NEBRASKA STATEWIDE WIND INTEGRATION STUDY

SUMMARY of Technical Review Committee Meeting #5

July 2, 2009 – 10:00 AM to 2:00 PM (Central Time)- Ventyx WebEx tele-web conference

BRIEF LIST of Followup Reports included herein in response to questions/comments at the meeting:

A. 4b shows that the largest 98th percentile hourly change in load net wind exceeds the largest average hourly change by 73% for the morning ramp up and by 88% for the night ramp down.

B. 4e shows numbers for the extreme Nebraska load following burden on a light load day in April (from minimum coal generation to maximum in sixteen hours).

C. 5e shows that the calculated Adjusted Production Costs and the CO_2 costs are reasonable.

D. 5g reports that a second Potter 345kV transformer will be added to reduce the curtailment increase in the rest of SPP with the addition of the overlay (all overlay cases to be redone).

E. 5h reports that all 2006 cases are to be rerun and Nebraska wind curtailments are expected to go away.

F. 5i shows that if wind generation in the ideal and actual cases were adjusted to match, then the integration cost result would increase by 7.6%, at least in the case examined and using the method shown (further discussion of this may be warranted).

G. 5m shows that the calculated CO_2 emission tons for SPP are reasonable.

H. 5o reports that the Harbine-Knob Hill 115kV should be modeled with at higher thermal limit, but it is believed that the results would not be significantly affected by the fix, or need rerunning.

I. 6a contains the latest thoughts on case run parameters and order.

J. 6b contains the meeting schedule changes:

August 11 meeting is changed to WebEx

September 23 meeting was added as a face-to-face in Omaha.

Reference Documents - Email to TRC and Observers dated 06.25.09 from Doug Kallesen (for Clint Johannes) containing four attachments: the meeting Agenda, TRC Meeting #4 Summary, Case and Schedule slides, and Roster, some of them having been updated from previous distributions. The EnerNex and Ventyx presentation files were provided in separate emails on 06.30.09 and then the updated Ventyx presentation file was emailed on 07.06.09, with all the updates to that point including some requests made in the 07.02.09 meeting.

TRC Members Participating:

Utility- Clint Johannes, Dave Rich, Doug Kallesen, David Ried, Jon Iverson, Bruce Merrill, Billy Cutsor.
Consultants- Bob Zavadil, Tom Mousseau, Gary Moland, Rick Hunt, Barbara Coley.
Technical Experts and Stakeholders- Matt Schuerger, Ed DeMeo, Mike Radecki, Jay Caspary, Sohrab Asgarpoor, Neil Moseman, Bruce Hauschild, John Hansen, Tim Texel, Michael Goggin, Steve Eveans.

Observers Participating:

Utility- Brian Brownlow (for Randy Lindstrom), Jim Fehr, Rocky Plettner, Ron Thompson, Tim Owens, Ron Steinbach, Max VanSkiver, Eric Hixson.
Technical Experts and Stakeholders – Tim McCoy, Mark Ahlstrom.

Overview of Meeting and Summary:

The complete agenda was covered and the general purposes achieved, that being to review new results, discuss and make decisions about future work including case definition and assumptions as well as work and meeting schedules.

This summary is intended to document key points of the discussion. *Questions and comments from the audience are usually identified in italics* and plain type is intended to indicate statements by the presenter at the time. Usually the person involved will be clear, but not always. [Followup is usually shown in brackets].

Afterthoughts and suggestions can be emailed at any time to Doug Kallesen, drkalle@nppd.com, 402-563-5274, and they will get "logged" into the study process, or to Clint Johannes, Chair of the TRC, cjohannes@neb.rr.com, 402-910-1856.

Key Points of the Discussion:

1. Rick Hunt, Ventyx, welcomed all and took roll call.

2. Clint Johannes, Chair of the Technical Review Committee (TRC) and Chair of the NPA Joint Planning Subcommittee (JPS):

    a. Welcomed all and provided an overview of the meeting purpose.

    b. Asked for any additional comments to the TRC 4 Meeting Summary dated and distributed 06.05.09. No comments offered.

3. Bob Zavadil, study technical manager, EnerNex, proceeded into the EnerNex presentation with some more background on meeting objectives and general work status.

