TOTF Meeting Summary
March 29, 2012
Draft
Webinar Recording (begins 8 minutes into meeting)

Meeting Objectives:

- **Review Scenario Load Flow Runs completed and discuss remaining work**
- **Review Transmission Alternatives under development**

Action Items:

- **Review results of Scenario Load Flow Runs and receive comments**
- **Review available gap analysis & direction of Transmission Alternatives to mitigate gaps**
- **Update Phase II Schedule as needed**

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1. **Update on Action Items from last meeting** (Dan Fredrickson, MAPPCOR) See presentation.
   a. All additions and deactivations have been completed along with Scenario 1, Blocks 1 and 13 load flow model.
   b. Scenario 2 & 3 load flow models still under development
   c. March 28 meeting was a collaborative effort of EIPC engineers and TOTF members to look at the load flow model results of Scenario 1
   d. SSI maps are under development; as transmission solutions are agreed on, additional maps will be developed.

2. **Demand Response Treatment** (David Whiteley, EIPC project manager**)** See presentation.
   a. During Phase I, each of the Futures had some level of demand response (DR). Future 4 (basis for Scenario 1) had DR, energy efficiency and smart grid, and distributed generation which would reduce overall demand. Specifically, 20% of energy resource needs annually would be met with the DR and EE.
   b. In final Futures, EE and DR were separated, in part because of the way NEEM handled DR differently from EE. EE would meet 20% by 2030 and DR would meet "full potential" as demonstrated in 2009 FERC Demand Response study extended through 2030.
   c. Peak loads were unmodified by DR. DR was calculated and directly offset the need for the generation resources to meet installed capacity reserve requirements.
   d. DR was also modeled as "pseudo-generators" with a high variable cost ($750/MWH), which NEEM could pick to meet load based on economics.
   e. DR pseudo-generator capacity was increased in size from the specified amount, because some regions treated it as a reserve margin credit and some regions treated it as a supply source; the multiplier was intended to reflect a compromise.
   f. Summary of the results of DR Capacity in 2030:
      - Scenario 1 – 152,450 MW (compared to 33.1 MW in 2010)
      - Scenario 2 – 70, 708 MW

- Scenario 3 – 70, 708 MW

g. Dispatch results indicate that the NEEM model used the available capacity only in Scenario 1 in FRCC and VACAR regions in Block 1; Nn DR was dispatched in Block 13.

3. Q&A on Demand Response (DR):

a. NGOs submitted questions in advance of the TOTF meeting and suggested that the DR also be made available as a resource to alleviate potential reliability problems such as overloads. NGOs inquired how DR will be factored into the production cost model at a later stage.

b. EIPC will consult with CRA to address the treatment of DR in production cost modeling later; and it will be appropriately discussed with the MWG along with other assumptions that need to be reviewed.

c. EIPC explained that in terms of study of the transmission system, planners do not make assumptions about how DR might be used in advance, even though it will be called on along with all other tools to address contingencies. This is the difference between an operating time frame and a planning time frame. At this higher level of planning, the PAs do not think it is appropriate to bring in operational consideration which would require an understanding of the local reliability problems, where the DR is located, and whether those resources are available to resolve that problem.

d. NGOs requested that PAs reconsider, and factor in DR more fully at this stage or consider DR to address contingencies at lower voltage levels given the very large DR capability in the resource mix. NGOs would like DR to be considered as part of re-dispatch solutions which will be considered by EIPC later in the process.

e. Public Power representative inquired why Scenario 1 has negative load growth, but Scenarios 2 & 3 have positive load growth. EIPC explained that EE and DR assumptions were not as aggressive in Scenarios 2 & 3.

4. Update on Scenario 1 transmission development work (Jeremy Bennett, SOCO)

a. PAs have completed gap analysis to identify intra-regional upgrades needed as a starting point.

b. Scenario 1, Block 1 load flow results were released 2 weeks ago along with ancillary files.

c. MISO and SPP are net exporters of 30,500 MWH and Southeast and PJM are net importers of 34,500 MWH, which explains the type of constraints seen. As you relieve the constraints in the further west regions, the constraints shift further east. With this situation, it made sense to look at DC lines to get the power flows across the entire eastern interconnection

d. PAs started by testing 6 DC lines from the Midwest with termination points in PJM, but these lines did not resolve the constraints further south in SPP.

e. DC lines worked well in Block 1 but not Block 13, where it was not fully utilized; PAs started developing a solution based on upgrading the 765 kV systems, adding 3 parallel 765 KV lines initially. Finally, late yesterday, PAs looked at DC (3500 MW bi-pole HVDC) along with the AC upgrades which turned out to be a good fix, but they haven't yet determined where the best end point termination is for the lines, which started in SPP. They will do more analysis to get to 'Pass 2' transmission solutions.

f. PAs lso updated the transmission in other regions for more local problems.

