MISO's Renewable Integration Impact Assessment (RIIA)

SUMMARY REPORT – FEBRUARY 2021

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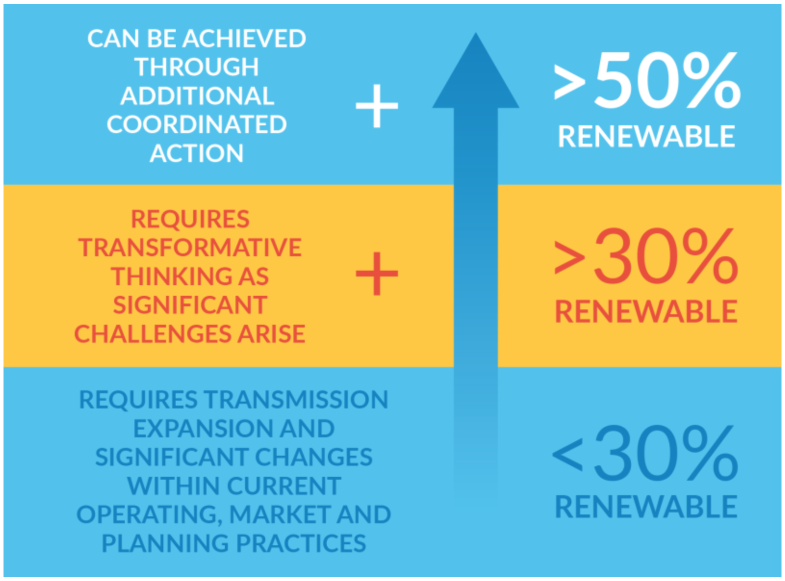
Contents

Executive Summary

A Technically Rigorous Exploration

MISO's Renewable Integration Impact Assessment (RIIA) demonstrates that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks. Managing the system under such conditions, particularly beyond the 30% system-wide renewable level is not insurmountable and will require transformational change in planning, markets, and operations. Through coordinated action with MISO stakeholders, RIIA concludes that renewable penetration beyond 50% can be achieved.



While grid operators have managed uncertainty for decades, MISO is preparing for an unprecedented pace of change. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the Reliability Imperative, which is broken into four categories Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements. RIIA is a key part of understanding the risks ahead.

RIIA is a technically rigorous systematic analysis that evaluates increasing amounts of wind and solar resources on the Eastern Interconnection bulk electric systems, with a focus on the MISO footprint. RIIA examines renewable penetration levels in 10% increments up to 50% to better understand the complexities of integration at each level. This assessment provides examples of integration issues and examines potential mitigation solutions.

RIIA is policy and pace agnostic: generation changes in the analysis are assumed to occur regardless of external drivers and timelines. As a technical impact assessment, RIIA does not directly recommend any changes to the existing electrical power system or construction of any new resources. That said, this body of work demonstrates that as renewable penetration increases, so does the variety and magnitude of system risk requiring transformational thinking and problem-solving.

"MISO, our members, and the entire industry are poised on the precipice of great change as we are being asked to rapidly integrate far more renewable resources. Given our regional Reliability Imperative, MISO must act quickly, deliberately, and collaboratively to ensure that the planning, markets, operations, and systems keep pace with these changes. We can achieve this great change if we work together."

— Clair Moeller, MISO President

New and Changing Risks Emerge, Requiring Support

As new risks emerge, adaptation within the existing planning, market, and operations constructs will suffice only to a point. As renewable generators are added, and conventional generators retire, RIIA identifies both new and changing risks and system needs:

New Stability Risk

The grid's ability to maintain stable operation is adversely impacted, primarily when renewable resources are clustered in one region of the transmission system. As inverter-based resources displace conventional generators, the grid loses the stability contributions of physically spinning conventional units. A combination of multiple technologies — such as high-voltage direct current (HVDC) lines, synchronous condensers, motor-generator sets and emerging technology such as grid-forming inverters — are needed to provide support, along with operational and market changes to identify and react to this risk as it occurs.

Shifting Periods of Grid Stress

The periods of highest stress on the transmission system shift from peak power demand to times when renewables supply most of the energy and long-distance power transfers increase. As power flows across longer distances, local planning and operational issues become regional challenges. As renewable resources supply most of the energy, the system becomes more dependent on the stability attributes of the remaining conventional generators, increasing the system risk associated with unexpected outages of those generators. As the direction and magnitude of power flows change rapidly due to the output of renewable resources that vary with weather conditions, increased flexibility, and innovation in planning and infrastructure is needed to adapt to new and shifting periods of stress.

Shifting Periods of Energy Shortage Risk

The risk of not having enough generation to meet demand shifts from the historic times of peak power demand to other periods, specifically hot summer evenings and cold winter mornings, when low availability of wind and solar resources is coincident with high power demand. These shifts are regional in nature. The colder and windier northern states exhibit different patterns than the hotter and sunnier southern states. To address this changing risk, the system needs to ensure (1) sufficient visibility of locational risk and (2) that other energy-supplying resources are available during these new times of need, with adequate transmission to deliver across regions.

Shifting Flexibility Risk

The ability of resources to provide system flexibility will be challenged. Current flexibility is needed primarily around the morning load ramp as energy demand increases and again during the evening load ramp as demand decreases. This risk shifts as variable renewables are added. As solar resources meet a larger share of the mid-day generation needs, non-solar resources are needed to ramp down in the morning and ramp up again in the evening to balance the solar pattern. Similarly, non-wind resources will ramp up and down to balance wind patterns, which change daily. To address this shifting risk, overall flexibility need increases and shifts to align with the periods in which it is required.

Insufficient Transmission Capacity

The current transmission infrastructure becomes unable to deliver energy to load. This is especially true if renewables are concentrated in one part of the footprint while serving load in another. Without added transmission, power flow across the footprint is hindered. The variable supply of renewables would, therefore, become much more challenging to manage, resulting in increased curtailment and markedly different operation of the remaining generators. Given how much time is typically needed to build transmission, proactive planning is necessary.

Integration Complexity Increases Sharply after 30% Renewable Penetration

In the general sense, system integration complexity is the effort needed to plan for, support, and operate new resources as they connect to the grid. In the RIIA analysis, complexity is measured quantitatively to understand its relative magnitude when comparing across various drivers.

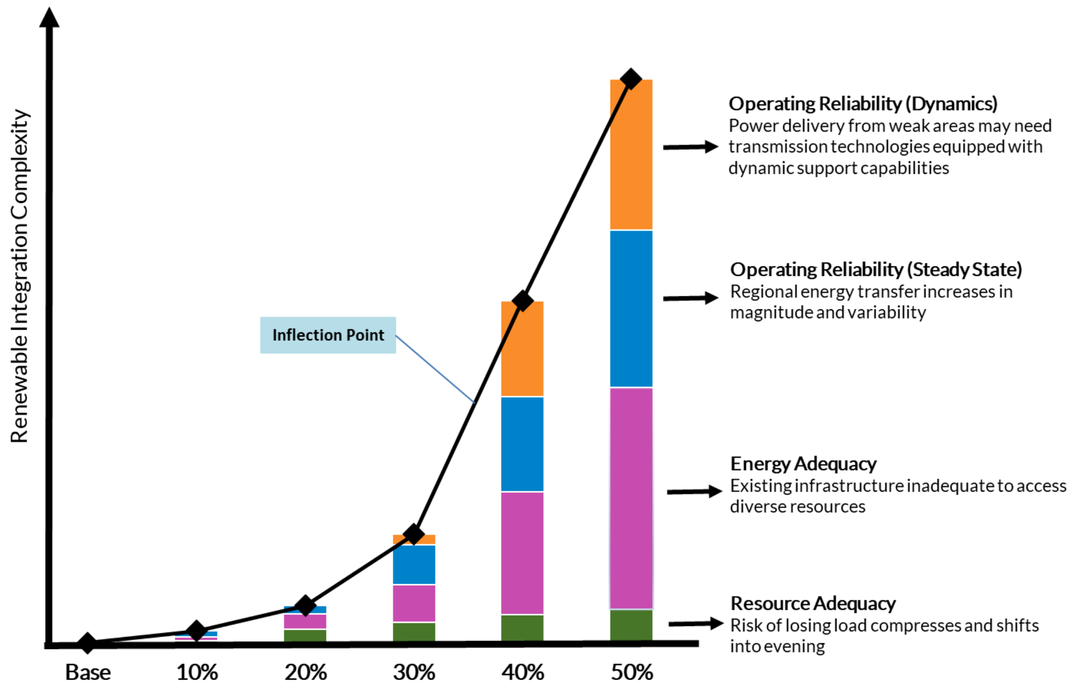


Figure 1: Increasing renewable penetration will significantly impact grid performance with complexity increasing sharply after 30% renewable penetration levels

> **"RIIA is the most comprehensive engineering study of the power system renewable transformation."**
> **— Aaron Bloom, Chair, System Planning Working Group, Energy System Integration Group**

RIIA found when the percentage of system-wide annual load served by renewable resources is less than 30%, the integration of wind and solar will require transmission expansion as well as significant changes to current operating, market, and planning practices — all of which appear manageable within MISO's existing framework. Beyond 30%, transformative thinking and coordinated action between MISO and its members are required to prepare for the significant challenges that arise (Figure 1). It is important to note that renewable growth does not happen uniformly across the MISO footprint, or the broader interconnected system. Growth occurs fastest in areas with high quality wind and solar resources, available transmission capacity, and favorable regulatory environments. For example, when MISO reaches 30% renewable energy penetration, some Local Resource Zones are likely to be approaching 100% renewable energy penetration. Locations which experience the fastest renewable growth experience challenges first, but beyond 30% renewable penetration the system as a whole facing new and shifting risks rather than simply local issues.

Today, MISO's renewable fleet accounts for 13% of MISO's system-wide energy, and MISO operates 26 GW of wind and 1 GW of solar. Nearly 80% of MISO's renewable resources are in the northwest region of MISO, concentrating the current integration challenges to one area.

Looking ahead, as the significant pipeline of generators with executed Interconnection Agreements reach commercial operation (6 GW of new wind, 10 GW of new solar), renewables are expected to account for approximately 20% of the system-wide annual energy mix. Beyond that, MISO Futures demonstrate the 30% milestone could occur as soon as 2026.

Three Key Focus Areas, RIIA Insights and Next Steps

RIIA illustrates areas of system weakness, recognizes when those weaknesses could become problematic and identifies potential means to address them. This work has informed initiatives already underway at MISO and will serve as a key input to initiatives in the future. The assessment aims to support a broader, more informed conversation about renewable integration impacts on the reliability of the electric system within the MISO stakeholder community and the greater industry. The analysis suggests three key focus areas for MISO and stakeholders (Figure 2) and informs the sequencing of actions required to manage various renewable penetration levels.

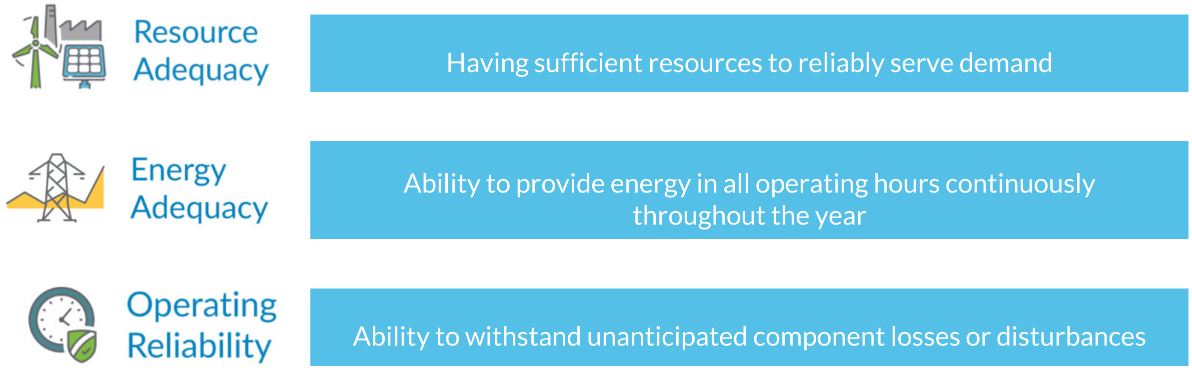
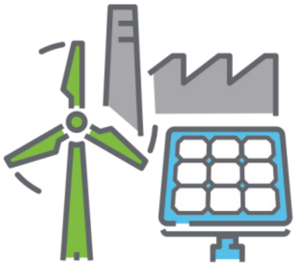


Figure 2: RIIA's three focus areas: Resource Adequacy, Energy Adequacy and Operating Reliability

Note: Where appropriate, the insights below are tied to the [Reliability Imperative](#) efforts in the categories of Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements.

Resource Adequacy



Resource Adequacy is the ability of available power resources to reliably serve electricity demand when needed across a range of reasonably foreseeable conditions. Resource Adequacy complexity is defined as the effort needed to maintain capacity necessary to maintain a "one day in 10 years" loss of load expectation target.

RESOURCE ADEQUACY INSIGHTS

INSIGHT: Risk of losing load compresses into a small number of hours and shifts into the evening. The risk of not serving load shifts later into the evening and is observed for shorter durations with higher magnitude. Sensitivity analyses show risk shifting to winter and later in the evening, depending on technology and geographic mix.

NEXT STEP

- Ensure resource availability outside of traditional risk periods, both during evening hours and winter periods (Market Redefinition).

INSIGHT: Resource changes will significantly impact grid performance, with complexity increasing sharply after 30% renewable penetration levels.

NEXT STEP

- Develop and implement market solutions to identify issues prior to the system reaching 30% wind and solar penetration (Market Redefinition).

INSIGHT: Diversity of technologies and geography improves the ability of renewables to serve load. Yearly weather variations drive Resource Adequacy outcomes.

NEXT STEP

- Develop ways to increase the fidelity of renewable energy forecasts by using improved weather data.

RESEARCH STEP

- Explore ways to incentivize new resource additions to enhance technological and geographical diversity to serve MISO reliability.

Energy Adequacy

Energy Adequacy looks at the ability to operate the system continuously and deliver sufficient energy every hour of the year. Energy Adequacy complexity is defined as the effort to develop the transmission needed to maintain and deliver renewable energy during every hour of the year. The generation fleet's ability to respond to the load is limited by existing generation and transmission constraints, and new transmission costs act as a proxy to measure the additional flexibility needed to access diverse resources.

ENERGY ADEQUACY INSIGHTS

INSIGHT: With renewable penetration levels above 40 percent, there is both a greater magnitude and increased variation of ramping needed. Increasing variability due to renewable generation will require generators to perform differently than they are today.

RESEARCH STEPS

- Explore the landscape of system flexibility solutions (e.g., renewables as a solution to variability need and nuclear plant ramping).
- Explore changing risks such as the ability of the natural gas system to deliver fuel to enable gas generator flexibility, and fewer units providing needed system flexibility (due to retirements).
- Explore flexibility incentives (Market Redefinition).

INSIGHT: Existing infrastructure becomes inadequate to fully access the diverse resources across the MISO footprint. Grid technology needs to evolve as renewable penetration increases, leading to an increased need for integrated system planning.

NEXT STEP

- Educate stakeholders about complexities and opportunities of emerging technologies (LRTP).

RESEARCH STEPS

- Explore co-optimization between economic and reliability transmission needs, along with resource deployment (software, process, and data development needed).
- Explore additional opportunities to align and co-plan for system needs across the various MISO planning functions.
- Explore the gaps, opportunities, costs, and benefits of new grid technology (such as FACTS, VSC HVDC lines, grid-forming inverters) and its ability to solve emerging grid needs.

INSIGHT: Storage paired with renewables and transmission help optimize the delivery of energy.

RESEARCH STEPS

- Explore concept to understand benefits better
- Explore process changes to align benefits with outcomes

Operating Reliability

Operating Reliability studies the system's ability to withstand sudden disturbances to system stability or unanticipated loss of system components. This focus area is subdivided into "steady state" and "dynamic stability" analysis and considerations.

Steady State

Steady-state analysis examines whether the transmission system exceeds the thermal ratings of lines, transformers, and other devices following deviations from normal operating parameters occurring without warning. Complexity in steady-state analysis is defined as the effort to create the transmission needed to ensure acceptable system performance after outages.

OPERATING RELIABILITY — STEADY-STATE INSIGHTS

INSIGHT: Resource location and system conditions cause transmission risk shifting to spring and fall and increasing in frequency. Additionally, sensitivity analysis shows risk shifting to summer shoulder load periods during high solar output.

NEXT STEPS

- Align planning dispatch assumptions with shifting system conditions and risk (LRTP).
- Develop tools and processes to capture changing risks as they appear for transmission planning (LRTP).

RESEARCH STEP

- Evaluate opportunities to align and co-simulate power-flow and production cost models.

INSIGHT: Regional energy transfer increases in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities. Transmission bottlenecks shift to higher voltage lines due to increased regional energy transfers.

NEXT STEPS

- Proactively align to future needs, develop long-range, cost-effective, and least-regret transmission plans, and move construction forward (LRTP).

Dynamic Stability

Voltage stability, frequency stability, rotor angle stability, and non-oscillatory behavior of electrical quantities are considered dynamic stability issues. Dynamic stability includes maintaining operating equilibrium of three distinct elements after a disturbance in the electric grid: (a) voltage stability; (b) adequate frequency response; and (c) rotor angle stability. Complexity in the Operating Reliability — Dynamics analysis is defined as the effort to install transmission equipment and control system tuning required to ensure stable operation.

RIIA identifies potential issues with all three dynamic stability elements along with converter-driven stability, which is an additional category associated with inverter-based equipment. Concerning voltage and converter-driven stability, the assessment demonstrates that as inverter-based resources increase in penetration, there is a corresponding decrease in the online thermal generation, which intensifies reliability issues. This is significant because commercially available inverter-based resources, such as renewables, need strong voltage connections to operate reliably and efficiently. This study identifies several approaches to address the issues, such as tuning inverter controls, re-dispatching generation, adding synchronous condensers, and using advanced technologies (FACTS, VSC HVDC). Frequency-related risks can be resolved by adding storage or maintaining online headroom from resources, including wind and solar.

OPERATING RELIABILITY — DYNAMIC STABILITY INSIGHTS

INSIGHT: Power delivery from "weak-grid" areas may need transmission technologies equipped with dynamic support capabilities.

RESEARCH STEPS

- Explore and decide ways to address "weak-grid" issues (such as improved inverter technology, new technology pilots, operational visibility, proactive and integrated transmission planning).
- Update inverter control tuning approaches as penetration of inverter technologies increases.

INSIGHT: Small signal stability issues increase in severity after 30% renewable penetration, thereby requiring power system stabilizers. Frequency response is stable up to 60% instantaneous renewable penetration but may require additional planned headroom beyond 60%.

