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Introduction and Evaluation Process

The North American Electric Reliability Corporation (NERC) Reliability Readiness Evaluation and Improvement Program is one of the commitments of NERC and the industry to strengthen the reliability of the North American bulk power system. The program conducts independent evaluations of balancing authorities, transmission operators, reliability coordinators, local control centers, transmission owners, and other key entities that support the reliable operation of the bulk power system to assess their preparedness to meet their assigned reliability responsibilities. The evaluations identify strengths and areas for improvement in an effort to promote excellence in operations among these organizations. The document *NERC Readiness Evaluation Procedure* describes and defines the process used for reliability readiness evaluations. This document and other documents related to the program are available at http://www.nerc.com/~rap/.

The reliability readiness evaluation teams, each led by a NERC staff member and a regional co-leader, include industry volunteers with considerable expertise selected to provide representation from other interconnections, other regions, and neighboring operating entities. The teams also typically include representatives from the Federal Energy Regulatory Commission (FERC) staff.

The public version of the reliability readiness evaluations report contains the majority of the evaluation team's findings. Any discussion of findings pertaining to critical energy infrastructure will be contained in Appendix 1, a confidential appendix to the report that is sent privately to the organization evaluated and is not included in the public version of the report.

The evaluation team for PECO Energy met on-site with PECO representatives on September 25 – 27, 2007. This report reflects the views and recommendations of the evaluation team regarding the readiness of the PECO to meet its responsibilities as a transmission owner/local control center.

Evaluation Team

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Organization Profile

Exelon Corporation, a Fortune 500 company with more than $15 billion in annual Rev.enues, is one of the nation's largest electric utilities. It distributes electricity to approximately 5.2 million customers in Pennsylvania and Illinois and distributes gas to 470,000 customers in the Philadelphia area. Exelon operates the largest nuclear fleet in the United States and the third largest commercial nuclear fleet in the world.

Exelon Corporation is the parent company of PECO Energy. PECO is an energy delivery and services company that provides electricity to more than 1.6 million customers in the city of Philadelphia as well as Bucks, Chester, Delaware, Montgomery and York counties in eastern Pennsylvania. Exelon and its nearly 2,300 PECO employees are responsible for maintaining more than 550 power substations and 21,000 miles of power lines that make up the electric transmission and distribution system. PECO has 1,179 circuit miles of transmission lines at 500, 230, 138, and 69 kV.

At the time of the Readiness Evaluation, the Transmission Operations and Planning organization was undergoing a transition whereby it would be structured with direct reporting up through the respective energy delivery companies of PECO and ComEd. Prior to this transition, Transmission Operations and Planning was centrally organized under the Exelon Energy Delivery (EED) organization. PECO's Transmission System Operations (TSO) reports directly to the PECO Transmission Operations and Planning organization.

PECO is a member of the PJM Interconnection regional transmission organization — registered as a NERC transmission owner, load serving entity, and distribution provider — and a member of the Reliability*First* (RFC) Region. PECO is well integrated into the PJM system. In 1927, PECO was one of the three utilities that signed the 1927 PA-NJ Agreement, creating an integrated power pool, which became the PJM Interconnection in 1956 when two additional utilities signed the PJM Agreement.

PJM is the registered NERC transmission operator, transmission planner, balancing authority, transmission service provider, and reliability coordinator for PECO. PJM coordinates wholesale power transactions and controls transmission assets assigned to PJM under its operating agreement. PECO has 138, 230, and 500 kV interconnection points, which are under the functional control of PJM. PECO interconnects with seven other utility-owned electric companies, all members of PJM, including Baltimore Gas & Electric at 500 and 230 kV; Old Dominion Electric Cooperative at 500 kV; FirstEnergy Solutions at 500 kV; PPL Electric Utilities at 500 kV and 230 kV; Public Service Electric & Gas at 500 kV, 230 kV, and 138 kV; and PEPCO Holdings Company at 230 kV.

PECO provides around-the-clock coverage with three to four real-time operating positions in its local control center. The shift manager position has overall responsibilities for the control room activities. PECO staffs a position known as the "reliability dispatcher," which interfaces with PJM, the shift manager, and transmission dispatchers on duty. This position also performs contingency analysis and load flow studies for scheduled and emergent activities on the

transmission system. Two transmission dispatcher positions are staffed from 0530 to 2130 Monday through Friday; one transmission dispatcher is on duty at all other times.

PECO is a summer-peaking company and reached its historical peak of 8,932 MW on August 3, 2006. PECO's winter peak of 6,852 MW was set on February 5, 2007.

Executive Summary

The evaluation team found no significant operational problems and concluded that the PECO local control center has adequate facilities, processes, plans, procedures, tools, and trained personnel to perform the local control center/transmission owner functions necessary to maintain its responsibilities for the safe and reliable operation of the bulk power system. The evaluation team identified a number of positive observations. It also offers 17 (seventeen) recommendations that, if implemented, will enhance PECO's readiness to operate reliably and maintain the reliability of the bulk power system. The recommendations are listed in order of importance.

