SUMMARY OF
THE WESTERN WIND AND SOLAR INTEGRATION STUDY
STAKEHOLDER MEETING

August 14, 2008
Embassy Suites Hotel Denver-Aurora

Note: The following is a summary of the presentations and the discussion at the Western Wind and Solar Integration Study (WWSIS) stakeholder meeting that took place on August 14, 2008. Presentations can be accessed at http://wind.nrel.gov/public/WWIS/stakeholder%20meetings/8-14-08/.

Executive Summary

Presentations on WWSIS were given by Debbie Lew of NREL on the overall project; Dave Renne, Ray George and Nate Blair (all of NREL) on the solar modeling; Cameron Potter of 3TIER on the wind modeling; and Dick Piwko, Kara Clark, Gary Jordan, Lavelle Freeman and Nick Miller (all of GE) on the scenarios studied to date; statistical analysis; production simulation analysis; and recommendations on future scenarios to study.

Next steps on WWSIS include the following:

- GE will begin work on the Mega Projects and Local Priority scenarios. NREL and GE will further refine the other two scenarios and will bring those to a meeting of the Technical Review Committee for review.

- NREL and GE will also consider whether to adjust the carbon price assumption of $5/ton.

- GE will also consider whether the assumed capacity value of $100/kW is reducing the potential impact of geographic diversity of potential wind projects.

- NREL solar staff will work on finding sub-hourly solar data, particularly for PV.

Introduction by Debbie Lew, NREL

Debbie Lew of NREL is the WWSIS project manager. She said the study is not intended to be a cost-benefit study or a transmission study; rather, it is intended to see if it is operationally feasible to incorporate 30% wind and 5% solar. Specifically, the WWSIS will attempt to understand the costs and operating impacts due to the variability and

uncertainty of wind, PV and concentrating solar power (CSP) on the grid. She also stressed that it is her desire that the study to be as open and transparent as possible, and that the modeling and data issues have been significant. Therefore, the results presented today should be viewed as preliminary.

Other points from Ms. Lew's presentation:

- The study year is 2017 to coordinate with WECC studies
- 2004, 2005 and 2006 load, wind and solar data will be simulated for a 2017 grid
- All of WECC will be simulated, with sub-hourly variability handled by utilities within Westconnect
- Baseline and high renewable scenarios will be developed and for each scenario, the data for 2004, 2005 and 2006 will be statistically analyzed. Production simulation and quasi-steady-state analysis will also be done for each scenario
- Within Westconnect, 30% wind and 5% solar will be studied, with CSP comprising 3.5% of the solar and PV 1.5%. For the rest of WECC, 20% wind and 3% solar will be assessed, with CSP making up 2.1% of the 3% solar and PV comprising the remaining 0.9%.
- Over 28 GW of wind; 2,884 MW of CSP; and 2,472 MW of PV will be studied within Westconnect. For WECC, over 36 GW of wind will be studied, along with 3,378 MW of CSP and 2,895 MW of PV. All told, 65 GW of wind; 6.2 GW of CSP; and 5.3 GW of PV will be assessed.

Ms. Lew reviewed the project schedule. Data collection, site selection and preliminary statistical analysis have occupied the project team to date. A goal of today's stakeholder meeting is to select scenarios, after which GE will begin detailed statistical, production simulation and quasi-steady-state analysis. Preliminary technical results are due by the end of 2008, and a draft report by May 2009. Another stakeholder meeting will take place at that time, with a final report in July 2009.

Dave Renne, Ray George, and Nate Blair, NREL, Solar Modeling

Mr. Renne began his presentation by providing a solar resource assessment status. The National Solar Radiation Data Base was updated, consisting of hourly solar resource estimates derived from cloud cover observations at 1,454 locations, with an estimated accuracy of plus or minus 10 to 20%. Satellite-derived estimates of hourly solar resources were also produced by the State University of New York at Albany (SUNYA) and NREL at a 10 km spatial resolution, also with an estimated accuracy of plus or minus 10 to 20%.

Separately, NASA has worldwide solar radiation data derived from satellites at a relatively coarse scale of about 1 degree latitude and longitude. High-quality historical measurements are available at a few dozen sites in the U.S, including NREL. In addition,

the International Energy Agency has created Task 36 that is intended to benchmark international solar resource assessments and resource forecasting methodologies.

