Eastern Renewable Generation Integration Study

Executive Summary

Aaron Bloom[1], Aaron Townsend[1], David Palchak[1], Joshua Novacheck[1], Jack King[2], Clayton Barrows[1], Eduardo Ibanez[3], Matthew O'Connell[1], Gary Jordan[3], Billy Roberts[1], Caroline Draxl[1], and Kenny Gruchalla[1]

[1]*National Renewable Energy Laboratory*
[2]*RePPAE LLC*
[3]*GE*

Main Report

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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Technical Report
NREL/TP-6A20-64472-ES
August 2016

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

1 Purpose: Aid in Planning for a Cleaner Energy Future

The U.S. Department of Energy commissioned the National Renewable Energy Laboratory (NREL) to answer a question: What conditions might system operators face if the Eastern Interconnection (EI), a system designed to operate reliably with fossil fueled, nuclear, and hydro generation, was transformed to one that relied on wind and solar photovoltaics (PV) to meet 30% of annual electricity demand?

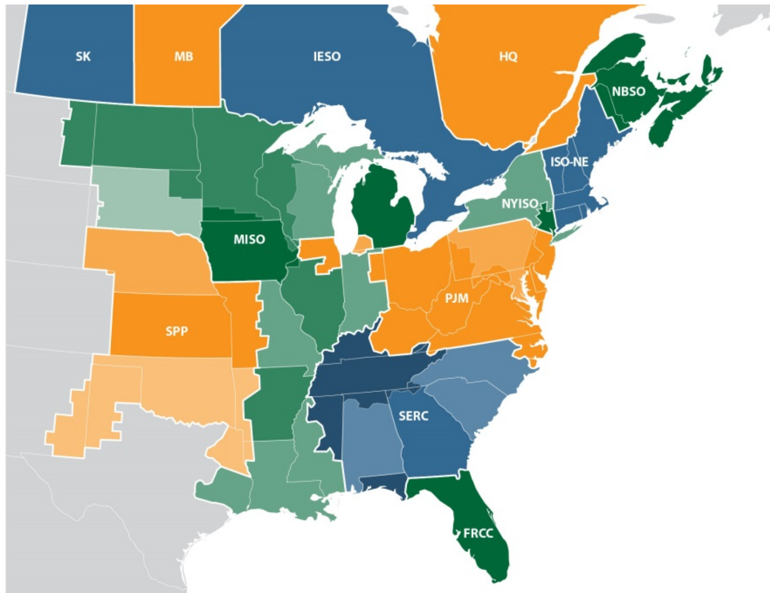

Figure ES-1. The study area, which includes the Eastern and Québec Interconnections, operate as a highly coordinated machine. It is considered to be one of the largest and most complex power systems in the world.

In this resulting study—Eastern Renewable Generation Integration Study (ERGIS)—NREL answers that question and, in doing so, gives insights on likely operational impacts of higher percentages—up to 30% on an annual energy basis with instantaneous penetrations over 50%—of combined wind and PV generation in the EI. We evaluate potential power system futures where significant portions of the existing generation fleet are retired and replaced by different portfolios of transmission, wind, PV, and natural gas generation. We explore how variable and uncertain conditions caused by wind and solar forecast errors, seasonal and diurnal patterns, weather and system operating constraints impact certain aspects of reliability and economic efficiency. Specifically, we model how the system could meet electricity demand at a 5-minute time interval by scheduling resources for known ramping events, while maintaining adequate reserves to meet random variation in supply and demand, and contingency events.

Secondarily, ERGIS demonstrates advanced techniques for power systems modeling. Building off and extending prior research, NREL used high-performance computing and new methods to model unit commitment and economic dispatch (UC&ED) of the EI (Figure ES-1). We model the operational impacts of high renewable penetrations at 5-minute resolution. The new approaches allowed the study team to build on previous work in this area (EIPC 2012, Enernex Corporation 2011, EPRI 2011, GE 2010, GE 2014a, GE 2014b, Lew et al. 2012, NREL 2012) in a way that dispenses with many simplifying assumptions while increasing fidelity.

With ERGIS, NREL demonstrates commitment to open energy research by publishing the production cost model, underlying data, and visualization tools alongside the final report. This study and the accompanying data sets and tools provide power system planners, operators, and regulators with new means and insights to anticipate and plan for operational changes that may be needed in cleaner energy futures.

2 Approach

To address the study question, we assembled a Technical Review Committee (TRC) composed of representatives from every region and many key stakeholder groups in the EI. The TRC played a critical role in guiding the study, analyzing results, and reviewing the final report. The TRC helped to define four power system scenarios for the EI (Table ES-1) to determine the operational impact of integrating approximately 1,000 TWh of wind and PV. We conducted a capacity expansion using the Regional Energy Deployment System (ReEDS) to determine the location, size, and type of new generators added to the system (Short et al. 2011). Our baseline scenario is the LowVG. That scenario was designed to meet all new generation requirements without using wind and PV. Other than announced generation additions, the ReEDS model made the economic decision to only build combined cycle and combustion turbine generators. The first high-penetration scenario is the RTx10, where the system is designed to align with requirements of state renewable portfolio standards (RPS) effective as of 2013. This equates to a total PV and wind penetration of approximately 10% of annual total load in the EI. In the RTx30 and ITx30 scenarios, we model additional wind, PV, and transmission to enable 30% of annual total load in the EI to be met with wind and PV. The transmission expansions for each of these scenarios are based on prior work by the Eastern Interconnection Planning Collaborative (EIPC 2012).

