



**Electric System Investigation Team of the  
U.S. – Canada Power System Outage Task Force**

Technical Conferences to Seek Recommendations Concerning  
the August 14, 2003 Blackout and Preventing Further Blackouts

**Philadelphia, December 16, 2003**

**Toronto, January 9, 2004**

**Submission made on behalf of the**

**INDEPENDENT ELECTRICITY MARKET OPERATOR (IMO)**

## **Introduction**

The IMO congratulates the Joint Task Force for the approach it has taken in this investigation, the clarity of the interim report's analysis and findings, and for the process it is following in seeking comments and in the development of recommendations. These recommendations should help the industry move quickly to more reliable operations, and to restore public confidence in the industry. They should remedy deficiencies already identified in the interim report by proposing immediate actions to close any gaps. Finally, other deficiencies not identified already must be uncovered through comprehensive audits by independent agents.

Before drilling down on the technical aspects of reliability outlined in the agenda for the Philadelphia technical conference, the IMO would like to take this opportunity to offer a number of general recommendations aimed at preventing large scale outages in the future.

## **Recommendations**

**Recommendation 1** - Reliability standards must become mandatory and enforceable.

**Recommendation 2** – NERC is in the best position to develop reliability standards for North America. The current standards development process based on industry consensus may not be an effective means of ensuring that sufficiently stringent reliability requirements are developed. Additional authority may be required to effectively develop key reliability standards.

**Recommendation 3** – Effective integration of market and power system operations is essential in those areas where both are in place. If not done well, superficial analysis can mask risks to reliability; e.g., assessing the feasibility of transactions is not sufficient analysis to ensure security. Effective markets do contribute to reliability by satisfying both adequacy and security concerns; particularly in avoiding the development of situations that threaten reliability. During the summer of 2002, Ontario relied on the Market to attract the supplies needed to cope with

extreme demand and generation shortfalls. Under some circumstances, to ensure reliability, Reliability Coordinators must be prepared take actions outside of the market including re-dispatching generation.

**Recommendation 4** - The reliability framework adopted by NPCC is a model that should be explored for the other regions. This framework provides for a contiguous Reliability Coordinator footprint and a limited number of Control Areas. While this Model has a proven track record and should be considered as “the standard,” other structures should not be precluded. However, any exceptions to this model must be well grounded as to the need for exception and must be demonstrated as reliable through an approved reliability plan that provides for compliance and facilitates coordination.

**Recommendation 5** – Operator training, training for those who directly support real time operations, and restoration exercises are investments in reliable operations and more emphasis should be placed on them. Minimum training requirements, in addition to NERC Certification (both for operators and possibly for operations support staff), must be developed to ensure that System Operators have the competencies to effectively use the tools, interpret the results of the tools and act independently if the tools fail. Verification of these minimum training standards should be conducted periodically through a rigorous audit process. This training must be coupled with the authority to take independent action (including load shedding) and the necessary knowledge to understand the consequences of contingencies when the tools fail. These competencies can be achieved through effective hiring criteria and staff development practices as well as through regular exercises that involve testing of procedures, tools, communication and non-control room staff. Training doesn’t necessarily have to be accomplished using a simulator.

**Recommendation 6** – Enhanced and clearly delineated authorities and obligations to act are essential. Entities must take action (up to and including shedding load) to

remain within a secure operating state and to quickly return to a secure state when limits are exceeded.

**Recommendation 7** - Minimum standards for tools and processes are needed with enhanced, independent, and expert auditing to ensure better management of both next day and real time reliability issues.

**Recommendation 8** – Meaningful and actionable information exchange among those with reliability responsibility is helpful and should be enhanced, but large volumes of unprocessed data can be detrimental.

