Appendix: Exelon and Ameren Seams Examples and Recommendations
July 11, 2012

1. DA and RT Market Model Coordination
    a. Inconsistent dispatch between RTOs (RT or DA)
        i. Example 1: Jan 5-Feb 8, 2011 transmission outage in PJM (Com Ed). Two units located in different RTOs impacting the same Reciprocally Coordinated Flowgate (RCF) however, RTO's prices signaling least cost unit to back-down and committing most expensive unit. After market participant notified RTOs, it took two days to resolve and for the RCF to stop binding in RT.
        ii. Example 2: Sept 26, 2011 - PJM binding on the Duck Creek-Tazewell 345 kV line. PJM DA model for 9/26 PJM bound on the Powerton jct.-Lily 138 kV (flo) Duck Creek –Tazewell 345 kV contingency from 12:00 to 17:00 even though the MISO Oasis show that the Duck Creek-Tazewell 345 kV line is planned out of service from 9/26 @ 08:00 to 9/28 @ 07:30. The Duck Creek-Tazewell outage was requested on 9/21 and was still in the MISO OASIS planned outage report on 09/26.
        iii. Example 3: Nov 17, 2011 - PJM has the Kewanee-Galesburg and the Kewaunee-Monmouth 138 kV lines in service in their DA model even though they are scheduled to be out of service from 11/17 @ 08:00 to 11/26 @ 18:00.
        iv. Example 4: Dec 6, 2011 - PJM's DA model is binding on the Powerton-Lilly 138 kV (flo) Duck Creek-Tazewell 345 kV even though Duck Creek wasn't bid into the DA model due to an outage. With Duck Creek offline the loss of the Duck Creek-Tazewell 345 kV line would not add any extra flow onto the Powerton-Lilly 138 kV line since Duck Creek is offline so PJM modeled a piece of MISO equipment as in service even though the unit was offline in the MISO DA model.
        v. Recommendation: Automate DA data exchange; align RTO-RTO DA and RT assumptions; coordinate planned transmission and generation outages using a longer lead time with deadlines on when outages can be rescheduled; maintain a list of units that can provide congestion relief for Reciprocally Coordinated Flowgates; develop M2M operating guidelines when significant outages are on the horizon; change Monitoring RTO for RCFs to the RTO that has the units that can mitigate the constraint; don't wait until flowgate binds to initiate M2M.

    b. Delayed model implementation (RT or DA)
        i. Example 1: RT events and data not being implemented into each RTOs DA model
        ii. Example 2: Implemented in one RTO's model, but not the others. During Jan 5-Feb 8, 2011 outage (same outage listed in 1.a. above) MISO DA market took 11 days to converge with MISO's RT market
        iii. Recommendation: RTOs align DA modeling and assumptions

    c. Contingency impacts not evident in both RTO's (RT or DA) (N-1 Model?)
        i. Example 1: May 14, 2012 - PJM had several major outages planned to come out of service. These outages resulted in MISO binding on the Ipava 345/138 kV transformer for the loss of the Kendall-Lockport 345 kV line which resulted in high congestion values at Duck Creek. In PJM's DA model there were no binding constraints in the central Illinois so the Powerton units had a very low congestion values. (There are also differences in the FFE between MISO & PJM that also impact this problem. But if this is just a FFE problem and not a problem with a flowgate not binding in PJM's DA model then it would appear to be an extreme FFE inequality between markets)
        ii. Example 2: May 7, 2012 - PJM took out the Jefferson-Rockport 765 kV line for maintenance and MISO failed to have the line out in their DA model the next day. PJM OASIS had the Jefferson-Rockport line out on 5/6 and MISO RT

showed that the line was out of service on 5/6 before 18:00 from a real time state estimator snap shot but MISO was binding on the Jefferson-Rockport 765 line in the 5/7 DA as a major contingency although the line should have been out of service.

