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The Western Wind and Solar Integration Study Phase 2

Preprint

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To be presented at the 11th Annual International Workshop on Large-Scale Integration of Wind Power into Power Systems as Well as on Transmission Networks for Offshore Wind Power Plants Conference
Lisbon, Portugal
November 13–15, 2012

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Conference Paper
NREL/CP-5500-56217
September 2012

Contract No. DE-AC36-08GO28308

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The Western Wind and Solar Integration Study Phase 2

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***Abstract*—The Western Wind and Solar Integration Study Phase 1 (WWSIS1) investigated the impacts of high penetrations of wind and solar power on the Western Interconnection of the United States. The Western Wind and Solar Integration Study Phase 2 (WWSIS2) built on Phase 1 but with far greater refinement in the level of data inputs and production simulation. It considered the differences between wind and solar power on systems operations. It considered mitigation options to accommodate wind and solar when full costs of wear and tear and full impacts of emissions rates are taken into account. It determined wear-and-tear costs and emissions impacts. New data sets were created for WWSIS2, and WWSIS1 data sets were refined to improve realism of plant output and forecasts. Four scenarios were defined for WWSIS2 that examined the differences between wind and solar and penetration level. Transmission was built out to bring resources to load. Statistical analysis was conducted to investigate wind and solar impacts at timescales ranging from seasonal down to 5 min.**

Keywords-wind; solar; integration; transmission; statistical analysis; production simulation; wear and tear; emissions

I. INTRODUCTION

The Western Wind and Solar Integration Study Phase 1 (WWSIS1) was a landmark analysis of the operational impacts of high penetrations of wind and solar power on the Western Interconnection (WI) of the United States, shown in Fig. 1 [1]. It showed that up to 35% wind and solar energy penetration could be accommodated in the WestConnect subregion (and up to 27% across the entire WI) if certain operational changes could be made. The most important of the operational changes were increased balancing area (BA) cooperation and increased use of sub-hourly scheduling for generation and interchanges.

Phase 2 of the WWSIS (WWSIS2) was initiated in 2011 because stakeholders noted the cycling and ramping of fossil-fueled generators in the high-renewables scenarios and asked us to obtain higher fidelity on the wear-and-tear costs and emissions impacts of this type of operation. Additionally, advances in synthesizing sub-hourly utility-scale photovoltaic (PV) plant output allowed us to include higher levels of solar penetration while maintaining technical rigor and credibility. Finally, Phase 2 took advantage of new production simulation models that can dispatch sub-hourly so that sub-hourly impacts of variable generation (VG) can be investigated in detail.

This paper discusses the creation of scenarios, development of transmission build-outs for the scenarios, and the results of the statistical analysis. Other work [2–6] discussed the synthesis of solar and wind output and forecast data sets, reserves methodology, wear and tear, and emissions data. Production simulation analysis is currently underway.

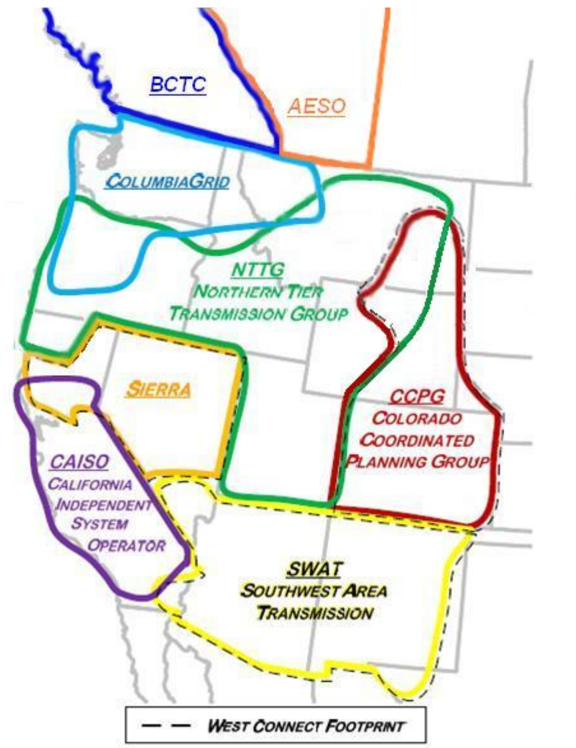


Figure 1. Map of WI subregions. WestConnect encompasses the Sierra Subregional Planning Group, Colorado Coordinated Planning Group, and Southwest Area Transmission subregions.