Mr. Renne said that satellite imagery is a cost effective means of collecting solar resource estimates over large areas, equivalent to having 80,000 solar resource collection stations. There are two approaches: converting satellite imagery to solar estimates, as practiced by SUNYA and satellite-derived cloud cover information, as practiced by NREL and NASA. Two types of satellites are used to collect the data: geostationary weather satellites that are high resolution and continuous in time but measurement accuracy decays at high latitudes, and polar orbiters that are very high resolution at all latitudes but measurements are taken only twice daily. Measurements are adjusted for terrain elevation, turbidity, snow cover and specular correction. The satellite data is corroborated with over a dozen ground sites, and a root square mean error of about 15 to 20% is generally found with the satellite data. However, Mr. Renne said satellite data will not provide good information on sub-hourly ramp rates for PV.

Mr. Renne concluded his portion of the presentation by noting that new efforts are being made with the CSP industry to install solar monitoring stations. NREL funds the design, deployment and data processing and archiving activities. About a dozen such monitoring stations will be installed, and there are industry requests for even more solar monitoring stations.

Mr. George then discussed solar site selection for CSP. The CSP site screening is done in three steps. Step 1 is only including sites with direct normal insolation of at least 6 kWh per square meter per day, with a ground slope of less than 1%. Potential CSP sites on federal protected lands, bodies of water, urban areas and wetlands are also removed. What's left is put into 2 km^2 CSP cells, amounting to 203,000 CSP cells and 11,500 GW.

Step 2 assigns a capacity factor for potential CSP projects, using location and average direct normal insolation and determining a cost of energy. Ranking by levelized cost of energy, CSP sites are assigned to existing transmission capacity until transmission capacity is exhausted. That results in 15,000 CSP or 267 GW.

Step 3 is relating each CSP cell, done at 2 square kilometers, to the near SUNYA cell, done at 100 square kilometers. About 3,900 SUNYA cells contain some CSP capacity, with the most being 5,600 MW. The top 501 SUNYA cells contain 207 assigned GW, or an average of 413 MW per cell.

Mr. Blair described the Solar Advisor Model that models solar performance, costs and financing for all solar technologies. For the WWSIS project, Mr. Blair only used the model for determining hourly output of CSP and PV projects. For CSP, Mr. Blair modeled a 100 MW parabolic trough project with six hours of storage. For PV, Mr. Blair reported on work done by Mr. George and Paul Denholm of NREL, where a composite of 11 different orientations and configurations at each location were modeled. Tom Ferguson of Xcel Energy asked whether the Solar Advisor Model reflects fast ramping for PV. Debbie Lew said the modeling only includes hourly data for PV and examining

sub-hourly operating issues for PV is in a later phase of the project. That said, Debbie said there is a lack of sub-hourly PV data, and it is an issue that needs to be addressed.

Charlie Smith of the Utility Wind Integration Group asked how much solar capacity was lost because the analysis limited solar projects to sites with existing transmission capacity. Nate Blair said this mainly affects the supply curve for solar and other solar sites may not be selected if transmission was included. Charlie wondered whether not having transmission affects the levelized cost of energy for the solar sites that are included.

Tom Carr of the Western Interstate Energy Board asked what is the impact on capacity factors of including storage with CSP. Nate Blair said without storage, the capacity factor for CSP is about 20% but with storage, it rises to 40-45%. Nate also noted that with six hours of storage, the CSP project can run into the evening hours. Brad Nickell of WECC asked how much more solar field is added with a CSP plant with storage. Nate said that depends on location, but about 80% more solar field is added. Ron Flood of Arizona Public Service said the storage provides a lot of capacity value, especially in the summer when the summer peak can extend into the evening hours.

Ed DeMeo of Renewable Energy Consulting asked about the confidence level of satellite data for solar. Dave Renne said the bias between satellite and ground measurements is very small, but there is a lot of scatter with satellite solar data. He said the root square mean error is about 15-20%.

Cameron Potter, 3TIER, Wind Modeling and Solar Forecasting

Dr. Potter noted that the WWSIS wind data set is the largest dataset created for a wind integration study to date. 3TIER's charge was to model an area of over four million square kilometers at a one-minute arc-minute spatial resolution (<2 km) at a 10-minute resolution for three years. A subset of points was modeled as potential wind projects, from which GE will select a further subset for their analysis.