**Recommendation 9** – The recently developed NERC Functional Model defines various functions necessary to ensure reliability. It is important that reliability standards development based on this Model proceed even while the relationships among functions are further developed. Care must be taken that the organization of these functions does not dilute nor impose operational or process constraints on the authority or ability of Reliability Coordinators to ensure reliable operation. To this end, reliability accountability should be transferred as soon as possible from the Control Areas to the Reliability Coordinators.

**Recommendation 10** – The existing Transmission Loading Relief (TLR) process is an equitable commercial mechanism for managing flowgate constraints. However, TLR should not be relied on as an effective control action for mitigating operating security limit violations. TLR takes too long to implement and only recognizes flowgates (not all operating security limits are flowgates).

**Recommendation 11** – In addition to satisfying total reserve requirements, generation reserves must be located appropriately for any N-1 contingency event to ensure associated operating security limits can be met during activation, which is common practice in the NPCC region.

## **IMO Responses to Detailed Questions**

We have organized our comments to correspond to the five panel sessions outlined in the technical conference agenda for Philadelphia.

Also attached is an Appendix setting out the background of the IMO, our specific accountabilities for reliability, and the key conclusions of NERC and NPCC audits of the IMO's reliability coordination and compliance operations.

### **Panel A: Reliability Coordination**

The Task Force should strongly urge governments to find ways to enforce compliance with reliability standards. We are aware that energy legislation in the U.S. has stalled, but other alternatives must be developed if it does not pass early in the new year. Provisions to make reliability standards mandatory and enforceable should be put in place where they do not already exist.

NERC itself and the standards development and compliance framework it administers have been developing and changing significantly over the past several years. The transformation has two objectives: first, to adapt to the changing structure of the industry in Canada and the U.S., and second, to prepare for an anticipated move to a mandatory compliance environment. The transformation of NERC and the regional councils is an ongoing task, and challenges all of us to continue to move forward in a coordinated way while accommodating an increasing number of interested stakeholders.

Our focus needs to stay on the public interest as the primary driver for reliability standards, not just the more restricted interests of individual market participants.

- 1. What lessons are learned from the August 14 outage regarding reliability coordination?**
  - We confirmed that the devices that are in place to protect equipment operated as planned.
  - We confirmed that maintaining a well-documented restoration plan, supported by training and rehearsals involving the IMO, market participants and government, was and will continue to be a key investment.
  - We confirmed that close cooperation amongst the IMO, Ontario Transmitters, Generators, market participants and government is essential to achieving an orderly restoration.

- The significance of communication protocols between different control areas and reliability coordinators became evident.
- We confirmed that Reliability Coordinators (RC) require information about their areas of responsibility and reinforced the need for timely dissemination of information.

**What recommendations are there to improve reliability coordination?**

- RCs need to see a wide-area within their Coordination Area. This involves more than flow gates for scheduling purposes
- The RC needs to have the authority to order actions to be taken by the control area/transmission operator under emergency conditions
- The RC needs to effectively communicate with surrounding RCs during emergencies and act in the best interests of the interconnections
- Improved awareness of both internal and external regional constraints, where those constraints impact the reliability of the Control Area (CA)
- Adjoining areas must have a joint operating agreements that address coordination issues
- Clearer standard for acceptable RC performance
- Adequate staffing, proper analysis capability, tools and training
- Common terminology and communication protocols

**2. What reliability coordinator functions and tools are essential for safeguarding the reliability of the interconnections and preventing wide-area blackouts?**

In addition to functions listed in the existing NERC policies (Policy 9D), RCs must have authority and obligation to act to correct frequency, reserve deficiencies and Area Control Error issues.

**What is good performance for each essential function and tool?**

Functions and tools facilitate good performance if they enable RCs to discharge their duties in a comprehensive, accurate and timely manner.

Industry-wide performance standards for tools have not been established.