Positive Observations

The evaluation team noted the following positive observations during the reliability readiness evaluation process:

1. PECO has developed and implemented a program named the Corrective Action Program that monitors and responds to all events; the program evaluates human factors, apparent root cause analysis, procedural requirements, systems operation, program execution, and all supporting communications in an effort to achieve operational excellence (Section 15).
2. PECO has an effectively managed outage coordination process (Section 8).
3. PECO has strong area voltage management procedures and practices (Section 12.d).
4. PECO has excellent document numbering and format protocols for operating policies and procedures (Section 6).
5. PECO has an excellent body of operating policies and procedures — new and revised (Section 6).
6. Confidential information on the computer system that is redacted from public report. See discussion in Appendix 1.
7. Company representatives did an excellent job organizing the requested documentation for the readiness evaluation.
8. PECO performs a walking vegetation inspection of the transmission system on an annual basis (Section 16).
9. PECO has a good geographical wide-area view and monitoring of the 500 kV systems that includes all classic PJM companies (Section 12.a).
10. PECO has an effective process to manage the model updates for the energy management system (EMS), state estimator, PJM base case, dispatcher training simulator (DTS), and real-time contingency analysis application (Section 7).

Recommendations

The evaluation team recommends that PECO take the following actions to address issues discovered during the evaluation process:

1. Develop and implement system dispatcher training on nuclear power plant critical bus voltage thresholds to enhance operator contingency response skills (Section 17).

2. Confidential information on communication systems and support redacted from public report. See discussion in Appendix 1.
3. Confidential information on computer systems and support redacted from public report. See discussion in Appendix 1.
4. Validate the operability of relays for the designated blackstart cranking paths identified in the restoration plan (Section 13).
5. Increase the use of the dispatcher training simulator (DTS) in the training program to provide opportunities for system operators to enhance their transmission system operating skills (Section 5).
6. Strengthen the evacuation procedure for the primary control center to address the transportation requirements associated with moving to the alternate control center (Section 9).
7. Include with the new EMS an alarm processor monitoring function that will immediately alert the system dispatcher in the event of an alarm processor failure (Section 12.b).
8. Review and implement, as appropriate, a simplification of the multiple voltage levels displayed on the mapboard (Section 12.d).
9. Develop and implement a procedure to notify neighboring control centers when maintenance activities are being performed on tie-line rights-of-way and the PECO control center for similar activity on PECO rights-of-way (Section 16).
10. Develop and implement training on NERC and RFC terminology, such as interconnected reliability operating limits (IROLs) and security operating limits (SOLs), to help operators establish a common basis of definition and terminology (Section 12.e).
11. Develop and implement an electronic system dispatcher log (Section 10).
12. Develop and implement a frequency display screen in a wide-area geographic format on the new EMS (Section 12.c).
13. Increase efforts in the current initiative to capture operational knowledge and manage the changing workforce demographic (Section 5).
14. Strengthen the shift-change procedure to specifically address the requirements to bring a system dispatcher back on-desk after an extended absence (Section 6).
15. Post the operator authority letter at the alternate control center to emphasize operator authority (Section 2).
16. Review and revise the transmission interconnection agreements, as appropriate, to reflect the current operating environment as defined in NERC standards and regional requirements (Section 1).
17. Investigate and implement, as appropriate, a training management tool to ensure all aspects of training are coordinated and documented (Section 5).

Discussion

The reliability readiness evaluation team examined the following key areas during the evaluation. The detailed discussion that follows provides the foundation for the recommendations and positive observations the team identified. The report uses the generic term "system operator" to refer to all on-shift operating personnel responsible for executing the functions necessary to operate reliably and maintain the reliable operation of the bulk power system. This term will be used for the discussions unless additional specificity is required, such as *balancing* system operator or *transmission* system operator.

Agreements

The local control center must have agreements that establish its authority as a transmission owner. The local control center must have agreements that establish the reliability coordinator and balancing authority/transmission operator for its footprint.

PJM is the regional reliability coordinator, transmission planner, balancing authority, and transmission operator for the PJM footprint, which includes the PECO transmission zone. PJM directs the scheduling, real-time load-following dispatch of generation and transmission system schedules, and congestion management. These responsibilities are part of the *PJM Operating Agreement*, of which PECO is a signatory.

As the local control center and transmission owner, PECO is required to physically operate and maintain its transmission bulk power facilities in a safe and reliable manner. The local control center is responsible for monitoring the transmission system voltage and directing the operational aspects of the voltage control equipment. Additionally, the local control center is required to take any additional actions required to prevent an imminent emergency condition and to restore the transmission system from a contingency event. Finally, the local control center is responsible for all physical switching and blocking of transmission facilities. These responsibilities are expanded in detail in the document *Amended and Restated Operating Agreement of PJM Interconnection — Section 11.3 — Member Responsibilities*.

PECO has interconnection agreements with all neighboring utilities and generators connected to the PECO transmission system. All PECO's interconnected neighbors and generators are members of PJM and governed by the *PJM Operating Agreement.* The Exelon generation and the nuclear power plants have signed affiliate-level service agreements with PECO that define in greater detail the operating services provided beyond the standard PJM agreement.

Since PECO was one of the three founding members of PJM (PA-NJ Agreement in 1927) and then the integrated power pool in 1956 when two additional members joined, some of the interconnection agreement documents pre-date the NERC standards and the associated regional standards and guidelines. The evaluation team could not verify that all of these interconnection agreement documents have been reviewed and revised as appropriate to reflect the current operating requirements of the NERC standards and regional guidelines. The evaluation teams recommend that PECO review and revise the transmission and generation interconnection agreements accordingly.

Operator Authority

The local control center is responsible for establishing and authorizing the system operator position that will have the on-shift responsibility for the safe and reliable operation of its portion of the bulk power system in cooperation with neighboring operating entities, the balancing authority/transmission operator, and the reliability coordinator.