He described the advantages and disadvantages of mesoscale numerical weather modeling and concluded that the advantages outweigh the disadvantages, and that such modeling is often the only option available.

The geographic area encompassed for WWSIS was too large to model as a single area and was therefore broken into four separate regional datasets that were later combined into a single dataset. For each grid point, the following was collected:

- Wind speed and direction at 10 m, 20 m, 50 m, 100 m, and 200 m
- Temperature at 0 m, 2 m, 20 m and 50 m above the surface
- Specific humidity at 2 m above the surface
- Pressure at the surface
- Precipitation at the surface

- Downwelling radiation (longwave and shortwave) at the surface

To combine the four regional datasets, the data was regridded to a latitude-longitude grid with a resolution of 1 arc minute by 1 arc minute. The individual datasets were then blended at the overlapping boundaries.

The resulting dataset consists of over 1.2 million grid points. Each grid point has a time series of 10-minute data for three years, and the time series encompassed 21 modeled variables.

To select sites for creating wind projects to study, 3TIER and NREL sorted sites by proximity to transmission within Westconnect; load correlation; and wind power density. Pre-existing and known planned wind projects were also included. Over 32,000 possible locations were identified after applying exclusion criteria such as national parks, mountain tops, and steep slopes. Each selected point covered an area of approximately 3.3 square kilometers and was modeled as a single 30 MW wind project encompassing 10 Vestas 3-MW turbines.

Dr. Potter discussed two potential methods of estimating plant output from these sites. One, known as rated power output, corrects the wind speed based on air density and then applies the manufacturer's power curve using the corrected wind speed. Another method is known as Statistical Correction to Output from a Record Extension, or SCORE. Dr. Potter cited several reasons why he prefers the SCORE method:

- Modeled wind speeds are often too persistent
- Simple upscaling of manufacturer's rating curves does not model farm-wide smoothing relationships
- "Farm-wide" rating curves are developed from empirical data for an entire farm and are subject to farm specifics such as project size and turbine layout
- Wind speed to power conversion is not deterministic

Dr. Potter explained that SCORE is based on empirical experience with wind speed to power output and is related directly to the size of the grid spacing used in the mesoscale model. However, he cautioned that SCORE is a probabilistic method and may not be correct at any particular moment. Instead, it is designed to provide statistically correct data.

The last step involves NREL applying hystersis loop to the data, where if the wind speed reached cut-out speeds of 25 meters per second, the wind turbine would not produce power until the wind speed had dropped below 20 meters per second.

3TIER also provided four kinds of wind forecasts for the 32,043 chosen sites and a mesoscale solar forecast for the 8,736 potential solar sites. The four wind energy forecasts were as follows:

- Perfect forecast (to evaluate the base cost)
- Persistence forecast (short-term prediction)
- Climatology forecast (baseline day-ahead)
- Mesoscale model forecast (baseline best practice)

The perfect and persistence forecasts were produced for both rated power and SCORE power output, as they are both intended to be used at time scales that may be affected by the SCORE conversion process.

Dr. Potter noted that the input data for the mesoscale wind energy forecasts was different than the one used for estimating wind output from wind sites. Weather fields from the Global Forecast System were used downscaled to a 6 km resolution, allowing the entire WWSIS to be modeled as a single region. A state-of-the-art model output statistics correction was not applied; thus, the wind energy forecasts are conservative.

Solar forecasts were produced for latitude-longitude grid with a grid spacing of 12 arc-minutes. Dr. Potter noted that solar forecasting methods are not as advanced as wind forecasting, and as such, 3TIER developed a relatively simple model as described more in Dr. Potter's presentation. 3TIER found the solar forecast values had a bias on clear days, perhaps from aerosols not represented in numerical weather models. A ratio of the 10-day maximum forecasted and observed value was used on clear days in the forecast to correct the bias.

The final deliverable for 3TIER was to create a web-based interface to provide users access to the data for over 32,000 wind sites. The web site will consist of a map that allows users to access sites by clicking on the map or by searching with either site ID or latitude-longitude coordinates. The web site will soon be available.