Table ES-1. ERGIS Includes Four Scenarios with Different Levels of Wind, PV, and Transmission Capacity Expansion

Scenario	Wind	PV	Total[a]	Attributes
LowVG	3%	0%	3%	• No new wind or PV generation installations after the year 2012. • Minimal transmission expansion.
RTx10 (Regional Transmission and ~10% VG)	12%	0.25 %	12%	• An approximately 10% VG penetration as reflected in state RPS and interconnection queues as of 2012.[b] • Intra-regional transmission expansion.
RTx30 (Regional Transmission and 30% VG)	20%	10%	30%	• Approximately 30% combined VG, with an emphasis on within-region wind and PV resources. • Identical transmission expansion to RTx10.
ITx30 (Inter-regional transmission and 30% VG)	25%	5%	30%	• Approximately 30% combined VG, with an emphasis on the best wind and PV resources in the U.S. EI. • Interregional transmission expansion with 6 large high-voltage direct current (HVDC) lines.

a. Values displayed in this table are target penetration levels. After simulation, the annual penetration for the LowVG, RTx10, RTx30, and ITx30 were 3%, 11%, 28%, and 29%, respectively.
b. For simplicity in naming conventions, the scenario acronym uses the number 10 instead of the anticipated penetration of 12% and actual penetration level of just over 11%.

Regional loads were grown using a forecast from the U.S. Energy Information Agency's (EIA) 2014 Annual Energy Outlook for the year 2026 (U.S. EIA 2013). A meteorologically synchronized data set was used for historical weather and load data to create 5-minute interval wind, solar, and load data based on the year 2006. We then used this 5-minute data in a production cost model to simulate the UC&ED in each scenario for an entire year. The economic costs of managing this system are presented using production costs, a traditional UC&ED metric that does not include any consideration of long-term fixed costs.

ERGIS increases the resolution of the analysis in several important ways. The study:

- Expands the range of resources analyzed by simulating large-scale adoption of PV, in addition to wind, in the U.S. EI
- Increases the temporal resolution to 5 minutes in order to understand the sub-hourly impact of these resources on system operations
- Increases the spatial resolution of the model to include all synchronous components of the EI and Québec Interconnection, on a comparable basis
- Adds to the fidelity and computational complexity of the UC&ED by modeling 5,600 generating units and over 60,000 transmission nodes using integer optimization (Figure ES-2).

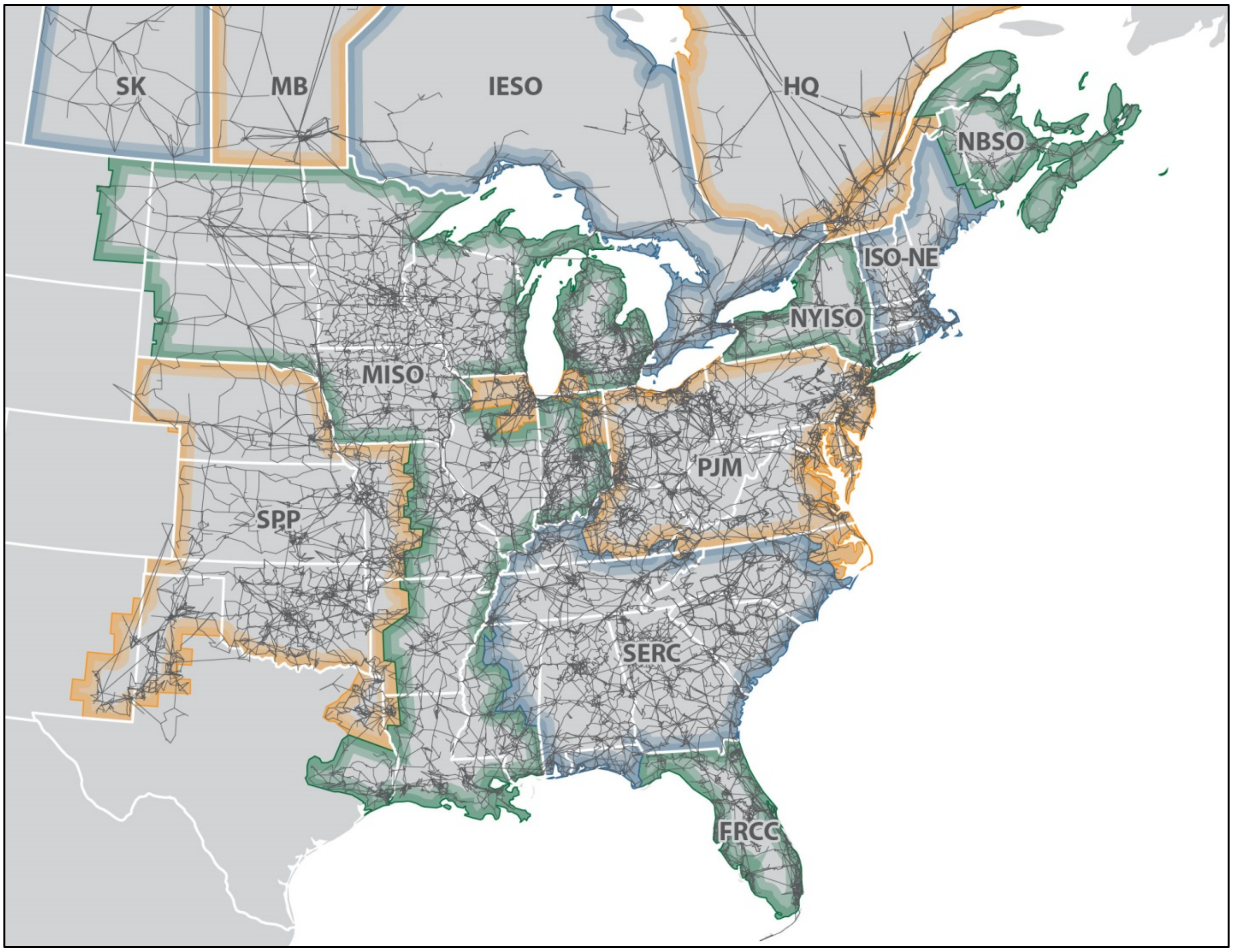

Figure ES-2. Base transmission network of the Eastern and Québec interconnections

NREL applied a novel modeling technique using time-domain partitioning to parallelize simulations, reduce computational limitations, and enable a variety of high-resolution operations analysis. Figure ES-3 illustrates the speedup in computational time achieved using time-domain partitioning (Barrows et al. 2014).

