Participants:

Jean-Marie Gagnon, Chairman, Hydro-Quebec TransEnergie
Jim Robinson, PPL Electric Utilities
Brian Keel, Salt River Project
Jeff Mitchell, Reliability*First* Corporation
Mike Pakeltis, CenterPoint Energy
Jason Shaver, American Transmission Company
Peter Gelineau, Canadian Electricity Association
Pete Harris, ISO-NE (Nov 20 only)
Ed Pfeiffer, Ameren
Gary Brinkworth, City of Tallahassee
John Seelke, NERC

November 20th minutes

1. Presentations. Chairman Jean-Marie Gagnon welcomed the members and began with the scheduled presentations per the agenda:
    a. John Seelke of the NERC staff presented a summary of the requirements of EIA Form 411, Schedule 7 which addresses transmission availability statistics. EIA requires reporting of planned and forced outage data above 230 kV (AC) and above +/- 100 kV (DC).
    b. Peter Gelineau of the Canadian Electricity Association (CEA) presented a summary of reliability data collected and reported by CEA members. While CEA members track transmission component forced outages at voltage levels of ≥ 60 kV[1], they also track delivery point interruptions which are a measure of when the transmission system was unreliable.
    c. Jeff Mitchell of ReliabilityFirst Corporation presented the approach taken by the previous ECAR region in collecting transmission outage data. They collected planned and forced outage data for line at 230 kV and above. That effort was suspended and is awaiting the outcome of the TADSTF. Availability trends were readily identified from the data collected.
    d. Brian Keel of the Salt River Project presented a transmission forced outage data collection effort that was recently approved by the WECC's planning and operating committees in October 2006 and is awaiting WECC Board approval. The system will require WECC members to report forced outage data beginning in the calendar year 2006 for circuits and transformers ≥200 kV and above. WECC developed a Probabilistic Based Reliability Criteria (PBRC) for Category B, C and D outages in 1998 and the forced transmission outage rate of individual lines will be compared to the PBRC defined rate.
    e. Mike Pakeltis of CenterPoint Energy presented a summary of EPRI's accomplishments and future plans that address transmission availability. His presentation was prepared in collaboration with Ram Adapa, EPRI's project manager. EPRI's approach addresses both the transmission line availability statistics (termed "deliverability") as well as interruptions at delivery points

[1] Nine transmission components are tracked.

(termed "delivery"). Mike pointed out various pitfalls in defining what constituted a "delivery point." Integrated T&D utilities that insure reliability by planning for equipment redundancy at the distribution level may have a poorer transmission delivery statistic than utilities who plan for redundancy at the transmission level if the delivery point is defined at the high-side of the distribution sub even though customer reliability may be the same or better

f. Jason Shaver of American Transmission Company presented a summary of the transmission availability data collected by ATC. They collect outage data on all their transmission lines (69 kV and above).
g. Pete Harris of ISO-NE gave a presentation of the type of outage data and definitions used by ISO-NE. ISO-NE carefully tracks forced outages as well as planned outages, including "actual versus scheduled" data for planned outages.
h. Jim Robinson of PPL Electric Utilities gave an update of a presentation that he had prepared for NERC's Transmission Issues Subcommittee to the Planning Committee. His presentation showed the results of a voluntary survey of forced outage statistics. His material included a spreadsheet of the data provided, which excluded the names of the company's who provided the data. The thrust of his presentation is that outage statistics need to be considered when evaluating contingencies for transmission planning. For example, some category D contingencies may be more probable than some Category C contingencies.
i. John Seelke intended to discuss a table that compared the various methodologies presented; however, the material was not readily comparable and therefore his table was not discussed.

The presentations conclude around 3:00 p.m. Although the presentations took more time than allotted on the agenda, all agreed that the material presented and the discussion among the TF members was worthwhile and productive.

2. General discussion. For the rest of the afternoon of the 20th, an open discussion was held regarding a number of items:
   a. It was agreed that it would be desirable for ERO to issue a request for the data from NERC Transmission Operators.[2] Under this approach, the data would be required of all NERC members. Non-US NERC members are not bound by EIA requirements. For EIA reporting requirements, NERC (or NERC regions) could report data to the EIA for their Form 411, Schedule 7 requirements.
   b. Peter Gelineau emphasized that data collected by various CEA entities is more useful in tracking trends of the reporting utility rather than comparing data between reporting utilities. He also stated that the data collected stimulated information exchange among members regarding such items as construction and maintenance practices which might influence availability. As a result, companies learn about the practices of others that might help them improve their own performance.

[2] A NERC data request would not require a "standard" and thus would not require FERC approval. However, NERC has not yet developed any internal review and approval process for issuing a data request.

c. The issue of requiring the collection of forced outage data at < 200 kV was discussed briefly. Since the number of lower voltage circuits would be greater that those ≥ 200 kV, much more effort would be required to collect the data. In addition, the 200 kV cut-off point was felt to be capture transmission lines which have the greatest reliability impact. ≥200kV also matched the current EIA Form 411, Schedule 7 requirements which appeared to be structured around bulk transmission.
d. The usefulness if collecting planned outage statistics was discussed briefly, but no consensus was reached. It was not clear to the group why EIA Form 411, Schedule 7 collected planned data. The collection of planned data may reflect more on operating conditions than line performance. It was suggested that the NERC Planning Committee consider discussions with the NERC Operating Committee to see if there was interest in planned outage statistics from their point of view.
e. The concept of measuring delivery point performance was a new concept to US utilities, and it was felt that that would be difficult to implement. The issues pointed out by Mike Pakeltis were recognized as potential barriers to implementing this approach. John Seelke noted that OE Form 417 *Electric Emergency incident and Disturbance Report* could be re-assessed and made a possible vehicle for addressing transmission system performance.