II. STUDY IMPROVEMENTS AND CONSTRAINTS

A. Differences Between Phase 1 and Phase 2

Although the driver for WWSIS2 was largely the use of higher fidelity cycling and ramping costs and impacts, WWSIS2 was able to capitalize on improvements and refinements in many aspects of the data inputs and modeling. Stakeholder feedback on WWSIS1 was also addressed.

A number of new data sets were created for WWSIS2 that provided significant improvement over previous input data, including:

- Unit-specific emissions data as a function of ramping and cycling;
- Wear-and-tear costs and forced outage rate impacts data for seven plant types;

- One-min resolution solar power output data for concentrating solar power (CSP) plants with thermal storage, rooftop PV, and utility-scale PV; and
- Adjusted day-ahead, 4-h, and 1-h wind and solar forecasts.

The WI was modeled using the commercial production simulation model PLEXOS. This model is able to dispatch down to a 5-min interval and optimize dispatch of CSP storage. It also can optimize security-constrained unit commitment and economic dispatch with a large number of constraints, including penalties for ramping of fossil-fueled generators to reflect wear-and-tear costs.

With the new developments in synthesizing sub-hourly, utility-scale PV plant output, WWSIS2 was able to address high solar penetrations in detail as well as compare solar to wind. As a result, WWSIS2 scenarios focused on the differences between wind and solar impacts on the power system.

The WI contains nearly 40 balancing areas (BAs) that must balance their load and generation. The base scenarios in WWSIS1 were run with the WI operating as 5 BAs. WWSIS2 modeled the WI as 20 zones with interface constraints between them.

Conceptual transmission build-outs were generated using expert judgment for WWSIS1 to bring resources to load. In WWSIS2, iterative PLEXOS load flows were run to bring shadow prices across interfaces down to a consistent cutoff level.

III. Model Setup

Modeling a power system as large as the WI requires a balance of detail (to ensure important inputs are properly characterized) and simplifying assumptions (to create a manageable model that can be run within a reasonable amount of time). We based our inputs and assumptions as much as possible on the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) model, which has been thoroughly vetted through a public stakeholder process. WECC is the regional reliability organization for the WI.

A Technical Review Committee (TRC) was established to provide expert and stakeholder oversight and review of data inputs, assumptions, methodologies, model configuration, and results. The TRC included WECC, experts in operations of fossil-fueled generators, and utilities in the WI.

It is very difficult to model the WI as it is actually operated because most of the WI is comprised of vertically integrated utilities that balance their system with their own generation and bilateral transactions with their neighbors that are confidential. Not having access to that information, we modeled the WI assuming rational economic dispatch. In WWSIS2, the WI was modeled as a set of BAs with hurdle rates between them.

WWSIS2 modeled the WI zonally, using the 20 WECC Load and Resource Subcommittee zones. This obviated the need to design transmission collector systems for each wind and solar plant. Each plant was assigned to a high-voltage bus.

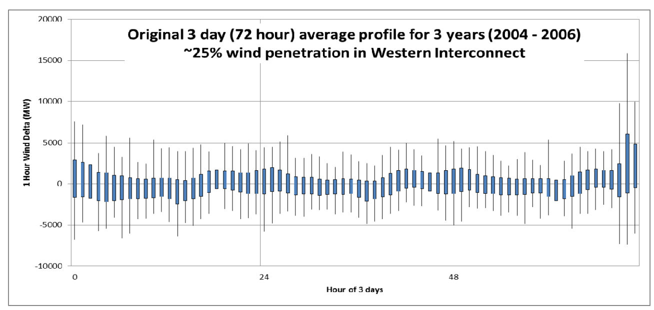
The year 2020 was modeled using historical weather patterns and loads from the years 2004, 2005, and 2006. The 2020 reference scenario was based on the WECC TEPPC Portfolio Case #1 (PC1) case [7].