The PECO transmission system dispatcher job descriptions clearly provide the system dispatchers with the authority to operate the transmission system in a safe and reliable manner. In addition, PECO system operations personnel have a published policy, *OP-ED-Y006 Transmission and Distribution System Operations Dispatcher Authority,* to operate the transmission system in a safe and reliable manner up to and including the dropping of firm load that is posted in the primary control center. A copy of this policy is not posted in the backup control center; therefore, the evaluation team recommends that a copy of this policy be posted in the backup control center. The evaluation team notes that PECO system dispatchers would normally shed load at the instructions of PJM as the transmission operator; however, the PECO system dispatchers would shed firm load in the event of an emergency condition that required immediate action.

The transmission system dispatcher interviews conducted by the readiness evaluation team strongly indicate that the PECO system dispatchers are both willing and able to operate the transmission system in a safe and reliable manner up to and including the shedding of firm load. The interconnected neighboring transmission system operators are confident of the PECO system dispatchers' capability and authority to operate the transmission system in a safe and reliable manner.

Delegation of Authority

Any functions that have been delegated must be clearly documented. The documentation must recognize that the balancing authority/transmission operator that is delegating the function continues to be responsible for that function.

PJM has not delegated any reliability coordinator, transmission planner, balancing authority, or transmission operator authority to PECO. PECO has not delegated any local control center or transmission owner responsibilities to PJM or any other entity.

PECO performs some overlapping operating functions with the balancing authority/transmission operator; however, these should not be considered as delegated operational functions. In the opinion of the evaluation team, the net result of these overlapping activities serves to strengthen operational reliability.

Staff Certification

Local control center operators must be PJM-certified transmission operators. The local control center must have a sufficient PJM-certified transmission operator staff for continuous coverage of the system operator positions. The reliability coordinator and the balancing authority/transmission operator must have sufficient NERC-certified operators for continuous coverage of all operator positions.

All PECO transmission shift managers, reliability dispatchers, and transmission dispatchers in real-time operation are required to be PJM-certified transmission operators. PECO complies with this requirement and documents this requirement in policy *OP-ED-Y009 PJM Certification Policy.* Additionally, four PECO shift managers are NERC-certified.

PJM Manual 01: Control Center Requirements requires transmission system operators in a local control center to pass the PJM certification exam. The exam's technical content, scope, number of questions and passing grade requirements is defined by the PJM regional transmission organization's training group. The PJM certification is valid for five years. PECO actively manages this process.

Training

The local control center system operators must be adequately and effectively trained to perform their roles and responsibilities. The local control center must have documents that outline the training plans for the system operators. The local control center must have training records and individual staff training records available for review.

PECO has a well-structured and documented training program staffed by two full-time training employees and another employee for whom training constitutes one-half of his assigned duties. The initial training program utilizes a combination of training delivery methods, including classroom instruction, self-study, off-site training at the PJM dispatcher seminar and initial training program, DTS activities, and one-on-one training. The on-the-job trainer uses a proficiency checklist to guide the training process and evaluate the progress of the trainee. Weekly and monthly reports are completed by the trainer to document the trainee's progress. Successful completion for the initial training program is determined by a management qualification review in accordance with *OP-ED-P047 TSO Dispatcher Qualification Review Standard.*

PECO procedure *OP-ED-P043 Continuing Training Program* provides training guidance to transmission dispatchers after they have completed the initial training program. This program consists of three mandatory six-week training cycles in which all dispatchers are required to attend three days of NERC-approved learning activities and the PJM dispatcher seminar. Training topics vary depending upon PECO's operating environment as well as the individual needs of the dispatcher. The curriculum is determined by a curriculum advisory committee for each year's cycle. The DTS is used to enhance and reinforce the hands-on aspect of training. The evaluation team recommends that PECO significantly increase the integration of the DTS into the training curriculum.

On average, the PECO training program provides 70 to 90 hours of training per year for shift managers, reliability dispatchers, and transmission dispatchers. The program will provide 70 to 80 hours of training in the calendar year 2007 — approximately 20 hours will involve the use of the DTS, and 20 plus hours involve emergency operations training. PECO uses a number of means to evaluate training effectiveness, such as tests, worksheets, team drills, DTS performance, and review by the Curriculum Review Committee. PECO considers training a key element in the Corrective Action Program discussed in Section 15 of this report.

PECO uses a learning management system to retain training records and manage the training program. Based on questions about the ability of this tool to adequately support this requirement, the evaluation team recommends that PECO develop and implement, as appropriate, a training management tool for total program management.

PECO continues to study its workforce demographic to determine key strategic issues, such as retention of knowledge and experience, potential candidate pools for operating positions, and appropriate barriers to entry into the operating career fields. The evaluation team recommends that PECO increase efforts in its current initiative to manage the changing workforce demographic to capture and retain the knowledge and skills necessary to support the challenging requirement of operating the bulk power system in a safe and reliable manner.

Operating Policies and Operating Procedures

The local control center must have an established procedure to ensure that system operators and operations staff is aware of any changes to NERC, regional, and/or local policies or procedures prior to taking over control of a shift position.

The balancing authority/transmission operator and the local control center must have shift change procedures for updating incoming shift personnel on the current status of the system.