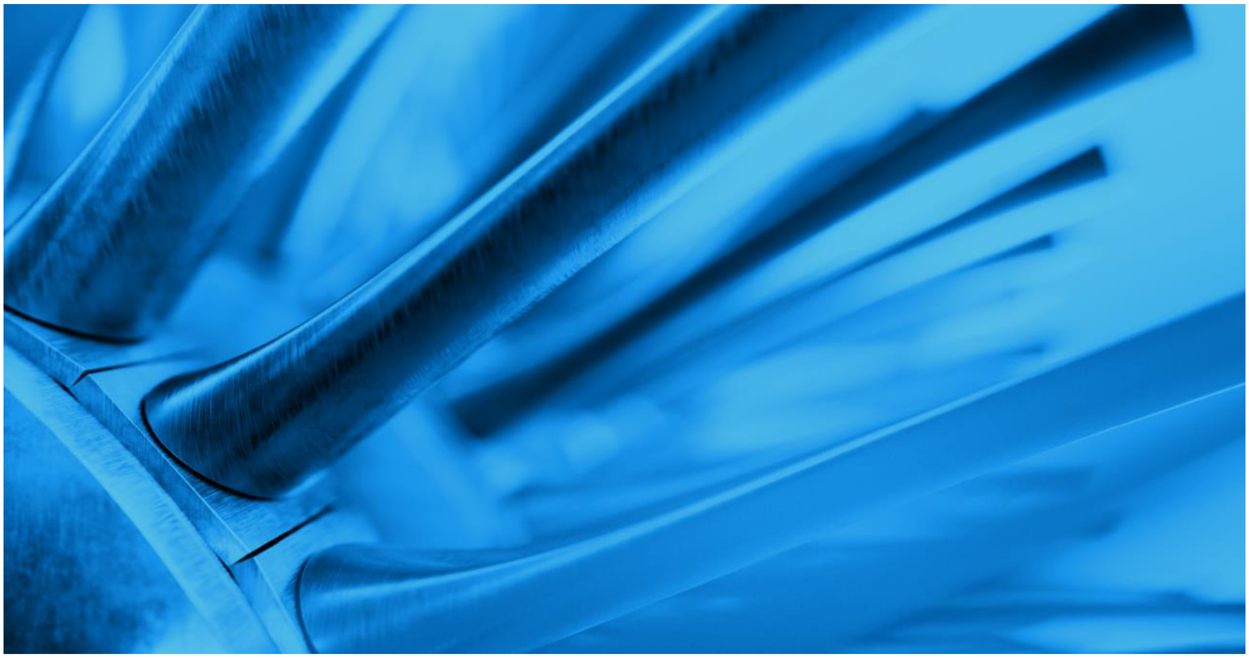
RESEARCH STEPS

- Explore new methods to stabilize the grid, such as battery storage.
- Explore operations tools to monitor and commit power system stabilizers when needed.

INSIGHT: On average Critical Clearing Time (CCT) improves as large generating units are replaced, but new local issues emerge.

RESEARCH STEP

- Explore process to plan for new protection techniques or new transmission devices.



Additional Work Is Needed

RIIA is the culmination of four years of stakeholder collaboration and intense exploration into the impacts of increasing renewable integration in the MISO region. While the analysis is highly comprehensive, it is not finished. Additional work is needed to transform the way MISO and the power system are planned and operated to continue to maximize reliability and value creation across the region in a high renewable system. RIIA has shown that while there are challenges, the MISO region can achieve renewable penetration of at least 50% with transformational change and coordinated action amongst all participants.

> **"We believe it will take transformational change, including redefined markets and planning processes, to enable efficient and reliable operations in the future. Coordinated action amongst all stakeholders will be necessary to facilitate participants' decarbonizations goals and plans for higher levels of renewable generation."**
>
> **— Richard Doying, MISO EVP Market & Grid Strategies**

Technical Summary

The Technical Summary serves as a detailed explanation of the results and insights of the Renewable Integration Impact Assessment (RIIA).

In 2017 as RIIA was in its initial scoping phase, the state of the industry was more uncertain. MISO, its members, and the broader industry were asking questions about the place wind and solar would have in the evolving grid and the speed at which the resources would seek interconnection into the system. Additionally, no large stand-alone systems in the world operate high shares of wind and solar resources, limiting the ability to learn from others. These resources are unique among the other types in that their ability to produce power is dependent on the weather, which creates uncertainty into the timing of their availability. Also, these machines' electrical properties are unique from those traditionally built - they are inverter based (i.e., electronically connected to the grid rather than mechanically connected). Due to the uncertainty of how high shares of these resources would interact with the power system, a highly detailed study was needed to explore how wind and solar growth would change the risk types and patterns of the system.

The RIIA work explored the growth of wind and solar resources both in MISO and the broader interconnected system to understand how the entire system would perform as more wind and solar were installed. This assessment focuses primarily on the MISO region. However, it was essential to model the complete grid in detail to see the MISO region's interactions with the rest of the grid. It was also important to link the modeling of different technical focus areas together so the results and insights of one could influence the others. Unique insights were gained, as an example, about the timing of system stress from the Energy Adequacy analysis that changed the way the Operating Reliability analysis was conducted. As seen in Background Studies, other high renewable studies employ traditional modeling techniques and miss the changing risk patterns seen in RIIA due to the decoupled nature of traditional analysis. A detailed description of the assessment process can be found in the Technical Assumptions Summary.

RIIA sought to facilitate a conversation both in the MISO region and beyond about the changing risks the grid may experience due to renewable energy growth. To accomplish this MISO, both hosted and participated in hundreds of meetings sharing RIIA insights and hearing from others about their questions and experiences. MISO hosted long-form workshops and webinars to share the work's details and how RIIA insights were developed. Many of these were recorded, and the knowledge lives on through continued sharing and viewing. Short-form discussions were facilitated primarily through the Planning Advisory Committee and occasionally through other MISO committees. MISO presented at numerous conferences, met individually with interested members, state commissions, government bodies, industry groups, and wrote journal and conference papers to continue to learn and share experiences. Due to this sharing, MISO believes the knowledge and conversations about the challenges and optional solutions to the growth of wind and solar in the MISO region has improved.

The primary purpose of this assessment was to systematically find system integration inflection points driven by increasing renewable integration. Other industry studies have shown that the complexity of renewable integration escalates non-linearly with the growing penetration of renewable energy. Over some renewable penetration ranges, complexity is constant when spare capacity and flexibility exist. However, at specific penetration levels, complexity rises dramatically as the excess capacity and flexibility are used. These are system **inflection points**, where the underlying infrastructure, system operations, or both need to be significantly modified to reliably achieve the next tranche of renewable deployment. This assessment aimed to find those inflection points for the MISO region and examined potential solutions to overcome them.

A technical impact assessment does not directly recommend any changes to the existing electrical power system or necessitate the construction of any new resources. Instead, the assessment purely provides information to shape ongoing discussions.

This results in this section are broken into three distinct focus areas: (i)Resource Adequacy; (ii)Energy Adequacy, where the results are categorized based on the planning as well as the markets and operations analyses separately; (iii) Operating Reliability, where the results are organized based on steady-state and dynamic stability analyses.

Understanding Renewable Complexity

RIIA is centered around the idea of integration complexity, so it is important to understand its causes and measurements.

"Renewable energy penetration" is defined as the annual renewable energy delivered compared to the load, consistent with the ways renewable portfolio standards are defined. Penetration levels were set by the study team for the entire Eastern Interconnection, and resources were spread within each market and ISO region (including MISO) within the EI. The mix and siting of resources in each region depended on generator interconnection activity, electrical system capacity, and resource quality.

Renewable complexity is measured as the incremental work needed to reach the next renewable penetration milestone. It is quantified by cost for the purposes of charting but, conceptually, includes risk and other supporting activities, as discussed in Defining and Measuring Complexity, needed to achieve those renewable levels (Figure UC-1).

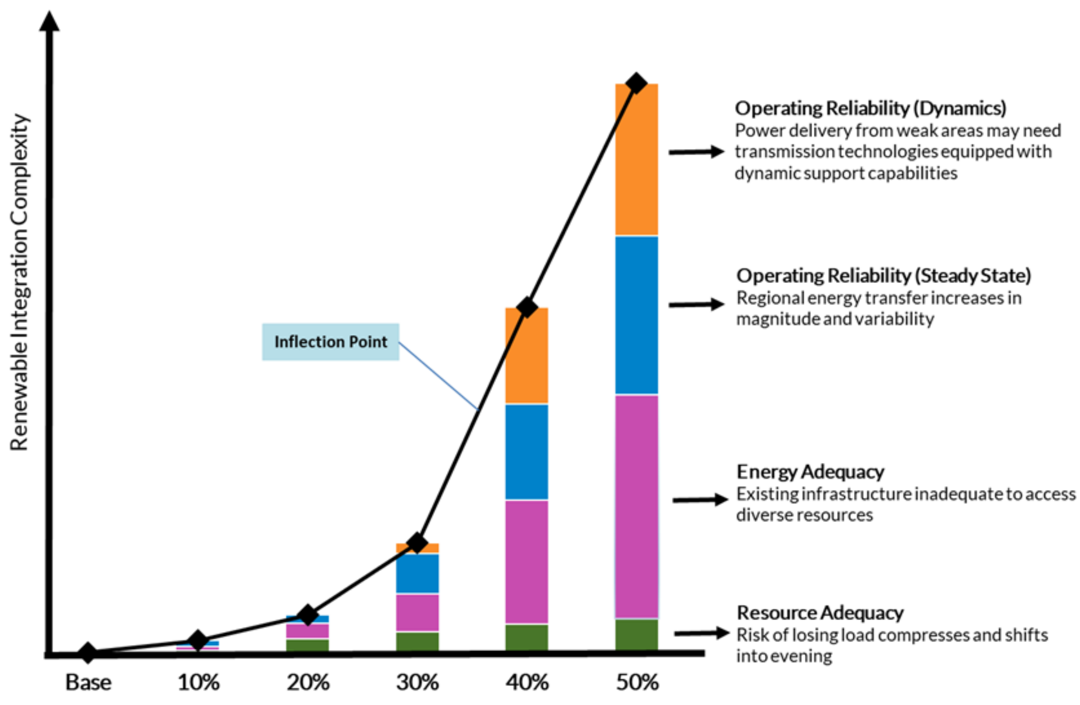


Figure UC-1: Inflection point of renewable integration complexity identified by RIIA

The Arc of Renewable Complexity Causality

RIIA found when the percentage of annual load served by renewable resources is less than 30% system-wide, the integration of wind and solar faces challenges but appears manageable with significant changes to transmission expansion, operating, market, and planning practices within the existing framework. This is despite the fact some local areas with high concentrations of renewables are experiencing some of these challenges today. Above the 30% level, significant system-wide complications arise, driven by the increased variability of wind and solar, changes in resource availability, and an overall lack of transmission capacity provided by the existing EI transmission system. RIIA finds changes to the framework the system operates under and coordinated action to address new and shifting risks can enable the grid to be operated reliably with 50% of the energy served by wind and solar resources.

RIIA presents results in two ways: annual energy penetration levels and instantaneous penetration levels. For example, the 40% milestone represents the proportion of MISO load served annually by renewable energy resources. Any percentage paired with "milestone" should be interpreted in this way. In some parts of the work, analysis examines the so-called "instantaneous" penetration, which represents the portion of MISO load served by renewable resources at a particular moment in time. The instantaneous penetration at a specific day and hour of a milestone may be much higher than overall annual energy penetration. The calculated penetrations in this study are done on a regional basis for MISO or the EI, as appropriate. As the penetration of wind and solar renewable resources grows, the type and magnitude of integration complexity changes (Figure UC-1). Causes of complexity for percentage each level of renewable growth varies.

0-10%: Local visibility and control issues (historical)

Modern power systems were designed to deal with the variability and uncertainty of system demand, the transmission network (such as N-1), and supply (for example, generator outages, failure to follow instructions, lack of fuel). As wind and solar resources began to participate in the power system, their unique characteristics (variable availability and inverter-based control) fit within the system's overall complexity. Wind and solar resources, like all resources, are individual machines. They are located at specific interconnection points and, when system penetration is low, have the most significant impact locally. As wind and solar grew, they caused local issues such as line overloads, especially if the machines were not within MISO's control. Early action was taken in the form of the Dispatchable Intermittent Resource (DIR) product, which allows the grid operator to have visibility and control over the resource to manage reliability risk. Another aspect of visibility is understanding the resources' availability in the near future to efficiently and reliably schedule other resources. Wind and solar forecasting were implemented to address this risk. As wind and solar reach 10% of the annual load served by MISO, MISO has successfully managed these pockets of risk.

10-20%: Subregional net load ramping issues, local generation pocket, and stability issues

As the penetration of wind and solar approaches 20%, large pockets of wind in some subregions and large pockets of solar in other areas start to appear. This phenomenon is driven by the non-uniform resource quality throughout the footprint and by utilities, customers, and regulators' preferences.

The local nature of renewable deployment causes outlet issues with the local and subregional transmission system. Transmission issues, seen through the lens of local transmission reliability and congestion, intensify but can be managed through continued incremental upgrades to the system since local cause-and-effect can be easily identified. Local inverter induced stability issues begin to arise due to controller interactions, but they can be corrected through proactive retuning of controller software.

High solar availability during midday hours and waning availability during evening hours, coupled with high evening load levels on hot summer days, creates a new risk period for the region. Consequently, the value of solar as a capacity resource falls. The adequacy of the resource fleet is one of the most acute problems that needs to be solved as the penetration of renewable energy approaches 20% of the regional load.

20-30%: Subregional issues due to very high subregional instantaneous penetrations

As the penetration exceeds 20% towards 30%, the trend of large local pockets continues. However, in this penetration range, more pockets form close to one another and create large subregional pockets, and issues start to propagate regionally. In these subregional pockets, the instantaneous penetration (i.e., the generation of wind and solar versus the subregional load) becomes very high in some hours. This makes it challenging to balance the subregional variability of the resources with other resources in the area.

Transmission was not traditionally designed to enable regional balancing and thus is limited in its ability to support these very high penetrations. Local generation flexibility needs greatly increase, along with the stress on the high voltage transmission system to allow regional transfer and balancing. Additionally, local stability issues become more prevalent as the amounts of inverter-based wind and solar resources reach a very high level in specific areas of the footprint. This introduces concerns about plant controller interaction stability and weak-grid voltage stability concerns, as the inverters cannot get a strong voltage reference to follow. Inverter-based resources need a strong voltage reference to determine the amount of power to inject into the system.

The largest risk introduced in this period of renewable growth is the magnitude of steady-state reliability risk, i.e. the risk that system voltage levels and thermal line flows will be outside their limits due to changes in renewable generation. Many of the solutions needed to address these risks are concentrated in a few subregions, but system-wide issues become present at times, with the region experiencing instantaneous penetration levels above 60%.

30-40%: Regional issues and high regional penetrations

Between 30% and 40%, the system experiences a fundamental shift. Region-wide renewable generation availability surpasses 100% of load for a few hours of the year. Large amounts of energy are curtailed during periods of low load and high renewable generation in order to keep long-lead time conventional units online for when renewable generation decreases again. Substantial regional pockets form where the average renewable generation output approaches 100% of the subregional load. This creates a situation where large amounts of energy are frequently produced over and beyond what can be consumed within the subregion, forcing more than occasional curtailment and necessitating frequent interregional transfer of energy. The existing infrastructure becomes inadequate to utilize this energy and large amounts of additional infrastructure are needed to access the diverse resource distribution across the MISO footprint. These regional pockets need to import and export at different times, as renewable generation varies across the hours, days, and months of the year. Regional energy transfers increase in magnitude and become more variable and the system must be planned and operated to accommodate it.

Large swings in renewable output mean the system's flexibility requirements also change in magnitude and type. The traditional generation ramping pattern to serve load, up in the morning and down in the evening, changes sharply to a bi-directional ramping pattern throughout the day. This change occurs as the availability of renewable resources sometimes moves in the direction of load change and sometimes counter to it. The flexibility that traditional generation units provide, if dispatched, will need to increase in magnitude and direction. Coupled with this, renewable resources will also need to contribute to system flexibility by dispatching less than their maximum available output during periods of high system change

This period of renewable growth presents a new risk related to system stability. Large regional pockets of inverter-based generation need strong reinforcement to maintain system stability, due to these resources' inability to maintain a stable voltage when concentrated in large numbers. Traditional transmission solutions, such as synchronous condensers and Flexible AC Transmission System (FACTS) devices, help stabilize the local system;

however, the large magnitude of the need for these solutions causes additional challenges. Two viable solutions are presented: high-voltage direct current (HVDC) lines to isolate a portion of the new renewable resources and connect them to a stronger part of the system; and the commercialization of advanced technology such as grid-forming inverters.

If the system were to lose a large generating resource, it needs to instantaneously make up the deficiency from other resources to stabilize the system frequency. During periods of high instantaneous renewable penetration, the amount of resources that can provide this form of power is limited. Although renewable resources can provide such a response when they have been curtailed, additional headroom needs to be planned and reserved from system resources during periods of high renewable generation and low curtailment. Solutions include operational or market practices to reserve needed headroom in real-time or installing stand-alone resources like battery storage to respond when needed. A relatively small amount of high-speed storage can also effectively provide this response for the entire system without other system changes.

40-50%: Regional issues intensify

As the annual share of renewable energy reaches 50%, frequent periods occur where nearly all load is served by wind and solar resources. During these periods, the need to actively co-manage renewable and load variability becomes paramount. The system now has predominantly power electronic rather than rotating machines, which has implications for system stability. Additionally, the system now experiences common long-distance power transfer patterns, as economic dispatch tries to maximize the use of low-cost generation to serve regional load. These changes lead to very different reliability risks than are experienced today.

The risk of not having enough available resources to serve load becomes highly concentrated into periods of low renewable availability and relatively high load. These periods are late evenings during hot summer months with high air conditioning demand and early mornings during cold winter months with high heating demand. Additional resources are needed to make up for wind and solar unavailability during these periods, leading to a lowering capacity value for wind and solar resources.

This period of renewable growth is not characterized by new risks on the system but rather by the continued intensifying of issues that emerged in prior periods of renewable growth. Effectively and efficiently addressing these risks becomes increasingly important.

Defining and Measuring Complexity

System integration complexity in the general sense is the work needed to plan for and operate new resources as they connect to the grid. All resources cause a change in system complexity, but the type and volume of change manifest differently depending on the new resource's unique attributes. This assessment sought to measure system integration complexity to achieve a holistic understanding of how renewable wind and solar resource integration would affect the power system. For this assessment's purpose, complexity needed to be quantitatively measured to understand its relative magnitude when comparing across various drivers. Although complexity is generally meant to be a broad measurement of system integration considerations, a specific process was implemented for this assessment. The following section lays out the definition of complexity as used for charting and comparison purposes.