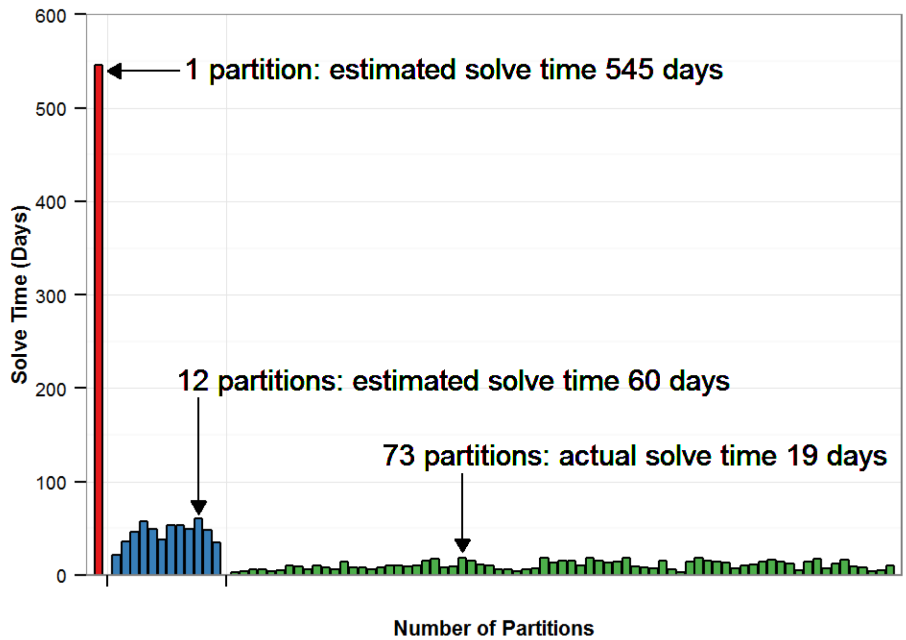

Figure ES-3. Computation times for annual simulations before and after time domain parallelization methods were applied to the ERGIS model

Detailed generator constraints such as integer unit commitment and part-load inefficiencies were enforced to replicate the actual UC&ED practices used in many parts of the system. Current operational practices such as interregional friction[1], reserves and reserve sharing regions, and operational sequencing were included to reflect the state of the present system. Additionally, flexibility from hydro resources was constrained to be realistic with respect to predominant operating practices, as hydro units are assumed unable to respond to wind and PV forecast errors. Additionally, to validate our model, we compared a benchmark year to historical data from the DOE Energy Information Agency to ensure our model adequately reflected historical system performance. ERGIS did not assume advanced flexibility options such as: new reserve products, an intra-day unit commitment, demand response, storage, or advanced thermal generator technology. However, the modeled system is likely more flexible than the present system due to the following key assumptions: a significantly expanded transmission network, coincident retirement of coal and expansion of gas generators, and centralized UC&ED.

Our analysis considered a variety of metrics including: starts, ramps, production costs, and variable generation (VG) curtailment. We also conducted a detailed analysis for three challenging periods of systems operations: one for high load conditions, one for high VG generation, and one with a high net load ramp and forecast error. All load was served in all simulations and soft constraint violations, such as temporarily falling below targeted levels of reserves or exceeding interface limits, were minimal, and are discussed in more detail in the full

[1] Here, the term friction is used to mean the economic inefficiencies across the borders between operating regions. These inefficiencies are usually caused by information asymmetry between regions.

report.[2] This analysis shows the importance of conducting annual simulations to understand seasonal operating conditions. It also highlights the importance of sub-hourly analysis, such as five-minute analysis done in this study, and creates interest in additional research at shorter time domains.

Still, as in many simulations of such large and complex systems, there are some limits to the scope of our analysis. This study did not investigate all aspects of system reliability and economic efficiency. It did not consider capital costs for generation and transmission, contingency impacts, changes to system frequency response, transient stability, or an analysis of the impact our natural gas expansions would have on natural gas infrastructure such as pipelines and gas storage. Only announced nuclear additions and retirements are included in the model. Nuclear plants are assumed to be inflexible, and cannot lower their output to accommodate system changes.

3 What We Learned

This analysis led to four primary conclusions with respect to the integration of wind and PV in the EI that we believe could be useful to system planners and operators. In addition, our work demonstrated the value of advanced data visualization for energy system analysis.

3.1 The operation of thermal and hydro generation changes as wind and PV increase.

The simulated wind and PV resources have seasonal and diurnal energy production patterns that impact how thermal and hydro resources behave in our model (Figure ES-4). Our simulations indicate that thermal plants will run fewer hours on an annual basis and cycle more frequently on a daily basis. Hydro and pumped storage resources shifted from a single peak per day to a morning and evening peak.

[2] The term "soft constraint" is used in this paper to refer to the relaxation of binding constraints in the model. Soft constraints have penalty prices that are added to the system wide production costs. These constraints are used widely in industry and academia to make the computational burden easier to manage.