**3. Should these reliability functions be shared (overlapping) between reliability coordinators and their member systems to assure redundancy? Or should these responsibilities and authorities be divided between reliability coordinators and member systems? If so, how should they be divided?**

We don't believe in shared or overlapping responsibilities. There needs to be clear lines of authority – not overlapping so as to confuse who is responsible under various system conditions. If the RC declares an emergency based on conditions dictated by agreed upon criteria, the RC must have the authority to order emergency redispatch, voltage reductions and load shedding as necessary to relieve overloaded facilities.

However, overlapping capabilities with respect to monitoring does provide valuable redundancy and can make sense within a logical division of accountabilities. For example, the same monitoring capability may be required by an RC with authority for secure operation of the integrated system as may be required by a generation or transmission owner with the responsibility to ensure assets are operated to avoid public safety or environmental hazards or to avoid destructive failure of equipment.

**4. Has the “wide-area overview” of the power system envisioned for reliability coordinators been implemented effectively in the industry?**

There are different interpretations of “wide-area overview,” In the context of Ontario, the IMO interprets “wide-area overview” to mean the monitoring/awareness of key facilities in the neighbouring areas that would have a direct impact on Ontario’s system. Based on this definition, “wide-area overview” of the power system is being implemented effectively in the Northeast.

**If not, why not?**

This has not been the case in other parts of the eastern interconnection:

A defined set of indices (a benchmark of good operating practices) must be developed and RCs should be required to meet these indices prior to "go live" status. NERC certification is a minimum requirement. RC staff must be adequately trained and prepared - they must have in-depth knowledge of their area.

The RC should be sufficiently staffed 24/7 to allow the system to be securely operating during both normal and abnormal events. This is a need to ensure that internal emergencies are handled quickly and notification to neighbouring RCs is immediate.

Emergency Operating Procedures with neighbouring RCs should be explicit as to actions to be taken by whom and when.

The NERC Functional Model that defines functions of various entities (Reliability Authority, Balancing Authority, etc) should clearly define the relationship among the various authorities and clearly define the authorities associated with those functions.

**5. Are the size and number of reliability coordinators and control areas factors in determining their effectiveness and, if so, in what way?**

In Ontario the footprints of the control area and reliability coordinator are the same. This has enhanced effectiveness as the coordination effort is far less than it would be if there were multiple control areas within the RCs footprint. That said, other models that clearly delineate accountabilities and authorities between the CAs and the RC have also worked well [we should know which examples we have in mind here].

**Do complex, changing geographic interfaces between reliability coordinators hinder their effectiveness in safeguarding reliability and, if so, what can be done to assure effective coordination across those interfaces during a transitional period?**

RTO boundaries are in a state of flux - some expanding as new members join, others contracting. Rapid RTO expansion has the risk of the RC not becoming knowledgeable enough about the detailed operations of new member systems. There has to be better training and enhanced tools. A thorough audit and certification process is required to ensure adherence to reliability plans and industry standards. Reliability plans need to be more detailed, and an audit process is required to ensure the RC is complying with the reliability plan.

**6. What recommendations are there to ensure the basic reliability safeguards noted in Chapter 2 of the Interim Report are effective in preventing future cascades?**

Clear and unambiguous standards that can be consistently applied with appropriate compliance monitoring and enforcement will ensure the basic reliability safeguards are effective.

## **Panel B: Emergency Response**

Prevention is by far the best approach in dealing with emergencies. This is accomplished through good planning and coordinated operations, adequate investments, effective certification, and compliance audits and reviews. Mandatory enforceable standards set the requirements, but they establish the minimum requirements. Compliance with those standards requires the right functions to be assumed by the right entities equipped with the required attributes, authorities and capabilities. All entities should comply with approved reliability requirements that are critical to the prevention of wide area outages. Prevention hinges on ‘Being Prepared’ - all parties must be continuously ready for the next contingency. Preparedness hinges on training, comprehensive knowledge of systems, service area, facilities and operating companies, and continuous rigorous education.