Charlie Smith asked about the implications of not having a model output statistics correction applied to the wind forecast. Dr. Potter said applying such a correction could remove a lot of the bias. Brian Parsons of NREL asked how does the synthetic wind forecast error compare with wind forecasting errors in real life. Dr. Potter said the errors are higher with synthetic wind forecasts. Eric Williams of Tri-State Generation and Transmission asked if 3TIER included offshore. Dr. Potter said it can be done but validation is difficult, since there is not a lot of offshore wind data. 3TIER did provide some close-to-shore offshore wind data for WWSIS, with the limitation that the offshore projects be no more than 50 km off shore.

Dick Piwko and Kara Clark, GE, Base Scenarios and Data

Mr. Piwko explained the project tasks that GE has been assigned to perform. Currently, GE is doing preliminary analysis and scenario development. Next is a baseline scenario for 2017 using existing wind and solar levels as of 2008. Following that is a high renewable energy scenario with 30% wind and 5% solar, otherwise known as an "in area" scenario, as each of the identified transmission areas must meet the wind and solar levels

inside the transmission area. Variations on those high renewable scenarios will be assessed next. An ELCC and LOLE analysis will be done for three scenarios. A draft and final report concludes GE's part of the project.

Mr. Piwko said the following analyses would be done for each scenario:

- Hourly and sub-hourly statistical analysis measuring variability, uncertainty, and extreme events, among other things
- Production simulation analysis using MAPS that will assess impacts of higher wind and solar generation on unit commitment, economic dispatch, spot prices, emissions, energy displacement and transmission constraints, among other things
- Quasi-steady-state analysis, consisting of minute-by-minute simulations of selected time periods
- Sensitivity analysis encompassing wind turbine controls, operating strategies, flexibility of dispatchable generation sources, and operation of hydro generation, among other things

Mr. Piwko reviewed the data that GE has available for its analysis; this is outlined in Mr. Piwko's presentation. He noted the absence of sub-hourly solar generation and the relative lack of load forecasts and sub-hourly profiles is something that may need to be addressed.

Mr. Piwko reviewed the basics of the scenarios. The 2006 loads are escalated to 2017 using 1.8% annual escalation, or 21.7% overall. Each scenario has 30% wind and 5% solar in Westconnect, with the rest of WECC having 20% wind and 3% solar. GE will also look at 20% wind and 3% solar in Westconnect (10% wind, 1% solar in WECC) and 10% wind and 1% solar in Westconnect and WECC. The solar levels consist of 70% CSP with six hours of storage, and 30% PV.

Ms. Clark reviewed the in-area scenario by noting that eight transmission areas within Westconnect are defined as in area. Those eight transmission areas are Idaho East/SW Wyoming; Wyoming Central East; Colorado West; Colorado East; Northern Nevada; Southern Nevada; Arizona; and New Mexico. A map of transmission paths and available in-area wind sites were also shown. Bob Easton of WAPA asked if the transmission ratings are based on what could be available in 2017; Kara Clark said it includes transmission upgrades expected in Nevada and between Arizona and California. Jerry Vaninetti of TransElect was asked if wind and solar could displace other resources on existing transmission lines; Kara said yes.

More wind and solar sites were available than were needed to satisfy the renewable energy requirements of the in-area scenario. GE created a sorting algorithm that considers the market and capacity value of the wind and solar generation and recognize geographic diversity and include the pre-selected wind plants. Energy value is based on hourly historical hub prices; capacity value is recognized as $100-kW-year, with energy produced between 1 p.m. and 6 p.m. during June, July, and August; and geographic diversity being incorporated as a 1% bonus every 100 miles.

Initial observations from GE's sorting algorithm are that Wyoming has many wind sites with relatively high capacity factor and that Arizona and Nevada have wind sites with relatively lower capacity factors.

Tom Acker of Northern Arizona University said the load forecast data looks incomplete and asked whether there are plans to try to fill that in. Dick Piwko of GE said they have day-ahead forecasts for unit commitment and hour-ahead for short-term, but they could use more short-term forecast data. Bob Zavadil of Enernex asked if day-ahead forecast uncertainty increases with 30% wind. Gary Jordan of GE said they have not come to that stage of the analysis yet.

Ed DeMeo asked whether the 30% scenario should be properly labeled 35%, since it includes 30% wind and 5% solar. Gary Jordan agreed, noting that the study was first drawn up as a 30% wind study before solar was added, and the 30% term stuck.