We modeled regulation, flexibility, and contingency reserves, basing regulation and flexibility reserves on the variability of the wind and solar output but tailored only to account for the unpredictable component of variability of solar because of cloud movement [2].

A. Wind Data

The original wind output data ("actuals") used in WWSIS1 had increased variability every three days because of a restart of the Numerical Weather Prediction (NWP) model used to synthesize that data [1,8,9,10]. Although the wind output for each site respected realistic 10-min maximum changes in output, unrealistic 10-min variability resulted when sites were aggregated. Various fixes were evaluated for realism in variability when sites were aggregated and for realism in spatial correlation between sites. Fig. 2 shows the fix that worked best, which included random splicing of data from unaffected days to the affected seams. This 10-min data set was converted to 1-min output using statistical down-sampling based on measured 1-min output from wind plants in the WI.

(a)



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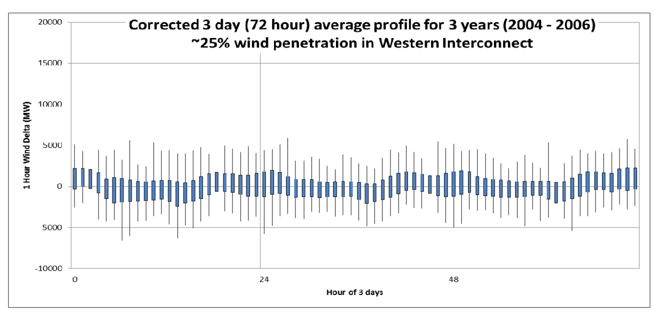


Figure 2. One-h change in wind output for the (a) original and (b) corrected data. The years 2004 to 2006 have been parsed into 3-day intervals to illuminate the 3-day seam that is seen by increased variability at the end of the third day in the original data. The whiskers are the min and max values for each hour of the 3-day intervals. The bars show the mean value plus and minus one standard deviation.

The original wind forecasts in WWSIS1 were synthesized using the same NWP model as the actuals but with a different input data set. Because these forecasts did not receive a statistical correction, there were some bias issues that resulted in forecasts tending to be 10% to 15% higher than actuals on average. Additionally, forecasting techniques have improved over time. To best reflect realism in forecasts, we analyzed measured wind forecast errors from the Public Service Company of Colorado, California Independent System Operator, and the Electric Reliability Council of Texas. We then adjusted the forecast error distributions of our forecasts from WWSIS1 to match the measured wind forecast error distributions [3].

B. Solar Data

The original solar data used in WWSIS1 was based on limited knowledge of sub-hourly solar PV variability and excluded utility-scale PV plants. In WWSIS2, new techniques were developed to characterize sub-hourly temporal variability based on spatial variability. Hourly satellite images from the 10 km x 10 km grid cell of interest plus the surrounding grid cells were characterized into five types of cloud patterns. This was then translated into sub-hourly temporal variability [4]. This was also validated using measurements of irradiance and PV plant output [11]. For WWSIS2, rooftop PV, utility-scale PV, and CSP with 6 h of storage were modeled.

C. Wear-and-Tear Cost and Impacts Data

To determine the impacts of cycling and ramping on fossil-fueled plants, in-depth studies have been conducted for specific power plants [12]. These types of studies were conducted over several decades for approximately 400 power plants. This proprietary data was distilled into generic data for wear-and-tear costs and impacts for 7 types of generators: small subcritical coal, large subcritical coal, supercritical coal, gas combined cycle, gas large frame combustion turbine, gas aeroderivative combustion turbine, and gas steam. Data included costs of cold, warm, and hot starts; costs of ramping; equivalent forced outage rate impacts from cold, warm, and hot starts; and long-term heat-rate degradation. [6,12,13,14]

D. Emissions Impacts Data

To determine the emissions impacts of cycling and ramping, measured emissions of NO_X, SO_2, and CO_2 from nearly every fossil-fueled plant in the United States were analyzed using the U.S. Environmental Protection Agency's continuous emissions monitor data set. Emissions impacts from start-ups, ramps, and partial loading were determined for each generator as inputs in our model [6,14].