4. Tom Mousseau continued the EnerNex presentation.

    a. *Doug Kallesen commented regarding slide 13 that the minimum load line shown of 2,587 MW is also very close to the minimum generation line (~2,500 MW) if defined as the minimum operating levels of the "must run" coal units, plus the nuclear units running at 100% output levels, minus approximately 600 MW of minimums from "must run" coal* *units being off line (e.g., a large NPPD unit and a large OPPD unit and a couple smaller units being off line at the same time in a typical spring or fall maintenance period).*

b. *Doug Kallesen commented regarding slide 15, 18, and 21 that the average hourly changes (average hourly ramps) are not drastically different when comparing load and net load wind. However, it would seem that the maximum, or near maximum ramps, would be of interest and problematic. Jim Fehr - Could some quantification of those data be done?*

[EnerNex has analyzed and reported these data for 98th percentile both in the largest up-ramp and largest down-ramp directions. The largest 98% morning up-ramp is 73% greater than the largest average morning up-ramp. The largest 98% night down-ramp is 88% greater than the largest average night down-ramp.]

c. *Ron Steinbach observed instances where load net wind ramps more than load.* These are situations where load ramp is increasing and wind generation is decreasing (common in the morning), or vice versa, making the net changes "additive". *Gary Moland added that PROMOD models hourly loads, and as such, does not deal directly with the even faster 20-minute ramps, which can be more demanding from the generation system.*

d. *Jim Fehr asked if we see more dump or unserved energy as "indicators" of generation "problems".* Expect there is a bit more dump energy – Ventyx will check into and report findings.

e. Slide 25 shows an example of a very difficult load following day where the wind generation goes from nearly full output at midnight starting the day to nearly zero output at the peak time of the day April 4, 2018 (2006 wind/load pattern). The variation in generation (load following) needed from non-wind resources is magnified from the no-wind scenario being 1,100 MW (from 3,200 to 4,300 MW load) to 2,800 MW (from 1,250 to 4,050 MW load net wind) in the 20% wind scenario (2,488 MW nameplate wind for NPA).

[The following was not discussed in the meeting but is added here to gain some perspective on the issue of load following what if Nebraska, on its own, tried to deal with 20% wind penetration throughout the selected day in April, when there can be highly variable winds and the load can be quite light, and some of the generation is on maintenance.

Examining the data that is set into PROMOD, the must run nuclear units and the coal units available to Nebraska (less two big coal units and two small coal units assumed to be on spring maintenance) yields a maximum capacity of approximately 4,200 MW. The minimum capacity for these units, assuming the nuclear units remain at full output, is about 2,500 MW. This yields a range of operation for these units of 1,700 MW. The ramping rates for the available units are about 630MW/hour up and 740 MW /hour down.

The data from slide 25 of the EnerNex presentation, a 20% penetration scenario, was eyeballed for every other hour and entered into the table below to give some feel for what the Nebraska generation system might need to be doing if it were to deal with the high wind variation shown for the day of April 4, on a low load day. Observations:

- Wind generation goes from nearly full output to nearly zero in sixteen hours time.
- Must run coal generation goes from minimum levels (2,500 MW) to maximum levels (4,200 MW) in sixteen hours (assuming the stated units are on maintenance) – coal units don't like to do this.
- Exports vary from 1,250 MW at 0100 hr to 100 MW at 1700 hour – the opposite pattern that the market will desire.
- The ramp rates could be satisfied with the Nebraska units only, but it is assumed that they are provided 60% by the Nebraska units and 40% by the export.]

Data from EnerNex Slide 25 (TRC #5)				Ramping in MW/Hour		
Hour	Load Net Wind (MW)	Must Run Gen (MW)	EXPORT (MW)	Req'd by Load Net Wind	Provided by Must Run	Provided by EXPORT
1	1,250	**2,500**	1,250	-	-	-
3	1,400	2,589	1,189	75	45	30
5	1,625	2,724	1,099	113	67	45
7	2,625	3,320	695	500	298	202
9	3,125	3,618	493	250	149	101
11	3,800	4,021	221	338	201	136
13	3,900	4,081	181	50	30	20
15	4,000	4,140	140	50	30	20
17	4,100	**4,200**	100	50	30	20
19	4,050	4,170	120	-25	-15	-10
21	4,050	4,170	120	0	0	0
23	3,025	3,559	534	-513	-306	-207

f. *Jim Fehr asked if we are modeling any loss of wind generation situations.* Situations where these could occur are high-wind shutdowns, high and low temperature trips (e.g., 104 ^{o}F and -20 to -25 ^{o}F, according to a Basin Electric source). EnerNex will examine the NREL data being used to see if evidence of any of these generation loss situations can be found and report findings.