November 21st Minutes

3. Future Meetings. Chairman Jean-Marie Gagnon addressed the timetable for future meeting and conference calls. The TF needs to be prepared with a report for the Planning Committee meeting on March 21-22.
   a. Future conference calls:
      i. December 7 from 2:00-3:00 p.m. Eastern: Jean-Marie Gagnon will be presenting a status report on the TF's efforts to date to the NERC Planning Committee (PC). This call will brief the TF members on the comments received from the PC.
      ii. December 20 from 11:00 a.m. -3:00 p.m. Eastern: This will be a working conference call to discuss the progress of assignments from this meeting (discussed in paragraph 7) and the agenda for the January meeting.
      iii. Additional calls will be scheduled as needed
   b. Future meetings:[3]
      i. January 23-24 in Atlanta *(was changed to Jan. 24-25 on Dec. 13)*
      ii. February 27-28 in Dallas

4. Data and Metrics Criteria. It was agreed that whatever data and metrics are recommended by the TF, they should be:
   - Comparable (which requires a consistently applied framework)
   - Attainable
   - Verifiable

[3] Each meeting will be 1½ days, ending at noon on the second day.

- Simple
- Relevant to various "users"
  - Transmission Owners, Transmission Operators, and Planning Authorities
  - ERO
  - Governmental bodies (FERC, EIA, etc.)

5. Areas of Consensus. The TF discussed several items and reached consensus on the following:
   a. Forced-outage data needs to be collected from Transmission Operators for all circuits (AC and DC) ≥200 kV.
      i. Data would be collected for transmission lines and cables as well as transformers with a low-side voltage of ≥200 kV. The TF agreed that given the critical nature of bulk transformers, data on their forced outages would be useful, especially given the long lead times for repair or replacement (~ 1 year). The EIA already requires this data for lines and cables, but not for transformers.
      ii. Since transformer data will be collected, the TF discussed whether other component availability data should be collected (e.g., circuit breakers, etc.) This issue will be re-addressed after the results of a future task assigned to Jim Robinson and described in paragraph 7.
      iii. Data needs to include both momentary outages (one minute or less) and sustained (> one minute).
      iv. Outages need to be classified as three modes: "independent," "dependent," and "common."
      v. EIA requires DC data for +/-100-199 kV circuits. Whether any DC circuits in this voltage range are actually operating is a question that will be researched by John Seelke.
      vi. Data needs to include a "yes" and 'no" check as to whether the outage caused a loss of end-use load and another "yes" and 'no" check as to whether the outage resulted in a significant disturbance which required the submission of a report (per EIA Form 417).

      The definition of what constitutes a forced outage was not decided and will be discussed at a future meeting.
   b. The TF recognized that specifying desired metrics and associated data requirements require an iterative approach. However, for the next meeting in Atlanta, the TF agreed to first focus on defining the relevant metrics desired and have those metrics drive the data needs.

6. Open issues. The following issues are still open:
   a. As stated above, the desired metrics as well as the outage definitions, categories, and cause codes still need to be developed.
   b. After much discussion, the TF did not reach agreement that planned outage data needs to be collected.
      i. Some felt that since planned outages are taken during off-peak periods, their impact on reliability is insignificant. Others felt that because of

significant planned transmission outages, off-peak periods constitute periods of significant reliability risk.[4]

ii. However, the TF agreed that without planned outage data, total availability statistics could not be produced. However, there was not consensus on whether a total availability statistic added value. Some felt that planned outages reflected operating conditions and should be considered separately from forced outages, if at all. Having planned outage data does allow one to evaluate the relationship between forced outages and planned outages. Finally, the TF recognized that EIA already requires this data but it was not clear to the TF why this data was collected; even though NERC regions reported it for 2006. More discussion is needed on the collection of planned outages and the intended use of metrics.

iii. The availability of planned outage data from Transmission Operators and the intended use for that data would be developed from a survey. (See Assignments in paragraph 7 below).

c. While line and cable outage data must be collected at the individual circuit level (with a circuit defined as a line or cable between two automatic interrupting devices), some expressed the desire to roll up the data to a voltage category level in reporting it to NERC. This requires further discussion as to whether rolled-up data would meet the needs of the users.

d. Data access and data confidentiality policies still need to be developed. At CEA, members have access to their own data and the composite data of all those reporting.

7. Assignments. The following assignments were accepted:

a. John Seelke will do the following:

i. Look at the EIA Form 411, Schedule 7 2006 regional filing by NERC regions. Did anyone have DC circuits in the +/- 100 -199 kV range? How reasonable does the data appear?

ii. After the TF completes it recommendations, develop a draft survey for Transmission Owners to determine what they collect now and how difficult it would be to collect what the TF recommends. Transmission Owners that are on the TF will be asked to complete the survey, with that feedback used to improve it prior to sending it out.

iii. Develop a first draft of a PC status report for Jean-Marie Gagnon.

iv. Discuss the status of OE-417 with Jeff Norman of the NERC staff regarding potential changes to better capture incidents that could be used to measure the performance of the transmission system.

b. Jean-Marie Gagnon will prepare a status presentation for the PC's December meeting.

[4] The difference in viewpoint may be a result of differences in load characteristics. Low load factor systems may have significant load valleys for transmission outages, while high load factor systems have less opportunity for taking transmission outages.

c. Jim Robinson will examine the transmission planning standards and list the data and outage codes that need to be collected to have sufficient outage information so that it would be useful to transmission planners.
d. Brian Keel will work through Peter Gelineau to have a call with Roy Billinton to see if Billinton can direct the TF to any reliability metric(s) that quantify the reliability and performance of large areas such as NERC regions or subregions.

Respectively submitted,

John Seelke

Secretary