IV. Scenarios

Four scenarios were defined and sited for the study using the National Renewable Energy Laboratory's Regional Energy Deployment System model [15]. The Reference Scenario (8% wind and 3% solar) was based on the WECC TEPPC 2020 PC0 base case scenario, which included enough renewables so that western states met their 2020 renewable portfolio standards targets. The High-Wind Scenario included 25% wind and 8% solar. The High-Solar Scenario included 25% solar and 8% wind. The High-Mix Scenario included 16.5% wind and 16.5% solar. Solar was defined as 60% PV and 40% CSP with 6 h of thermal storage. The scenarios are shown in Table 1.

TABLE I. Solar and Wind Build-Outs for Each Scenario

Reference

	Rooftop PV		Utility Scale PV		CSP		Wind		Total	
State	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF
Arizona			1171	23%	472	43%	3681	30%	5324	30%
California			3545	25%	3221	45%	7299	27%	14065	32%
Colorado			1342	21%	169	37%	3256	30%	4767	27%
Idaho							523	28%	523	27%
Montana							838	34%	838	34%
Nevada			304	21%	334	42%	150	25%	788	31%
New Mexico			140	25%	156	39%	494	30%	790	30%
Oregon							4903	23%	4903	26%
South Dakota										
Texas										
Utah			571	20%			323	22%	894	24%
Washington							4652	26%	4652	27%
Wyoming							1784	42%	1784	42%

High-Solar

	Rooftop PV		Utility Scale PV		CSP		Wind		Total	
State	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF
Arizona	4498	19%	9570	23%	9644	42%	270	33%	23982	30%
California	9006	18%	14258	23%	9197	43%	5203	29%	37663	28%
Colorado	1127	18%	4437	22%	1440	36%	3617	34%	10620	27%
Idaho	3	17%	2	18%			583	28%	588	28%
Montana	25	15%	34	18%			988	36%	1047	34%
Nevada	772	19%	6503	24%	672	40%	150	25%	8098	25%
New Mexico	943	20%	2874	24%	574	38%	644	35%	5034	26%
Oregon	101	14%	126	20%			4665	27%	4892	26%
South Dakota	4	17%	6	20%			330	37%	340	37%
Texas	233	20%	335	23%					568	22%
Utah	2132	17%	3759	21%			323	22%	6214	20%
Washington	405	13%	759	18%			4952	27%	6116	25%
Wyoming	10	18%	18	21%			1634	44%	1662	42%

High-Wind

	Rooftop PV		Utility Scale PV		CSP		Wind		Total	
State	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF
Arizona	1975	19%	2330	24%	3303	43%	4941	30%	12548	31%
California	4875	18%	5372	25%	2469	45%	11109	28%	23824	28%
Colorado	1059	18%	1128	22%	169	37%	6226	37%	8581	31%
Idaho	3	17%	2	18%			1333	29%	1338	29%
Montana	22	15%	34	18%			6658	36%	6714	36%
Nevada	398	19%	344	22%	439	42%	3270	30%	4452	30%
New Mexico	172	20%	209	27%	156	39%	4784	39%	5321	37%
Oregon	91	14%	101	20%			5473	26%	5665	26%
South Dakota	4	17%	6	20%			2640	36%	2650	36%
Texas	76	20%	122	27%					198	24%
Utah	361	17%	489	20%			1343	31%	2193	27%
Washington	371	13%	492	18%			5882	28%	6745	26%
Wyoming	9	18%	18	21%			10184	42%	10211	43%

High-Mix

	Rooftop PV		Utility Scale PV		CSP		Wind		Total	
State	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF	Capacity (MW)	CF
Arizona	3655	19%	5394	25%	9374	42%	1440	30%	19863	33%
California	8412	18%	9592	24%	3594	45%	6157	27%	27754	26%
Colorado	1127	18%	1653	21%	169	37%	4396	36%	7344	29%
Idaho	3	17%	2	18%			1093	29%	1098	29%
Montana	25	15%	34	18%			4288	37%	4347	36%
Nevada	772	19%	3282	26%	562	40%	1560	31%	6177	28%
New Mexico	943	20%	1280	27%	298	40%	3134	39%	5654	33%
Oregon	101	14%	126	20%			5413	25%	5640	26%
South Dakota	4	17%	6	20%			1950	36%	1960	36%
Texas	208	20%	193	25%					401	22%
Utah	1204	17%	1216	21%			683	30%	3102	22%
Washington	405	13%	709	18%			5762	28%	6876	26%
Wyoming	10	18%	18	21%			7244	43%	7272	44%