Andrew Mills of LBL asked how new generation was selected to meet load growth. Gary Jordan said GE used "reasonable choices" that assumed more combined cycle and gas turbines and less coal, with a 15% reserve margin.

Lavelle Freeman, GE Energy, Statistical Analysis

Mr. Freeman began his presentation by defining net load as consumer load minus wind and solar output. Alternatively defined, net load is the amount of generation required from dispatchable units. For the 30% in-area scenario, Mr. Freeman noted that wind and solar generation account for over 50% of monthly generation in the Westconnect region in March and April, but much less than that in July and August. Solar also tends to complement wind generation over the day.

Mr. Freeman compared the net load duration for an entire year for the baseline, 10%, 20% and 30% levels of wind and solar. At the 30% level, net load is below existing minimum load for about 60% of the year. Wind also has a 108% penetration for a short period of time at the 30% level.

Comparing the hourly profiles of wind and solar at 30% by season, Mr. Freeman noted that wind has relatively flat profiles in the winter and fall; tends to peak mid-day during the spring and has a more diurnal pattern in the summer. CSP has extended hourly output in the spring and summer because of storage, while PV peaks at or around noon and falls off.

Mr. Freeman discussed how statistical analysis was used to characterize variability. Delta is defined as the difference between successive data points and is used to explain up or down ramps. The mean is the average of the deltas while sigma is the standard deviation of the deltas. He pointed out that the there is a significant increase in variability as the penetration of wind and solar increases from 10% to 20% to 30%.

There is also a substantial increase in maximum 1-hour variability as wind and solar penetration increases from the baseline to 30%, particularly during winter, spring and fall evening hours. In one slide, he noted extreme net load ramps of about 15 GW per hour on one day. Tom Ferguson thought that was questionable and suggested that the model be re-examined. After the meeting, 3TIER said they found a modeling error and will redo the results.

Gary Jordan, GE Energy, Operational Impacts

Mr. Jordan's presentation includes the production simulation results with simulations with no wind and solar generation; base wind and solar generation as of 2008; in-area with 10%, 20% and 30% wind and solar with state-of-the-art wind and solar forecasts; and in-area with 10%, 20% and 30% wind and solar with perfect forecasts. Data from Energy Velocity is used for all of WECC and load is escalated using NERC forecasts.

Mr. Jordan reviewed WECC generation by fuel type for the no-wind-and-solar, base, 10%, 20% and 30% cases, using state-of-the-art forecasts.. As wind and solar penetration increases, combined cycle natural gas generation decreases, with coal generation not being displaced until wind and solar is at 30%. Less coal is displaced with a perfect forecast.

Mr. Jordan also reviewed estimated emission reductions of NOx, SOx and CO2 with higher levels of wind and solar generation. Estimated WECC average system spot market prices are reduced with state-of-the-art forecasts, more so with a perfect forecast. That said, higher wind and solar penetrations could increase system spot prices at times because of forecast uncertainty.

A review of the impact of higher wind and solar generation on the effects on pumped hydro generation was also undertaken, with pumped hydro generation about doubling in the 30% case as compared to the base case. A further review on the effects on individual pumped storage plants found significant increases in generation at some individual pumped storage plants but not others, and it may be appropriate to build more pumped storage hydro plants. Mr. Jordan also examined the impacts on hydro generation of greater levels of wind and solar generation, using the weeks of March 13th and July 10th, and while some impacts were found, they also were considered manageable. An analysis of the annual hydro generation duration curve and the hourly hydro delta generation curve also found no significant impacts from higher wind and solar generation.

Mr. Jordan noted that generator's revenues decrease as more wind and solar generation comes on-line, since it is assumed that wind and solar is a price taker. Decreases in revenues for combined cycle natural gas, coal and hydro generation was observed. Although wind and solar generator revenues on an absolute basis, they decrease on a $/MWh basis as more wind and solar generation is added.

In closing, Mr. Jordan determined, from a very high level and using "bubble" modeling of the transmission system, that energy penetrations of up to 30% for wind and 5% for solar appears feasible.

Brad Nickell asked if operational limitations of generators are modeled. Gary Jordan said minimum up and down levels and cycling levels of generators are recognized in MAPS. He emphasized that there is a difference between what conventional generators can do versus what operators want to do.