Resource Adequacy (RA) complexity is defined as the capacity necessary to maintain a "1 day in ten years" loss of load expectation target. It uses the Cost of New Entry (CONE) as a proxy for RA complexity.

Energy Adequacy (EA) complexity is defined as the transmission needed to maintain and deliver renewable energy during every hour of the year. The modeling framework accounts for existing generation, transmission, and other system constraints. Thus, the ability of a generator to respond to the load is limited by existing constraints, and new transmission cost acts as a proxy to measure the additional flexibility needed to unlock diverse resources.

Operating Reliability - Steady State (OR-SS) complexity is defined as the transmission needed to maintain acceptable voltage and thermal performance across the system under contingencies

Operating Reliability - Dynamic Stability (OR-DS) complexity is defined as the incremental transmission needed to maintain stable voltage performance across the system under contingencies. Traditional solutions of AC transmission and FACTS devices (STATCOMS, SVCs, etc.) were included, along with new types of solutions as needed to solve new risks, such as HVDC with voltage source converters (VSC).

Operating Reliability - Frequency Stability (OR-FS) complexity is defined as the cost of 30-minute, high-speed batteries built to provide headroom.

This assessment sought to limit implicit assumptions of solutions, but, in some cases, it was unavoidable. The expansion of renewable wind and solar resources, along with existing operating and planning practices, includes resource diversity that acts as a solution. Diversity of geography ameliorates variability due to different weather and time zone patterns. Diversity of technology changes the time and location of when energy is produced. For example, solar with fixed panels can have higher output during certain times of the day compared to solar with tracking, but tracking produces more energy in the morning and evenings. Wind turbines with taller hub heights can access different layers of the troposphere, enabling increased production. As the sun rises, eastern solar helps support western load and, as the sun sets, western solar helps support eastern load.

Not all complexity was measured as it became difficult to quantify the risk and the cost of the solution. Examples of complexity that were excluded:

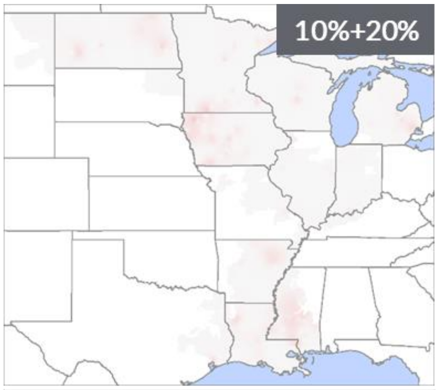
1) The costs to provide additional ramping
2) Software and operating practice changes needed to reliably and efficiently operate the system
3) New market product development, implementation, and market costs
4) The cost of preserving, or constructing new resources to allow for resource adequacy, even if the resource is never used. Only the incremental cost of the degrading capacity value of wind and solar was included.

Solutions

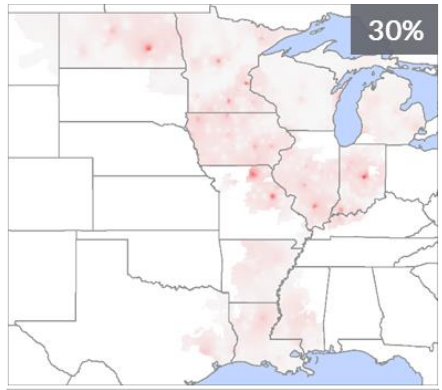
This section summarizes the RIIA data as to describe the type, location, and relative cost of solutions. This assessment is not meant to move forward particular solutions, and thus they are not presented in detail. The assessment focuses on the types and magnitude of risk that growing renewable energy presents and the types and magnitude of solutions to best integrate these resources.

The Technical Summary is organized to show the key findings of the solutions with the additional equipment the analysis had to implement to achieve resource adequacy, energy adequacy, steady state, and dynamic stability criteria. The results of the simulations are presented in the following subsections with the details on why each additional technology was considered to mitigate the challenges identified by the assessment. This section is organized to show the key findings of the solutions with the additional equipment the study had to implement to achieve analysis criteria.

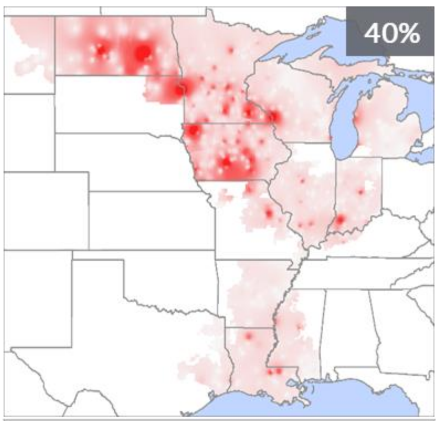
Key Findings



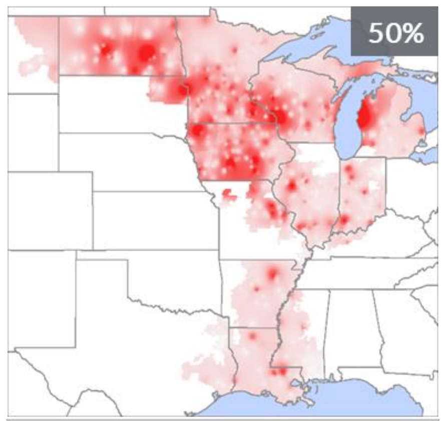
	161 & below	230	345 & above
Ckt*miles	1500	300	400



161 & below	230	345 & above	HVDC
1700	300	600	400



161 & below	230	345 & above	HVDC
1600	900	3800	1600



161 & below	230	345 & above	HVDC
500	800	5200	700

Figure UC-2: Cumulative complexity for all system needs at renewable penetration milestones

Figure UC-2 maps and tables show the cumulative and incremental mitigation at each renewable penetration milestone. Up to 30% penetration, the mitigations are deployed evenly across the footprint, with a few local concentrations. At the 20% and 30% milestones, the hotspots mainly occurred next to renewable generation sites, noticeable in the wind-rich regions of Iowa and North Dakota. However, as the renewable penetration level increases, the solutions are deployed over larger regional areas, including next to load centers. At the 40% penetration level and higher, in addition to energy adequacy solutions, systemic stability issues are observed and addressed by devices supporting dynamic stability of the region, such as HVDC and switched shunt equipment.

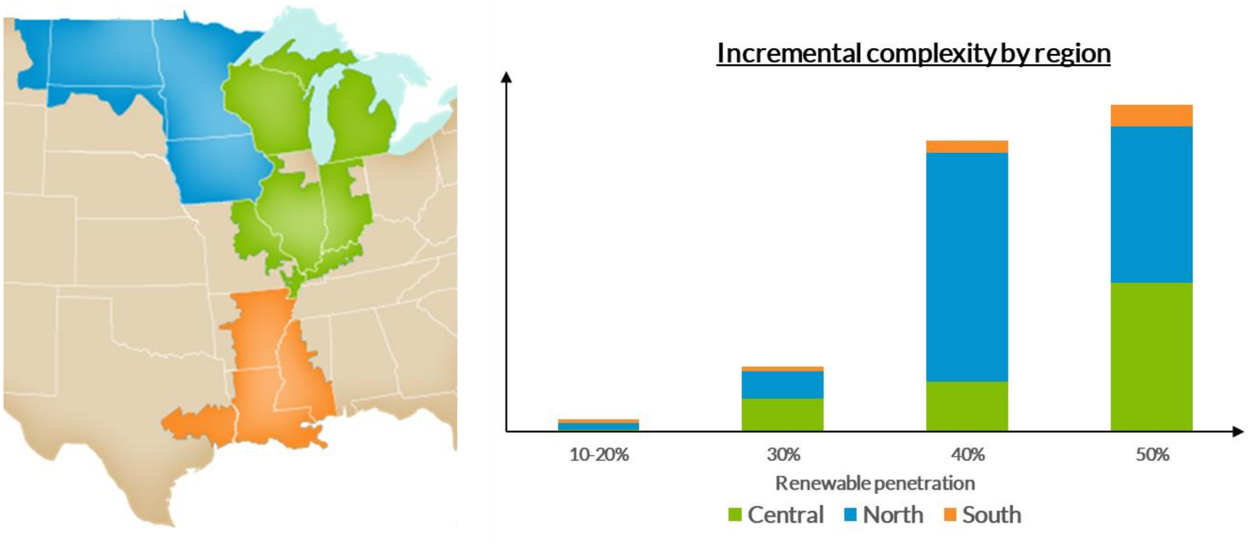


Figure UC-3: Regional distribution of incremental complexity at renewable milestones

Figure UC-3 shows the incremental complexity of all installed technology in the North, Central, and South MISO subregions. At 10% and 20% milestones, the integration complexity is even distributed across the regions. Between 30% and 40%, there is a significant increase in complexity in the North region, driven by an even combination of energy adequacy, steady state, and dynamic stability needs. At 50%, the incremental complexity is more evenly distributed between the North and Central regions. However, the largest percentage increase shifts to the Central region, driven primarily by energy adequacy and dynamic stability issues.

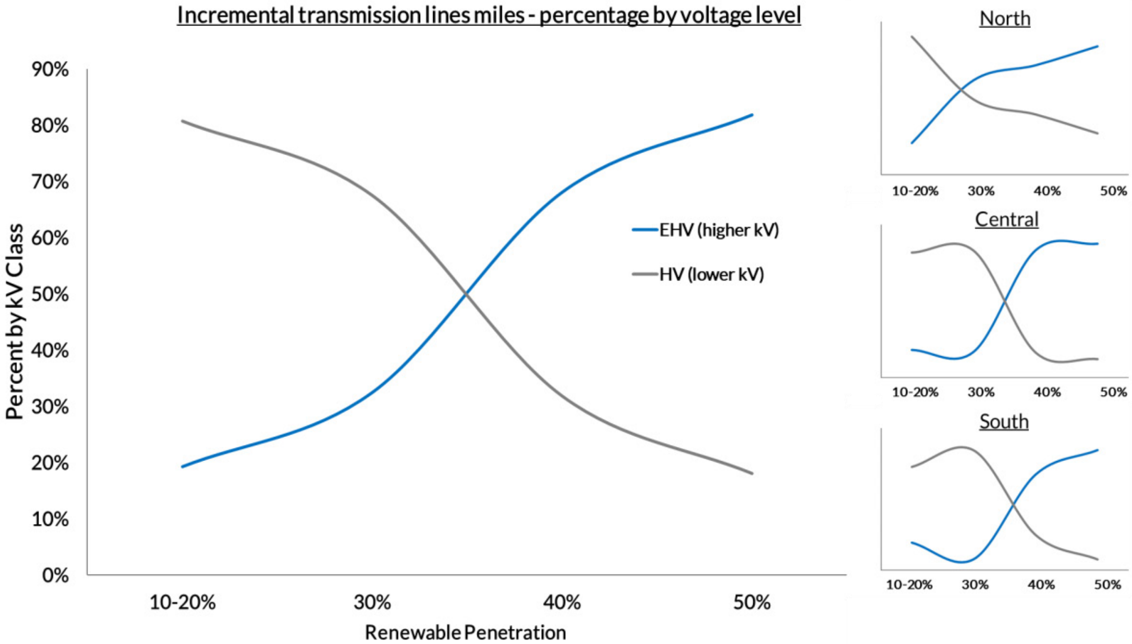


Figure UC-4: Ratio of incremental High Voltage (230 kV and below) and Extra High Voltage (345 kV and above) transmission at each renewable penetration level

Figure UC-4 focuses on the regional installation of high voltage AC (HVAC) transmission lines measured in the number of circuit miles either upgraded or built.

At the MISO system level, between 30% and 40%, there is a shift towards higher voltage, longer, higher capacity transmission lines. At this inflection point, the percentage of incremental Extra High Voltage (EHV) transmission exceeds that of High Voltage (HV) transmission (Figure UCRS-3). However, in the North region, this shift is observed at a lower system-wide penetration level, in part due to the North region reaching higher local penetrations earlier than the rest of the footprint. For example, at the MISO-wide 30% penetration level, parts of the North region see penetration levels ranging from 40% to over 100% local penetration.

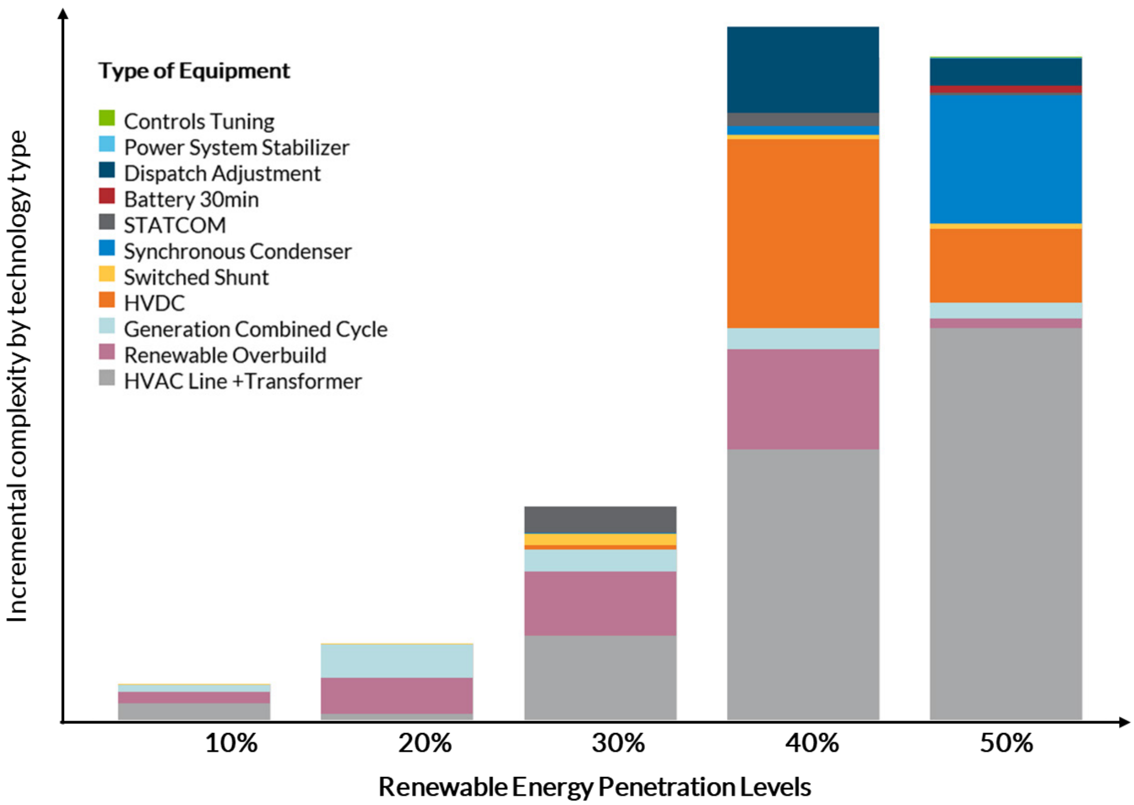


Figure UC-5: Incremental complexity by technology for each renewable penetration milestone

Figure UC-5 shows the technology breakdown of the incremental solutions modeled to achieve reliable operations at each renewable energy milestone level. The exponential growth of the solution complexity can be seen as MISO transitions from the 10% renewable milestone to 50%. Although high voltage transmission lines constitute the largest share of the overall growth of complexity, the diversity of technologies needed increases dramatically with penetration level.

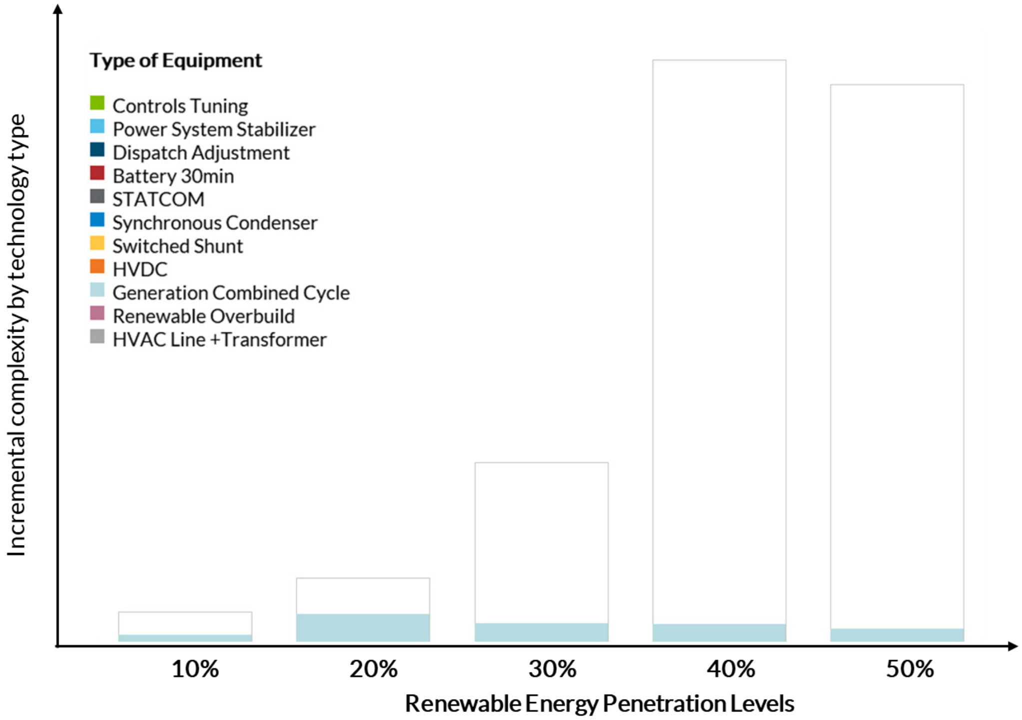
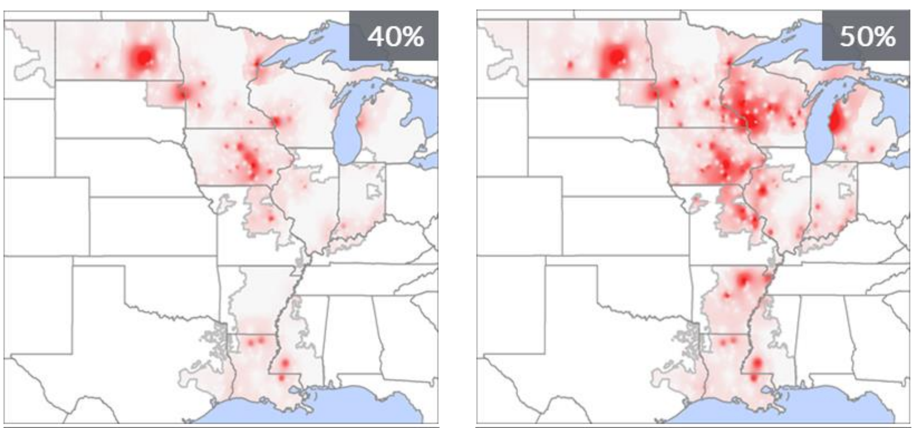


Figure UC-6: Resource adequacy solutions - incremental complexity by technology for each renewable penetration milestone

Figure UC-6 shows the solution complexity of meeting Resource Adequacy assessments. The motivation of assessing Resource Adequacy in RIIA is to understand how the risk of not serving load changes and how the capacity contribution of wind and solar to system adequacy evolves with higher penetration of renewables. Additional generation capacity was added to counteract the declining capacity value of wind and solar resources as their penetration increases.