g. Slide 27, last line should say ".8 to 1.00 high correlation".

h. Diversity of wind generation, when measured hourly or for longer time frames, is primarily created by geographic separation. This can be shown by slide 28, for example, where sites 47 and 22 are side by side in Madison County, and have a correlation factor of 0.99 (high correlation) for three years of NREL data. Oppositely, sites 695 and 208 at opposite ends of the state (Kimball and Butler counties) have a correlation factor of 0.21 (low degree of correlation).

i. Diversity of wind generation, when measured in shorter time frames (sub-hourly) relates both to turbine-to-turbine variations, including the number of turbines at a wind farm and to geographic separation. We do not show individual turbine data to demonstrate the first aspect, but comparing slides 30 and 31 show how the 10-minute changes are "softened" or partially cancel by aggregation.

   Note that on an individual site basis (slide 30), roughly 62% of the time (summing the middle four bar sets) the change from one 10 minute period to the next is between ± 2% bounds. This translates for site 22, a 261 MW site, that 62% of the time the site is increasing or decreasing no more than 5.2MW.

   Going then to the aggregated results (slide 31) this amount of time within ±2% bounds increases to 80% of the time. That is, just noting the two histograms the occurrences are pushed more to the middle representing small changes.

   The turbine-turbine diversity appears to show up a bit in slide 30. For example, site 70 is 1,100 MW with over four times as many turbines as site 22 at 261 MW. Comparing the bars for these two sites, it appears that site 70 has a higher frequency in the center (small changes) and lower frequency in the outer bar sets (big changes), but this effect does not appear to be dramatic in the NREL data probably because all the sites we selected are fairly large (≥ 235 MW) with many turbines already.

j. EnerNex spoke of some "rules of thumb" that NREL had developed regarding aggregation. In followup, we will try to identify and document the specifics of these, as they could prove to be helpful information.

k. Factors creating the low integration cost results were listed as:
   i. Diverse wind generation locations and characteristics,
   ii. Large operating pool (SPP)
   iii. Assumptions that wind resources are not constrained (at least minimally)
   iv. Current definition of the proxy resource being hourly changing

l. *Ron Thompson asked concerning forecast error assumptions.* Answer that the NREL data comes in typically at a normal 15% Mean Absolute Error for the standard Day-Ahead forecast process which covers 18-42 hours into the future because of the timing of its development relative to the 24-hour period of interest "day-ahead". For persistence forecasts (assuming next hour will be like the current hour) for real time markets, typically 5% Mean Absolute Error.

m. On slides 30, 32 and 33 there are some short bars at the left edge. These represent the total frequency over the range -20% to -100% aggregated together. There would be similar frequency data to the right edge, except there it has been truncated rather than aggregated.

n. Slides 36-38 are all using 20% penetration data and are based on the hourly load and NREL wind data. The plots are done be 3rd party software and apparently do some smoothing of the data from hour to hour and from day to day to develop the contours rather than just plotting discrete data. These plots clearly show that there are a considerable number of hours with load net wind up-ramps between 400 and 600 MW per hour in the mornings with a few larger at 600-800 MW per hour.

5. Next, Rick Hunt of made the presentation (slide numbers herein refer to the version distributed to the TRC and observers on July 6 that contained a few additional items requested in the TRC5 meeting).

    a. *David Ried asked about some initial understanding he had from some meeting reports that the SPP Wind Integration Task Force study now underway was finding problems in getting their 20% penetration case to solve as a load flow model.* Matt Scheurger a member of the SPP WITF TRC indicated that this was all preliminary, that efforts were underway to understand why, that this was pointed to today's transmission system modeling that was more engineering, detailed oriented being a load flow and stability study. Jay Caspary indicated he was not surprised with such problems showing up given problems in current operations with lower penetrations, and lack of system development being represented.

    b. *Jay Caspary asked how PROMOD was dealing with the 240 MW being added in central-western Nebraska relative to the transmission system restrictions in Nebraska.* Answer that we assume that Gentleman units are backing down when needed to allow outlet of wind generation. Such flows are being monitored and expect to learn more about this from sample examinations of monitored line results.

    c. *Jim Fehr asked how many miles of 765kV line are being modeled in the SPP overlay.* Jay Caspary indicated about 3,000 miles.

    d. Point was made on slide 14 that the Adjusted Production Cost is typically higher for the actual run (than for the ideal run) because the generation system has to account for an increased regulation reserve commitment (this is approximately 515 MW additional regulation capacity per every 10% additional penetration in the SPP area, as taken from slide 10 of the TRC4 Ventyx presentation), and for the error in the day-ahead forecast that is incorporated in the actual run (but not in the ideal run).

    e. *Jay Caspary indicated that the Adjusted Production Costs, as shown on slide 14 looked high for SPP, and wondered if possibly the Entergy area was included in the costs.* Rick Hunt indicated that Entergy is not included in the calculated costs, and indicated that results assume a carbon cost plus escalation to 2018.