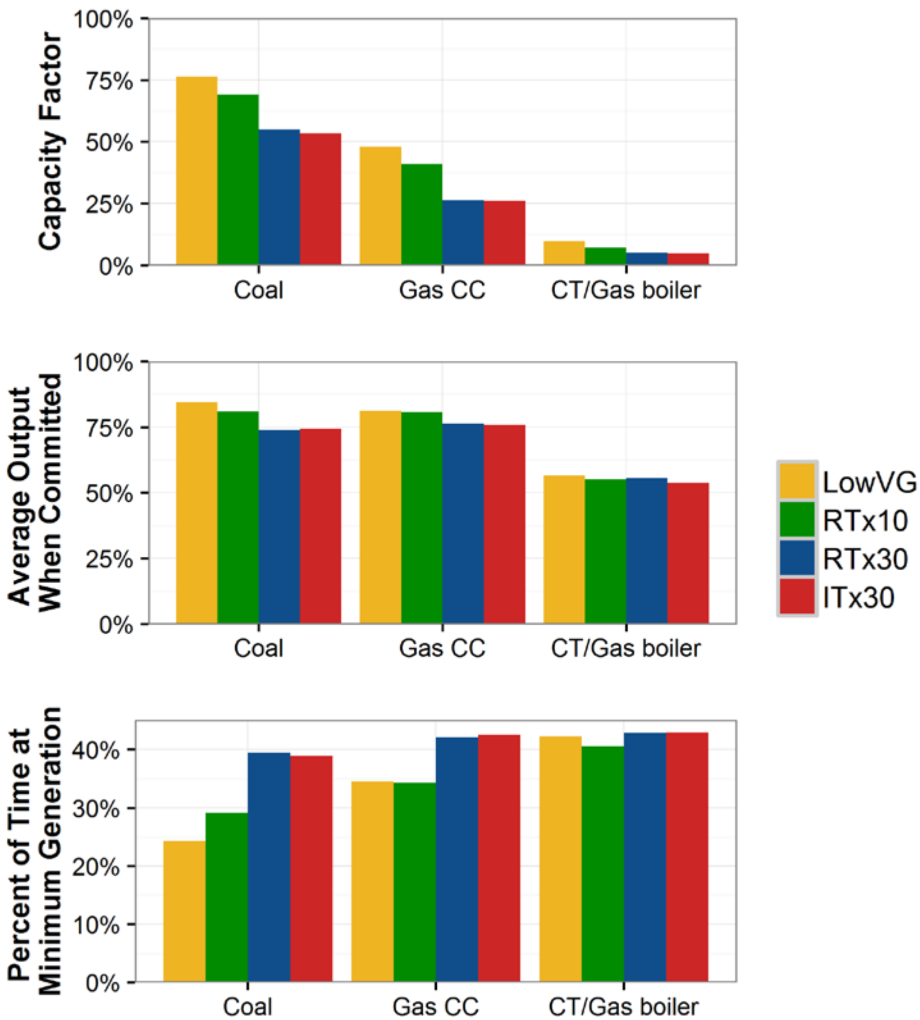

Figure ES-4. Capacity factors of thermal units for the total fleet in the U.S. EI (top), Average output of committed units (middle) and percent of online time at minimum generation (bottom)

Capacity factors are calculated as the nameplate capacity of the generators by fuel type for all periods of the year divided by the total energy produced. 'Average output when committed' counts only committed units and calculates the output as a percentage of nameplate capacity of the unit.

Wind and PV primarily displaced coal and combined cycle (CC) generation. ERGIS simulations show that annual wind and PV penetrations of 30% decrease coal, CC, and combustion turbine (CT) capacity factors by 30% to 50%.

Typical daily operational patterns also change in the 30% scenarios. Coal units increase time at minimum generation levels by 50% and CC units by 15%. As wind and PV are added to the system, generation from thermal and hydro resources is shifted to different times of the day. Increased thermal and hydro utilization is observed in the hours before and after peak PV generation, see Figure ES-5. These changes in resource behavior are departures from the low renewable case, but can be accommodated with the modeled technologies and assumptions. Our findings on the operational patterns and ability to accommodate them are consistent with the broad consensus of renewable integration literature. Further analysis could help determine how these operational changes would impact the long-term financial viability of generators and fuel supply.

The variability of wind and PV cause other generators to ramp and start more frequently. In the 30% penetration scenarios, ramps per unit of energy by coal units increases by about a third and ramping by CC units increases by about a quarter. Starts for coal units increased by about 20%, and starts for CC units increase by more than 40%. CT starts decreased due to lower overall CT operation. While start costs reflected the additional wear and tear costs and emissions associated with cycling, they did not include other potential long-term impacts, such as increased forced outage rates due to increased wear and tear.

The regional impacts of high penetrations of VG varied due to regional differences in the thermal and hydro generation fleets and VG fleets. In general, the operational impacts tend to be greater when there is more installed PV in conjunction with less inter-regional transmission. These factors, coupled with hurdle rates[3] between regions, cause some regions to have a greater reliance on balancing their own systems with local generation rather than using imports and exports.

3.2 System operations at sunrise and sunset could follow different patterns.

Our analysis shows that operations during the hours surrounding sunrise and sunset change more rapidly in the scenarios with higher renewables. The morning and evening load ramps have always been a challenging time for system operators and require expensive fast-starting, flexible resources before the addition of wind and PV to the system. After low load hours over night, morning load grows quickly in most parts of the country and typically stays high until peaking sometime in the afternoon or evening, depending on the season. Our simulations (Figure ES-5) indicate that the dispatch and commitment patterns of thermal and hydro resources will change as wind and PV are introduced to the system, creating a potential need for new operating rules, regulations, and practices to properly incentivize efficient operations. Around high wind and PV time periods, thermal and hydro plants tend to ramp faster and operate for shorter periods of time.