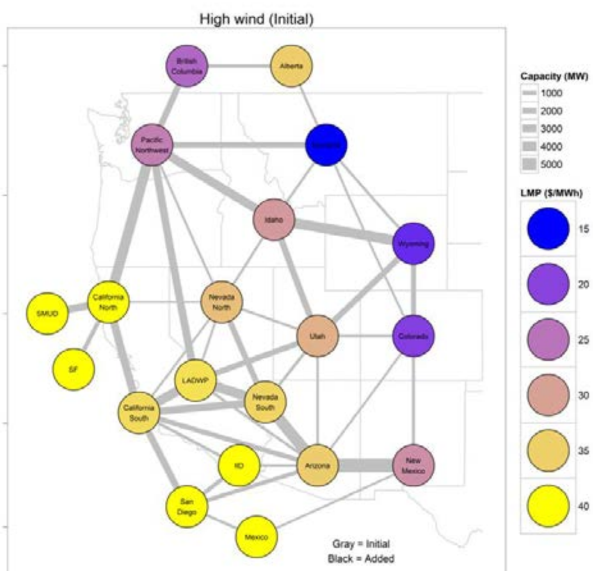
V. Transmission

To bring resources to load, we expanded transmission using iterative load flows in PLEXOS. Forty-four transmission paths were considered at a zonal level so that collector systems did not need to be designed for this study. Nodal transmission build-outs may need to be considered in future analyses to examine details of congestion and flows. We did not add new source and sink pathways in this transmission expansion but rather increased capabilities on existing paths.

It is important to note that in much of the WI, utilities have physical rather than financial rights to transmission. That is, a transmission path may be fully contracted during some period of time yet not fully utilized during that period. Because those transmission contracts are confidential, we were unable to model them. Instead, we assumed that all transmission was used optimally.

Although parts of Canada and Mexico are in the WI, we did not build additional transmission to those zones, but rather built in enough conventional generation in those zones to meet load so that paths to those zones were not congested. This is consistent with WECC TEPPC practice (e.g., actual flows between Canada's Alberta Electric System Operator and the United States are very limited).

(a)



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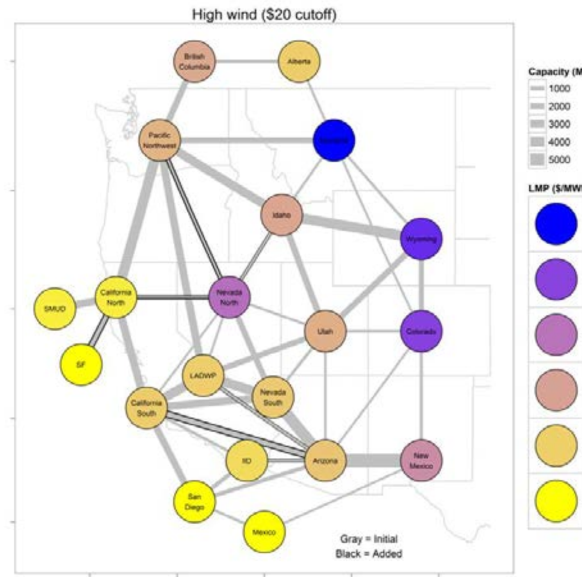