Conditions change in unanticipated ways, and all entities must have the capability of ensuring their systems remain secure immediately following any significant change in status. Clear accountabilities are essential for the day to day integrity of grid operations. The Task Force Interim Report notes this at page 6: “ The central organizing principle of reliability management is to be prepared for the unexpected”. In analyzing previous blackouts, the taskforce found that “ Operators in several of the events were unaware of the vulnerability of the system to the next contingency” (page 72).

1. **What recommendations are there to improve the ability of operators to identify, declare, and effectively respond to emergencies? What training and certification of qualifications should be required?**
  - Establish a framework for a coordinated and effective response to emergencies. A good framework assigns each market participant specific roles in an emergency plan. This coordinated effort ensures the capability to respond to a wide range of emergencies.
  - Operations staff must have operating guidelines and strategies that are robust and sufficiently wide in scope to apply to a wide range of post disturbance configurations
  - Continuous review and update of Restoration plans and procedures must be carried out. Various components of the plan are subjected to integrated testing so that equipment critical to the restoration process is tested on a regular basis

- Effective emergency response requires capable and trained personnel implementing actions supported by the right processes, facilities and equipment. Pre-identification of priority loads is critical.
- High standards for Uninterruptible Power Supply (UPS) and other equipment (phones, SCADA etc)
- NERC certification is a minimum requirement – operators require an in-depth detailed knowledge of their area and general knowledge of surrounding areas
- Drills and exercises – regular extensive, top to bottom, including extensive and detailed emergency preparedness based training. Clear concise, controlled, orderly and methodical Restoration implementation helps prevent equipment damage, protects public safety and ensures orderly load restoration without recollapse

**2. What minimum tools do operators (and reliability coordinators) need to recognize and manage system emergencies effectively?**

- Operators must operate the system under studied and known conditions at all times. The ability to derive limits and act within NERC approved timelines is the key objective of emergency preparedness. It is an onerous task at times, but it is essential and tools must enable this core Reliability Coordinator’s accountability.
- Tools must quickly enable operators to identify the next critical contingency and actions required to remain secure. The occurrence of multiple contingencies must not be allowed to become a source of insecure operation because of inadequate tools or procedures.
- Flexibility in the range and depth of the tools’ scope of analysis is essential. During emergency events the tool must enable operators to scan a wider area if necessary, and to zoom in and explore specific details if necessary
- Potential islanding sites require frequency monitoring - continuous attention to voltage profile during restoration is critical to success
- Restoration aids that assist in voltage profile calculations, load restoration capabilities and equipment constraints are a must.
- Proper communications protocols must be followed each and every day to ensure effectiveness when required during emergencies

**3. Between system operators and reliability coordinators, who has the authority and responsibility to declare emergencies and how should that relationship work?**

- In Ontario the IMO is the RC, the CA and directs the operation of the IMO controlled grid (equipment > 50KV). Within the Electricity Act, the Ontario market rules and downstream agreements and manuals, individual entities have the right to declare emergent conditions for safety, equipment or environmental protection. The IMO has the local and global perspective and has the authority, responsibility and obligation for determining emergent conditions. We’ve found this practice to work exceptionally well.
- . The RC should have the authority to declare emergencies within their reliability area.

**4. Do operating personnel (and reliability coordinators) have the necessary authority to act in a timely manner during an emergency? Are they empowered to act in an emergency to prevent conditions that could lead to a cascading outage? What can be done to reinforce that authority?**

- In Ontario, this is certainly the case. The interim report’s findings suggest that other Reliability Coordinators did not exercise their authority to act in a timely manner. We also point to the importance of awareness of system status.

- To assist in reinforcing that authority, specific stronger language should be added to the current NERC policies. As well, specific direction should be sent to Reliability Coordinators and their operating authorities to reaffirm their obligation to the above. Finally, the obligation for operators to respond to a Reliability Coordinators direction should be clearly articulated and failure to do so should result in sanctions.