[3] Hurdle rates are an economic constraint in the model designed to approximate some of the economic inefficiencies, such as information asymmetry, that impact inter-regional electricity trade.

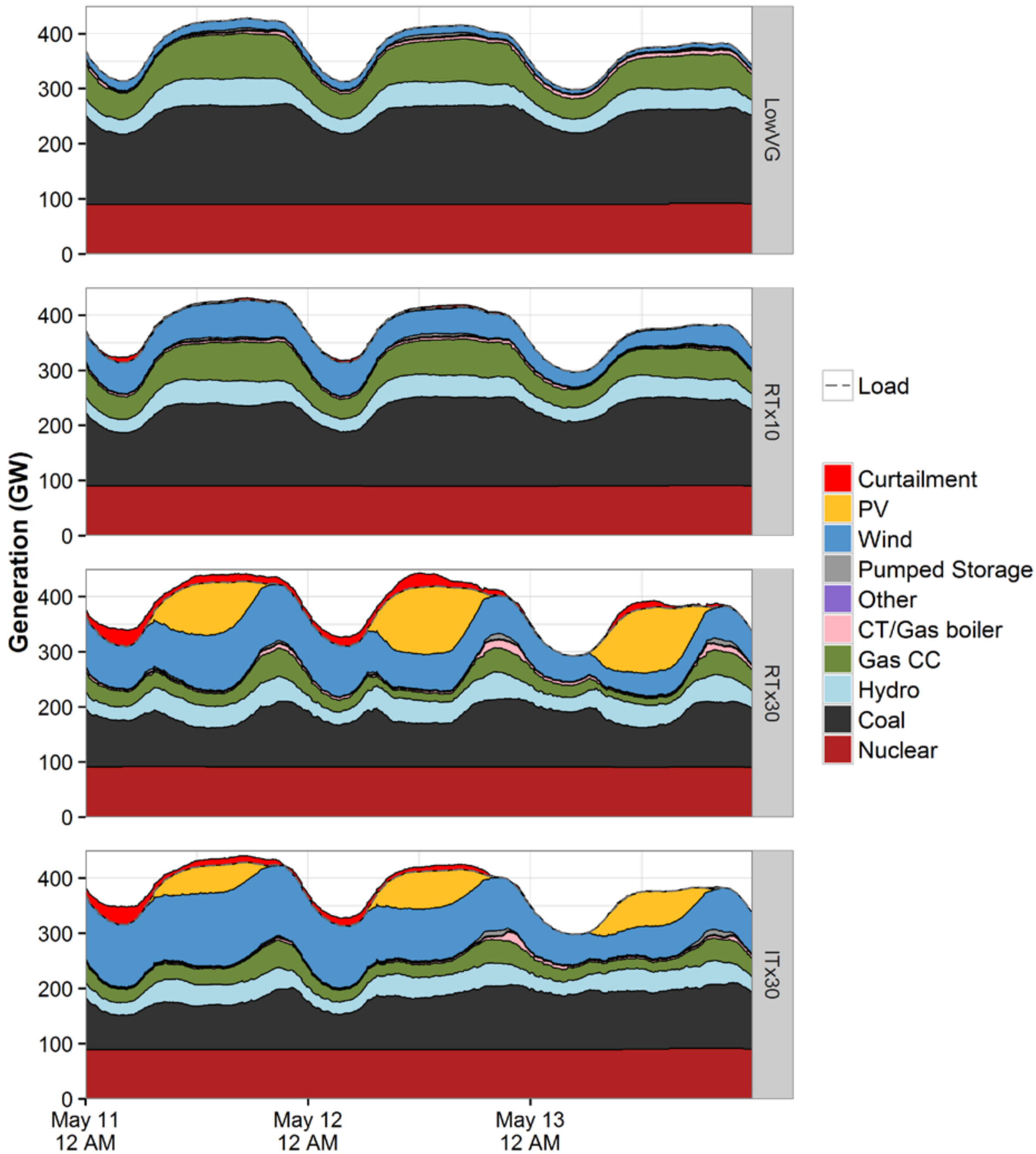

Figure ES-5 Dispatch for the U.S. EI during high wind and PV conditions.

Daily schedules for thermal and hydro units are quite different in the 30% cases than in the LowVG case. Instead of being committed and dispatched to meet a typical single peak load, our results indicate that thermal and hydro plants will be committed and dispatched to meet two *net*-load peaks. The first occurs just before sunrise. The second occurs at sunset as PV generation decreases.

Because our study was framed around annual average generation targets of 30% energy from wind and PV, the modeled system experienced numerous periods of generation that were above and below the annual average. Peak penetration of VG approached 60% in some intervals while the minimum penetration from VG was approximately 10%. During some periods of high wind and PV generation, two types of very low net load events may exist on the system. The first is a minimum net load at night, driven by wind generation. The second is a minimum net load during the day, driven by PV generation. The minimum net load levels are lower than normally observed by system operators and the addition of a minimum net load in the middle of the day is a significant difference from current system operating conditions.

3.3 Transmission flows will likely change more rapidly and more frequently with higher penetrations of wind and PV.

We observed that the average daily power flows between regions change substantially as more VG was added to the system. Some of the increased flows are due to the increased transmission buildout in the EI in our four scenarios, but changes due to the high penetration of VG are also evident. For example, in Figure ES-6 and Figure ES-7 we note the impact of PV on system-wide transmission flows. The PV in FRCC and SERC has a large impact on regional flows during the daylight hours that is not present in the LowVG. [4] Not only do exports from the Southeast to the rest of the EI increase, but in the RTx30 (the scenario with the most PV capacity) exports from MISO and Hydro Québec to the high load regions on the U.S. East Coast decrease due to the cheaper power coming from SERC and FRCC.