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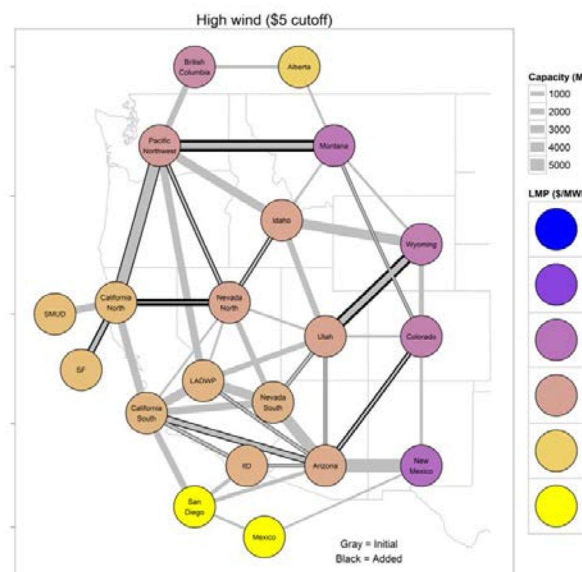


Figure 3. Iterative transmission build-out for the High-Wind Scenario showing (a) initial and final interface capabilities for (b) the $20 cutoff shadow price and (c) the $5 cutoff shadow price. Locational marginal price is shown by the colors of each zone. The transmission capacity for major interfaces is shown by the width of the grey lines. New transmission capacity is shown by the width of the black lines.

We developed a methodology to expand capabilities on existing transmission paths by running the four scenarios in PLEXOS for a full year and examining shadow prices across interfaces. We "built" 500 MW of additional transmission across interfaces whose shadow price exceeded some cutoff. We then iterated and re-ran the revised scenario with the additional transmission in PLEXOS and added more transmission as appropriate until shadow prices no longer exceeded the cutoff.

We tested cutoffs from $5/MWh to $20/MWh. These were consistent with the approximate transmission costs of $1,600/MW-mile for 250 miles of new transmission with a $0.11 fixed-charge rate. Fig. 3 (a) shows the starting transmission build-out and Figs. 3 (b) and 3 (c) show transmission build-outs for a high and low cutoff.

Transmission build-outs were evaluated considering transmission costs, production cost savings, and curtailment. For a fixed cutoff value, as the penetration of renewables, especially wind, increased, the amount of transmission built also increased. Curtailment decreased with expanded transmission. Curtailment was much higher in the scenarios with higher penetrations of wind because wind tends to be higher at night, when base-load generators run down against their minimum generation limits.

Fig. 4 shows the net benefit of the transmission expansion, defined as the production cost savings minus the approximate transmission cost. As the cutoff value decreases and transmission is expanded, the net benefit increases and then tops out and decreases. The cutoff value where this net benefit tops out varies but is approximately $10/MWh. As a result, we selected the $10/MWh cutoff value to define the transmission build-out for each scenario. Table II shows the transmission build-outs at that $10/MWh cutoff value for the three high-renewables scenarios.

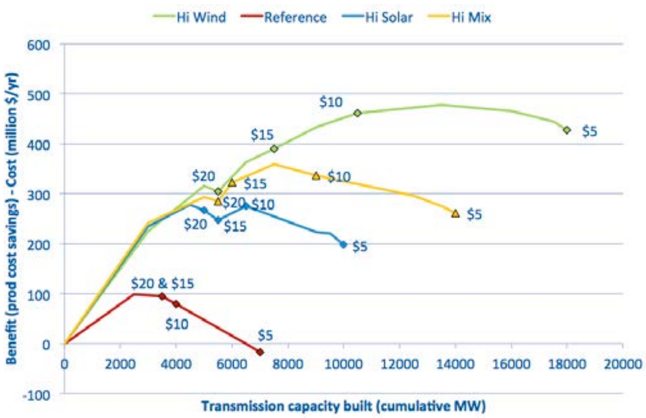


Figure 4. Comparison of transmission build-out metrics for the Reference, High-Solar, High-Wind, and High-Mix Scenarios, showing (a) production cost savings versus MW built, (b) curtailment versus MW built, and (c) net benefit versus MW built.