161 & below	230	345 & above	HVDC
300	100	2000	400

161 & below	230	345 & above	HVDC
-	-	3400	700

Figure UC-7: EA solutions - cumulative complexity at renewable penetration milestones

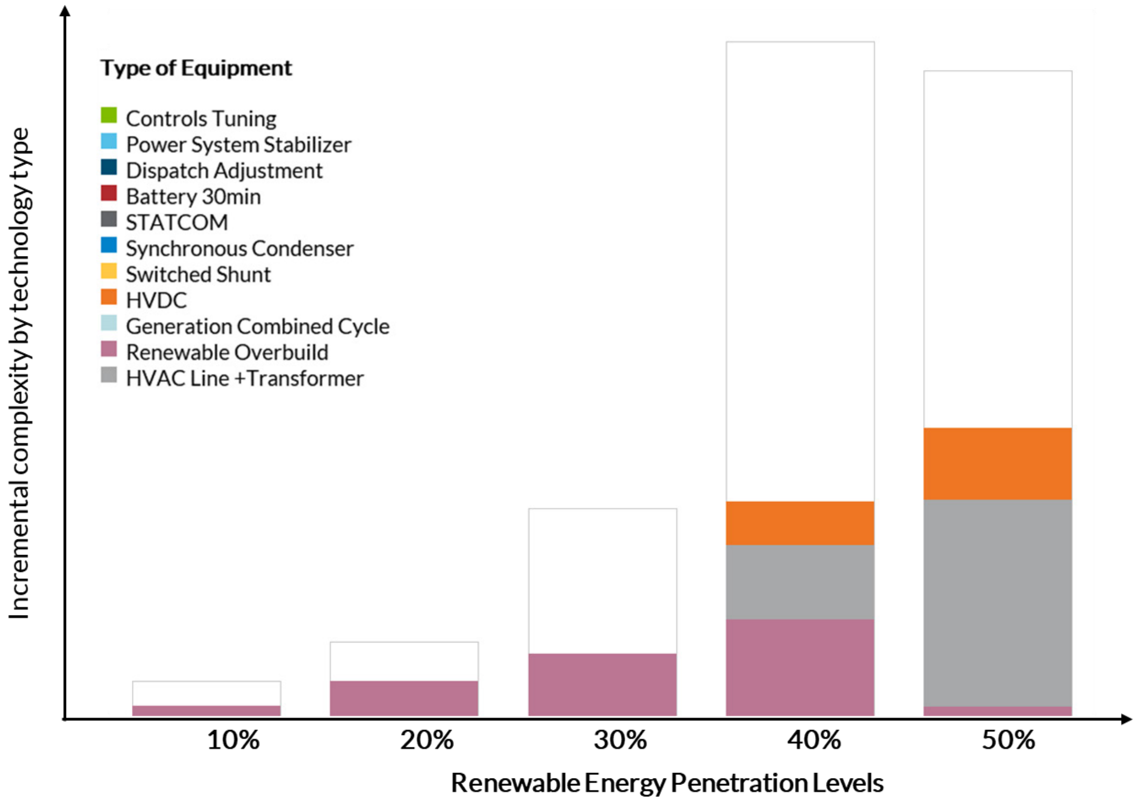
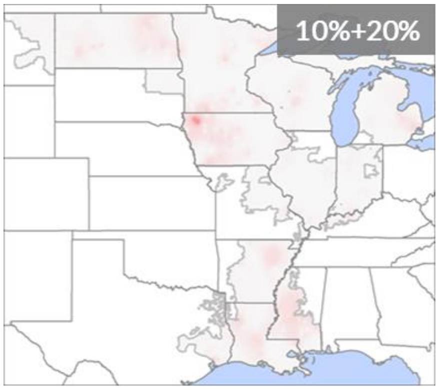
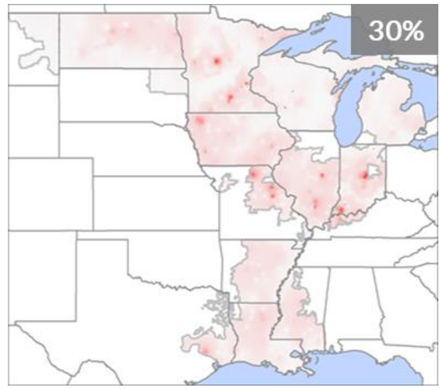


Figure UC-8: Energy adequacy solutions - incremental complexity by technology for each renewable penetration milestone

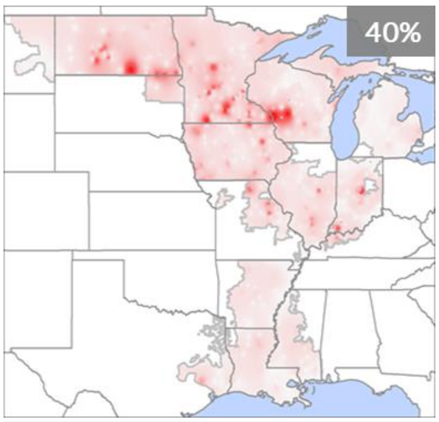
Figure UC-7 presents the Energy Adequacy (EA) assessment solutions. Before the 40% milestone, no transmission solutions were needed for Energy Adequacy; the energy targets were met in part by an over-build of wind and solar capacity. However, past the 30% level, the penetration targets could not be met without additional transmission expansion. As renewable energy reaches 40% of annual energy, the transmission system requires upgrades to further facilitate the integration of renewables and access the benefits of diversity in renewables and load. To balance generation and load over a larger area, longer, higher capacity transmission lines, such as EHV AC and HVDC, may be required. Figure UC-8 shows the complexity of solutions implemented to meet Energy Adequacy assessments.



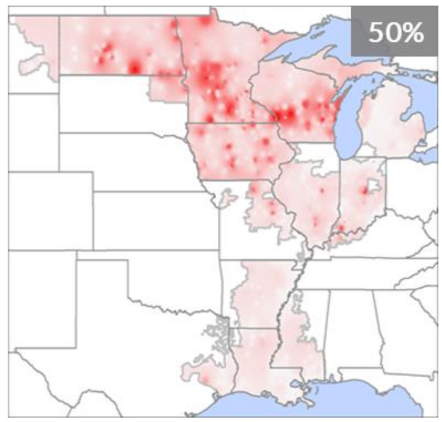
	161 & below	230	345 & above
Ckt*miles	1500	300	400



161 & below	230	345 & above	HVDC
1700	300	600	-



161 & below	230	345 & above	HVDC
1400	800	1400	-



161 & below	230	345 & above	HVDC
500	800	1700	-

# of equipment per milestone	10%	20%	30%	40%	50%	Total
Switched Shunts	6	10	169	119	155	459
Transformers	15	24	87	46	95	227

Figure UC-9: Steady state - cumulative complexity at renewable penetration milestones

Figure UC-9 shows the mitigations needed for steady-state operational reliability. The high mitigation areas were evenly distributed up to 20% penetration; however, starting at the 30% milestone, hotspots appear in the North and Central regions. At 40%, the majority of incremental steady-state solutions are deployed in the North region. Finally, at 50%, the complexity of steady-state solutions is evenly distributed between the North and Central regions. As renewable penetration increases, there is a greater need for higher voltage transmission solutions.

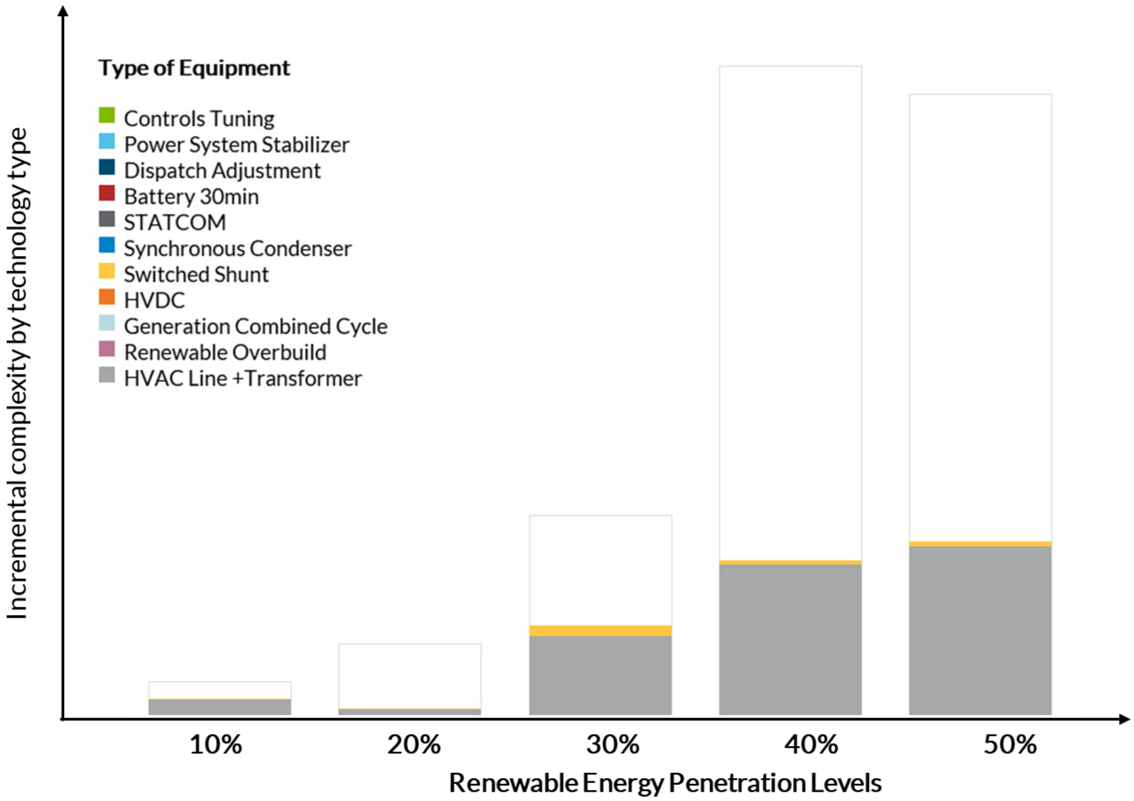
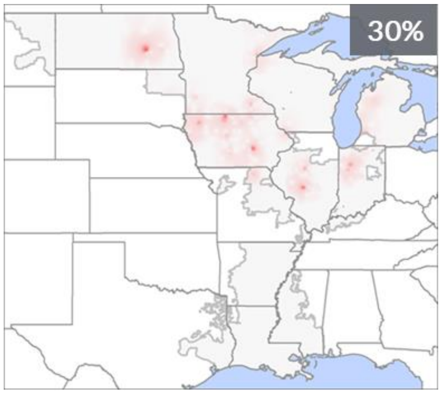


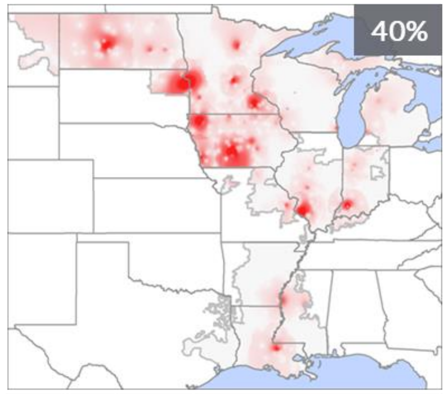
Figure UC-10: Steady state solutions - incremental complexity by technology for each renewable penetration milestone

Figure UC-10 shows the estimated solution complexity to address steady state issues by technology. Past 20% penetration level, the complexity of additional transmission lines grows rapidly. Although several switched shunts are used, they account for a small portion of the total complexity because of their low-cost relative to transmission lines.

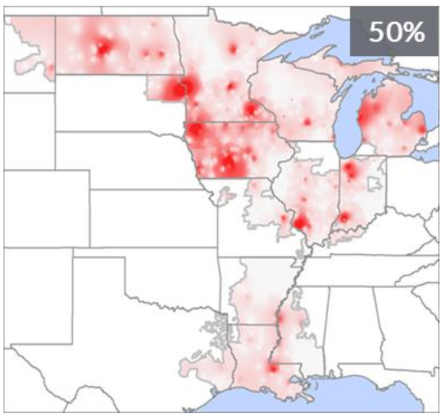
These solutions increased renewable energy delivery and mitigated thermal overloads on the bulk electric system, 100 kV and above. However, since RIIA used a bottom-up planning approach to upgrade the existing facilities for operating reliability, there is an opportunity to optimize transmission planning to reduce the complexity and potential cost of integration.



161 & below	230	345 & above	HVDC
-	-	-	400



161 & below	230	345 & above	HVDC
-	-	400	1200



161 & below	230	345 & above	HVDC
-	-	-	-

# of equipment per milestone	MISO Only				MISO + Eastern Interconnect			
	30%	40%	50%	Sub-total	30%	40%	50%	Total
Batteries (30min)	-	-	118	118	-	-	1,233	1,233
Controls Tuning	-	-	319	319	-	-	1,787	1,787
Dispatch Adjustment	-	60	17	77	-	169	60	229
HVDC	1	4	-	5	1	4	-	5
Power System Stabilizer	-	-	4	4	-	-	109	109
STATCOMs	25	8	5	38	47	31	23	101
Switched Shunts	-	-	-	-	-	-	1	1
Synchronous Condenser	2	10	163	175	5	14	248	267

Figure UC-11: Dynamic stability solutions heatmap of thermal mitigation at renewable milestones and installed units of technology

Figure UC-11 and Figure UC-12 show the complexity to address Dynamic Stability issues. Achieving stability becomes a significant challenge beyond the 30% milestone as the amount and location of renewable generation stresses the system. Various technologies, including HVDC, synchronous condensers, STATCOMs, and batteries, were implemented to provide appropriate support, which changed as the generation profile changed at different milestones. A more significant number of HVDC lines had to be distributed in regions where wind generation increased while transmission capacity was limited. Synchronous condensers and STATCOMs were required for voltage stability, especially by the 50% milestone, because of displacement of conventional units and the grid following technology that the current renewable resources exhibit. To reach the 50% milestone, batteries were used to sustain the grid's frequency response performance. New power system stabilizers were used to address small signal stability challenges due to the displacement of thermal plants, which currently host the technology, by wind and solar plants.

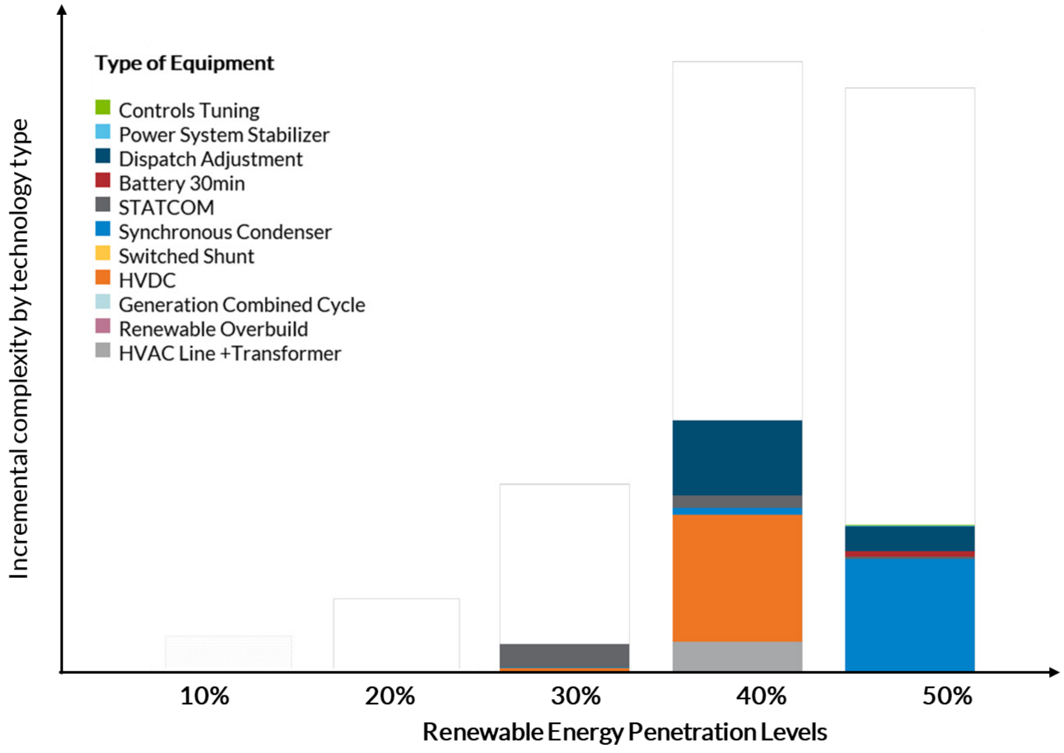


Figure UC-12: Dynamic stability solutions - incremental complexity by technology for each renewable penetration milestone

Resource Adequacy

Overview

The objective of modern resource adequacy assessments is to ensure that there is sufficient installed generation capacity to meet electric load, measured against a prescribed target. As the resource mix rapidly changes towards wind and solar, it is becoming increasingly important to evaluate the reliability of a system with a high penetration of variable, weather-dependent resources. Even as these resources play a critical role in serving load, their stochastic and 'fuel-limited' nature may result in changes to the reliability risk profile and a shift in the probability of loss of load to periods that are outside of the traditional risk periods. The motivation of assessing Resource Adequacy in RIIA is to understand how the risk of not serving load changes and how the capacity contribution of wind and solar to system adequacy evolves with higher penetration of renewables.

RIIA studied the implications of a changing mix on resource adequacy under both wind-heavy and a more balanced wind/solar generation mix. MISO targets having enough resources available so that there is only a one-day-in-10-year probability of having a loss-of-load event. The key resource adequacy questions being addressed in RIIA include:

- What is the capacity contribution of wind and solar to system adequacy as renewable penetration levels increase?
- How does resource mix, storage, and technology and geographic diversity impact the capacity contribution of wind and solar?