Energy transfers between zones were limited based on hurdle rates and interface thermal limits. While the limits allowed us to simulate some of the economic and engineering constraints of inter-regional transmission utilization, this approach is not comprehensive. Our analysis relies on a single centralized UC&ED, while actual UC&ED is distributed across many entities in the EI. Furthermore, our model assumes a structure akin to an organized market. In reality, the EI features both organized and vertically integrated markets. This economic friction between markets is represented by hurdle rates and physical transmission limits are based on thermal constraints. However, no limitations on the ramp rates of flows between regions were modeled. In current operations, most regions have ramp rate limits for interchange schedules (PJM 2016). The exclusion of ramp rate increases the overall flexibility of the system.

[4] A video of these results is available at www.nrel.gov/ERGIS

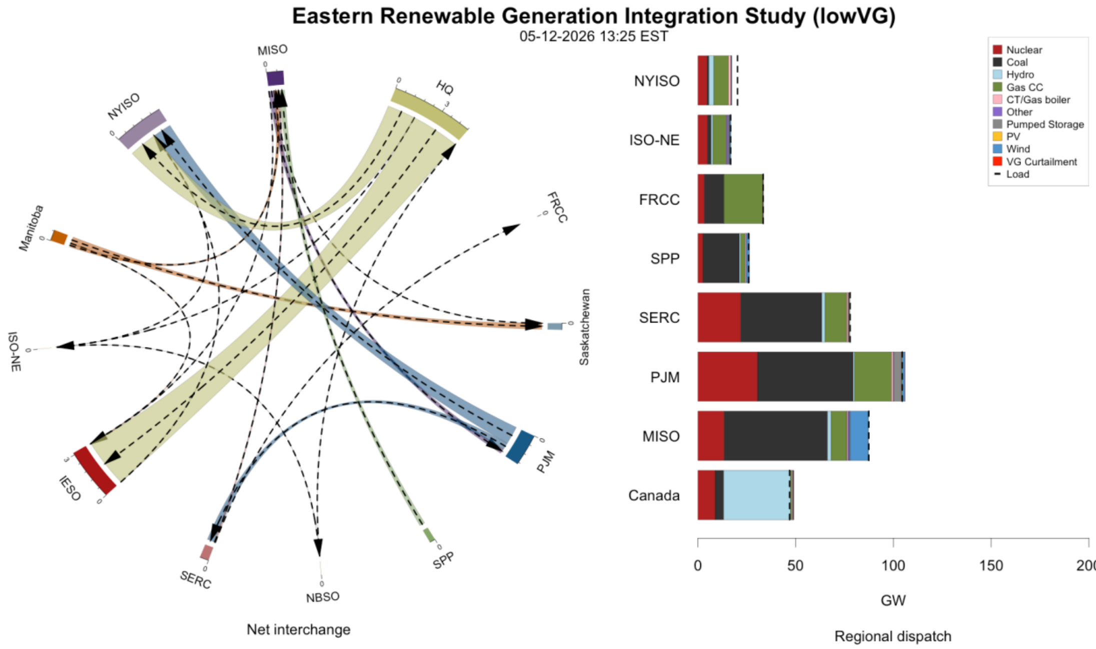

Figure ES-6. Net interchange in the LowVG on May 12, 2026 at 13:25

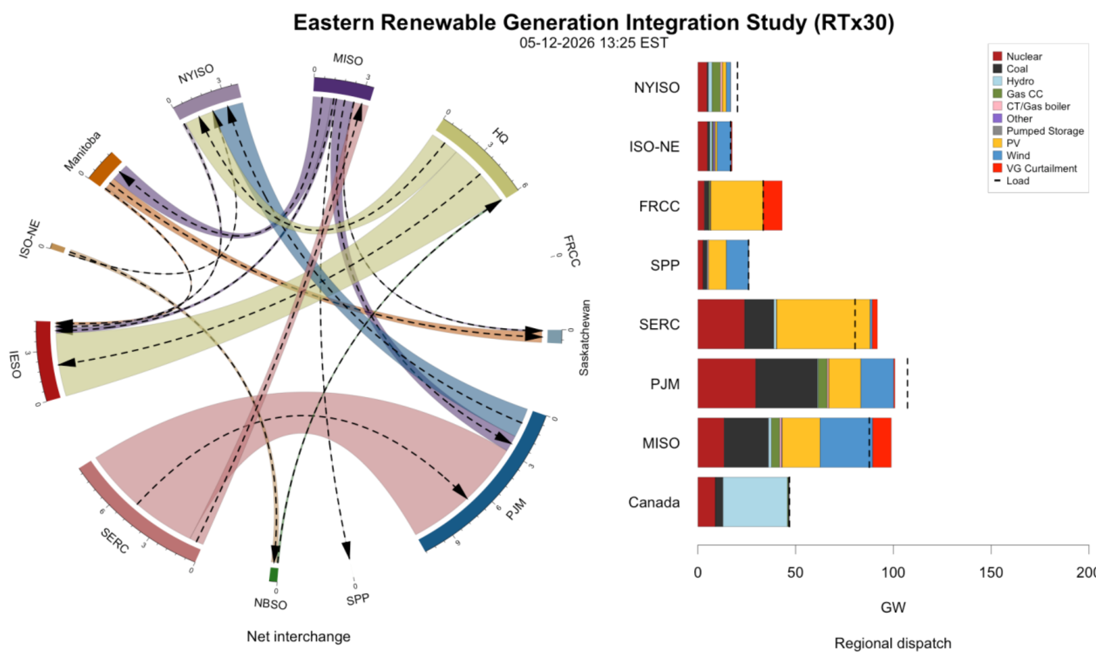

Figure ES-7. Net interchange in the RTx30 on May 12, 2026 at 13:25

Daily patterns of power flow change from increased VG, and the rate at which the power flow changes is also impacted. However, both of the 30% VG scenarios show a more rapid change in the power being transferred between regions than the lower penetration scenarios. This suggests that greater coordination between regions to handle faster changes on interface flows may have an economic benefit if large amounts of wind and PV are installed throughout the interconnection.