TABLE II. TRANSMISSION BUILD-OUTS WITH $10/MWH CUTOFF

	High-Wind	*High-Mix*	*High-Solar*
Cumulative additional transmission capacity (MW)	10,500	9,000	6,500
Cumulative transmission annualized cost (M$/yr)	462	396	286
Production cost (B$/yr)	10.9	10.6	10.9
Cumulative production cost savings (M$/yr)	923	733	561
Average benefit/cost ratio	2.00	1.85	1.96
Incremental benefit/cost ratio	1.54	1.11	1.65
Curtailment (TWh)	9.2	2.3	1.3

	High-Wind	*High-Mix*	*High-Solar*
Curtailment as fraction of potential wind and solar production	0.035	0.0009	0.005
Transmission cost per MWh curtailment savings ($/MWh)	29.7	55.7	129.5

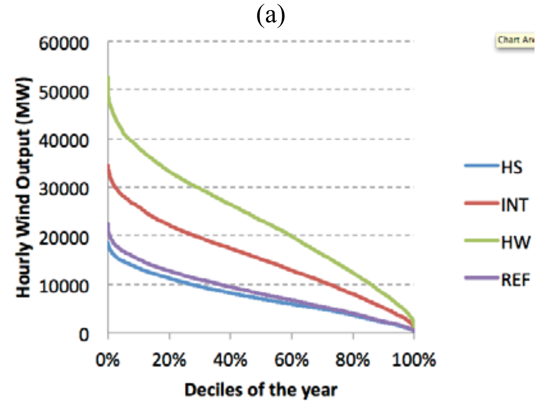
VI. STATISTICAL ANALYSIS

We conducted statistical analysis on the four scenarios, examining variability and uncertainty on various timescales, investigating penetration levels on various timescales, determining impacts of aggregation and geographic diversity, and comparing the impacts of wind and solar. Additional statistical analysis, including analysis of 5-min variability and solar aggregation, was also conducted [5].

Fig. 5 shows the hourly duration curves for wind and PV. The High-Wind Scenario had a 25% wind energy penetration and the High-Solar Scenario had a 15% PV (and 10% CSP, not shown here) energy penetration, but both produced similar peak output during the top wind and PV output hours. PV output was zero for half of the year during nighttime hours.

Fig. 6 shows the contour plots for the net load for each scenario. The Reference Scenario, with 11% VG, shows the high summer peaks in the afternoon and early evening in the WI. The High-Wind Scenario depresses much of this peak and also exacerbates the net load minimums during the night in the winter. Finding ways to decrease the minimum generation level of fossil-fueled units will be important in this scenario.

(a)



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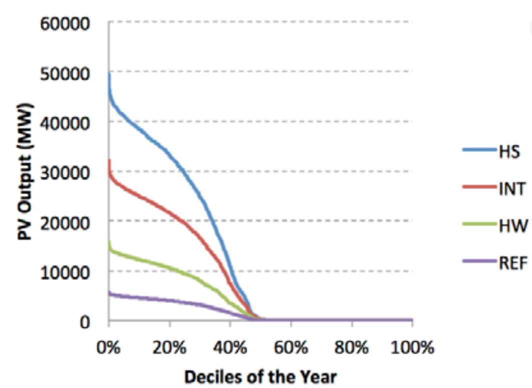

Figure 5. Hourly (a) wind and (b) PV duration curves for the High-Solar (blue), High-Mix (red), High-Wind (green), and Reference Scenarios.