The analysis found that the probability of loss of load could potentially shift both diurnally and seasonally. As the penetration of solar increases, loss of load events may also be observed in the winter. Although peak demand remains important, the analysis shows that changes to net-load peak (load minus renewables) becomes a key indicator of capacity insufficiency. As the net-load peak shifts, driven by an increasing amount of installed renewable capacity, the value of the capacity, measured by the average Effective Load Carrying Capability metric, declines. However, the findings show that to a point, geographical and technological diversity and storage improves the ability of renewables to meet the load at every hour.

In summary, RIIA Resource Adequacy analysis shows that:

- The risk of not serving load shifts to later into the evening and is observed for shorter durations with higher magnitude
- Sensitivity analyses show risk shifting to winter and later evening, depending on technology and geographic mix
- Storage, the diversity of technologies, and geographic diversity improve the ability of renewables to serve load

Key Findings

Finding: The risk of not serving load shifts to later into the evening and is observed for shorter durations with higher magnitude

As renewables serve the load during the traditional gross peak hour, the net-load peak becomes more critical. The hours of risk of losing load shift to non-traditional hours: later in the summer evenings and to cold winter mornings.

As renewable penetration increases, the risk of losing load shifts to later in the evening and compresses into a smaller number of hours (Figure RA-1). While the aggregate risk of not meeting load remains constant, the risk in specific hours increases; the expected demand not served becomes a short-duration event of higher magnitude. Although higher levels of renewables result in a more acute risk, resource adequacy is still maintained across milestones. There are several options to mitigate the shifting risk. Pairing solar with batteries is one option. Load modifying resources, a larger footprint, allowing renewables to reserve capacity, and a continental-wide macro-grid are other options.

Renewable availability during gross and net-load times is not a good indicator of capacity value. Deterministic approaches can provide insights on how capacity values evolve directionally, but it omits the probabilistic nature of generator's availability (both from a weather and mechanical aspects). A loss of load probability analysis with hourly renewable data is required to account for thermal performance, load forecast uncertainties, planned maintenance, and other system components (LMRs, storage).

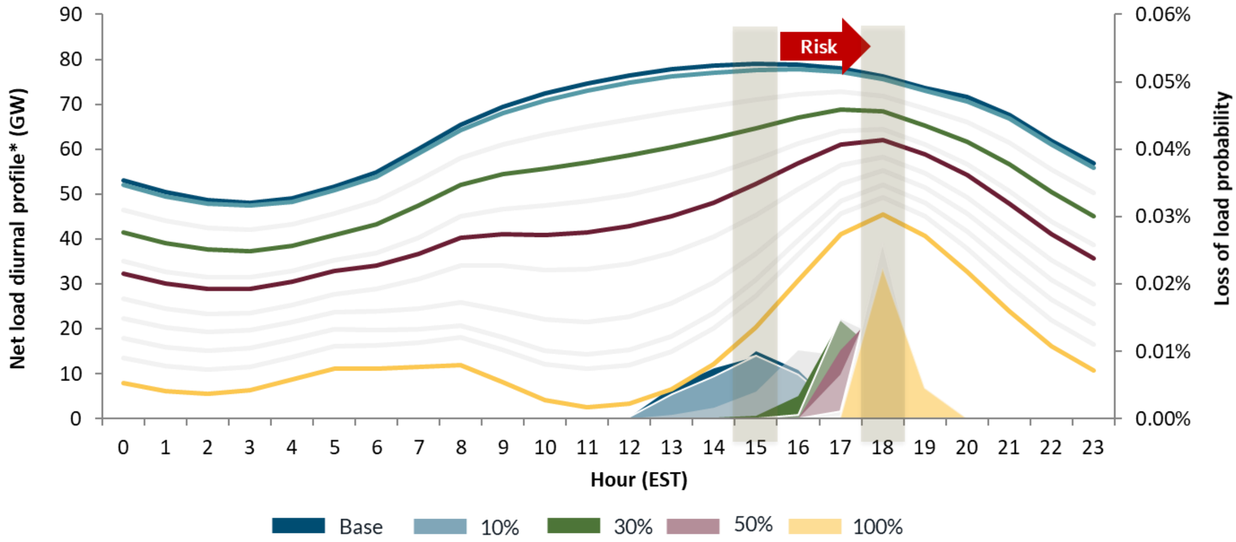


Figure RA-1: Shift in LOLP risk profile

In RIIA, the MISO system was planned to maintain the same reliability level, a Loss of Load Expectation of 1 day in 10 years. Therefore, the total magnitude of the risk is held constant, the profile of the probability of load exceeding generation changes as renewable penetration increases.

When considering Loss of Load Probability (LOLP), at 10% renewable penetration, the risky hours are from 12 p.m. to 5 p.m. and highest at the traditional load peak of 3 p.m. (Figure RA-2). At 50%, the probability of not serving load shifts to between 3 p.m. to 7 p.m. And by the 100% penetration level, the window of risk shrinks even further to 4 p.m. to 7 p.m. The shifts in the risk profile are directly tied to the changing net-load shape. Peak net-load represents the maximum remaining load to be met after unmodified wind and solar resources have served all the load they can.

Higher LOLP with shorter duration is not necessarily worse than a smaller LOLP with longer duration. Higher LOLP translates into more predictability. Understanding the diurnal and seasonal pattern of this new risk profile provides additional certainty in system operations.

Resource Adequacy centers around the system's generation resources' ability to meet load at the most critical hours. These hours of highest risk of load not being served are the hours when generation resources are least available to meet that load. Historically, these have been periods of the highest system load, generally in the afternoon on a hot summer day. This assessment has found that as renewables serve the load during the traditional peak, the net-load peak hours become the more critical periods, even if these periods do not have the highest absolute load. The diurnal shape of the net load changes with the increase in renewable penetration. This change is driven by the increasing magnitude of the wind and solar crests and troughs (Figure RA-4).

The assessment finds that as renewables serve load during the middle of the day, the net-load peak moves from the traditional peak-load hour of 3 p.m. to several hours later in the evening, depending on the amount of solar capacity on the system. The new risk coincides with the periods when the load is still relatively high, the sun is setting, and the wind is still ramping up. At the 10% penetration level, the net peak hour is 3 p.m. By the 30% penetration level, it has moved 2 hours later to 5 p.m. It then shifts to 6 p.m. at the 50% penetration level and holds at that time, even at the 100% penetration level.

In addition to LOLP, several other reliability risk metrics (RRMs) are used in probabilistic studies to assess resource adequacy[1]. Expected Unserved Energy (EUE) is a measure of the expected amount of demand (MWh) that will not be served when the available capacity is less than demand. EUE confirms the findings from looking at net-load and LOLE. It is a summation over all hours in a given period, accounting for both magnitude and duration of load not served. Figure RA-2 shows that as more renewables are added, the periods in which there is a risk of not serving load: 1) shrinks to a narrower window, 2) moves to later in the evening, and 3) and is more concentrated. At the 10% milestone, the period of risk runs from 9 am to 10 p.m. and is concentrated around 3-4 p.m. As renewable penetration increases to 50%, the periods of risk narrows to between 5 p.m. and 8 p.m., with the highest risk of not serving load at 7 p.m. It is worth noting that the shift of the highest risk to between 6 and 7 p.m. occurs by the 30% penetration level.

Figure RA-2: Heatmap of EUE by time period and milestone

As a result of the shift in risk of losing load, the available energy from wind and solar during the new hours of high-risk decreases. The ability of a resource to serve load at the riskiest period can be measured by its Effective Load Carrying Capability (ELCC). The ELCC of a resource measures the additional load that the system can supply with the particular generator of interest, with no net change in reliability. A resource that can provide a larger percentage of its capacity to serve load during periods of high risk will have higher ELCC than a resource that is unable to. As the

[1] NERC Probabilistic Adequacy and Measures Technical Reference Report July 2018

net-load peak shifts, the new risky periods align with the times when the energy available from wind and solar is limited. As such, the ability of wind and solar to meet load is similarly limited, resulting in a reduction in the resources' ELCC.

When considered in isolation (solar only), there is an initial steep decline in the ELCC of solar (Figure RA-3.)This initial decline is primarily driven by a corresponding steep increase in the amount of installed solar capacity in MISO, from a low current level of under 500 MW. For both wind and solar, the ELCC continually declines and eventually plateaus as each resource's installed capacity increases. The relatively faster decline in the ELCC of solar, compared to wind, is a function of two factors:

- The lower installed capacity levels of solar as compared to wind on the MISO system
- The higher impact of solar in shifting the net-load peak to later hours of the day

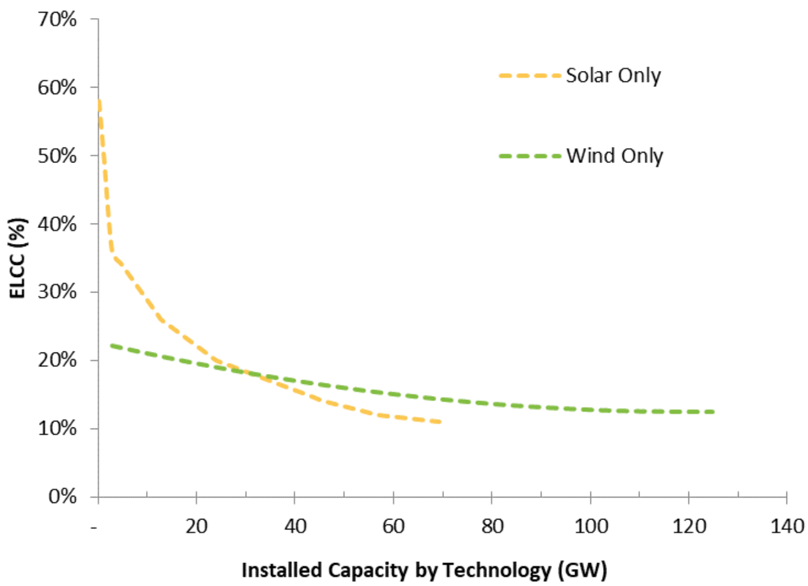


Figure RA-3: Change in ELCC as a function of installed capacity

The new risky periods align with the times when the energy available from wind and solar is more limited. The ability of wind and solar to meet load during these periods therefore results in a reduction in the resources' capacity value.

Changes to net-load shapes are seasonal; however, the highest risk of losing load still occurs during the summer at higher penetration levels. Wind speed is driven by changes in atmospheric conditions, specifically temperature change. This change is highest in the transition from summer to winter (i.e. fall) and winter to summer (i.e. spring), along with the transition from day to night and night to day. Wind resources achieve their highest availability during these transitional periods. In the summer, the morning daylight hours produce the lowest output, and in the winter, the lowest output is afternoon hours. Solar resources produce power in a very different way. For this assessment, photovoltaic (PV) solar plants with various technology configurations were used. Power production is directly related to the PV plant's location with the sun subject to blockages (i.e., clouds, snow, dirt, smoke). Consequently, solar availability is highly concentrated across the footprint in the north-south direction due to the sun rising in the east and setting in the west. Solar production is generally higher in the summer and lowers in the winter; since summer hours are longer than winter hours, solar plants are more available in the day's early and late hours.

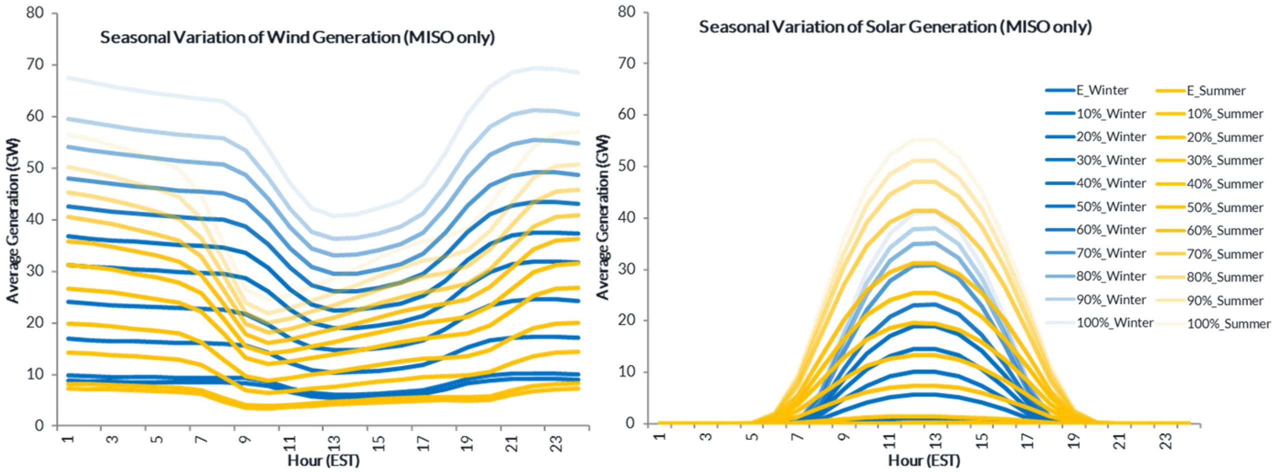


Figure RA-4: Availability of wind and solar by the time of day and season

Finding: Diversity of technologies and geography improves the ability of renewables to meet load

On average, a diverse mix of wind and solar improves renewables' ability to serve load at risky periods.

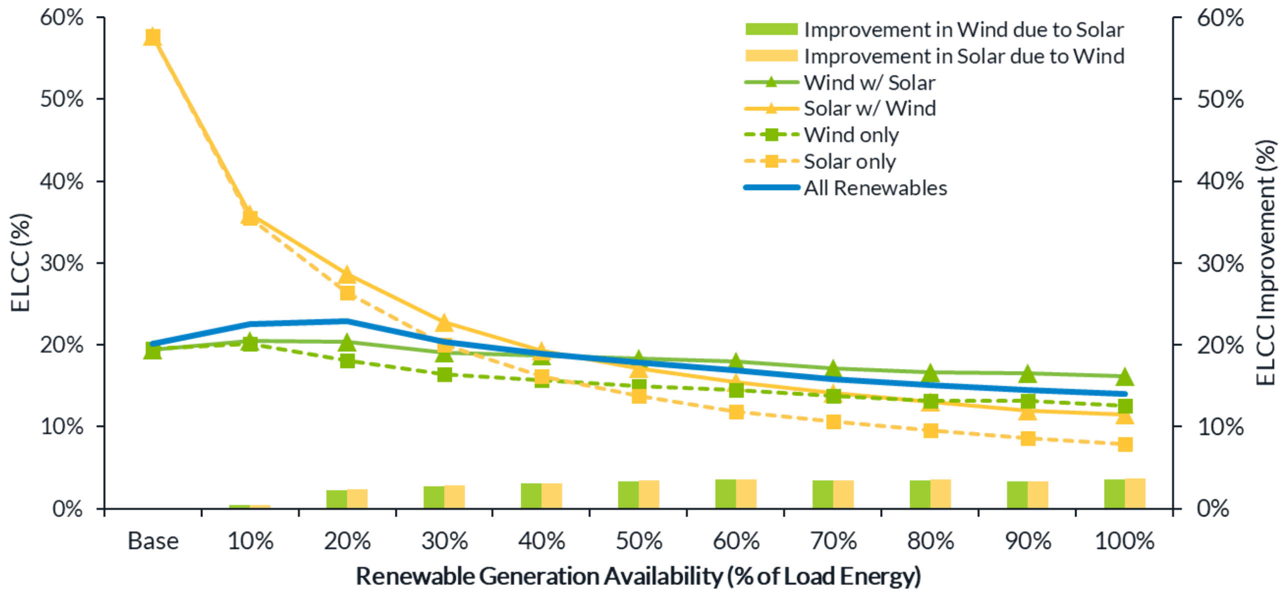


Figure RA-5: Change in ELCC with technology diversity

Technology diversity also enhances the individual ELCC of both wind and solar. Three cases were run to isolate the impact of ELCC of each technology on the other: a wind-only system, a solar-only system, and a system with both wind and solar. The results show that the two technologies have a mutually beneficial relationship (Figure RA-5); on average, the ELCC of wind and solar increases by 2 to 5 percentage points when the other technology is included in the system.

In both a solar-only and solar-wind cases, the ELCC of solar drops with an increase in penetration. However, the presence of wind in the system both increase solar's capacity value slows the rate of this decline. The ELCC of wind is affected similarly; as the penetration level increases, the impact of wind and solar on each other initially increases and then levels off. The combined ELCC of all renewables, therefore, sees an initial rise due to an increase in the geographic and technology diversity; it then gradually declines with higher penetration levels, eventually leveling off. As more resources are added without increasing geographic diversity, the additional shifts in the net-load peak and the risk profile reduce, in turn slowing the decline of the ELCC of renewables. This effect is due to the different availability patterns (Figure RA-4).

Wind and solar have a mutually beneficial relationship; on average, the capacity value of wind and solar increases by 2 to 5 percentage points when the other technology is included in the system.

Finding: The combination of wind and solar decreases the probability of not serving load during periods of high risk.

Further analysis of the shifting risk profile shows that wind and solar have opposing effects on the shift in net-load peak and, therefore, on the risk profile (Figure RA-6). Since solar peaks during the middle of the day, and demand is higher in the evening than the morning, these resources tend to shift the net-load peak to later hours of days. As more solar is installed and, therefore, more solar energy is available later in the day, an increase in solar shifts the risky period to the evening hours.

On the other hand, as wind ramps up in the evening and peaks at night, an increase in the wind capacity tends to move the risk profile to the left, earlier in the day. The opposing effect on the net-load peak means that wind and solar each move the net-load to periods in which the other resource can better serve load. As such, this push-pull effect is beneficial to the ELCC of the individual resource types; wind and solar are complementary.