5. Q&A

a. PAs did consider SPP and MISO overlays with a 345 kV collection system as part of the solutions to exports.
b. They assumed that PJM and TVA can withstand the loss of a single-pole 3500 MW HVDC line, which is considered a single contingency. Other suppliers representative inquired why the PAs did not test both poles of HVDC in the contingency analysis as they do in New England. EIPC explained that PAs will likely need to test both poles later; not doing a complete reliability test yet. NERC planning standards allow a single pole outage (category B event) to be considered as a single contingency, but it may make sense to test both poles (category C event).
c. In Phase I, EIPC posted the reliability tests that will be conducted and how they would relate to NERC standards knowing that we would not be able to comply with an exhaustive NERC standards review.
d. End User representative asked that PAs be aware of when the addition of HVDC may exceed the current single contingency and the cost that may have on the system. Also need to look at both the HVDC that is carrying power (as is the case in the current study where HVDC replaces AC lines) and HVDC that is delivering a certain resource similar to Hydro Québec, the loss of which would be a contingency.

6. **PJM Transmission Overlay** (Fred Von Pinho, PJM)
   a. Scenario 1 resulted in significant deactivation of coal, replaced in large part by Combined Cycle generation units. PJM also had significant wind to bring on line.
   b. PJM sited new wind generation on western portion of PJM's system based on an earlier resource study.
   c. Performed a peak analysis and light load analysis to identify the worst overload for each element of the system. PAs made upgrades to its PJM West 765 kV overlay. Additions also help disperse the imports from MISO to PJM. Other upgrades were made where power was offloaded from the 765 kV systems.
   d. NGO representative noted at the last TOTF meeting it was agreed that PAs would rely on NEEM dispatch to determine the amount of wind dispatched to meet load, and later PAs would apply interconnection criteria, such as the 80% deliverability criteria for wind, in sensitivities. PJM confirmed that under the peak analysis, wind was dispatched according to the NEEM dispatch. They have just completed the light load analysis with 80% criteria, and did not see anything surprising and it would not make a difference in the wind dispatch. PJM believes it is appropriate to do the generation interconnection analysis first. The second step was to look at the transfer analysis. PJM has not addressed all the problems that arose under Block 13.
   e. After HVDC lines from MISO to PJM were added, few upgrades were needed. PJM noted the addition of some terminal equipment and transformers.
   f. NGOs requested the list of all regional overlays, summarized as PJM just did with some explanation of the purpose. EIPC stated that the maps will eventually provide all the overlay information; explanation of the purpose of each addition will have to take place in a discussion.

7. **MISO overlay** (David Duebner, MISO)
   a. MISO overlay was added strictly for the integration of wind. Due to the magnitude of the wind (~100 GW), MISO relied on the Regional Generation Outlet Study (RGOS) as guidance for selecting the necessary transmission overlay; this in turn was based on EWITS and NREL wind resource analysis.

    b. Diagonal flow from Northwest to Southeast tracks the Buffalo Ridge geography, which is a high wind resource area.

8. **SPP overlay** (Doug Bowman, SPP)
    a. Overlay was designed to integrate over 100 GW of wind in 3 states. SPP has not yet made changes to the system for the regional interties.
    b. Clean Line proposal would connect at Woodward and terminate in Memphis area. Clean Line clarified that its proposed HVDC transmission project will connect to SPP grid with the intention of no net flow, but the line would be subject to open season.

9. **ISO-NE overlay** (Stan Doe, ISO-NE)
    a. Upgrades include High Gate (400 -2000 MW) to integrate hydro and wind; DC input to Orrington; DC to Boston via submarine cable; not many overloads to 345 kV lines.

10. **Next Steps** (Jeremy Bennett)
    a. Scenario 1 – PAs will incorporate all transmission additions developed to date; by next week, EIPC will release new subsystem files and Pass 2 case. Will then begin to simulate actual dispatch from NEEM. That step may create a new Pass 3 which has not been thoroughly analyzed.
    b. Scenario 3 (BAU) – PAs have a solved load flow case under review. May be available next week. Ancillary files have not been developed yet and will lag in release.
    c. Scenario 2 (National RPS, Implemented regionally) has just been started.

