Transfer Distribution Factor (PTDF) - A measure of the impact of a power transfer transaction on a Flowgate. It is a measure of the responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer. The PTDF applies only for the pre-contingency configuration of the system under study. The NERC IDC provides PTDF values for all transactions having more than a threshold value impact on a Flowgate.

Protected Transaction(s) - The Dependent Transaction(s) protected against curtailment by implementation of LEER.

Purchasing-Selling Entity (PSE) – One who buys, sells, and arranges for the transfer of electric power in the energy market.

Re-dispatch Option - Generation raised (INC) or lowered (DEC) to control a transmission constraint.

Reliability Coordinator Information System (RCIS) – The Internet-based communication service provided to Reliability Coordinators by the NERC.

Sink – Collectively, the DEC unit and the Control Area in which it resides.

Source – Collectively, the INC unit and the Control Area in which it resides.

Transmission Loading Relief (TLR) – The Transmission Loading Relief procedures developed jointly by the market and reliability sectors of the electric industry, under the sponsorship of NERC.

ABBREVIATIONS

CA  Control Area
EMS  Energy Management System
GSF  Generation Shift Factor
IDC  Interchange Distribution Calculator
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
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<tbody>
<tr>
<td>LEER</td>
<td>Lake Erie Emergency Re-dispatch</td>
</tr>
<tr>
<td>OTDF</td>
<td>Outage Transfer Distribution Factor</td>
</tr>
<tr>
<td>PSE</td>
<td>Purchasing-Selling Entity</td>
</tr>
<tr>
<td>PTDF</td>
<td>Power Transfer Distribution Factor</td>
</tr>
<tr>
<td>RC</td>
<td>Reliability Coordinator (formerly Security Coordinator)</td>
</tr>
<tr>
<td>SC</td>
<td>Security Coordinator (term superceded by Reliability Coordinator)</td>
</tr>
<tr>
<td>RCIS</td>
<td>Reliability Coordinator Information System</td>
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<tr>
<td>TLR</td>
<td>Transmission Loading Relief</td>
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</table>
APPENDIX B: LEER PROCEDURE EXAMPLE

Limiting facility – post-contingency overload on the Kammer 765/500 kV transformer AEP) for the loss of the Belmont 765/500 kV transformer (PJM/AP). Consumers Energy (in MECS Control Area) is purchasing 100 MW of energy from New York and is the Dependent System. The MECS transaction from NY contributes 15 MW (100 x .15) to the constraint. The most effective controlling actions are to reduce equivalent generation in western PJM and increase Gavin (GSF = 41%) generation, under PJM and AEP control, respectively. Not implementing LEER would result in the curtailment of 100 MW of MECS load.

1. MECS (Dependent System) Control Area announces extent of dependency.

2. Lake Erie RCs/CAs review projected system constraints and how MECS dependency is affected.
   - **PTDF** and **GSF** Viewers used to determine general distribution factor effect.
   - **EMS** or off-line powerflow used to determine appropriate controlling actions based on current system conditions (more accurate GSF developed).

3. MECS (Dependent System) Control Area initiates conference call via LEER Hot Line.

4. AEP (Constrained System) Reliability Coordinator identifies projected constraint and appropriate controlling action. AEP anticipates that the Kammer 765/500 kV transformer must be relieved by 200 MW. The dependent transactions have a 15% effect on the Kammer 765/500 kV transformer. GSFs indicate that most effective controlling action is to lower PJM generation and raise AEP generation. PJM and AEP are identified as the Controlling System Security Coordinators. In this instance AEP has a dual role. Other RCs/CAs identify additional potential sources of replacement energy.

5. MECS (Dependent System) Reliability Coordinator, AEP (Constrained and Controlling System) Reliability Coordinator, and PJM (Controlling System) Reliability Coordinator are to agree on the GSF effect of controlling action, replacement energy and identified dependent transactions. RCs/CAs agree that the appropriate controlling action is to reduce Generation in Western PJM (GSF = 41%). RCs/CAs must include the effect of emergency replacement energy on constrained facility. If AEP is determined to be the source of replacement energy, the analysis would indicate that equivalent Generation in Western PJM must be reduced by 37 MW to relieve constraint (15MW/.41)) MECS arranges for 37MW of replacement energy, to be supplied from AEP, to replace the controlling action on the PJM system. Discussion does not have to be part of the initial conference call. MECS is responsible for the costs of the replacement energy.
6. AEP (Constrained System **Reliability Coordinator**) identifies **protected transactions**, **controlling action**, and the anticipated duration of the constraint using the RCIS.

7. AEP (Constrained **Reliability Coordinator**) notifies RCs/CAs once constraint is relieved.

8. AEP (Constrained System) **Reliability Coordinator** notifies the LEER participants including PJM (Controlling System) and MECS (Dependent System) via telephone (LEER Hotline) once **controlling action** is no longer required.

**Settlement Process**

MECS is the Dependent System and is responsible for all charges incurred in acquiring replacement energy including transmission charges consistent with existing tariffs.

PJM, as the Sink **Controlling System** will initially pay all energy and transmission service charges as if it were the purchaser of the redispatch service. AEP will send a bill to PJM for applicable energy and transmission services charges.

PJM will then send a consolidated bill for all the payments it made to AEP, adding in additional applicable charges, to MECS for full recovery.
ATTACHMENT B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Northeast Power Coordinating Council Docket No. ER02-___

NOTICE OF FILING


NPCC states that copies of the filing were mailed to the commissions in the states of Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Dakota, Ohio Pennsylvania, South Dakota, Virginia, West Virginia and Wisconsin.

The LEER Participants request that the revised LEER Agreement described in this filing be made effective October 10, 2002.

Any person desiring to be heard or to protest such filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions or protests should be filed on or before ____________. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of these filings are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

Magalie R. Salas
Secretary