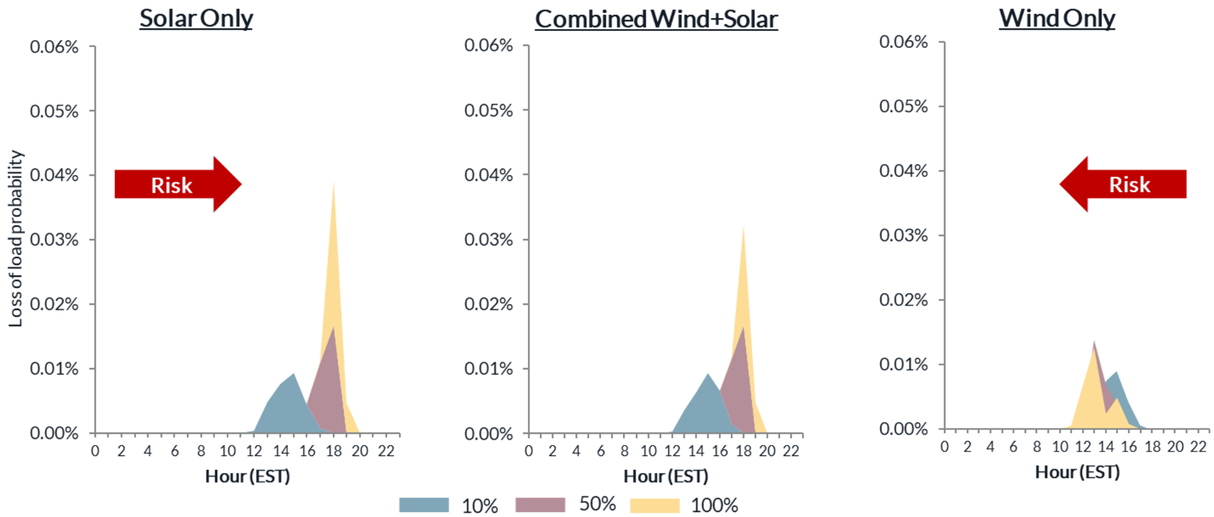
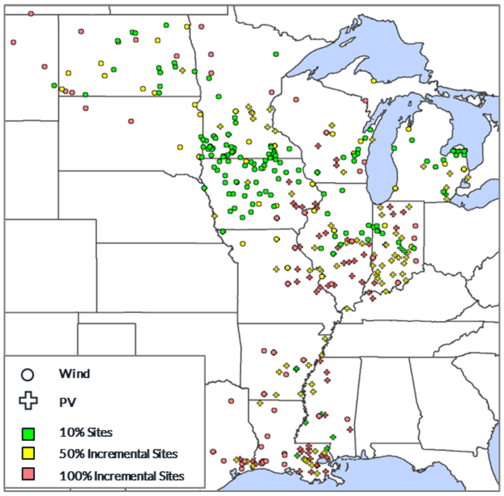


Figure RA-6: Change in LOLP by technology and milestone

Finding: Geographic diversity improves the ability of renewable resources to mitigate the risk of losing load

As resources are spread more throughout the footprint, taking advantage of geographic diversity, renewables as a whole are better able to mitigate the risk of not serving load. Three scenarios were tested to investigate the impact the geographic diversity by siting all capacity needed to meet 100% penetration level at an increasing number of sites, distributed differently across the footprint:

- Siting capacity needed for the 100% penetration level at only the sites used for a 10% penetration
- Siting capacity needed for the 100% penetration sited at the 50% penetration level sites
- Siting the 100% capacity needed at the 100% milestone locations



Sites	ELCC
10% sites scaled to 100% level*	11.1%
50% sites scaled to 100% level*	13.4%
100% sites	14.0%

**Generation at sites selected for 10% and 50% penetration levels was scaled to match the generation needed for the 100% penetration level.*

Figure RA-7: Change in ELCC due to geographic diversity

As more sites were used across the entire footprint, the aggregate energy available from renewable resources can better meet the load. This is a result of different weather and load patterns across the footprint.

As resources are spread more throughout the footprint, taking advantage of geographic diversity, renewables are better able to mitigate the risk of not serving load

The ELCC of renewables, therefore, increases (Figure RA-7). The rise in ELCC from the 10% sites to the 50% sites (11.1% to 13.4%) is higher than the increase from 50% to 100% sites. This is in part due to less geographic diversity of sites going from 50% to 100%.

On the other hand, because of a reduction in load and weather diversity, renewables serving a smaller footprint have a lower ELCC. Two sample cases were studied to illustrate this: a high wind subsystem in the North and a high solar subsystem in the South.

The effect of a smaller geographic footprint with a high wind concentration is twofold: a reduced ELCC, and LOLE events in the morning winter mornings. The reduced ELCC is driven by the reduction in load/resource diversity, and the misalignment of local wind resources with the changing net-load peak in the mornings and afternoons (Figure RA- 8). Unlike the risk profiles of the entire footprint, as more wind is added to this small system, the probability of not serving load does not condense into a single smaller window. Rather, starting at the 50% penetration level, the risk profile has peaks in both the morning and evening. As even more wind is added, the risk of not serving load is higher in the morning than any other time of day. The morning LOLE events occurs as the relative ramp-down of wind increases in the morning at the same time load is ramping up.

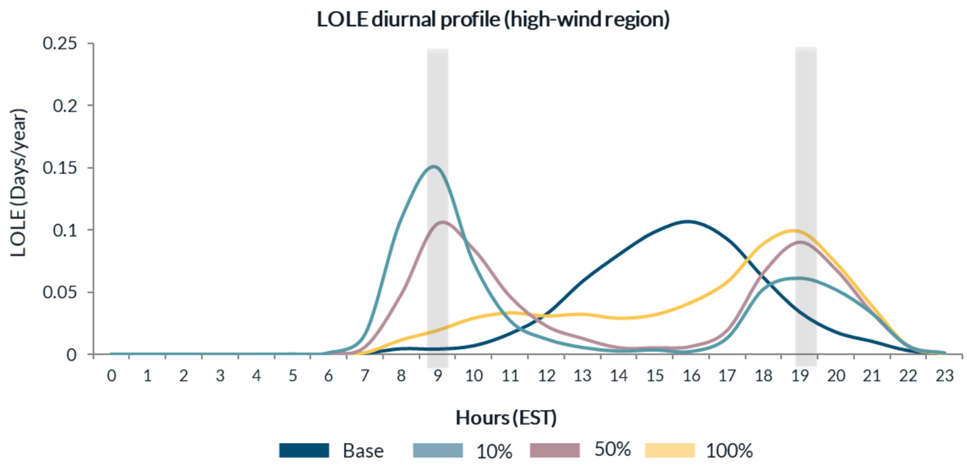


Figure RA- 8: Hourly LOLE in high wind northern region

The shift to risk morning events is therefore particularly likely during cold winter days (Figure RA-9). The evening LOLE events continue to occur when load is relatively high, and wind is still picking up.

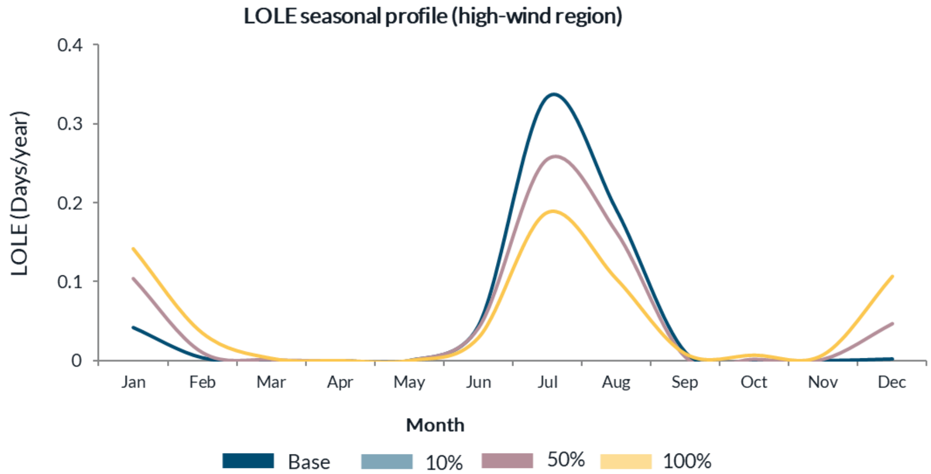


Figure RA-9: Monthly LOLE in high wind northern region

Similarly, the effect of a smaller geographic footprint with high solar is a reduced ELCC. As is true for the larger footprint, the probability of not serving load moves later into the evenings and is compressed into a smaller, more acute window (Figure RA-10)

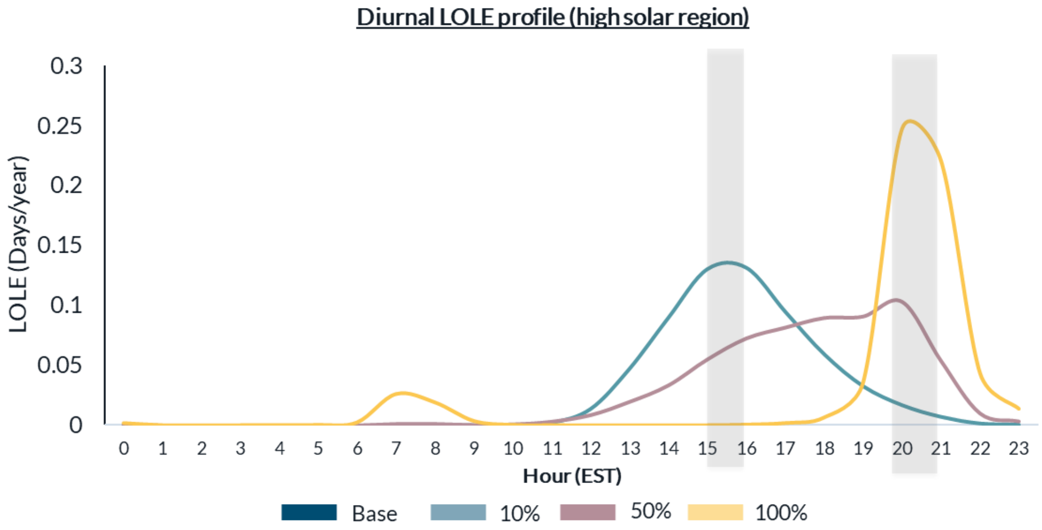


Figure RA-10: Hourly LOLE in high solar southern region

To further test the impact of a geographic region's size on ELCC, analysis was performed at the Local Resource Zone (LRZ) level. Figure RA-11 illustrates that renewable's performance is significantly better when meeting MISO's peak net-load than when meeting only the non-coincident peak net-loads of each individual LRZ. Comparing the ELCC of wind and solar shows that ELCC in the latter case is about 5 percentage points lower. This is true at both the 10% and 50% renewable levels. This finding further confirms the increase in the ELCC of resources in a broader, more diverse region vs. serving an isolated, smaller system.

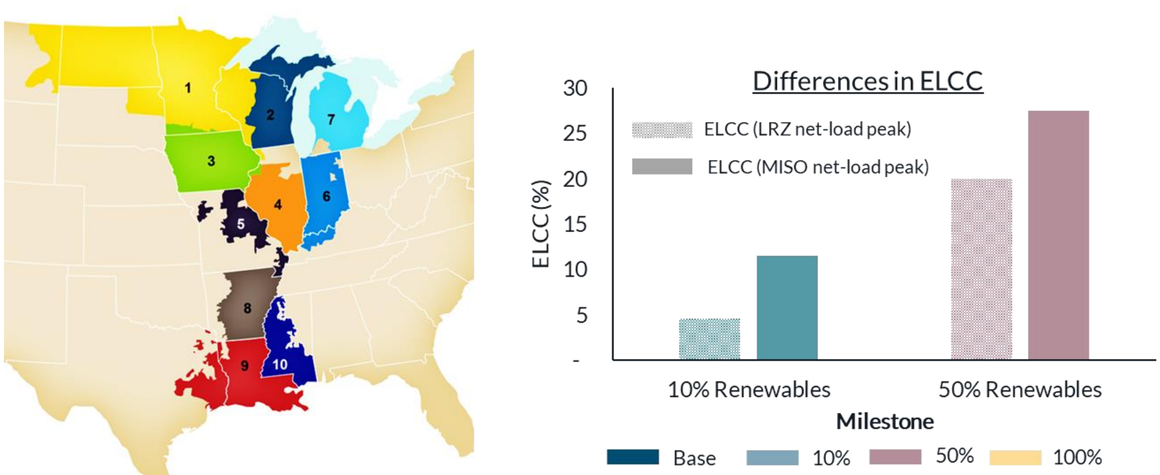


Figure RA-11: Change in ELCC by region size (MISO LRZ vs. MISO)

Furthermore, the study found that the ELCC of renewables increases if resources are used to serve load with the shape of a wider geographic area. This was investigated by using the load of the Eastern Interconnect. The ELCC of MISO renewables is higher when these resources are used to meet load across a large portion of the Eastern Interconnection (MISO, PJM, SPP, SERC), compared to when meeting only MISO load.

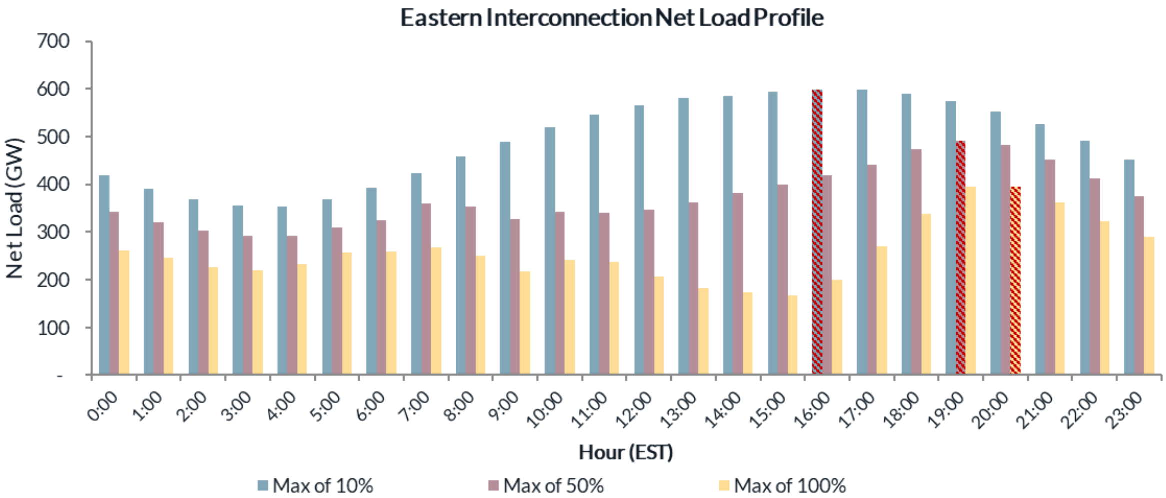


Figure RA-12: Eastern Interconnection Net Load Profile; peak net-load for each penetration level is highlighted.

MISO's ELCC comparison (all renewables) *		
Milestone	**MISO Load**	**MISO, PJM, SPP, and SERC Load**
50%	15.0%	25.2%
100%	12.5%	24.6%

Table RA-1: Change in ELCC by region size (MISO vs MISO+)

At the 50% and 100% penetration level, the ELCC of MISO renewables increases by 10 percentage points on average (Table RA-1). The increased footprint, particularly to the East and South East of MISO, gives MISO renewables better alignment with the aggregated load of the EI, the majority of which is in the Eastern Time Zone (Figure RA-12).

Finding: Yearly variations drive the ELCC bookends, as opposed to technology or data source

An investigation of the impact on solar technology type shows that on average 2-axis tracking has a higher ELCC than single axis tracking panels. When all the solar was modeled as either 2-axis or 1-axis tracking in addition to the same level of installed wind, the model with 2-axis tracking solar outperforms one with 1-axis tracking solar. After the 20% milestone, there is a ~5% difference in ELCC of all renewables over the penetration levels in the two models (Figure RA-13). The 2-axis solar performs better as a capacity resource at higher penetration levels as better tracking of the sun at the end of the day increases the availability of solar energy to serve load.

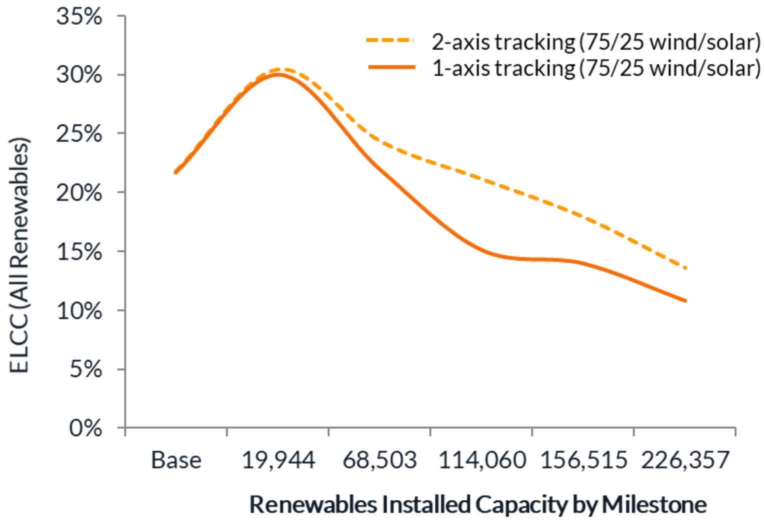


Figure RA-13: ELCC comparison of 2-axis vs. 1-axis solar

RIIA further wanted to understand what drives the bounds of the ELCC of wind and solar: meteorological conditions or technology. The data suggests that meteorological conditions drive the upper and lower bounds of a combined wind and solar ELCC (Figure RA-14). Although a change in technology (e.g. 2-axis vs 1-axis solar) results in changes in the ELCC for a given weather year, the yearly meteorological variations drive the ELCC bookends.

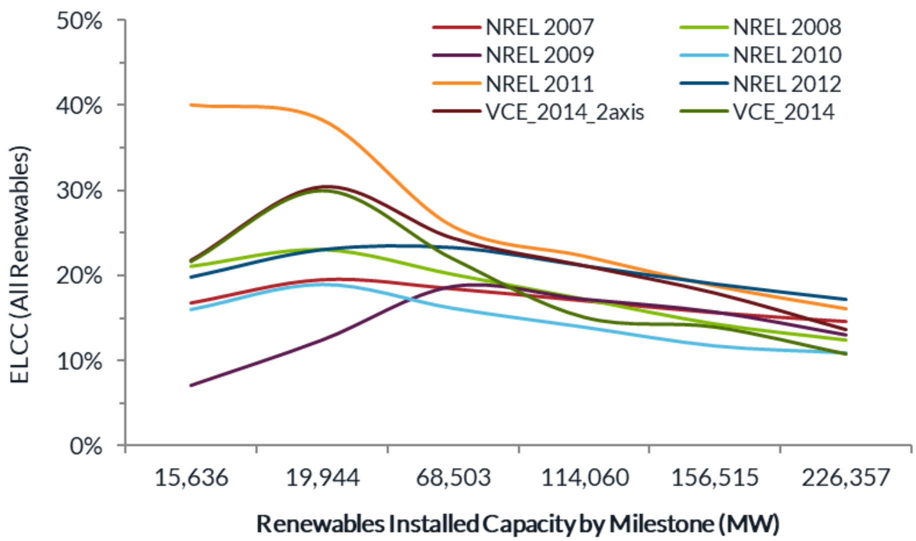


Figure RA-14: Change in ELCC by installed capacity per weather year

Resource Adequacy: Sensitivity Analysis

(A) Siting Sensitivity

RIIA made reasonable projections of the amount, mix, and location of renewable expansion to meet each region's penetration target (Figure RA-15). In addition to the base assumptions, a sensitivity was studied in which both the mix and siting of renewables were altered. The assumptions in the sensitivity resulted in several key changes

- Expansion of renewables based on Local Resource Zone (LRZ) load ratio results in a shift of capacity from the North to the Central and South regions
- The combined assumptions of a more regional distribution and recent queue trends for each subregion results in a continued shift from wind to solar

Finding: The risk of not serving load shifts to later in the evening, but the new expansion displaces the risk profile towards midnight

The net-load shape, and therefore the risk profile, is further impacted in several ways by having more solar on the system. Compared to a 'wind-heavy' system, as higher amounts of solar capacity are added, the highest risk period is pushed even further into the evening at all higher penetration levels (Figure RA-16). On average, while the highest risk moves from 3 p.m. to 6 p.m. in the wind-heavy scenario, by the 50% penetration milestone, in a more balanced wind-solar scenario, the most stressful hour shifts from 3 p.m. to 8 p.m.