    [The following is a double-check to see what might be a $/MWh for APC translating to today's dollars with no wind and no carbon cost. The 10% case results for 2004, actual APC on slide 14 is extrapolated to the stated conditions in the following way:

Actual APC (for SPP including Neb), wind at 10% = <u>\$15,050 M\$</u> (slide 14) (including carbon and escalation)

Estimated APC <u>without</u> wind = <u>\$16,644 M\$</u> = Actual APC +Delta (Scen 1-Scen 2)/0.9 (including carbon and escalation) = \$15,050 + (15,050 – 13,615)/0.9

(extrapolating with 0.9 as an estimate of the decreasing effect on APC reduction per 10% increasing wind by looking at APC results for scenarios 1 to 2 and then 2 to 4.—this estimation uses results that are going to be redone per subsection (g) below, but for this estimation the current results should be sufficient.)

CO2 emission cost estimate for no-wind case = <u>\$5,250 M\$</u> = \$5,070 M\$ + (5,070@10% – 4,890@20%) from slide 37

Estimate of APC escalation from 2009 to 2010 = <u>42%</u> = 1.04^9 – 1.00 … the gas price assumption is \$5.80/MMBtu today, escalating by 7.4% per year to 2018

Therefore the estimate of <u>“normal” APC costs for SPP including Nebraska for 2009</u>, as a reference, without wind and without CO2 = <u>\$30.33/MWh</u> = 1000 x (16,644 M\$ - \$5,250 M\$) / (225,134 + 39,402) SPP incl Neb GWh / 1.42

It is believed that the resulting \$30.33/MWh for “today's” APC is reasonable, given the assumption of a today price of \$5.80/MMBtu for gas being a part of the mix.

Also examining the CO2 cost results, the 2018 cost per load MWh is an extrapolated \$19.85 = \$5,250 M\$ / (225,134 + 39,402) GWh load or \$19.85/MWh in 2018, probably reflecting that some coal-based energy is being exported, thereby the dollars being included in APC for MWh that are not in the load (assumption for CO2 cost is \$25.00 per short ton in 2018). This seems quite reasonable, too.]

f. Barbara Coley discussed as one of the reasons for the low integration cost is that there are lots of extra MW committed in the rest of SPP, i.e., spare reserves are “built in”. *Bob Zavadil commented that it is the shape of the wind that causes there to be extra reserves at times, especially in the off-peak.*

g. Rick Hunt continued with slides 15-16 indicating that the curtailment results in the rest of SPP are intuitive, except for the increase in curtailment at the 20% level resulting from adding the transmission overlay. Rick has traced this problem to congestion at the Potter transformation shown on slide 17, in turn caused by the addition of the Tolk-Potter Co 345kV line as part of the overlay. *Jay Caspary indicated that this point probably needs a second transformer.*

[In followup during the week after the TRC5 meeting, Jay advised Rick to “Please add redundant autotransformers at every SPP EHV substation with multiple EHV lines”. On

08.13 Rick has advised that this is being done for such situations where monitored lines exist, and Scenario 3 and 4 (with overlay) cases to date are being rerun, and the associated results will change.]

h. Rick noted that slide 16 shows wind generation curtailment in Nebraska for all the 2006 cases and that this will need further investigation because none of the cases for 2004 or 2006 show any curtailment in Nebraska.