**5. Do operating personnel (and reliability coordinators) have adequate system resources (redispatch, reconfiguration, load-shedding, etc.) to take timely corrective action during a system emergency? Is a full range of credible emergencies being assessed during operations planning? Are there adequate resources available to respond to rapidly escalating system emergencies?**

- Yes. System resources are generally available, the important factor is for Reliability Coordinators to be aware, in detail, of the full range of options available to them, including load shedding. To illustrate that load shedding is an effective emergency action, due to extreme events, Ontario has shed firm load twice in recent history to remain within security limits and protect the interconnections.
- We take the view that over-reliance on TLR (Transmission Loading relief) as a method to manage real time limit violations is not prudent, and can in fact lead to an insecure operating state. The focus on a few flow gate conditions is inadequate. To illustrate this inadequacy, there have been two instances in the past 6 years where portions of Ontario have collapsed when external entities attempted to call TLRs while overloads existed in their systems beyond the NERC 30 minute standard – this isn't acceptable
- On the question of whether a full range of credible contingencies is being assessed, we stress that in addition to an exhaustive range of analysis, appropriate actions must follow from the results. The most critical is reparation - ASAP but no longer than 30 minutes. Its an obligation that rests with all the RCs to act in the best interests of the interconnections
- Satisfying total reserve requirements is not enough. Reserves must be located appropriately to ensure associated operating security limits can be met during activation. Reserves must be positioned such that they can be activated when required.

**6. What recommendations are there to improve communications among operating personnel (and reliability coordinators) during emergencies?**

- Priority communication paths to be used by staff with authority to act
- Consistent industry approved terminology with positive confirmation
- Practice and training

**7. What recommendations are there to ensure operators (and reliability coordinators) focus on reliability and are not distracted by other activities?**

- Roles and authorities should be well established and documented
- Overall expectations and priorities should be well understood by all

## **Panel C: Operating Tools**

Reliability Coordinators must have access to a suite of tools that allows them to exercise their accountability to maintain the reliability of their coordination area. These tools must have the capability to define and monitor Interconnection Operating Reliability Limits (IROL's) and assess contingencies. Appropriate and reliable data must be provided to support these tools and clear information must be presented to system operators. Off line studies and analysis must be performed to define IROL's and study system conditions both pre and post contingency. Reliability Coordinators must have the training necessary to effectively utilize these tools and interpret their results.

**1. What criteria for “observability” of the power system must be met to ensure reliable operation and avoid cascading outages?**

Operators must ‘observe’ all elements that can have an impact on reliability. Identification of the scope of observation is therefore dependent on the specific system and its operating criteria. We refer to NERC Policy 9D, which identifies the criteria and functions of a Reliability Coordinator, including requirements for continuous monitoring of a reliability area, monitoring parameters “that have a significant impacts within the reliability areas,” conducting assessments and having monitoring programs to assess contingency situations. Reliability Coordinators must be required to control frequency, correct ACE, perform security assessments and have monitoring programs to assess contingencies that impact on a wide area and could result in cascading outages.

**2. Are dynamic map boards essential for maintaining a broad overview of system conditions? What other primary or backup tools/displays can be provided to allow the operator to effectively maintain an overview of system conditions?**

Dynamic map boards are the preferred means of providing operators with a broad overview of system conditions. Modern wallboards consisting of projection screen arrays provide additional flexibility in displaying key information, zooming-in on specific areas and displaying non-traditional relevant information. A wallboard and other tools are only as good as the data they depend on. It is important to; 1) have sufficient data to provide adequate monitoring and analysis; 2) have redundant data and data communications paths to reduce the risk of losing critical data.

**3. What minimum set of operating tools should system operators and reliability coordinators have to be able to do their jobs effectively in normal and emergency situations?**

We have combined the answers to questions 3 and 4 (see Q.4 below).