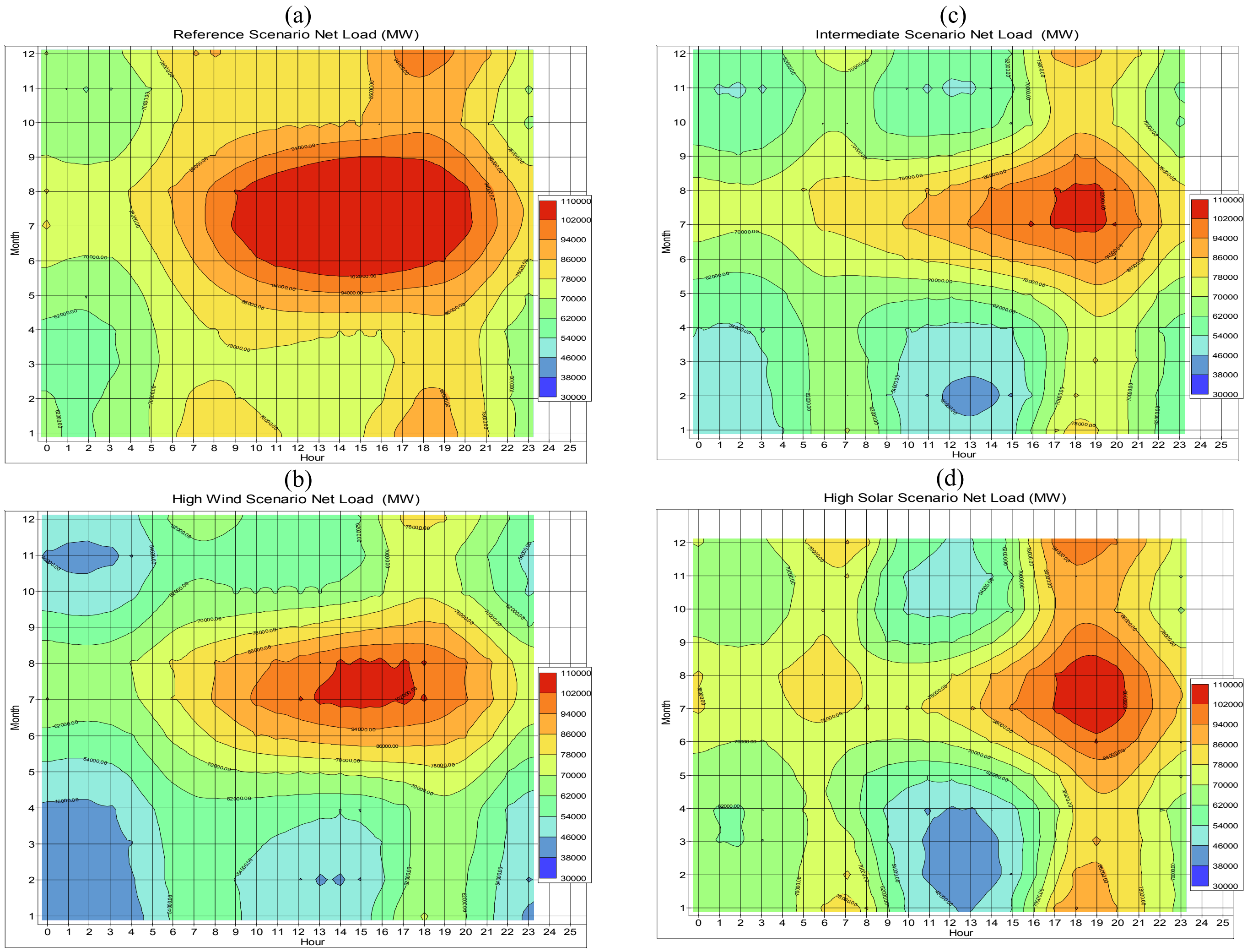

Figure 6. Net load as a function of month and hour of the day for the (a) Reference, (b) High-Wind, (c) High-Mix, and (d) High-Solar Scenarios. These are all plotted using the same color scale.

The High-Solar Scenario clearly shows the diurnal double peak caused by the depression of net load during midday when solar output is highest. Contour lines that are close together, such as those in the non-summer months after the morning net load peak and again before the evening net load peak, indicate steep net load ramps. Increasing ramping capabilities or reducing start-up times of fossil-fueled generation may be helpful in this scenario. Decreasing minimum generation levels will be important to manage winter midday net load minimums.

VII. Conclusions

WWSIS2 illuminates the challenges of integrating high penetrations of wind and solar power into the grid. It shows how important the need is for flexibility in the fossil-fleet, with an emphasis on lower minimum generation levels for both wind and solar and an emphasis on additional ramping or fast-start capability for high penetrations of solar power. Future and ongoing work is focused on operational simulations of these scenarios and retrofit options for the fossil fleet to determine how best to manage wind and solar variability and uncertainty. Ultimately, a cost-benefit analysis of retrofit and operational strategies for the fossil fleet will be completed.

VIII. Acknowledgments

This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory.

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