11. **Schedule update** (David Whiteley)
    a. The TOTF is currently in Week 13 of the detailed schedule, working on steps 10-13 in the outline of tasks.
    b. Step 13 – Identification of transmission for each Scenario- was scheduled to be completed by 4/13/12, but it is unlikely PAs will be able to meet that deadline. Since the schedule has another 12 weeks for load flow and transmission analysis, meeting the schedule will depend on how quickly the other Scenarios can be solved.
    c. EIPC intends to re-incorporate into the schedule re-convening of the MWG to prepare for the production cost modeling.
    d. SSC meeting in April may include new information on Scenario 3.
    e. Reliability tests will be done comprehensively at the end of the development of the three Scenarios.

First Name	Last Name	Company	Sector
Official Task Force Members			
Robert	Sinclair	OPA	Canadian Provincial Representatives
Kerry	Marinan	American Transmission Company LLC	EIPC
David	Whiteley	EIPC	EIPC
Samrat	Datta	Entergy Services, Inc	EIPC
Joseph	Payne	Entergy Services, Inc	EIPC
Stan	Doe	ISO New England	EIPC
Dan	Fredrickson	MAPPCOR	EIPC
David	Duebner	MISO	EIPC
John	Buechler	NYISO	EIPC
Zach	Smith	NYISO	EIPC
Chuck	Liebold	PJM	EIPC
Jeremy	Bennett	Southern Company	EIPC
David	Till	TVA	EIPC
Fred	Plett	Massachusetts Attorney General	End Users
Erin	Hogan	NYSERDA	End Users
Michael	Goggin	AWEA	Generation Owners and Developers
Ed	Pfeiffer	NGO/Quanta Technology	NGOs
Marya	White	EISPC	Other
Robert	Stein	Signal Hill Consulting Group	Other Suppliers
Dustin	Betz	Nebraska Public Power District	Public Power/TDU
Michael	Wegner	Kansas Corporation Commission	States
Craig	Taborsky	MD PSC	States
Diane	Barney	New York State Dept of Public Svc	States
Evan	Wilcox	AEP	Transmission Owners and Developers
John	Stovall	EISPC / Oak Ridge National Laboratory	Transmission Owners and Developers
Randell	Johnson	Northeast Utilities	Transmission Owners and Developers
Other Participants/ Experts			

Srinath	Kamireddy	Entergy	EIPC
Keith	Daniel	Georgia Transmission Corporation	EIPC
Tu (Toby)	Hu	ISO New England	EIPC
Samuel	Zewdie	MAPPCOR	EIPC
Kenneth	Wei	New York ISO	EIPC
Frederico	Von Pinho	PJM	EIPC
Jim	Busbin	Southern Company	EIPC
Jerrod	Moll	Southern Company	EIPC
Doug	Bowman	SPP	EIPC
Harvey	Scribner	SPP	EIPC
Jason	Speer	SPP	EIPC
James	Normansell	Tennessee Valley Authority	EIPC
Timothy	Smith	Tennessee Valley Authority	EIPC
Ian	Grant	TVA	EIPC
Wil	Burns	NGOs	NGO
Samir	Succar	NRDC	NGO
Thomas	Gentile	Quanta Technology	NGO
Bob	Pauley	EISPC	Other
Emily	Fisher	Lawrence Berkeley National Lab	Other
Joseph	Eto	Lawrence Berkeley National Laboratory	Other
David	Meyer	US Dept of Energy	Other
Ben	D'Antonio	New England States Committee on Electricity	State Representatives
Stan	Hadley	Oak Ridge National Lab	States
Doug	Gotham	Purdue University	States
Barry	Huddleston	Clean Line Energy Partners	Transmission Owners and Developers
King	Look	Con Edison	Transmission Owners and Developers
Tyler	Ruthven	National Grid	Transmission Owners and Developers
Webinar Participants			
Garrett	Bissell	Couch White, LLP	
Ed	Ernst	Duke Energy	
Marya	White	EISPC	

Matt	Schuerger	ESCS	
Syed	Ahmad	FERC	
Anie	Philip	LIPA	
Stuart	Hansen	Minnesota PUC	
George	Smith	NESCOE consultant	
Jonathan	Forward	New York State Department of Public Service	
John	Zarzycki	NJBPU	
Sunil	Palla	NYPA	
Jason	Fordney	Platts	
Joann	Henry	We Energies	