**4. What SCADA/EMS functions (e.g. state estimation, real-time contingency analysis, voltage/reactive monitoring, controls; alarms, backup systems/centers, etc.) are necessary to assure reliable power system operation and what should be the performance criteria for each?**

The minimum required tool set for Reliability Coordinators is established in NERC Policy 9D. These include monitoring and analysis tools such as state estimators, contingency analysis tools, communications facilities, and off line study and analysis tools. This minimum set of tools should

be expanded to include adequate alarms to indicate when critical functions are not updating and when data is not current. This information is critical to ensuring that tools can be relied on when needed and are providing the proper results to system operators

Off line analysis, while not considered a system operator's tool, is critical in identifying Interconnection Reliability Operating Limits (IROL's). Without adequate analysis to identify IROL's and to provide sufficient monitoring of these IROL's the system operator can't maintain reliability. System operators must understand where their system is constrained, why it is constrained and what control actions are available to mitigate constraints.

In both real time and off line assessments, contingency analysis tools are only as good as the scope they cover, the quality of data, and the accuracy of the models they use. The scope must cover all IROLs, the models must be representative of the system being studied, and the data must be comprehensive and accurate.

To ensure reliability, the industry must shift its focus from identifying and managing flowgates through commercial processes, such as TLR, to identifying and managing IROL's. Flowgates and IROL's are not always synonymous. We support market-based congestion management, but RCs must clearly recognize that they must have additional measures, when market-based mechanisms will not be sufficient or timely to correct violations and re-prepare within 30 minutes.

NERC Policy 9 also identifies requirements for the next day operations planning process. This includes performing system studies and security analysis to ensure that the bulk power system can be operated in anticipated normal and contingency conditions. This can only be done if the Reliability Coordinator has the authority to manage outages to transmission and generation facilities to ensure that IROL's will not be violated. IROL's protect against voltage instability and are dependant on minimum voltages being maintained. Adequate reactive resources can be ensured, in the planning timeframe, through a comprehensive outage management program.

While it is important to obtain data from neighboring reliability areas that impact on your area, it is not important to have visibility of IROL's within the neighboring area. This can lead to confusion where interpretation of IROL's is required or where control actions are in place to mitigate the impact of a contingency.

**5. What actions are appropriate (for IT and operating personnel) when mission-critical monitoring and control systems fail? What backup tools, provisions, or procedures are needed for mission-critical monitoring and control systems?**

A system operator's tools must have a high degree of reliability attained through redundant infrastructure and carefully controlled change management processes. NERC policy 9 requires a Reliability Coordinator to have continuous monitoring of their reliability area including provisions for backup facilities. Policy 6 requires Control Areas to have a plan to continue operation in the event its control center becomes inoperable however does not address this for Reliability Coordinators. Coordinators must have a viable and complete set of back up tools. In Ontario there are triplicated capabilities, any one system can provide coordination capability.

While defining the required tools is essential, it is equally important to recognize their limitations. If tools fail, the backup is the competence, experience, preparedness, and knowledge of operating staff. These should translate into the ability to:

- 1) correctly interpret the result presented by tools;
- 2) adequately assess system conditions when the tools fail;

- 3) act independently, without confirmation by the tools, to ensure the system is operating in a secure state.

**6. Are SCADA/EMS systems being properly maintained? Are identified problems being proactively resolved and shared among users of SCADA/EMS systems?**

In Ontario, there are established performance measures for the EMS. There are vendor user groups that allow experience to be shared.

## **Panel D: Planning, Design and Maintenance Issues**

- 1. Are planning and seasonal studies effective in assessing future system conditions, particularly with regard to avoiding cascading outages? What additional studies or improvements are appropriate?**

Yes these studies are effective, provided they consider expected conditions, and also consider credible outages and transfers.

- 2. Are system models used for study and analysis sufficiently accurate, particularly with regard to generator and load power factor assumptions and dynamic characteristics, etc.? What improvements are appropriate?**

The models are sufficiently detailed, however the assumptions must be benchmarked against actual conditions, to ensure that the study conditions are realistic. To do this may require checking actual historical data, conducting surveys and performing tests.