Tom Carr asked what if the assumed carbon value of $5/ton is raised. Gary Jordan said the carbon value must be raised above $50/ton before any impacts are noticed and to $75/ton before coal is switched out to natural gas.

Andrew Mills asked if wind curtailment is modeled; Gary Jordan said yes but without cost. Bob Zavadil asked if system reserves are constrained. Gary Jordan said they are still working on data and operational issues but plan to look at this issue. Mark O'Malley asked how generator forced outages are reflected; Gary Jordan said random draws of generator outages are done, and planned outages are respected in MAPS. Mark O'Malley asked how many hours that load was not served. Gary Jordan said there were few hours of energy being dumped or load not being served.

Tom Ferguson assumed that GE is not modeling increasing O&M costs or gas costs to chase wind. Gary Jordan said that is correct, although GE is including variable O&M costs. Mark O'Malley asked if capital costs were included; Gary Jordan said not with new generation, although the capital costs of adding new wind and solar plants and transmission will be included. Andrew Mills asked if the heat rate of generators changes. Gary Jordan said yes.

Tom Ferguson noted that at night, Xcel Energy still runs gas plants out-of-merit to provide regulation. Gary Jordan said all of WECC would be modeled and GE will assess how much regulation per hour is needed. Nick Miller of GE said the statistical analysis of sub-hourly load and generation, plus the minute-to-minute analysis of selected periods with quasi-steady-state simulation will get at Tom's question.

Ron Lehr noted that in Xcel's integrated resource planning case before the Colorado PUC that under their gas supply contracts, Xcel is required to burn a certain amount of gas or pay a penalty. He asked if GE accounts for this. Gary Jordan said no, contract requirements are not accounted for in GE's model. Tom Ferguson said new gas storage may take care of that. Gary Jordan said GE may have to take gas storage into account as they proceed with this project.

Brad Nickell asked if he should interpret from GE's presentation that adding more renewables results in lower power prices. Gary Jordan said that renewables are modeled as price takers in GE's model, and adding more renewable will displace higher priced power in the spot market. Mark O'Malley said this could be counter-balanced by

including capital costs in the model, plus if conventional power plants shut down with higher levels of renewables, spot prices could increase.

Ed DeMeo asked if solar prices will take the spot price and whether that is economically feasible for solar. Gary Jordan said it probably is not economically feasible for solar, but the point of this study is to test the operational feasibility of incorporating more wind and solar, not the economic feasibility. Ed DeMeo said it sounds like that there is an assumption there is enough revenue for wind and solar projects to operate. Debbie Lew cautioned that results being presented are preliminary and there is more modeling and analysis to come.

Nick Miller, GE Energy, Candidate Scenarios for Further Analysis

Mr. Miller discussed four possible scenarios for additional analysis beyond the 30% in-area scenario. These four potential scenarios are:

- Mega Projects
- Local Priority
- High Solar
- High Capacity Value

Other scenarios that were contemplated include greater geographic diversity and lowering the renewable energy penetration levels. Unless otherwise indicated, all scenarios are at 30% renewables, with total renewable energy generation held constant.

The four scenarios will involve relaxing the restrictions on in-area renewable energy development and will include swapping out less valuable renewable energy projects in one area, making it a net importer, for more valuable renewable energy projects in another area, making it a net exporter. GE developed an algorithm for swapping projects between areas. New transmission costs were assumed to range between $800 and $1600 per MW-mile, with a transmission diversity factor of 0.7, i.e., one MW of generation uses 0.7 MW of transfer capability. The capital cost of wind was assumed at $2000/kW and solar at $4000/kW. Transmission losses were projected to be 1% every 100 miles and were factored as a cost penalty.

GE also determined what would be the inter-area mix of wind and solar if half of existing transmission capability was made available for wind exports, and if all of existing transmission capability was made available. If existing transmission is made available for wind exports, higher capacity and remote wind projects will displace lower capacity local wind projects. In addition, less new transmission will need to be built, and as more new transmission needs to be built, at higher capital costs, the potential savings from developing remote sites decreases. GE noted that solar exports tend to be counterflows on the transmission grid, and therefore assumed that no new transmission is needed.