d. Modeling differences between PJM & MISO. We request the RTOs clarify and document modeling practices and differences and work together to resolve discrepancies that lead to seams inefficiencies. Here are some examples where we believe modeling differences exist (some examples are identified in the Utilicast report).
   i. Differing wind forecasts (DA and RT)
   ii. Modeling of DC lines different for each RTO (DA)
   iii. Modeling of GFAs different for each RTO (DA)
   iv. DA Model of External M2M Constraints: Loop flow (PJM) vs. FFE limits (MISO)
   v. Seams modeling: Proxy (PJM) vs. Universal (MISO)

e. Reciprocal Coordinated Flowgates– Process and Transparency
   i. FFE transparency – what is the FFE share of each RCF
   ii. Agreement on which RCFs should be included – PJM & MISO currently not determining flowgates together. PJM suggesting MISO has too many
   iii. Differentiate between "loop flow" and non-host RTO flows on RCFs
   iv. Constraint Relaxation removed on MISO constraints but still used on M2M RCF and PJM internal constraints
   v. Communicate to market why and when new RCFs or proxy RCFs are created

f. Congestion Management Process & Settlement
   i. Shadow Price Determination for M2M redispatch (RT)
      1. Eliminate the need for "Shadow Price Override" to ensure constraints priced accurately and ensure appropriate market signals
   ii. M2M Settlements not going to units providing benefits
   iii. Treatment of energy only-wind, dispatch/curtailment. Is wind exacerbating seams congestion leading to M2M event because wind is not sensitive to RT LMP in most cases?
   iv. Impacts from Transmission Outages & Generation Outages
      1. Lack of outage coordination leads to, in some instances, inefficient M2M redispatch (see for example 1a(i) above).
      2. See also 2b below.

g. Consistent BPM language clarity for both MISO and PJM
   i. Review uplift charges (MISO RSG or PJM operating reserves) assessed to import/export schedules and cost based offer rules for external capacity resources.
      1. Currently there is no alignment between clearing the capacity must offer in the PJM eMKT system with the export tag/schedule in the MISO market. This risk of clearing in PJM DA and not the schedule in the MISO DA market results in risk of RSG for a RT MISO export. We request review of whether a market participant can include this risk in the MPs PJM eMKT offer. We note the PJM IMM has denied such costs to be included in the PJM Cost Based Offer. The RTOs should work together to determine how to eliminate the risk of an unrecoverable cost, or at the very least allow the MPs to include this risk in their cost based offer. Similar risks would apply for capacity that is sold from a PJM resource into the MISO.

ii. Clarify the DA Must Offer rules when a single unit's capacity is sold between markets and, during the operating horizon (DA/RT), the unit is not available for the full ICAP value.
    1. To be clear, we believe the Must Offer shall be made in the RTO in which capacity is sold, but accounting for derates requires a reduction in the offer to one or both RTOs for the must offer and also the RTO outage tracking systems (MISO Crow and PJM eDART system). Neither RTO's BPMs describe how market participants should handle such offers. Should both offers be prorated by the ratio of capacity sold to the ration of capacity available or can the MP choose which RTO gets the full reduction.

iii. Clarify, via each RTOs BPMs, the Must Offer rules for external resources when one or both RTOs are in an emergency situation.
    1. For example, consider a unit that is rated at 200MW ICAP unit and the MP has 100MW of ICAP capacity sold in both MISO and PJM. If on a given day the unit is derated to 100MW and the MP makes their Must Offer of 50MW in each market, what happens if only one of the RTOs is in an emergency? Should the MP schedule the full 100MWs available to the market with the emergency since 100MWs is available? Then if the other RTO transitions in an emergency, then should the MP split the MWs to 50MW for each RTO?

2. Modeling and Data Coordination in the Planning Horizon
    a. The System Impact Study process for both PJM and MISO is not transparent and seems to be uncoordinated. In addition there are differences in MISO and PJM's queue processes for assessing long term transmission requests as described below.
        i. Example 1: A SIS for a 3006MW AEM request for the period 6/1/2012 – 6/1/2017 (MISO Project A562, OASIS Reference # 76918058, queued 11/02/2011 @ 13:56:38 ES) was completed and published by MISO in January 11, 2012. AEM submitted 3 reciprocating requests on the PJM OASIS in order to complete the transmission path into PJM for the same term (Queue Position X3-096, OASIS # 3023630, queued 10/31/2011 @ 16:27:55; Queue Position X3-097, OASIS # 3023634, queued 10/31/2011 @ 16:30:28; Queue Position X3-098, OASIS # 3023635, queued 10/31/2011 @ 16:33:11). Despite the tandem requests submissions, the PJM SIS was not completed until June 29, 2012.
        ii. The MISO SIS result considered the entire term of AEM's request which included both near term and out term scenarios. The 3 PJM SIS results did not address the near term (2013-2014, only the out term (2015 forward). PJM stated for service prior to 2015, as the study results were based on PJM's 2015 RTEP base case, an interim study would be required. The misalignment of the study timing and the differences in the reporting standards from the two RTOs left AEM in a position to make a business decision without complete knowledge of its transmission position.
        iii. Recommendation: If possible, align the queue process between both RTOs so that results are published in such a timeline where business decisions can be made to accept the transmission on one system without risking being denied on another system. Further, we request the RTOs to review and determine if other transmission study inefficiencies exist that could impact the effectiveness of the joint and common market.