   [On 07.13 Rick advised that these Nebraska curtailment results for the 2006 pattern were a result of an input data problem that has now been corrected and there will be new results forthcoming for all 2006 cases.]

i. *Jim Fehr commented on slide 16 that the curtailment amounts in the ideal and actual runs appear to be very close, although more decimals in the table percentages is needed to show how much difference there might actually be. Assuming there is some difference, then would it be necessary to make a special adjustment to the Adjusted Production Cost calculation to account for this difference in amount of wind generation present? For example, then the delta in APC would be affected by the delta in the amount of wind generation present (for which no price is included in APC) – would, or would not, that cost/benefit amount properly be a part of the integration cost calculation or not? If not, then do we need to adjust for it or not (adjusting APC to align with consistent wind generation between actual and ideal runs)?*

   [To identify some typical numbers in our results, the following case was examined, subsequent to the TRC5 meeting, with a possible "adjustment" process believed to follow the question posed.

   The differences in curtailment can be determined in the generation details - Appendix 1. Examining the 10-20% scenarios for 2004-2005, the differences in wind generation (conversely curtailment) are:

<u>more wind generation (actual – ideal)</u>		<u>amount less curtailment</u>
69,205 MWh	for 2004, 10%, or	0.32%
45,655 MWh	for 2005, 10%, or	0.19%
87,659 MWh	for 2004, 20%, or	0.20%
98,018 MWh	for 2005, 20%, or	0.20%

   Of these results, the most impacting adjustment should probably come from 2005, 20% because of the greatest MWH delta. Making an adjustment along the lines of what apparently was being suggested (not sure exactly), here's a test case:

   <u>2005, 20% Integration Cost (now) is calculated as</u>:
   $13,447,070,000 APC-actual (slide 14)
   <u>$13,356,810,000 APC-ideal (slide 14)</u>
   $ 90,260,000 APC delta (actual – ideal)
   <u>Divided by 51,630,000 MWh actual wind generation</u>
   = $1.7482 per MWh of actual wind generation

Assuming that the adjustment consists of further adjusting (outside PROMOD) the APC so that the ideal run has the same amount of wind generation as the actual case that is being used for the denominator:

Then assuming that the LMP price to be used for the APC adjustment is $70/MWh weighted for wind, for example (had to take this from eyeballing NPA's LMP prices on slide 42).

And believing that the adjustment is to add 98,018 MWh of wind generation to the ideal 20% case at a cost savings then of $6,861,000,
This would then make for an adjusted integration cost of:

$13,447,070,000 APC-actual (slide 14)
$13,349,949,000 APC-ideal (13,356,810,000 (slide 14) – 6,861,000)
$ 97,121,000 APC delta
Divided by 51,630,000 MWh actual wind generation
= $1.8811 per MWh of actual wind generation

This "adjustment" raises the computed integration cost in this case by 7.6%, not a big amount but probably worth discussing a bit more. Would it be a proper adjustment? It wouldn't be hard to do.

Another associated question is why the actual runs normally appear to result in more wind generation (or less wind curtailment) than the corresponding ideal runs. For the four cases listed above: results of 45,655 to 98,018 MWh more generation, or 0.19% to 0.32% less curtailment. It is believed this is due to slightly more resources generally being committed under the added uncertainty conditions of the actual run methodology. These additional resources can provide additional redispatch capability that allows slightly more wind outlet opportunity (i.e., slightly less curtailment).]

j. *Ron Thompson asked what amount of time are the combined cycles running – are they running around the clock?* In the meeting, Rick indicated off the top of his head, he thought typically 40% capacity factor.

[In the area of slides 18-19, there is no bar chart slide for CC generation like there is for combustion turbine and steam generation – we should add one next time. The delta (actual – ideal) slides 23-24 do include CC deltas, but there is no gross generation values presented for CC except in the Appendix –Detailed Generation Results at slides 44-55. In those 2004-2005 cases for 10-20% penetrations without the overlay, the CC generation in Nebraska is typically 3,000 GWh per year. The CC capacity modeled in Nebraska is believed to be 937 MW (Salt Valley-167, Beatrice 240, Cass County-530). If this is the classification used in the PROMOD setup, then the associated annual capacity factor would be typically 37%. It would be good next time to generate a capacity table like the Appendix 1 Generation tables, and it would be good to generate a table of operating hours for the three combined cycle units, and what kind of operating cycles, if possible. This would more directly answer the question.]

k. *Clint Johannes asked if the wind generation could be added to the generation slides.* In response, Rick Hunt has added those values and another category "Other (Fixed Energy)" plus a total line to each of the slides 44-55 in the Appendix 1 subsequent to the meeting.

l. *Ed DeMeo indicated that it will be important to determine how impacting is the assumption of flat hourly block for the proxy resource in driving the low integration cost results were are getting.* Bob Zavadil agreed.

m. *Clint Johannes asked about the 31.5 million short tons of CO2 emissions for Nebraska owned units showing up on slide 33, remembering that historical DOE-EIA data runs generally more in the 22 million metric tons area (roughly).* Rick Hunt reminded that these data include:
   i. additional new units,
   ii. units outside Nebraska but for which Nebraska receives the energy by participation or ownership share,
   iii. standard emission rate assumptions, and
   iv. short tons instead of metric tons.