Mr. Miller reviewed the proposed four scenarios in more detail. The Mega Projects scenario is based on a transmission build-out to access the higher quality wind resources. GE assumed 345 kV or 500 kV for bulk interties that could transmit 1200 MW or 1600 MW per circuit, respectively. HVDC was used for long distance and for transmitting higher levels of power. The net impact was 23,100 MW of wind at 770 sites, over 5,900 MW less than in the in-area scenario. Over 5000 GW-miles of transmission was necessary, amounting to $8 billion in capital costs. Because less wind capacity was needed, the total capital costs necessary was reduced by $4.7 billion as compared to the in-area scenario.

The Local Priority scenario factored in local positive externalities such as increased employment and retained tax revenues by reducing the annual carrying cost of in-area generation. Transmission in the base case used to transmit renewables in the base case was included in the Local Priority scenario. In this scenario, 831 wind projects were selected for a total capacity of 24,930 MW, a reduction of 4,110 MW from the in-area scenario. About 3,500 GW-miles of new transmission was necessary for a total cost of $5.6 billion, but because fewer new wind projects were necessary, total capital costs was reduced by $3.4 billion as compared to the in-area scenario.

The High Solar scenario would double solar penetration to 10% in-area (7% CSP, 3% PV) and about 6% outside the Westconnect region (4.2% CSP, 1.5% PV). The 30% wind level would be maintained, and no new inter-area transmission would be included.

The High Capacity Value scenario would increase the capacity value from $100/kW/year to $800/kW/year. In doing so, more higher capacity value wind sites would be selected in place of higher capacity factor but lower capacity value wind sites. As with the High Solar scenario, no new inter-area transmission would be included.

Mr. Miller urged that some decisions be made today on what additional scenarios GE should study. The next steps in GE's analysis would be to conduct the statistical analysis, the production simulation analysis and the quasi-steady-state simulation analysis for all scenarios and examining operational issues in hourly and sub-hourly time frames and examining mitigation alternatives.

Charlie Smith asked why GE opted not to recommend scenarios on geographic diversity and lower renewable levels. Nick Miller said GE could force their plant selection algorithm to reflect more geographic diversity, but the results are somewhat crude and the other scenarios seem more illuminating. He thought there should be a group discussion on whether the level of renewables studied should be lowered.

Loyd Drain of the Wyoming Infrastructure Authority questioned GE's data showing the capacity factor of wind resources in Colorado and Wyoming differing by only one percent. He said their data shows higher capacity factors for Wyoming wind resources. Nick Miller said the footprint of the transmission areas is unusual in that some of the Colorado region includes a small part of Wyoming. He also thought the pre-selected wind projects could be affecting the capacity factor data.

Jerry Vaninetti asked if non-developable sites were eliminated. Debbie Lew said yes, that sites on high elevations, with steep slopes, and on National Parks, among other factors, were eliminated from consideration.

Discussion (Led by Charlie Smith of UWIG)

Charlie Smith led off the discussion by first asking for general comments, then saying he would ask for comments on the proposed scenarios and on the overall assumptions for the study.

Mark O'Malley asked whether capital costs for additional thermal projects should be included in the study, since costs of new transmission are included. Charlie explained that this is merely an operational impact study. Dick Piwko said the focus of the project was on the system impacts of higher levels of wind and solar penetration; adding a capital component to the study could double the scope of the project. Mark and Charlie both suggested that the report be clear that capital costs are not included. Ed DeMeo noted that DOE's 20% wind vision report did include capital costs, and that amounted to roughly 0.8 cents/kWh.

Andrew Mills asked if a 2017 case can be run without building anything new than wind. Gary Jordan said they added 10,000 MW of new generation within WECC, 80% of which was combustion turbines.

Cameron Potter asked if a climate mitigation scenario with maximum efficiency should be included. Gary Jordan said they ran a case with 30% wind without increasing load from 2006 levels. Large system impacts were noted, with nuclear being cycled at night.

Walter Short of NREL suggested a new scenario where renewable energy credits are emphasized and less transmission is built. Gary Jordan and Dick Piwko said they could see if transmission lines are not fully utilized in the GE MAPS model, and drop the line.

Ed DeMeo said they did not see such significant ramps or impacts in the Minnesota study as was shown in Lavelle's presentation. Charlie wondered if lower capacity factor wind resources may have aggregated the ramps. Dick Piwko said they are not far enough along in the analysis to answer that yet. Gary Jordan said they saw some significant but predictable ramps in their ERCOT study.