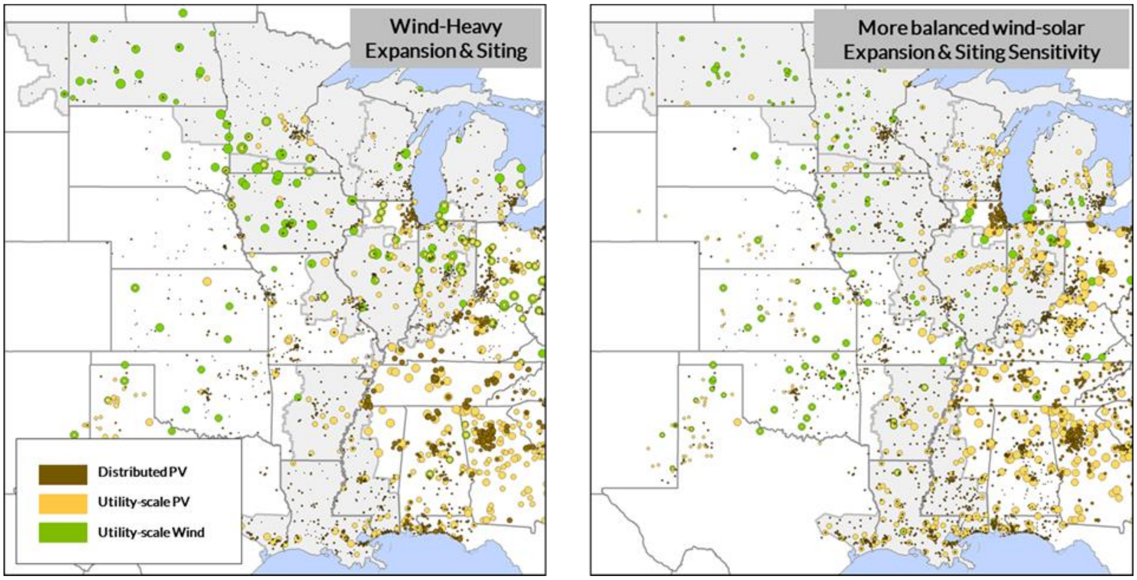


Figure RA-15: Wind and solar siting sensitivity

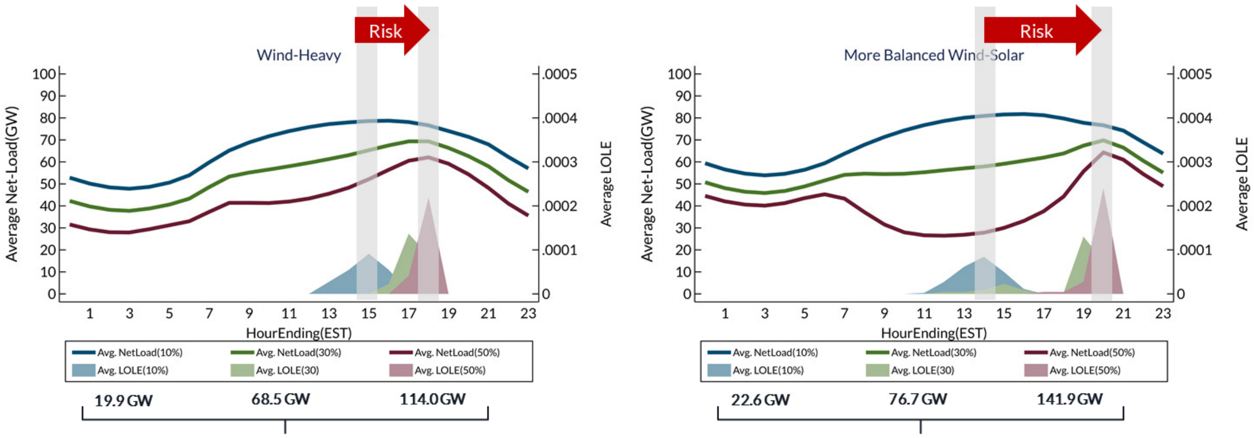


Figure RA-16: LOLE of wind-heavy resource deployment vs. balanced deployment

The average diurnal solar profile accounts for this dramatic shift in the risk profile. Figure RA-17 shows that a combination of higher amounts of installed solar and more diversity in the solar siting drives an overall increase in available solar energy during high-risk hours. The growth in available solar results from both the higher solar peaks and the additional hours of sun in the evening. This increase in solar energy is observable in the winter months but is more pronounced in the summer.

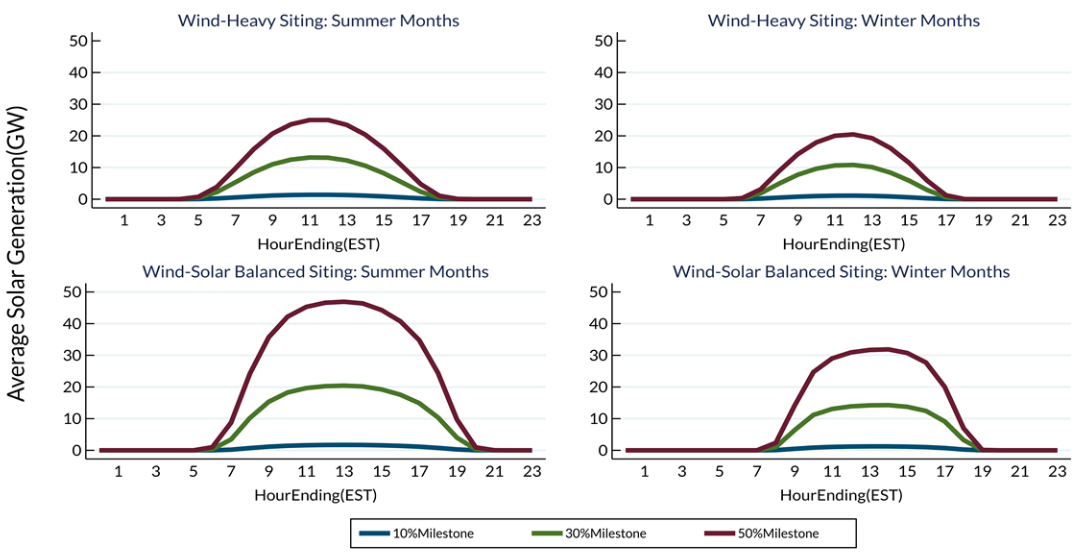
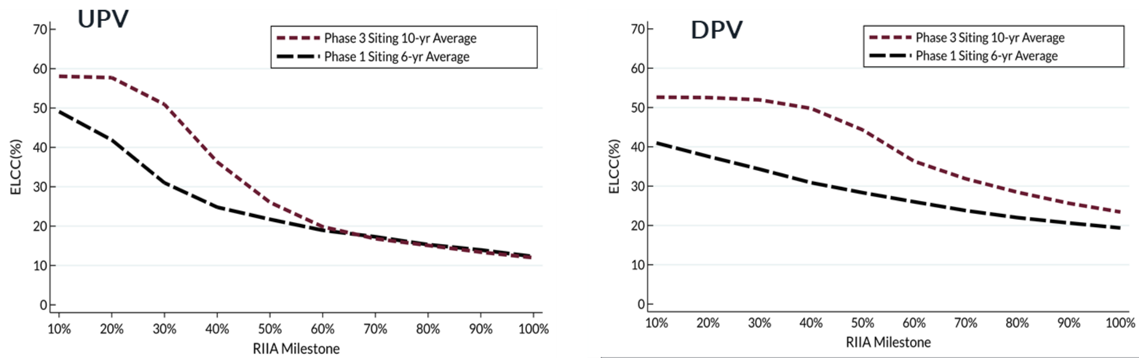


Figure RA-17: Average solar generation of siting sensitivity

The average potential ELCC of solar in the balanced resource mix scenario is higher than in the wind-heavy scenario as more solar is added in the West and South of the MISO footprint. This increased solar diversity moves the aggregate available solar energy to periods that are more coincident with the system load. However, in both cases, as discussed earlier, the solar ELCC declines faster at the lower penetration levels, then level out starting at the 60% penetration level.

The rate of decrease of ELCC is a function of the rate of increase in installed capacity from one penetration level to the next. For solar, the high rate of decline at lower penetration levels results from the steep absolute ramp down of solar in the evening hours. Therefore, the rate of decline in the ELCC is steeper in the more balanced resource mix scenario, where considerably more solar capacity is added from milestone to milestone (Figure RA-18).



UPV ICAP(GW)										
Milestone	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Phase 1	1.3	9.1	16.3	24.0	31.5	38.6	46.0	53.6	60.5	69.3
Phase 2s and 3	1.5	11.3	26.7	42.9	61.7	83.7	100.1	112.7	128.9	146.6

DPV ICAP(GW)										
Milestone	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Phase 1	1.3	4.7	8.5	12.3	15.5	18.9	22.7	26.1	29.1	32.4
Phase 2s and 3	1.7	5.6	11.7	18.8	26.6	35.2	41.7	47.9	54.2	60.4

Figure RA-18: ELCC comparison in siting sensitivity

Including additional weather years in the siting sensitivity results in a wider bound of inter-annual ELCC values for Utility Scale PV (UPV) and Distributed PV (DPV) solar. Figure RA-19 shows the disaggregated ELCCs of the individual weather years. Increasing the number of weather years results in wider bands of the ELCC of both UPV and DPV. The impact of different weather years is more pronounced at lower levels of installed solar. This is driven mostly by smaller number of solar units spread over the footprint and therefore more susceptible to higher inter-annual weather variance. As the penetration level increases, the band of ELCCs levels off as local weather effects are minimized as installed capacity increases; this phenomenon is not observed with wind units.

The range of ELCCs for DPV stays constant because significantly less DPV is installed compared to UPV. However, as more DPV is added, the ELCC of distributed solar can be expected to behave similarly to UPV.

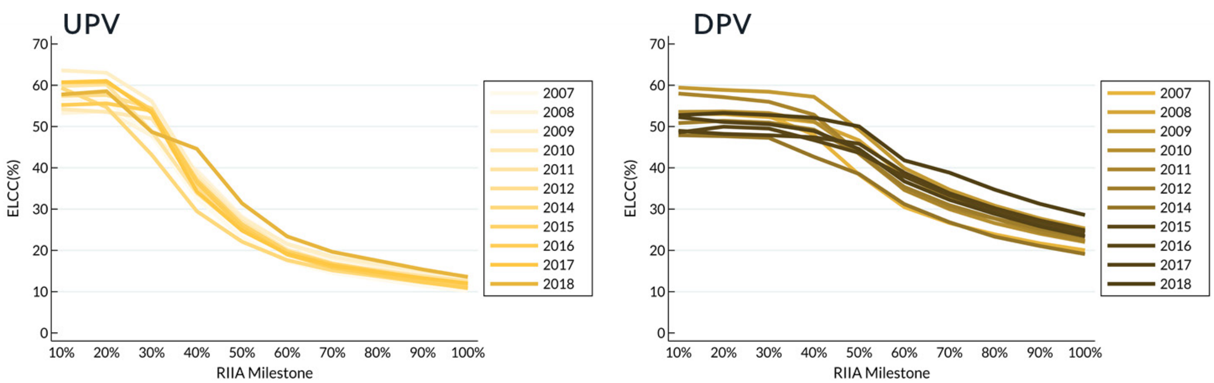
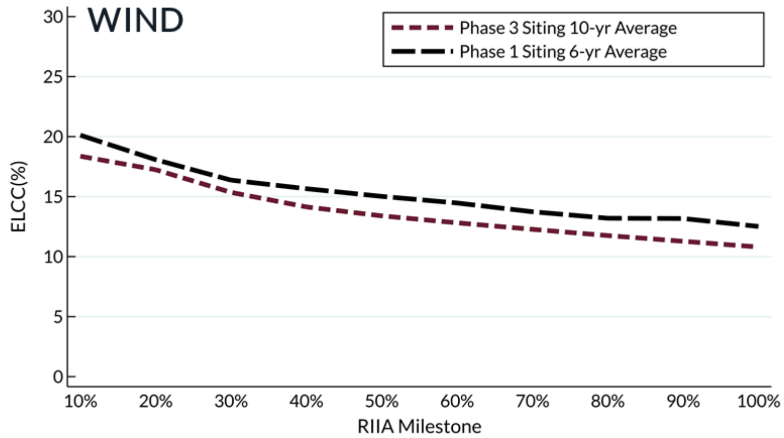


Figure RA-19: ELCC of solar by weather year

The effect of the more balanced siting on the MISO-wide ELCC is minimal. Unlike solar, the change in resource mix only slightly impacts the ELCC of wind. This minimal impact is consistent with the low correlation between wind and the risky periods. However, like solar, though to a lesser extent, the ELCC of wind in both scenarios sees a faster decline in the lower penetrations with subsequent leveling off as more capacity is added.

Figure RA-20 shows the modest impact of higher levels of installed wind on the risk profile. The higher availability of wind later in the day tends to shift the diurnal risk profile to the left, earlier in the day. However, since the wind profile's shape doesn't change significantly, given the more gradual wind ramps in the evening, wind does not heavily impact the hour of net-load peak and, therefore, the risk profile.



ICAP (GW)										
Milestone	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Phase 1	17.4	30.9	43.7	56.9	67.1	77.6	87.8	99.1	109.8	124.7
Phase 2s and 3	19.4	28.6	38.3	46.6	53.6	61.8	67.6	73.9	83.6	89.2

Figure RA-20: ELCC of wind of siting sensitivity

This modest impact on the risk profile(Figure RA-21) accounts for the less dramatic reduction in the ELCC of wind in both a high wind and more balanced resource-mix scenarios.

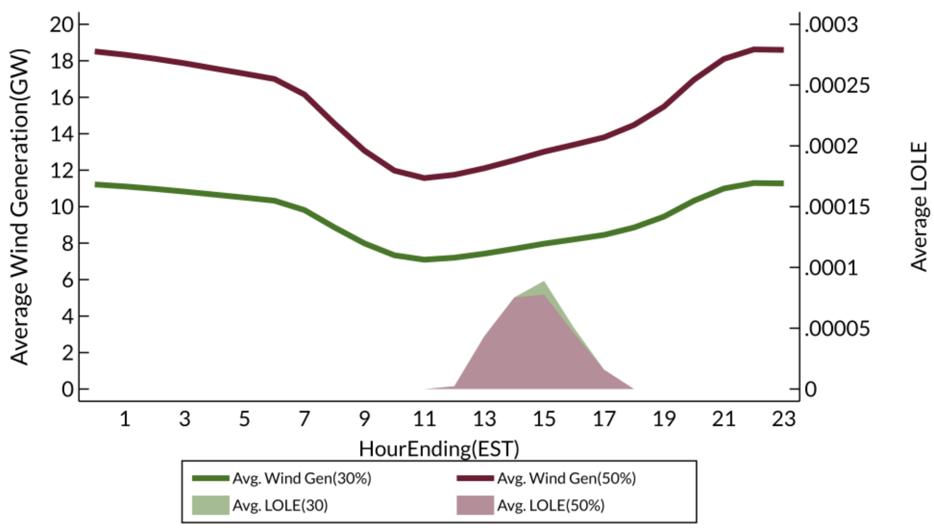


Figure RA-21: LOLE of wind at 30% vs. 50% penetration

The different weather years have a significant impact on the band of ELCCs, especially at the lower penetration levels (Figure RA-22); as wind penetration increase, the ELCC's based on the different years converges into a narrow band. The range of ELCCs can be understood by the variety of wind profiles in different years. The additional number of weather years expands the upper bounds of wind's ELCC. The breadth of the ranges of ELCCs under the various weather years confirms the importance of including a wide variety of weather conditions to better capture correlated risk events.

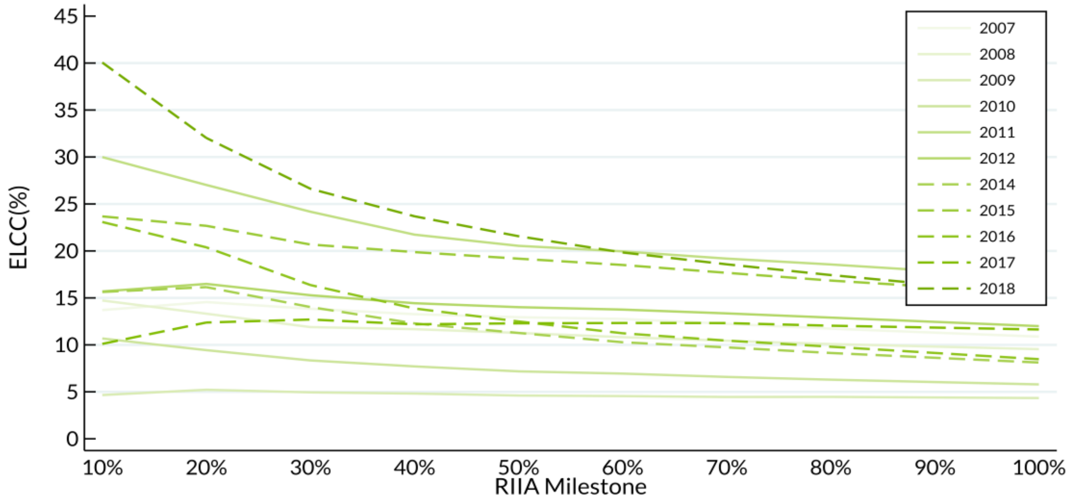


Figure RA-22: ELCC of wind by weather year

Finding: The risk of not serving load is also observed in non-summer months as the penetration of renewables increases with a higher contribution from solar

A resource mix with a higher percentage of solar causes a diurnal shift to the evening hours (average conditions). At every penetration level in the more-balanced resource mix scenario, the risk profile, measured by average Expected Unserved Energy, is quite different from a wind-heavy scenario (Figure RA-23). This can be attributed to the higher solar capacity in the more balanced mix, which is also more distributed throughout the footprint with higher amounts in the South and West.