PECO has a very comprehensive body of operating policies and procedures that follows a well-defined numbering protocol and supports, clarifies, and implements the requirements stated in PJM operating manuals and procedures. The PECO operating policies and procedures are reviewed and revised on a four-year cycle; however, this practice is under review, as a common fixed-review cycle may not be appropriate for each procedure. These documents are stored and made available for use on the Exelon Management Model Web site. Commonly used procedures in Transmission System Operations are maintained in a Microsoft SharePoint site within the intranet and listed as "TSO Commonly Used Procedures." These procedures are backed up to a compact disc monthly and made available to the shift manager. The evaluation review team commends PECO for the following:

- An excellent body of operating policies and procedures that cover the full scope of transmission system operations for a transmission owner
- Excellent document numbering and format protocols for operating policies and procedures that classify distribution into four levels based on document complexity and importance

PECO has a well-defined process, listed in *AM-ED-1001 Development, Review, Approval and Revision of Controlled Documents*, for providing document life cycle guidance. After a document is approved it is assigned one of four classifications for distribution: information only, read-and-sign review, supervisor briefing, or education which requires training. The Exelon learning management system is used to track the required actions associated with the distribution classification as explained in procedure *EA-ED-2001 Document Change Implementation*.

The evaluation team reviewed *OP-ED-9076 Dispatcher Shift Turnover and Brief* and found that the aspect of bringing a transmission dispatcher back on-desk after an extended absence is not

covered. The evaluation team recommends that PECO strengthen the shift-change procedure to specifically address the requirements to bring a system dispatcher back on-desk after an extended absence. Additionally, the team suggests that PECO consider a checklist approach to shift change that involves a mutual sign-off between the incoming and outgoing transmission dispatchers.

Planning

The local control center and its supporting planning organizations must have a process for day-ahead planning and for longer-term planning, such as week-ahead, seasonal, and year-ahead, for the operation and outage scheduling of transmission facilities and generation and reactive resources.

The local control center and its supporting planning organizations must have agreements with the reliability coordinator to ensure that day-ahead and longer-term plans for the operation and outage scheduling of transmission facilities and reactive resources will not jeopardize the reliability of the bulk power system.

PJM is the registered transmission planner and planning authority for PECO. PECO participates in the PJM Operations Analysis Task Force (OATF) study process for the preparation of the upcoming summer and winter peak season studies. The 2007 OATF studies did not identify any operational issues in the PECO transmission footprint. PECO also participates in RFC seasonal assessment studies. These study results are published and presented to PJM and RFC members, and copies are available to the PECO shift manager.

PECO works with PJM to develop the Regional Transmission Expansion Plan (RTEP). This process includes the explicit development of transmission expansion requirements 5 years out; long-range transmission requirements in the 5 to 15-year planning window; and various sensitivity analyses for generation, loads, and firm transmission transactions.

The Exelon transmission planning staff performs independent transmission studies in evaluating the 7 to 10-year window. Also, required transmission expansion plan projects in the 6-year window are evaluated. These studies often enable PECO to suggest solutions to the OATF- and/or RTEP-identified problem areas. Additionally, PECO performs voltage and reactive adequacy studies on a regular basis to ensure that adequate reactive resources are in place to support the voltage during contingency conditions.

Operational planning in the day-ahead to week-ahead time frame is primarily the outage coordination study process, detailed in Section 8 of this report, conducted by the principal operation specialist. On the day ahead, the reliability dispatcher will perform a power flow analysis with the scheduled outages and forecasted peak loads followed by a contingency analysis study. On the day of the scheduled outage, the transmission dispatcher will contact the reliability dispatcher and provide notification that they are ready to start switching. The reliability dispatcher will contact the PJM operator, who will perform a last-minute state estimator analysis before giving permission to PECO to commence switching.

The PECO transmission system support group is responsible for updating the transmission system model in accordance with *OP-ED-9005 SCADA/EMS Data Validation* and *AM-ED-4011 Transmission Rating Update Procedure.* The support personnel, engineers, and real-time information technology (IT) personnel meet to discuss the upcoming model changes. IT performs the data build for the model update, which is performed every two weeks. Model updates are supplied to PJM on request, usually two to four times per year. The evaluation team commends PECO for this proactive process utilized to perform real-time system model updates.

Outage Coordination and Communication

Planned outages by the transmission owner of transmission facilities must be coordinated with the balancing authority/transmission operator and reliability coordinator to ensure that conflicting outages do not jeopardize the reliability of the bulk power system.

Information relative to forced outages of transmission facilities that may jeopardize the reliability of the bulk power system must be shared with affected balancing authorities, transmission operators, and the reliability coordinator as expeditiously as possible.

PJM has the overall responsibility for managing outage coordination in its geographic area. PECO has the responsibility to plan, coordinate, and notify others regarding transmission outages on its transmission system. The guidance for this outage coordination process is in *PJM Manual 03: Transmission Operations* Section 4 — Reportable Transmission Facility Outages. The principal communication vehicle used by PJM in administering the outage coordination program is the dispatcher applications and reporting tool (eDART). PJM is responsible for communications with the reliability coordinator position and the regional reliability organizations.