Tom Carr asked whether consolidation of balancing areas is a separate scenario. Dick Piwko said this will be addressed with each scenario, along with other potential mitigation strategies. Charlie Smith noted that previous wind integration studies assumed one control area; the WWSIS study is unique in that multiple control areas will be addressed.

Ron Lehr asked the source of the assumed CO2 price of $5.10. Gary Jordan said it came from the Energy Velocity database, and he is aware of higher estimates. Tom Carr noted there are several studies with CO2 cost projections of $40-60. Tom Ferguson said utility resource planners typically use $20-40. Gary Jordan said CO2 prices had to be $50-75/ton to have significant impact in MAPS. Dick Piwko noted that if CO2 prices are high enough, then gas will displace coal. If the added gas plants are more maneuverable, it may have an impact on system operability. After more discussion, Charlie Smith suggested that study team revisit the CO2 price and be prepared to run different sensitivity cases.

Ed DeMeo said the four scenarios seem reasonable. He asked whether a wind curtailment or semi-dispatchable scenario should be considered instead of a lower renewable level. Dick Piwko said operating and mitigation strategies will be considered in all scenarios, including wind curtailment.

Charlie Smith asked whether the High Solar case should still include 30% wind, or whether wind should be decreased. He also asked if there are any concerns about the lack of intra-hour PV data. Gary Jordan suggested dropping wind to 25%. Brian Parsons noted that hourly and sub-hourly solar data collection and assessment is at an earlier stage than wind, and the lack of sub-hourly PV data pushes the limits of credibility for WWSIS. Ben Kroposki of NREL wondered if 5% PV is too high. For a lower renewables scenario, he suggested limiting it to state RPS levels in the West. Dick Piwko thought that could be worth considering. He pointed out that GE will do six scenarios—baseline, in-area and the four under discussion—and one of those could have renewable less than 30% wind and 5% solar.

Charlie Smith asked GE how late could GE wait to finalize scenarios without affecting the project schedule. Dick Piwko was not exactly sure but not right away, as GE is a number of weeks away. He explained that the scenarios are not done in parallel; rather, they are staged. He would like for the stakeholders to agree on at least two scenarios.

Ron Lehr asked about the high capacity value scenario and whether it will at least partly capture geographic diversity effects. Kevin Porter of Exeter Associates said he was concerned about not having a specific scenario on geographic diversity. Nick Miller showed a chart that suggested it would take very high multiples on geographic diversity to have an effect on wind plant selection. Walter Short said the geographic diversity is not captured because the capacity value is fixed at $100/kW. Nick Miller said they will consider this some more.

Ray George of NREL spoke in favor of including a High Solar scenario and wondered if the PV sites are sufficiently spread out in GE's analysis. Gary Jordan said PV is spread out over several sites and to improve diversity, PV and CSP projects are each limited to 100 MW. Ray George suggested more PV be included in the High Solar scenario and that sites be distributed over a wider area. Dick Piwko said the hourly PV data shows little fluctuation, other than perhaps from sites north to south because of solar radiation. The larger issue is the lack of sub-hourly PV data; Dick said a previous GE project

examined wind and solar integration, and they only found sub-hourly PV data for two sites, both outside of California. Ben Kroposki said he and Ray George can model PV data based on 1-minute solar radiation data. Dick Piwko said with 3 GW of PV divided into 100-MW plants, they will need sub-hourly data for 30 different sites.

Charlie Smith reviewed what has been discussed so far. He said Walter Short's point that the $100/kW capacity value may diminish geographic diversity needs to be examined, but other than that, there is not enough information on whether to have a separate scenario for geographic diversity or not. He said Walter's suggestion on including RECs instead of transmission will be addressed in MAPS. He also thought the definitions of all four scenarios needs to be fine-tuned.

Dick Piwko reiterated that he wants agreement on a couple of scenarios, and suggested that GE proceed with the Mega Projects and Local Priority scenarios. After some discussion, Gary Jordan suggested that GE proceed with those two scenarios and hold the High Solar and High Capacity Value scenarios for further discussion. Debbie Lew said the project team can refine the High Solar and High Capacity Value scenarios and bring those to the Technical Review Committee for review. It was agreed that the GE team would proceed with the Mega Projects and Local Priority scenarios, and the other two scenarios would be further defined.