It appears that part of the reason the timing is misaligned between the MISO and PJM SIS is because PJM performs an Initial Study prior to the SIS while MISO does not. The baseline RTEP model used for this study covers the prompt planning year. However, the long-term request goes well beyond this time horizon. Also, due to the static nature of the Initial Study model, certain recent and major system impacts have been excluded.

Besides, being done only in PJM and having incorrect inputs, the Initial Study results were completely different to the SIS results

i. Example 1: Two related transmission requests (PJM X3-096 & MISO A562 - October 2011), both in PJM and MISO resulted in an Initial Study only in PJM. The PJM Initial Study did not include Duke within PJM even though Duke was a PJM LBA at the time. This was due to the model having been completed prior to Duke joining PJM and the model was not updated for the study.
ii. Example 2: In the study mentioned above (PJM W3-083 – October 2010), the Initial Study impacts varied widely, some near the generator source and some hundreds of miles away. But none of these same Initial Study Impacts showed up later in the SIS.
iii. Conclusion: We request PJM and MISO determine the value and need of Initial Studies as it directly relates to market efficiency, functional markets, and timeliness. Unless sufficient benefit can be determined, PJM and MISO should consider removing the need for an Initial Study as this may allow for better inter-RTO alignment and a timelier queue process.

On a related issue, we question whether the CBM benefit is being maximized between MISO and PJM through proper coordination and utilization. We are not aware of any CBM coordination efforts between MISO and PJM at this time. The improvements to modeling, planning and seams coordination advocated herein, should also facilitate CBM discussions and solutions that serves efficient and economic markets while also preserving the reliability elements of CBM.

b. Transmission Outage Planning and Scheduling coordination: Lack of adequate outage planning and coordination impacts the ability to achieve effective, least cost dispatch in the DA and RT M2M coordination process (as discussed above) and impacts the FTR markets and funding of each RTO. In addition, planned outages that ComEd has worked through the PJM process are cancelled by MISO shortly before the outage start date due to issues in MISO. In addition, Outage planning coordination needs and impacts will increase due to MVP build-out and expected EPA retirements or retrofit compliance actions.
   i. Examples
      1. 2011 Outage, Line 15504 (Nelson-Sterling Steel): PJM planned outage canceled and rescheduled due to MISO constraints around Galesburg despite multiple pre-outage conference calls between ComEd-MISO-PJM-ITC-MEC.
      2. 2011 Outage, Line 2102 (Kincaid-Latham Tap): PJM planned outage canceled due to conflict with MISO's outage for Brokaw - Clinton line.
      3. 2012 Outage, again Line 2102 (Kincaid-Latham Tap): PJM planned outage canceled due to MISO job at Brokaw in connection with Line 8001.
      4. ComEd and Ameren had an overlapping outage planned for the same week (Oct 2011); RTOs coordinated roughly two months prior to outage occurring; PJM canceled the ComEd outage 6 weeks in advance only to have Ameren cancel the outage 3 days prior to outage occurring. This impacts ComEd outage planning, generation outage planning, and negatively impacts DA and FTR models
   ii. Recommendations:
      1. PJM requires 6 months notice for planned transmission outages vs. MISO's requirement of a 2 week notice. Review whether MISO should revise its tariff to require planned outages be reported six months prior to the planned outage instead of two weeks. Transmission Owners could retain ability to change outage schedules only in limited circumstances to

maintain certainty in the schedule. (Or consider aligning outage scheduling rules (per tariffs) limited to transmission elements with high seams impact in both RTOs.)

    a. Once MISO's rules change, PJM and MISO begin to coordinate outage schedules 6 months in advance.
    b. MISO and PJM develop, by early 2013, operating protocols to efficiently manage through, the anticipated EPA related generation outages.