PECO internally manages its outage coordination process using the equipment scheduler module internal to the PECO EMS. The PECO procedural guidance is in *OP-ED-1083 Transmission Outage Planning.* The PECO principal operations specialist is responsible for the coordination of long-range planning, near-term planning, and scheduled transmission system equipment outages. The specialist uses forecasted loads and scheduled generation outages to update the functional equipment group (operationally integrated equipment that can be removed from service as a system under a common working clearance) schedule and integrate the schedule with the transmission system equipment maintenance schedule in the updating process. Additionally, the specialist coordinates scheduled outages with internal customers, external customers, and the interconnected neighboring transmission systems. After completing the analysis and coordination, the specialist enters the outage in eDART and the PECO equipment scheduler.

Overall, the PECO outage coordination process is carefully defined and documented, well managed, and fully communicated to ensure the reliability of the interconnected transmission system in the PECO zone of the PJM geographic area. The team commends PECO for its efforts in this critical area of system reliability.

Plans for the Loss of Control Facilities

The local control center must have a workable plan to continue to perform the transmission owner functions that are required to maintain a reliable bulk power system following the sudden catastrophic loss of its primary control facility, or the partial or full failure of its computer facilities or monitoring tools at the primary control facility.

PECO has a fully functional backup control center located less than one hour from the primary control center that provides PECO the ability to continue operational control of its transmission system during situations preventing continued use of the primary control facility. PJM continuously monitors the transmission system in the PJM footprint; however, PECO will notify PJM of its loss of control facilities and relocation to the backup control center. PECO will notify its distribution system operations of the loss of control facilities and ask them to monitor the system from the distribution management and control system. This process is procedurally documented in the *Exelon Business Continuity Program, OP-PE-159-813 Activating the Backup Control Center* and OP-*PE-1120 TSO East Fire Alarm and Evacuation Response*. Communications are maintained using cell phones, satellite phone, and 800 MHz portable radio communications. Additionally, PECO has the Government Emergency Telecommunications System at the backup control center.

PECO conducts a minimum of four primary control center failure drills per year, and the transmission system is actually operated from the alternate location twice per year in order to involve all operating personnel and use the full functionality of the computer and communications equipment. PECO follows the guidelines of *PJM Manual 01: Control Center Requirements* Section 2 — Staffing upon Loss of an EMS or a 765, 500 or 345 RTU (remote terminal unit). PECO provides staffing in its 500 kV substations; however, it does not have any 765 or 345 kV facilities.

The evaluation team reviewed the plans and procedures for evacuation to the alternate control center. This review exposed a gap in the plan: identifying and resourcing the transportation requirements for moving personnel to the alternate control center. The evaluation team recommends that the evacuation procedure for the primary control center be revised to address the transportation requirements associated with moving operating personnel to the alternate control center to assume control of the PECO transmission system.

Tools

The local control center must have adequate analysis tools to perform the appropriate control and monitoring functions. Such tools include state estimation, pre-contingency and post-contingency analysis capabilities (thermal, stability, and voltage), mapboard (static, dynamic, hardwired, or projected), e-tagging program, weather service, outage scheduling system, trending tools, and a voice recording system.

PECO has a full suite of tools — including a supervisory control and data acquisition (SCADA) system, state estimator with a study mode, a DTS, real-time contingency analysis application, an outage scheduling program, a tagging system, an EMS-driven dynamic mapboard, a load forecasting tool, a PI Historian tool, and a load shedding program — to fulfill its assigned responsibilities for the safe and reliable operation of its transmission system. Additionally,

PECO has dispatcher trending capabilities with real-time trending at 15-second, 1-hour, 24-hour, and 48-hour increments.

PECO has other weather tools, such as radar, satellite imagery, and lightning detection. PECO uses a voice recording system in the primary and backup control centers that records all conversations at the shift manager, reliability dispatcher, and transmission dispatcher positions. PECO uses a manual dispatcher log to document the daily dispatcher activities of the primary control center. The evaluation team recommends that PECO acquire and implement an electronic transmission dispatcher log for the primary control center.

Load Shedding Plans

The local control center must establish plans for automatic load shedding for underfrequency or undervoltage conditions, coordinate load shedding plans with other interconnected entities, implement load shedding in steps to minimize further uncontrolled events, and have plans for operator-controlled manual load shedding to mitigate violations of system operating limits (SOL) or interconnection reliability operating limits (IROL).

PECO has an underfrequency load shedding (UFLS) program that complies with the legacy MAAC (a former NERC Region for the PJM area) standards for UFLS. This standard will be replaced by an RFC standard in the near future. This standard requires PECO to shed at least 30 percent of its total forecasted load at three pre-determined frequency set points and in approximately equal amounts. Load that is shed by the UFLS program is restored manually, as PECO does not use automatic load restoration. PECO does not utilize an undervoltage load shedding program.

PECO's manual load shedding program is executed at the direction of PJM in accordance with *OP-ED-4026 PJM Emergency Operations Manual Implementation* and *EP-ED-2012 Load relief Measures.* PJM specifies the amount of load to be shed, and PECO places these values in the EMS manual load shedding program; the system opens and closes pre-identified feeder breakers in a programmed rotating sequence. There is overlap between the UFLS and manual load shedding programs; however, procedures specify a limit of no more than 30 percent load overlap for any step of the manual load shedding program. PECO transmission dispatchers participate in annual load shedding exercises and PJM drills for both UFLS and manual load shedding.

Real-Time Monitoring

System Visibility

The local control center must monitor operating data and status in real time for its area and adjacent areas as necessary to maintain situational awareness of its system.