- 3. What recommendations are there to ensure transmission lines and facilities ratings accurately reflect actual conditions? How should ratings be effectively coordinated? Are dynamic ratings for lines appropriate?**

Same as 2 above. Dynamic ratings are appropriate, provided they accurately reflect the capability of the circuits.

- 4. What should be done to ensure adequate voltage support on all parts of the system, including static and dynamic reactive reserves? What can be done to improve the coordination of voltage schedules and reactive power across system boundaries?**

Studies must assess voltage control capability for expected or credible conditions, including the ability to restore voltages to acceptable levels following recognized contingencies. Where studies show that the security of an area depends on the VAR resources (type, amount and location) in a neighbouring area, then these requirements must be known by both areas, they must share the information about them, and they must co-ordinate their actions so that the requirements are satisfied. A next day and real-time outage management process is needed to ensure that adequate reactive reserves are available and minimum voltages can be maintained pre and post contingency.

- 5. What recommendations are there to address vegetation management and right of way maintenance issues to ensure non-random line failures similar to those experienced on August 14 do not occur in the future?**

In Ontario, the equipment owners are responsible for setting their equipment ratings. From the IMO perspective, it is the expectation and obligation of the asset owner to perform the required maintenance or revise facility ratings to accurately reflect the conditions of the equipment and its environment..

- 6. Are simultaneous transfer capabilities being consistently evaluated on a wide-area basis in the Eastern Interconnection? What improvements are recommended?**

In the northeast, we believe they are. Where it is impractical to assess all possible combinations of transfers, a selected set of conservative or “stressed” transfer conditions are evaluated to identify boundary conditions. In the IMO, real-time dispatch and hourly schedules are always checked against these boundary conditions before approval.

- 7. Is a complete and robust set of contingencies being evaluated with regard to avoiding and minimizing the impacts cascading outages? What improvements are recommended? What changes are needed to system design criteria to reduce the risk of uncontrolled cascading?**

In Ontario, we assess all design and operating contingencies and adhere to the NPCC design and operating criteria (A-2). To avoid cascading outages, we believe that studies must include all design criteria contingencies; that the assessments test for thermal, voltage and stability limits; and, that they include credible or conservative variations in dispatch and simultaneous transfers. Sensitivity studies ought to identify the impact on transfer capability for single or multiple prior outage conditions.

## **Panel E: Protection and Controls Issues**

1. **What practical technologies or methods could have reduced the amount of load and generation lost on August 14 and/or contained the blackout to a smaller geographic area? What could have been done to minimize the amount and duration of electricity customer service interruption?**
  - We encourage the development of proven new technologies, but want to be careful not to implement designs that fragment the system unnecessarily.
  - We are not convinced that “safety nets” – i.e., pre-designed separation points – is a workable or a preferable strategy; particularly in the tightly linked eastern interconnection. We prefer strengthening the coordination to preventing weak links from developing, rather than disconnecting from neighbours at the first sign of trouble.
  
2. **Are the line protection schemes commonly used today sufficient to arrest and minimize the effects of system cascades? What improvements are recommended to transmission system protection approaches?**
  - No. Line protection schemes are meant to protect equipment, not the entire system.
  
3. **Are the generator protection and control schemes commonly used today sufficient to arrest and minimize the effects of system cascades? What improvements are recommended to generation protection and controls based on the performance of generators on August 14 during the cascade and subsequent restoration?**
  - No. Generator Protection schemes are meant to protect equipment, not the entire system.
  