Additional analysis could more accurately represent economic friction between markets. Similarly, additional work on computational approaches and methods could enable an even more complete list of transmission constraints to be included in large network models such as the EI. Finally, ramp rate limits on transmission lines should also be considered in future work to determine if there are limitations on the ability of systems to use trading with neighboring regions to accommodate net load ramps. If the actual utilization of interregional transmission is more limited than allowed in this study, additional analysis could explore other possible approaches for accommodating high penetrations of VG. Solutions may include utilizing more flexibility in the thermal fleet (ramping or starting/shutting down local generators) or curtailing more of the VG.

3.4 The operating practices of generators and transmission operators will be critical to realizing the total technical potential of the interconnection.

The ability of the EI to integrate and balance hundreds of GW of wind and PV generation depends on generator and transmission operators offering their capabilities to the system operator. In ERGIS, we used detailed modeling assumptions and advanced methods that were vetted by a TRC to determine whether our model could commit and dispatch resources to balance load at a 5-minute intervals for an entire year of simulated operations. We show that the system can be committed and dispatched to balance the system in a variety of conditions, including high load, high VG, and during extreme ramping conditions. However, we did not investigate whether transmission and generation operators will have sufficient incentives to provide the necessary ramping, energy, and capacity services for futures like the ones we studied. While ERGIS shows it is technically possible to balance periods of instantaneous VG penetrations that exceed 50% for the EI (Figure ES-8), the ability of the real system to realize these futures may depend more on regulatory policy and market design to incentivize the needed operating procedures.

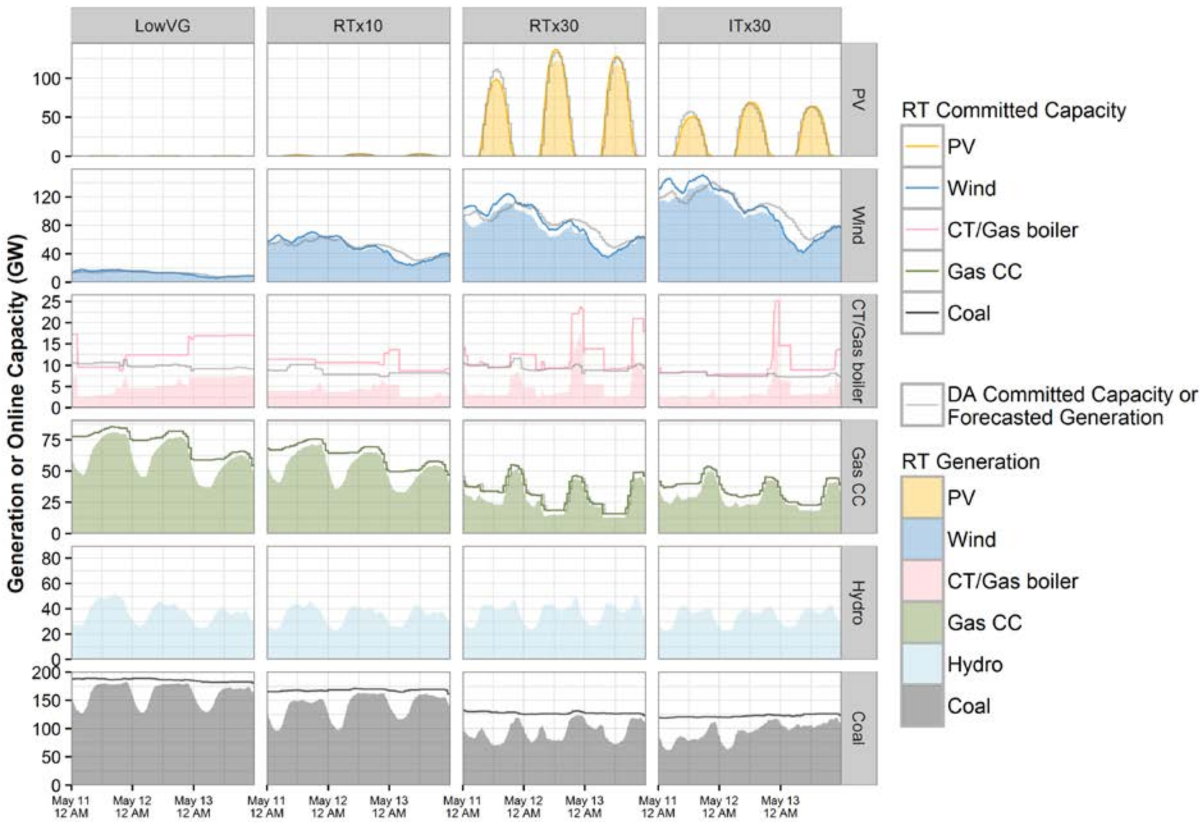

Figure ES-8 Day-ahead and real-time results for a period of high wind and PV generation

We assume hydro, pumped storage, and thermal resources are willing to offer their capabilities at any time. In reality, many of the operating practices of generators are based on historical behavior, equipment limitations, and regulatory structures focused on peak load conditions. In ERGIS we observed a shift in thermal, hydro, and pumped storage plant operations from a single peak to two shorter and steeper peaks during high VG conditions. This change has implications for system operating practices. In futures with high amounts of wind and PV, system and plant operators will need to focus their attention on different times of day and could expect to cycle or ramp their resources more frequently. If adequate short term opportunities and regulatory structures are not in place to incentivize this flexibility, resources may exit the market or prefer not to make their full flexibility available to the system operator, compromising the ability of the system operator to manage the types of conditions simulated in this study. These new flexibility requirements may also provide opportunities for technologies like demand response or energy storage to support the management of the conditions explored in this study.