PECO uses a dynamic mapboard that displays from 500 kV on the transmission system down to 13 kV on the distribution system. This mapboard displays MW, Mvar, and MVA values as well as circuit breaker status, alarms, and tagging of switches. This approach to the display of the PECO system and the associated operating values is very compact and, to an inexperienced observer, presents somewhat of a challenge to grasping system conditions in real time. The evaluation team recommends that, as opportunity

permits, PECO evaluate the possibility of reducing/simplifying the voltage levels displayed on the dynamic mapboard to focus on transmission voltages.

The PECO mapboard has an excellent display of the 500 kV systems for all the classic PJM companies. The evaluation team commends PECO for this wide-area view that enables the PECO transmission dispatchers to see the operating dynamic on the bulk power system in real time.

At present, five locations are not telemetered to the backup control center. When the backup control center assumes operation of the PECO system, the state estimator will converge and provide solved studies without the data from these locations. According to procedure *OP-PE-159-813 Activating the Backup Control Center,* these locations will be staffed as directed by PECO's operating personnel.

Alarms

The local control center must have effective and reliable alarming capability. This should be supported in the energy management system (EMS) and/or supervisory control and data acquisition (SCADA) system by alarm priority.

The PECO EMS uses four alarm priority ranges: indicating a "significant event," an "intermediate event," an "informational message," or a "minor event." Priority ranges one, two, and three produce an audible alarm and remain flashing until acknowledged by the transmission dispatcher.

PECO procedure *OP-ED-1069 EMS Active Monitoring Display Guidelines* instructs transmission dispatchers to monitor alarm displays and report a possible problem if a malfunction is suspected. These EMS alarm screens are classified as either an event-summary screen that displays all alarm events or an alarm summary that is set up on dispatcher preference. If the alarm screen is being monitored by the dispatcher, auto-paging will be disabled; conversely, if the alarm screen is not being monitored, auto-paging will be enabled.

The evaluation team recommends that PECO develop and implement an active monitor to monitor the health of the alarm processor. Additionally, the team recommends that this function not only notify the transmission dispatcher but also the proper resource to restore the alarm processor to service.

Frequency

The balancing authority/transmission operator must monitor frequency, direct actions to resolve significant frequency errors, and correct real-time trends that indicate potentially developing problems. Frequency monitoring points should be of sufficient number and from several locations with sufficient area coverage to allow the balancing authority/transmission operator to effectively monitor the balancing authority/transmission operator footprint to determine possible islands.

Frequency monitoring and management is the primary responsibility of PJM as the balancing authority/transmission operator. As a backup to the PJM frequency monitoring, PECO monitors the frequency at all combustion turbines plus other designated points on its transmission system. In all, PECO monitors transmission system frequency at 26 points. These points can be shown on a tabular frequency summary display on the PECO EMS. The dispersion of these monitoring points is more than adequate to indicate possible islanding on the PECO system during contingency events. The evaluation team recommends that PECO develop and implement a geographic display for transmission system frequencies to allow rapid analysis by the transmission dispatcher.

Voltage/Reactive Reserve

The balancing authority/transmission operator and the local control center must monitor voltage levels and take appropriate actions to support the bulk power system voltage if real-time trends indicate potentially developing problems. Voltage measuring points must be of sufficient number and from several locations and voltage levels to allow the balancing authority/transmission operator to effectively monitor the voltage profile of its footprint.

The balancing authority/transmission operator must ensure that reactive reserves are available and properly located to satisfy the most severe single contingency.

PJM is responsible for voltage coordination on the bulk power system. This process and the associated voltage schedules are found in *PJM Manual 3* Section 3 Voltage and Stability Operating Guides — Voltage Limits. In general, PJM monitors and controls voltages on the 500, 230, 138, and 69 kV systems. PECO monitors and controls voltages within the defined pre-contingency and post- contingency limits on the 69 and 34.5 kV systems. PECO also monitors the higher voltage systems; however, the corrective actions for pre-contingency and post-contingency conditions on these systems will be directed by PJM. PECO usually handles both voltage monitoring and control on the 69 and 34.5 kV systems. In general, there is no problem maintaining assigned voltage schedules or operating ranges on the PECO transmission system. The evaluation team commends PECO for the comprehensive voltage study, voltage and reactive resource placement, and effective voltage and reactive equipment operation to maintain system voltages in a pre-contingency as well as a post-contingency environment.

PECO has a number of tabular summary voltage displays on its EMS. PECO transmission dispatchers can view a reactive reserve summary broken down into spinning, quick-start, and static capacitor reserves. The PECO reliability dispatcher is authorized by PJM to contact generators in the PECO footprint and request an adjustment to the current reactive output. The generation operator will notify the PJM operator after complying with the request. Any change in the automatic voltage regulator setting or status is posted to eDART and can be viewed by all PJM members.

Critical Facilities

Monitoring of facilities that are critical to the reliability of the bulk power system is a joint responsibility of the balancing authority, transmission operator, the reliability coordinator, and the local control center.

An established process must determine which facilities are critical to the reliability of the bulk power system. Real-time operating information (data, status and operating limits) for these critical facilities must be provided to the balancing authority, transmission operator, and the local control center by the reliability coordinator

PJM defines and monitors the interconnected reliability operating limits (IROLs) for the PJM footprint. The IROLs and its associated mitigation procedures are published in *PJM Manual 37*. IROLs and system operating limits (SOLs) are identified in the yearly planning studies, which are created from accepted criteria. RFC identifies transfer path capabilities in its annual study process, and PJM identifies the IROLs in its study process.