4. **Is the under-frequency load shedding philosophy commonly used today sufficient to arrest and minimize the effects of system cascades? Was automatic under-frequency load-shedding effective and can it be improved based on performance on August 14? Should under-voltage load shedding be given more consideration for certain applications?**
  - NPCC is currently investigating this issue and will report back in 2004. It is important to not treat symptoms but to focus on the root cause of the problem
  
5. **What existing or new technologies could be cost-effectively adopted, such as digital tools for automated monitoring (e.g. phasor measurements); special protection schemes; and controls? What is the feasibility of islanding schemes or other special protection schemes to reduce the risk of uncontrolled cascade?**
  - We encourage the development of proven new technologies, but want to be careful not to fragment the system unnecessarily.
  
6. **What improvements can be made to system measurements and diagnostics for event analysis? What were the lessons learned regarding measurements and diagnostic data from the analysis of the August 14 blackout? Can more robust measurements be used to validate system analysis models? What is the value of adding time synchronized equipment?**
  - Event analysis devices in Ontario were very effective. Throughout the interconnection there is a need for more of them and they need to be synchronized in time. A common standard is required.

The IMO appreciates the opportunity to table these comments, and looks forward to participating further as the Task Force moves toward its Final Report.

## Appendix

### Background on the Independent Market Operator in Ontario (IMO)

The IMO was created in 1999 as part of Ontario's restructuring of its electricity sector, and is the functional equivalent of a U.S. based ISO or RTO such as NYISO, PJM, or ISO-NE. The objectives of the IMO are established by Ontario's *Electricity Act, 1998*. Our objectives are to:

- (a) exercise and perform the powers and duties assigned to the IMO under this Act, the market rules and its licence;
- (b) enter into agreements with transmitters giving the IMO authority to direct the operations of their transmission systems;
- (c) direct the operations and maintain the reliability of the IMO-controlled grid;
- (d) establish and operate the IMO-administered markets;
- (e) collect, and provide to the public, information relating to the current and future electricity needs of Ontario and the capacity of the integrated power system to meet those needs;
- (f) participate in the development by any standards authority of standards and criteria relating to the reliability of transmissions systems; and
- (g) work with responsible authorities outside Ontario to coordinate the IMO's activities with their activities.

Participation in and operation of the IMO-administered markets is governed by a comprehensive set of Market Rules. A Board of Directors, made up of independents as well as stakeholders, governs the IMO and approves the Market Rules. The IMO-administered markets have been in operation since May 1, 2002.

## **Specific IMO Accountabilities Regarding Reliability**

The IMO's objects assigned to it by Provincial legislation include participating in the development of standards and criteria relating to the reliability of transmissions systems, as well as directing the operation and maintaining the reliability of the IMO-controlled grid.

The IMO's licence, granted by the Ontario Energy Board (OEB), obligates the IMO to enter into agreements with Transmitters for purposes of directing the operation of the grid.

An extensive set of Market Rules goes into considerable detail related to reliability obligations, authorities, monitoring and enforcement. A copy of the Market Rules is available on the IMO website ([www.theimo.com](http://www.theimo.com)).

The IMO has full statute-based authority for establishing, monitoring and enforcing reliability standards. In this regard, the IMO has been an active participant in NERC and NPCC and has adopted the standards developed through those organizations as the basis for reliability standards in Ontario.

The IMO is Ontario's Control Area operator, and is party to the Northeast Power Coordinating Council (NPCC) agreement.

The IMO is also the reliability coordinator for Ontario and was the subject of a NERC reliability coordination audit in October, 2002. The audit report concluded as follows: "The Audit team congratulates the IMO on an excellent audit report, and concludes that the IMO meets the intent of Policy 9 and Appendices for a Reliability Coordinator. The Audit Team was favorably impressed with the IMO

operation.”

A 2002 reliability compliance audit by the NPCC concluded that the IMO’s procedures and practices are exemplary in discharging its reliability authority functions. The audit concluded that “the Ontario Area compliance program is unique in that it is directly tied to the established market rules and licensing requirements. This structure makes compliance a binding obligation and facilitates in the administration and enforcement of compliance. NPCC’s Compliance Monitoring and Assessment Subcommittee (CMAS) encourages other Areas to consider such a compliance program model”.