   [To double check this, consider that the 2018 system being modeled:
   i. contains 933 MW of new coal capacity (ADM, Whelan 2, Nebraska City 2), which if running at 75% capacity factor (roughly)and emitting 0.97 metric tons per MWh (approx), yields 5.9 million metric tons of CO2 emissions;

   ii. contains 346 MW of coal capacity located outside of Nebraska (Laramie River and Walter Scott, a.k.a. Council Bluffs), which if running at 70% capacity factor (roughly) and emitting 1.05 metric tons per MWh (approx), yields 2.2 million metric tons of CO2 emissions; and

   iii. converting these metric ton estimates (22 + 5.9 + 2.2) to short tons yields a total of 33.1 short tons of CO2 emissions in 2018, which is quite close to the results being reported on Ventyx's slides 33-36.]

n. *Ed DeMeo observed in the CO2 slides (33-36) that emissions increase for Nebraska with the overlay.* Reason is that fossil generation increases with the addition of the overlay that allows more low-priced surplus generation out of Nebraska, as shown on slides 25 and 27-29.

o. *Jay Caspary asked why Harbine-Knob Hill 115kV (a future Nebraska-Kansas line) was hitting limits under normal operations, as shown on slide 40. Did it need to be built bigger with more capacity?*

[Subsequent to the TRC5 meeting, and upon review of the model assumptions, the 115kV line was found to be showing a capacity of 100MW, and Rick intends to increase that to 200MW. Rick had also reviewed the impact of this assumption on the results and determined that it was not significant enough to warrant rerunning already completed cases.]

p. *Jim Fehr asked about the magnitude of the incremental reserves included in the actual runs.* Reply that numbers are listed in the TRC4 Ventyx presentation at slide 10. Reserves change by the hour, so both maximum and averages are listed in that slide 10. These incremental reserve results for regulation (incremental above those for the ideal wind runs) for all of SPP (including NPA) range from 513 MW average for 10% penetration to 2,728 MW hourly maximum for 40% penetration.

q. *Mike Radecki inquired regarding forecast error and associated incremental reserves, what criteria is being met.* Reply from Bob Zavadil that the implication in the analytical method is that compliance with Control Performance Standard #2 is held constant when incremental regulation reserves are added to compensate for the added wind generation. The 301 MW listed for average regulation reserves for load alone(slide 10 of Ventyx's TRC 4 presentation) is 1% of the average hourly load for the year (before considering regulation requirements for wind generation).

[This would indicate that the average hourly load for SPP (including NPA) is 30,100 MW. With the annual energy demand for SPP (incl NPA) being 264,536,000 MWh (slide 4 of Ventyx's TRC 4 presentation), this makes the average hourly load be 30,198 – so this all cross checks.

Further the max value listed is 533 MW, which apparently implies that the peak load for SPP (including NPA) is 53,300. Dividing the average hourly load by the peak hour load implies an annual capacity factor of 56% -- this seems quite reasonable.

The incremental reserves listed on slide 10 of Ventyx's TRC4 presentation involve statistical analysis that combines the variations of the wind taken against those of the load.]

r. Rick Hunt pointed out on slide 42 that the LMP results for Scenarios 1 and 3 plot on top of each other.

[All of these values, being 2006 results, are being recalculated].

6. Bob Zavadil led the discussion of next steps for the study.

a. **CASE LIST** - After an extended discussion about what sensitivities we know we will be running, and what cases we need to think more about, here is the result of the discussions at the TRC5 meeting an some followup work and thoughts by the study team annotated in brackets [ ]. These cases were previously listed in the study Case and Schedule slides provided to the TRC after the TRC 4 meeting.