In the system dispatcher interview, the system dispatcher was not clear as to the definition of critical facilities, IROLs, and SOLs. The evaluation team recommends that PECO develop and implement training on NERC and RFC terminology associated with IROLs and SOLs. It should be noted that PECO's answer in Section 7.4 of the Transmission Owner Questionnaire prepared for this evaluation is clear on this issue.

Transmission System Congestion

The transmission operator must monitor transmission flowgates and be prepared to take actions to alleviate congestion in conjunction with, and as directed by, its reliability coordinator.

This area of transmission reliability is managed by PJM. PECO follows any directives that it receives from PJM related to transmission system congestion.

Load Generation Balance

The balancing authority must monitor the balance of load, generation, and net scheduled interchange in its balancing area. The balancing authority must take actions to mitigate unacceptable load, generation, and net scheduled interchange imbalance.

This area of transmission system reliability is managed by PJM.

Contingency Reserves

The balancing authority must monitor the required reserves and the actual operating reserves in real time, and take action to restore acceptable reserve levels when reserve shortages are identified.

This area of transmission system reliability is managed by PJM.

Special Protection Systems

The balancing authority/transmission operator and the reliability coordinator must be aware of the operational condition of special protection systems that may have an effect on the operation of the bulk power system.

Two special protection systems (SPS) are installed on the PECO transmission system: the Muddy Run and the Linwood SPS. Both are generator tripping schemes and listed in *PJM Manual 3*. The transmission service organization procedure *OP-PE-932001* details the arming and disarming of the Muddy Run scheme. Both SPSs are always armed for normal system operation and certain planned equipment outages. The status of the SPSs is indicated on a single EMS screen as "on" or "off" to indicate armed or disarmed. This operating data is available to PJM on the intercontrol center communications protocol, or ICCP.

The SPS relay maintenance is part of the PECO preventative and predictive maintenance procedure as defined in *AM-ED-P034*. The SPS relay maintenance, testing, and calibration program is on schedule. The SPSs are studied by PECO on a regular basis to determine that the application is still operationally viable.

System Restoration

The transmission operator must have a documented system restoration plan that is consistent with NERC Reliability Standard EOP-005-0 — System Restoration Plans. This restoration plan must be provided to its reliability coordinator.

The transmission operator must be prepared to restore its transmission area following a partial or total collapse of the system and coordinate system restoration with its transmission owners, neighboring transmission operators and with the reliability coordinators.

PECO's system restoration plan includes its blackstart plan. This restoration process is implemented according to the procedural guidance of *PJM Restoration Manual M-37* and the Exelon Energy Delivery *EP-ED-2024 Blackout Restoration Procedure*. The blackstart plan is built on the basis of nine strategically located blackstart sites with multiple blackstart capable units. Once the units are started, appropriate amounts of load are restored so as to stabilize the frequency within the island. Pre-identified blackstart paths are then utilized to start the next grouping of units with load restoration sufficient for frequency stabilization. These islands are then synchronized together before being re-synchronized with the interconnection. The PECO reliability dispatcher directs the initial phases of the blackstart process, and a PJM operator directs the resynchronization of the PECO islands to a neighboring system or the interconnection.

The PECO blackstart restoration plan is reviewed and revised annually, and yearly refresher training is provided to all system dispatchers. PECO completed studies to validate the blackstart restoration plan in 2005. The need for new studies is assessed in the annual review of the plan. PECO has validated the pre-identified blackstart cranking paths by using the DTS; however, these paths have not been validated in an actual test or a study that models the dynamic of the associated protection and control systems. The evaluation team recommends that PECO perform

blackstart cranking path validation studies, taking into account the dynamics of the associated protection and control systems.

Capacity and Energy Emergency Plan

Each balancing authority must have a capacity and energy emergency plan that address the applicable requirements of NERC Reliability Standards EOP-00-01 – Emergency Operations Planning and EOP-002-0 – Capacity and Energy Emergencies.

As the balancing authority/transmission operator, PJM specifies (in *PJM Manual 13: Emergency Operations*) the requirements for PECO to respond to any directives by PJM during implementation of the capacity and emergency plan. PECO provides additional procedural guidance in *OP-ED-4026 PJM Emergency Manual Implementation.* The areas where PECO may be directed to respond are generally represented as follows:

- Active load management
- Public appeals for load reduction
- Voltage reduction
- Manual load shedding, rotational load shedding, or both

Equipment Maintenance and Testing

Transmission owners must ensure that maintenance of transmission lines, substation equipment, and transmission protective systems are carried out according to company, regional, and/or NERC requirements.

PECO has an Exelon Energy Delivery procedure, *AM-ED-P034 – Preventative and Predictive Maintenance Program* that provides detailed guidance for comprehensive program inspection, maintenance, testing, and calibration of substation relays and equipment. PECO uses a maintenance management tool — known as Passport — for the scheduling, work order management, and documentation of the equipment maintenance and testing program.

The annual inspection, maintenance, testing, and calibration program for 2006 was not completed on schedule; however, the program does provide for a grace period of 25 percent deviation from the required time window to allow for scheduling issues. The 2007 program was on schedule at the time of this readiness evaluation. The program tracks all required activities that are either “overdue” or “past due” to ensure that these functions can be accomplished at the earliest possible opportunity.