Our analysis also indicates that futures with high amounts of VG will likely benefit from multi-regional coordination. Our model assumes that there is a single mathematical formulation used to commit and dispatch the entire power system. As such, we observed instances where high levels of wind and PV appear to be transferred across more than one region. This is because the model saw economic value and the technical ability to transfer energy very long distances. In reality the operations of the EI and the market are currently managed by a variety of entities. While operations between those entities are coordinated to some extent, this coordination will likely become more important in the future. While we have modeled some of the economic and technical constraints on interchange between regions, market participants will likely require significant, additional coordination across multiple areas in order to act on resource availability that is multiple regions away.

Finally, our model assumed a common thermal generating fleet across scenarios regardless of renewable penetration. This means that in our high wind and PV cases, the RTx30 and ITx30, there is likely more thermal generating capacity in our model than would be expected on the actual system. The ability of resources to obtain sufficient revenues from the new operating patterns will likely impact resource adequacy. Given the reduced utilization of many generators, it is unclear whether energy market revenue alone will be sufficient to keep units from retiring. Additional analysis of these long-term economic impacts is essential to determine the true feasibility of the simulated scenarios.

3.5 Advanced visualization tools are helpful for understanding spatially and temporally rich models.

New visualization tools help to ensure model accuracy and provide analytical insights. Power system futures with high levels of wind and PV require simulations with large datasets featuring high spatial and temporal resolution. The large amounts of data create the need to programmatically create, manage, and analyze big data sets. We created two visualization tools in the statistical software package, R, to manage this data, ensure accuracy, and provide timely analysis (Figure ES-9).[5]

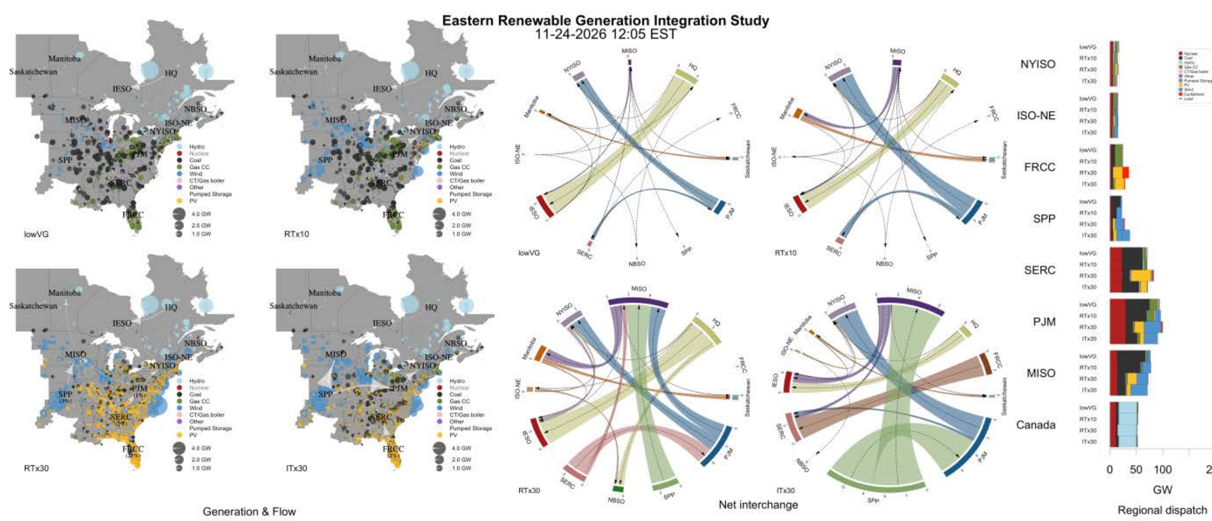

Figure ES-9. Sample screen from "kaleidoscope" visualization tool, one of two tools developed for ERGIS

These tools assisted us in two ways. First, they streamlined the analysis process by enabling the rapid visualization of numerous interim simulations conducted for the study. This enabled the team to identify anomalies and verify results. Second, these tools helped us understand how the model was using coordinated operations across multiple regions to manage the changing

[5] A sample of the kaleidoscope visualization for large displays is available at www.nrel.gov/ERGIS

conditions presented by wind and PV. In animations created using kaleidoscope, we observed how varying wind and solar generation drives interchange across multiple regions.

The broader research and industry community may use these tools and contribute improvements of these tools via the open source platform GitHub.[6] We hope that others will be able to use these *research grade* tools to manage the results of production cost model simulations, visualize results, explore data and results in new ways, and reduce the amount of time necessary to validate and act on analysis.

4 Key Takeaways

Using high-performance computing capabilities and new methodologies to model operations of the Eastern Interconnection at unprecedented fidelity, we found that the integrating up to 30% variable wind and PV generation into the power system is technically feasible at a five-minute interval.

Achieving this level or higher penetrations of variable renewable generation would likely change the way traditional generation sources work on the system and could require operational changes such as increased coordination across the system.

This study and the accompanying data sets and tools provide power system planners, operators, and regulators with new means and insights to anticipate and plan for operational changes that may be needed in cleaner energy futures.

[6] Links to the GitHub repositories are available at www.nrel.gov/ERGIS

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