Regional Planning Group
Meeting Notes
September 15, 2015

Misc. Updates

1. RTP Update: Sun Wook: Short circuit analysis. Study finished, results posted on MIS.
   Q: If we have a breaker that is not meeting the criteria, do we recommend replacing that and that gets included in the result spreadsheet?
   A: Yes
   Q: TPIT question: Does breaker replacement need to be reported in the TPIT?
   A: This short circuit analysis is just for the 2015 RTP and it is not related to TPIT.
   We developed preliminary mitigation plans for the 2016 summer peak base case. The preliminary mitigation plans were sent to the TSPs. TSPs, should review the mitigation plans and let us know if you have any comments. We are also working on multiple element outages, the old NERC category C or D type contingencies, as well as economic analysis.
2. West Texas study: Reliability analysis. Working to identify projects based on preliminary reliability analysis results. Identifying transmission projects to solve reliability issues. Will have an update at October RPG.
3. Panhandle report: Expected to be filed with the PUC today.
4. Additional panhandle updates (operational transfer studies) to be completed by end of 2015.
   Q: Does that include the short circuit ratio analysis that was being done?
   A: Yes
   Q: Are you going to incorporate the results of that work into the RTP economic assessment?
   A: No, the results won't be ready by the time we complete the economic assessment.
   Q: For these studies, will you be energizing series capacitors for a series of time?
   A: We are working with stakeholders to develop the reliability requirements, the appropriate studies to ensure the use of series capacitors are safe for all equipment on the grid. Series capacitors will not be energized until these issues are resolved.
   Q: Are you going to require that protocols are set in place and active in the Operating Guide, Planning Guide, Protocols, etc., before series capacitors are put in service?
   A: New series capacitors will not be energized until we receive input from market that putting series caps in service is safe for all equipment.
5. PLWG Update: Meeting to begin immediately after RPG meeting.
   a. PGRR-42 will remain on table until proceedings at commission are complete
   b. PGRR-45 resource commissioning dates will be only agenda item today

AEPSC Live Oak Project—ERCOT Independent Review (Ying Li)

Ying presented on the results of ERCOT's IR for the Live Oak project.

Q: Slide 11—what threshold did you use?
A: 90%

Q: Do you recall the load levels in the South Central and South load zones?
A: Same case for 2015 RTP, South-South Central case.
Q: Did you have to scale load to make that case solve?
A: This was the N-1 secure case coming out of RTP. Did not scale any load in this assumption, but load scaling went into the RTP.

Q: Do you know the total load in the load cases?
A: Cases are posted and loads were presented in January RPG meeting.
Q: Did you maintain 2800 MW reserves in this study?
A: Yes
Q: How do you allocate those reserves? Is it 2800 MW of true spinning generation, or are you counting that there's 2800 MW of load resources in there, but those load resources are not allowed to shed in your case, so it's not really like you're showing 2800 MW? What do you still have left when you trip the G-1 unit?
A: The cases are posted. We don't have the numbers now, but we can put them together, if needed, before TAC.
Q: Assuming no plans to run another study using 90/10 SC forecast instead of the 11.5% different, higher forecast.
A: At this point, we're not. This is not just the summer peak reliability issue, there are also N-1-1 maintenance outage issues.

2016 LTSA Assumptions (Doug Murray)
Doug presented on the scenario assumptions that will be used in the 2016 LTSA.
Q: (Slide 4) On the generation resource adequacy. In scenario 2 you say you have 13.75% reserve margin target. But other scenarios say same as current trends, but current trends have no reserve margin.
A: Because it's a target, it's not a mandatory number that we need to meet. When we do scenarios we build generation based on economics unless a reserve margin is specified.

Q: Could you forecast fuel costs for different vehicle types?
A: We will not. This effort is not an electric vehicle study.

Q: (Slide 11) Is that charging pattern per year?
A: Pattern per day, each day of the year.

Q: Any plan to reflect cost of backup and reliability of the system?
A: Typically we do not, we let the model tell us what it needs. Unless we have a reserve margin requirement, we always end up with scarcity requirements and unserved energy.
Q: Will there be an ancillary services study?
A: No

Lower Rio Grande Valley (Brad Schwarz)
Brad presented an overview of the RPG project that Sharyland Utilities and CPS Energy will submit for the LRGV area.
Q (to ERCOT): What is the process this will go through when there are multiple project submissions?
A: ERCOT received a submittal for this project and will send out as a new project today. It will go through the normal RPG process where you can provide comments in a 21-day comment period. Then, it goes into study mode, which is another 28 days.
Q (to ERCOT): How does ERCOT decide which project will be used?
A: Multiple projects can be submitted and all options will be studied and reviewed.

Q: Why is DC tie not showing up as a stronger case?

A: Back to back DC tie gives you a shorter-term solution, doesn't perform as well in the long-term and is not meant to be long-term solution for the Valley. Does offer short-term bridge option for new generation projects to be started in the Valley.
Q: Does the DC tie solve the reliability issue?
A: No
Q (to ERCOT): Do you consider staying away from series compensation as much as possible?
A: Depends on issue. Look for preferable solutions without compensation.

Q (to ERCOT): How do you analyze the cost of series compensation on the system? Other costs will potentially need to be analyzed.
A: We will do our analysis to include all considerations.

Q: Option 4 is the 500 kV option. Options 5 and 6 are double-circuit 345 kV options. What's limiting on Option 4?
A: 500 is not just the line itself.

Q: Access to additional wind in LRGV, especially at Ajo. Have you included that?
A: No. we didn't see the benefit of adding additional cost to a project to get more wind output.

Q: Another difference between your analysis and AEPs was what generator?
A: Redgate—STEC unit.

Q (to ERCOT): Is there a point at which ERCOT will evaluate the ancillary benefits of looking at these two projects?
A: Look at two projects to see if they have similar performance and costs, then we would look at all additional benefits of the two. However, we're still in beginning stages of looking at these projects. We'll keep it open as possible, bring it back to RPG, and you can provide comments.

Comment (Hunt Power): We're not opposed to looping into Ajo. If you do, you get additional reliability import benefits and you get additional wind integration.

Q: (Slide 25) With Option 5, what is the limiting system condition that prevents you from moving forward?
A: Option 5 smaller SVC limit. Looked at trying to optimize dynamic reactive devices to get the most incremental impact.

Comment: AEP's proposal was 1300 MW of incremental load-serving capacity.

Q: (Slide 28) For the cost of transmission lines, are you including ROW?
A: No
Q: Would those load costs include terminals?
A: Yes
Q: And for Option 5 did you assume you would have to have line shunt reactors?
A: No
Q: Were line terminal costs evaluated for La Palma?
A: La Palma has accounted for the line termination

Q: SVC locations, are those contract costs for the SVC?
A: Those are based off ERCOT estimates, averages. We have not gone out to an SVC vendor and asked for updated costs.