PECO uses a concept of functional equipment groups — groups of operationally integrated equipment that can be removed from service as a system under a common working clearance. Due to the use of redundant protection schemes, some protective relay testing can be accomplished while the protected equipment remains in service. PECO refers to this practice as “hot calls” or “hot testing”; however, it must be noted that the equipment is never in an unprotected state during this operation.

For the past 12 months, PECO has had four relay misoperations, which have been investigated and reported to the region. In 2006, there were 10 relay misoperations of transmission relays on the PECO transmission system. Over the past 12 months, there were 12 transmission interruptions related to the failure of substation equipment: two air-pressure trips, five sulfur-hexafluoride (SF_6) gas pressure trips, three water-intrusion trips, and only two actual equipment failures. These failures were investigated and appropriate actions were taken.

PECO has one GPS-synchronized digital disturbance recorder installed at a 500/230 kV substation. The recorder has multiple analog channels that monitor 500 kV voltages; however, no digital data is monitored at this time.

The team reviewed the Transmission System Operations goal of operating in a safe and reliable manner with zero events and in an environment that fosters continuous improvement. This initiative, known as the Corrective Action Program or CAP, is actively supported and monitored at the corporate-officer level. The program evaluates human factors, apparent-cause analysis, procedural requirements, systems operation, and program execution. The program also reviews and acts on items such as the equipment-related outages mentioned above, the quality of the maintenance and testing program, the execution of clearances and the associated switching, and all supporting communications. The team commends PECO for this comprehensive effort to seek continuous improvement towards operating excellence.

Vegetation Management

The transmission owner must have a documented vegetation-management program.

PECO has a well-documented vegetation management program that is systematically implemented to achieve the desired results of no vegetation-related transmission line interruptions. To maximize the benefit of the program efforts, PECO integrates tree removal and trimming, side trimming to open the rights-of-way to the easement limits, and herbicide application. The contractor-supplied vegetation management workforce is managed by the PECO transmission project leader using a geographic information system-based database called ROWKeeper along with various spreadsheets and pivot tables.

The PECO vegetation-management program is based on a five-year cycle with an annual walking inspection of all transmission line rights-of-way and facilities 500 to 69 kV. The evaluation team commends PECO for the annual walking inspection of the transmission system. Though it does not use the term, PECO performs “danger” tree activities. Certain areas with limited easements called “chronic focus areas” are the object of a PECO initiated program designed to resolve the limiting factors associated with the transmission rights-of-way and associated clearances. These areas often have annual vegetation management activities performed so as to maintain the operating integrity of the transmission system.

PECO coordinates all transmission maintenance on tie lines with the interconnected neighbor but does not notify the interconnected neighbor of vegetation-management activities on tie line rights-of-way. The evaluation team recommends that PECO develop and implement a procedure to notify the appropriate interconnected neighbor when vegetation-management activities are being performed on tie-line rights-of-way.

PECO uses metrics to evaluate the effectiveness of its vegetation-management program. PECO also uses a third party to evaluate its maintenance standards, guidelines, clearance requirements, and program effectiveness. In the opinion of the evaluation team, this commitment to continuous improvement is a key element in ensuring an effective vegetation-management program. The PECO vegetation management program was finished on schedule in 2006 and was on schedule for 2007 at the time of the readiness evaluation. There were three vegetation-related line outages in the last half of 2006, and all three involved shared rights-of-way with the railroad on a hillside.

Nuclear Power Plant Requirements

Transmission operators must support nuclear power plants in meeting regulatory requirements that allow the plant operators to maintain voltages within design limits and adequate off-site power sources in both normal and abnormal operating conditions (n-1 and system restoration).

Exelon Generation owns the two nuclear power plants in the PECO transmission footprint. A comprehensive group of documents defines the operating relationships and responsibilities among the nuclear plants, PJM, and PECO. These documents include the interconnection agreements, interface agreement procedures, work management interface, engineering and planning interface, operations interface, and the affiliate-level arrangement agreements. In addition, the PJM requirements are detailed in *PJM Manual 39: Nuclear Plant Interface Coordination*.

The security analysis SCADA program monitors the post-contingency voltages based on real-time telemetry and the state estimator. Guidance for responding to voltage violations is provided in Exelon Energy Delivery procedures *OP-ED-9085, Response to Security Analysis Violation* and *OP-PE-1116, Response to Nuclear Station Off-Site Source Voltage Violation in Transmission System Operations — East*. Additionally, as the transmission operator, PJM monitors the same voltage limits and will contact the PECO system dispatcher when discovering a voltage violation. The post-contingency nuclear power plant station service loads are factored into the voltage limits established by the plant, and these are the limits monitored by PECO and PJM.

The PECO system dispatcher interview indicated a lack of clarity regarding the nuclear power plant voltage thresholds for pre- and post-contingency conditions. The evaluation team recommends that PECO develop and implement training to enhance the system dispatcher's understanding of this important operational area. It is additionally suggested that joint training be considered in this area, as it may produce a shared level of understanding in the area of nuclear power plant voltages.

PECO places considerable emphasis on effective communications with nuclear plants. PECO has documented procedural guidelines for both normal and emergency communications between the system dispatcher and the nuclear power plant reactor operator. PECO uses a protocol of three-way communications, and each system dispatcher is audited twice per year. Many times, the plant operator participates in evaluating the effectiveness of the communications being reviewed in the audit.

APPENDIX 1: Critical Energy Infrastructure

APPENDIX 2: Evaluation Participants

APPENDIX 3: Documents Reviewed