2. Review economic impact of outages including cross border outages; create option for TO to voluntarily reschedule outage due to economic impact (Currently a place holder in the MISO budget for modeling the economic impact of transmission outages – refresh this this budget item and provide regular and documented updates to stakeholders)

c. Generator Interconnection Process: Coordination of the generator interconnection queues between MISO and PJM continues to be an issue, which has caused long delays in PJM issuing study reports. The issues involve determining MISO impacts of PJM generator interconnection projects and getting MISO agreement on these impacts. Also, there is an issue of which PJM projects need to be included in MISO interconnection studies, and visa-versa which MISO projects need to be included in PJM interconnection studies. One other aspect of coordination is when major new 765kV, 345kV or DC lines are being studied as part of the interconnection process. Currently, it doesn't appear like there is much coordination between PJM and MISO all the way through the impact studies. This lack of coordination can result in the transmission system being overbuilt and an unnecessary increase in transmission rates. In addition to the less than optimal transmission solutions being identified, the lack of coordination results in redundant and/or conflicting work wasting time and resources.

    i. Examples of previous ineffectively coordinated interconnection requests
        1. For the PJM O queue, facility studies had been completed by PJM but not coordinated with MISO. The issuing of ISAs to customers had to be delayed for approximately one year while MISO was determining what impacts the interconnection requests had on their system.
        2. In the PJM S queue there is currently a HVDC interconnection request that is being studied but not being coordinated with MISO despite the interregional impact it may have.
    ii. Recommendation: We request MISO and PJM finalize their proposal for studies in the interconnection process that impact another RTO. We request the studies be coordinated starting with the feasibility study as this will start the coordination in an early phase of the interconnection study process.

d. Tie-Line Ratings do not align PJM requests that its TOs provide only the limiting rating for their end of the tie-line and then will get the MISO TO's limiting rating from MISO. However, MISO TOs only provide a coordinated rating (lowest rating based on both TO's equipment) to MISO not the rating of equipment on their end. This can result in MISO or PJM having an incorrect tieline rating or not know which TO equipment rating is limiting the coordinated rating (this information is needed to determine whether MISO or PJM should be controlling a tieline overload). Another issue with tieline ratings is that PJM requires their TOs to provide a load dump rating while MISO does not use load dump ratings. What rating should be used for the MISO TO end of a PJM load dump rating remains unresolved. These two issues can threaten reliability and can cause potential equipment damage in addition to creating the following issues for operations:

- When one company is on winter ratings and another on summer (there is a coordinated winter rating and summer rating but not a coordinated summer/winter rating)

- Determining who should take controlling action for a tieline overload.

i) Example of Issues with Tieline Rating Coordination: Recently ComEd completed work on 345 kV L17703 (Burnham-Munster), a tieline between ComEd and NIPSCO, that increased the overall rating. ComEd submitted the new ratings to PJM and also notified NIPSCO of the change. NIPSCO accidentally submitted the old rating to MISO who then sent it to PJM. PJM caught the discrepancy and contacted ComEd. ComEd then informed MISO and NIPSCO of the error and the rating was corrected. Until this process is clarified there is a possibility of incorrect ratings being used that could endanger reliability.

ii) Recommendation: We request MISO and PJM develop tieline and load dump rating protocols that can be consistently used and applied on both sides of the seam. We request MSIO and PJM develop protocols to ensure outdated or inaccurate ratings are not provided to RTOs from Transmission Owners.

e. Transmission Planning – Cross Border Impacts: New transmission that involves both MISO and PJM needs to be jointly evaluated and approved otherwise reliability may be endangered and/or the transmission system could be overbuilt gratuitously increasing transmission rates. In addition, the most efficient market or reliability mitigation measures may not be identified continuing the need for heavy reliance on market-to-market coordination and redispatch in the day-ahead and real-time markets that could be avoided if transmission planning was properly coordinated.

   i. Example: ATC & Duke's proposal to MISO, through MISO's MTEP, to break ComEd's Davis Creek to Burnham 345 kV line, establish a new substation in ComEd and create a new tie line going east to NIPSCO. Without a thorough study by PJM and ComEd ,that is coordinated with MISO, reliability on the ComEd system may be endangered.
   ii. Recommendation: Link RTEP & MTEP process

3. FTR Underfunding due to seams issues

   Each RTO relies on information and data from the other RTO to build FTR models, e.g., outage data. When that information is wrong, outdated, or changes after the FTR models are developed, the base models are inaccurate which leads to FTR underfunding or, in MISO's, case limiting FTR feasibility.

   i. Recommendations:
      1. Again, we request MISO revise its tariff regarding transmission outage scheduling rules from a two week notice to a 6 month notice.
      2. Coordination of outages between RTOs 6 months out
      3. Coordination of outages from model to model (e.g. FTR model to DA model)
      4. Develop joint report on FTR funding impacts due to seams issues.