CASES WE KNOW WE WILL BE RUNNING [listed in tentative order proposed by Ventyx on July 13]:

i. High CO2 cost ($50/short ton), with 765kV overlay, 20% case, SPP market.

ii. Previous proxy resource model - DAILY FLAT BLOCK PROXY – Consultants to provide input on whether to do on 10% case or 20% case and what lines up with EWITS daily flat block proxy)
[Discussion by the study team on July 13 concluded to do this case with the DAILY FLAT BLOCK PROXY applied to Nebraska and the rest of SPP (rest of the Eastern Interconnection as before) and using 10% penetration for two reasons:
1) Ventyx indicated that EWITS daily flat block case done with the reference case which was 7-8% penetration which is closest to our 10% case, and
2) By running this case at 10% it will be just one change from the 10% base case with SPP-wide market and hourly proxy, while also being just one change from the Nebraska only market sensitivity case also having a daily proxy assumption – that is, making one change at a time will allow us to separate impacts].

iii. Market sensitivity case #1 – Nebraska alone (10% scenario WITH DAILY FLAT BLOCK PROXY for Nebraska and the rest of SPP), and modeling the rest of SPP as a single market.

iv. 345kV overlay in Nebraska for the 20% case (only the Nebraska 765kV lines are deleted with 345kV lines substituted as Axtell – Gentleman 345kV, Gentleman-new Cherry County 345 kV (with 2 transformers to new Cherry County 115kV), new Cherry County – Hoskins (Norfolk) 345kV (and additional transformer), and Hoskins – Ft Calhoun 345kV).

[This case is not in study scope but is considered important so the plan is to substitute this one for one of the sensitivity cases listed below to think more about].

v. Existing Wind only – [This case will show 140MW wind in Nebraska and 3,000 MW wind in the rest of SPP , making this case a single change off from case (iii) above.]

vi. Mitigation - WAPA interaction (expect multiple methodologies)

CASES WE NEED TO THINK MORE ABOUT YET [one needs to be deleted per note above]:

vii. Forecast Sensitivity Case #1 (GENERAL FEELING WAS NOT TO DO THIS ONE due to already low integration cost results, so not much to be learned here, probably)

viii. Market sensitivity case #2 (AFTER DISCUSSION, GENERAL FEELING SEEMED TO BE TO RUN THIS ONE) – Consultants will think through and propose a high hurdle rate value that would limit exports some , e.g., $20/MWh. Concern here is on export volatility and can we really expect market to absorb large, volatile variations without some sort of economic penalty. The purpose of this case would be to reduce the ability of SPP to export so freely and in turn to handle more of the generation variations. Best solution would be to increase external wind in MISO etc for every SPP penetration, but this is beyond scope of work, so this case could be considered a next best approach. [Probably this case would be run at 20% penetration <u>without</u> the transmission overlay.]

ix. Mitigation – flatten load profile for demand side (how to do, what results to be gained with low integration costs already?)

x. Third proxy resource model or Nebraska hydro flexibility.

xi. Third CO2 price sensitivity (zero or reducing cost) – OR CONSIDERABLE DISCUSSION ABOUT TRYING TO MAKE THE MODEL REDUCE CO2 EMISSIONS (comply with targets) – various ideas proposed, many not feasible to model.

1) Maybe we did not completely rule out matching the coal generator maximums to the wind patterns (e.g., high maximums when wind is low and low maximums when wind is high, or setting low maximums in the off peak periods – needs to be SPP-wide probably).

2) [Also subsequent to the meeting, Jim Fehr has proposed one more idea for this purpose that is attached. Limit Coal Gen Scenario]

xii. Mitigation – hydro pumped storage (what size, for Nebraska only or for sharing in rest of SPP?)

b. OTHER DISCUSSIONS and DECISIONS:

i. Decided to use 2006 as the load/wind profile year for the sensitivity cases due to the interest associated with the curtailment that was showing up in Nebraska. However, the 2006 cases are being rerun subsequent to the TRC5 meeting, and that curtailment in Nebraska is expected to go away.

[In a study team discussion on July 13, it was decided to continue using 2006 as the reference year for the sensitivity cases because of the somewhat greater amount of wind generation associated with that profile.]

ii. Ron Steinbach indicated that the draft writeup on the western export brief study will be ready for the next meeting.

iii. **FUTURE MEETINGS were set as:**
August 11, Tuesday, 10:00am – 2:00 pm Central time, <u>WebEx</u> meeting (this is a change from it being previously scheduled as face-to-face)

September 23, Wednesday, 9:00 am – 3:00 pm Central, face-to face, Omaha (Reasoning that we need more time to write and review the report and to have that done before our final face-to-face meeting).

By Doug Kallesen, NPPD (for NPA)