At the 10% level, even with comparable amounts of installed solar capacity (2.6 GW and 3.2 GW in the wind-heaving and balanced mix, respectively), the risky periods change:

- The annual risk from June-September to June-August
- The diurnal window from 9 a.m. 10 p.m. to 1 p.m.–6 p.m.
- The hours of highest risk from 3–5 p.m. to 4–5 p.m.

By the 30% penetration level (~28 GW vs. 38 GW), the hours of risk have narrowed significantly, and the risk is concentrated at 9 p.m. This trend continues at the 50% penetration level, where the riskiest hour moves to even later in the evening (Figure RA-23).

Furthermore, the resource mix changes also cause a seasonal shift in the risk of serving load towards winter and diurnal change to the evening hours; EUE is useful in investigating these seasonal impacts. By looking at the maximum EUE, under extreme conditions, the transition to a higher solar resource mix drives a diurnal shift to the evening hours (Figure RA-24).

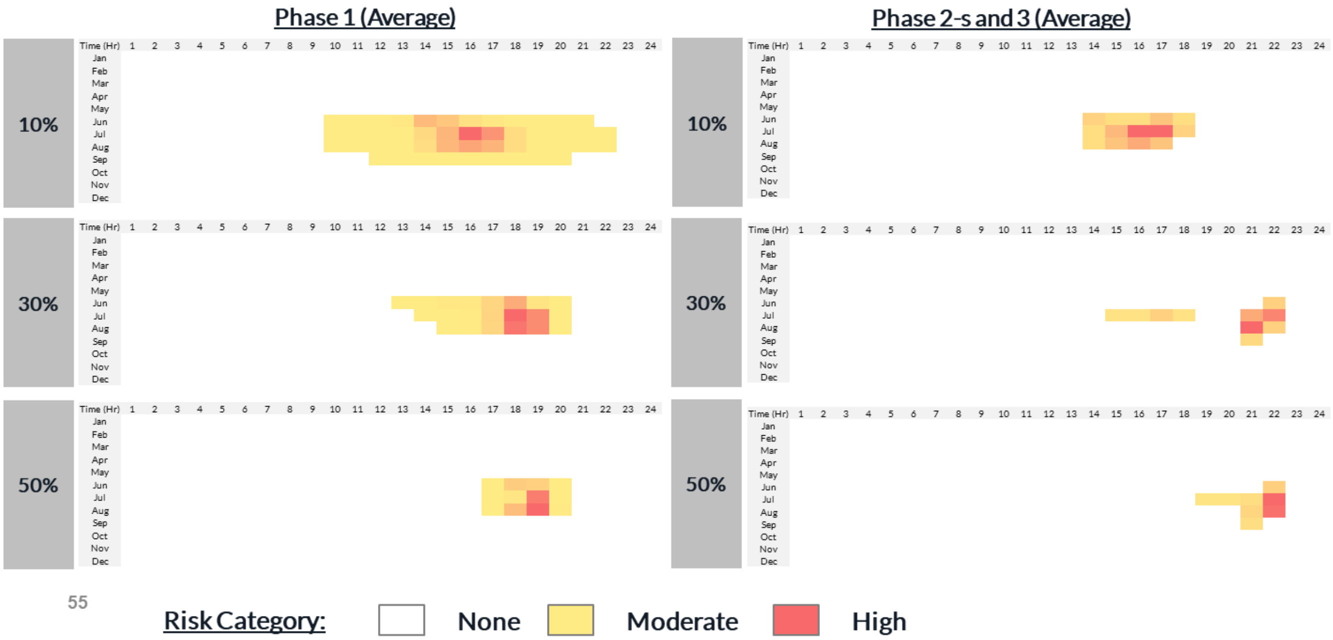


Figure RA-23: Average EUE by sensitivity and milestone

By the 30% penetration level, the occurrence of events in which capacity resources are unavailable to meet load is highest at 9 p.m. and can occur as late as midnight. Although the risk of not meeting load is concentrated in the afternoon and evening hours, as renewable penetration increases, the risk starts to appear in the morning hours across most seasons.

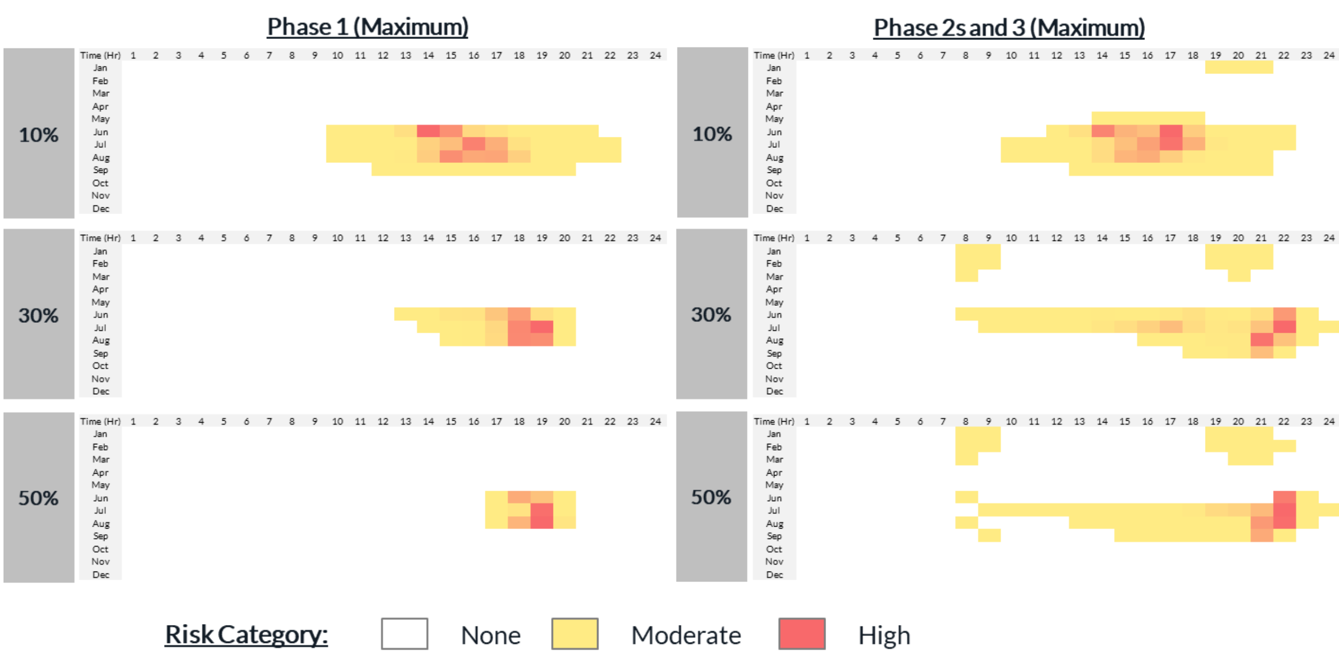


Figure RA-24: Maximum yearly EUE by sensitivity and milestone

In addition to the diurnal changes, although summer still has the periods of highest risk, a seasonal shift towards winter can be observed as the resource mix changes to include more solar. Starting at the 10% level, loss of load events may occur in January. This is due to high winter heating load coupled with low seasonal solar output, and low wind availability on calm cold winter days. The time period is like summer in that it occurs during sundown when load is still relatively high, and solar output is dropping. As the penetration increases further, these events are possible not only during the winter evenings but also on cold winter mornings. The morning events are likely when the load is relatively high, solar is still ramping up, and wind, though with lower impact, is ramping down. These seasonal and diurnal shifts are both driven primarily by solar.

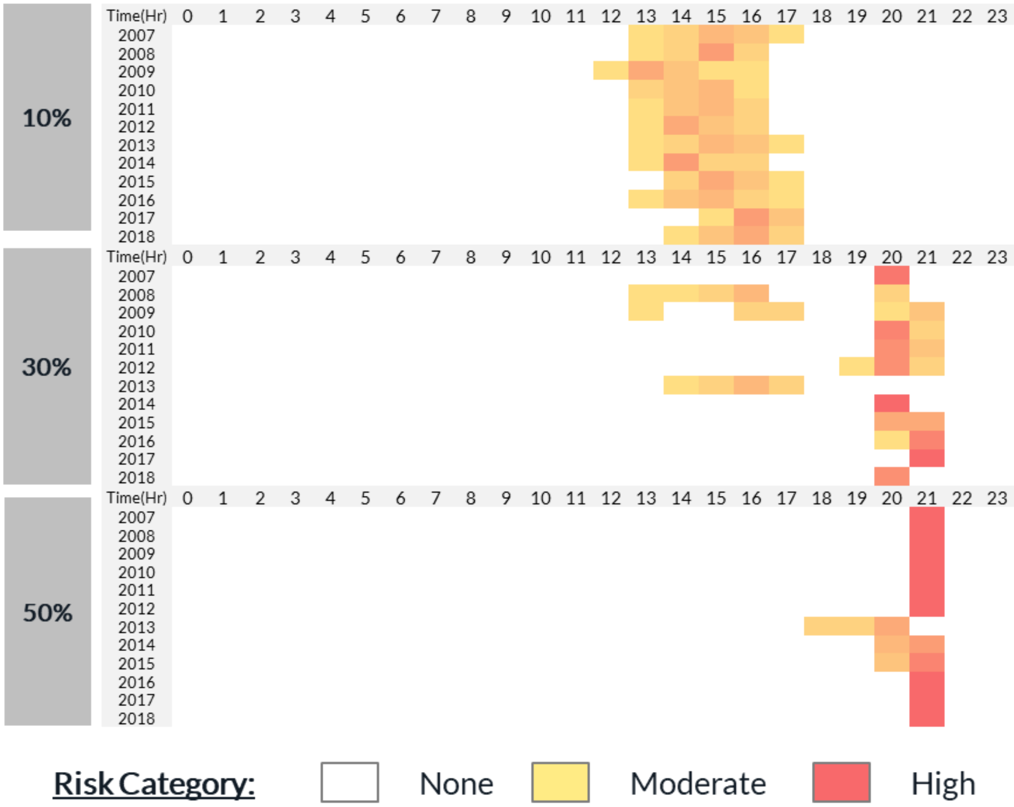


Figure RA-25: EUE by weather year and milestone

EUE also shows that the inter-annual variability of risk at lower penetration is similar. However, there is some divergence in the risk profile of the various meteorological years at higher penetration levels (Figure RA-25). Additional weather years, therefore, provide a more comprehensive characterization of risk across milestones.

EUE can offer more insights into the reliability of a system. Even when the system is planned to meet a fixed-constant LOLE level over all renewable penetration levels, Figure RA-26 demonstrates that the normalized EUE can have a significant range across different weather years and changes as renewable penetration increases. The increase in normalized EUE illustrates that the system is getting less reliable by one metric even as the LOLE metric remains constant at 1-day-in-10-years. Evaluation and examination of multiple metrics is important to consider as the share of renewable energy increases in a system.

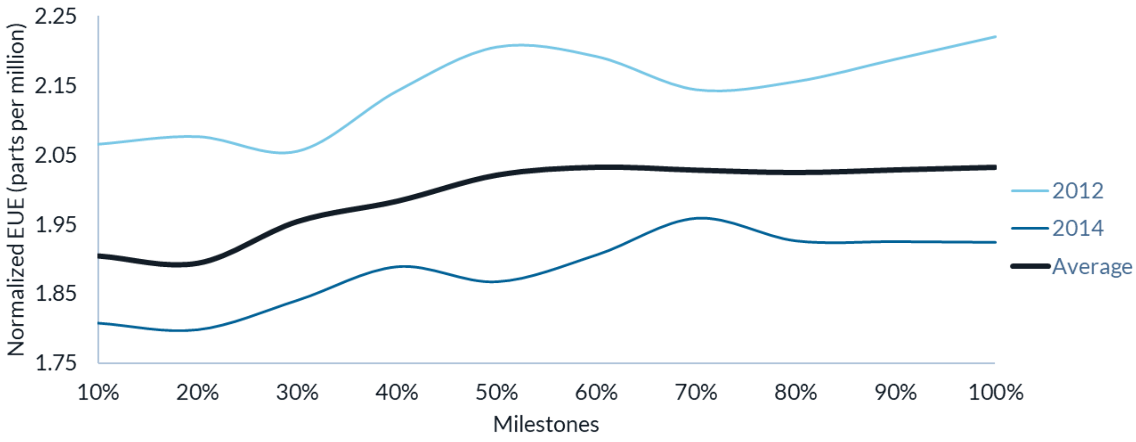


Figure RA-26: Change in normalized EUE by weather year and milestone. The 'average' respresents 11 weather years

Finding: The new technology mix improves the ability of renewable resources to mitigate the risk of serving load from 10%-50%

As resources are distributed more broadly across the footprint, the system initially benefits from the geographic and temporal diversity of both renewables and load. The increased diversity drives an increase in the ELCC of all renewables at lower penetration levels across most weather years (Figure RA-27).

As renewable energy penetration increases, there is a need to examine and evaluate multiple reliability risk metrics

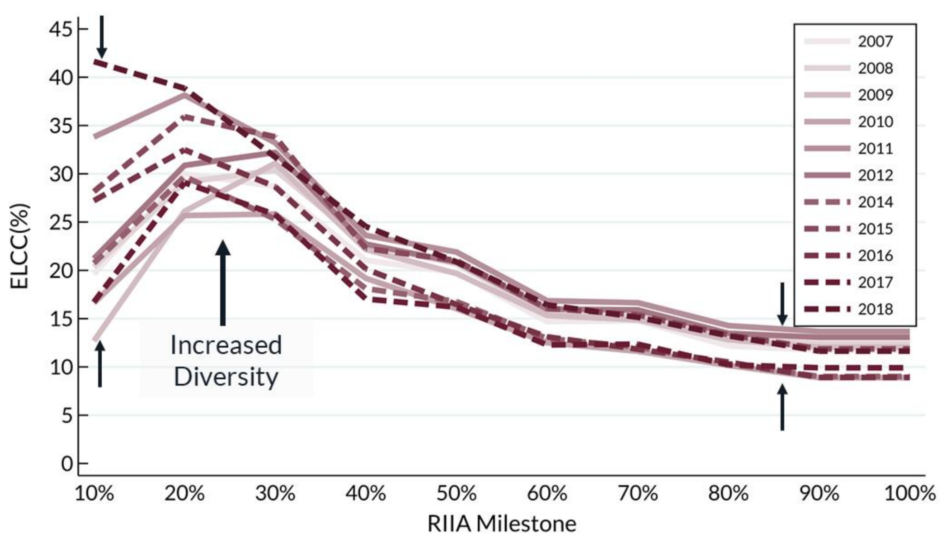
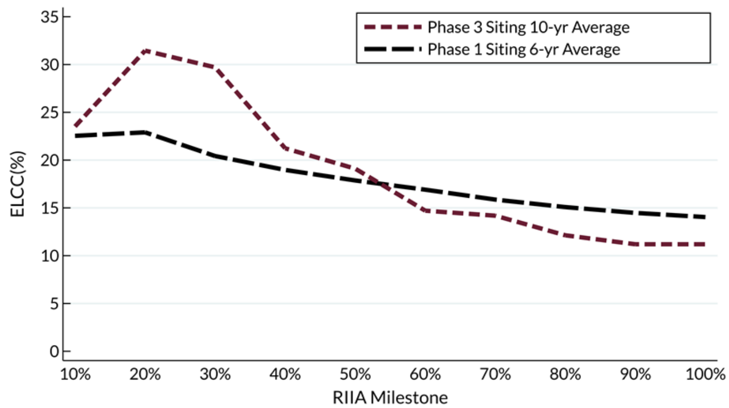


Figure RA-27: Change in ELCC due to diversity and weather year

However, as the penetration level of renewables increases, the diversity benefits are outweighed by changing net-load hour to periods that are less aligned with the energy generation from renewable resources. After the 30% penetration, this steeper decline in ELCC is due to the higher amount of more local solar expansion (Figure RA-28).



ICAP (GW)										
Milestone	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Phase 1	19.9	44.6	68.5	93.2	114.1	135.2	156.5	178.8	199.4	226.4
Phase 2s and 3	22.6	45.6	76.7	108.3	141.9	180.7	209.4	234.4	266.7	296.2

Figure RA-28: Comparison of the benefits of diversity in the siting sensitivity

(B) Storage Sensitivity

Hybrid (solar + battery) resources also improve the ability of renewables to meet load. An initial simplified analysis showed that to maintain the ELCC of all renewables a constant high level of ~31% (attained at 20% penetration), on average 0.225 MW of storage is required for every 1 MW of added renewable capacity (Figure RA-29) The analysis assumed the balance-mix of wind and solar and used 4-hour duration batteries.

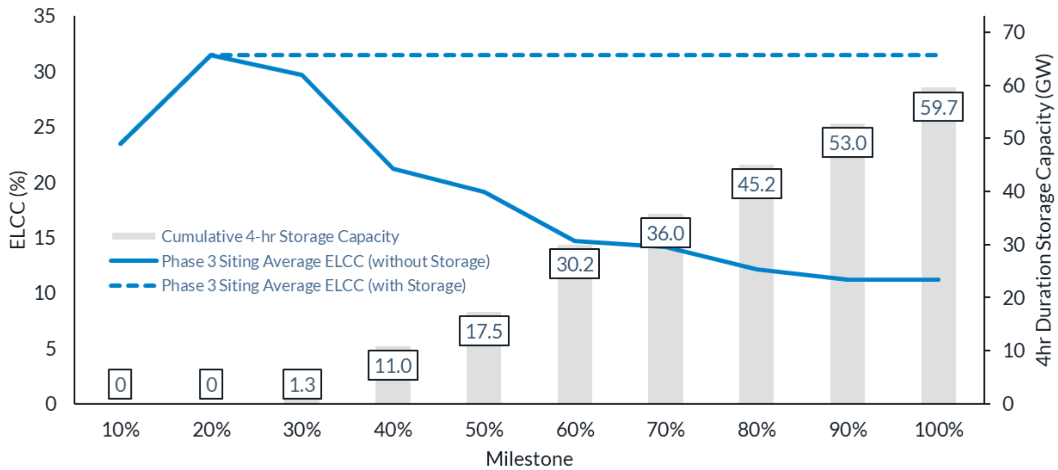


Figure RA-29: Amount of battery storage needed to maintain a constant ELCC

As more storage is added to the system, the ELCC of renewables initially improves; however, past a point, the addition of more storage has a diminishing impact on the increasing the ELCC of renewables (Figure RA-30). There is, therefore, an optimal amount of storage that can increase the capacity contribution (ELCC) of renewables.

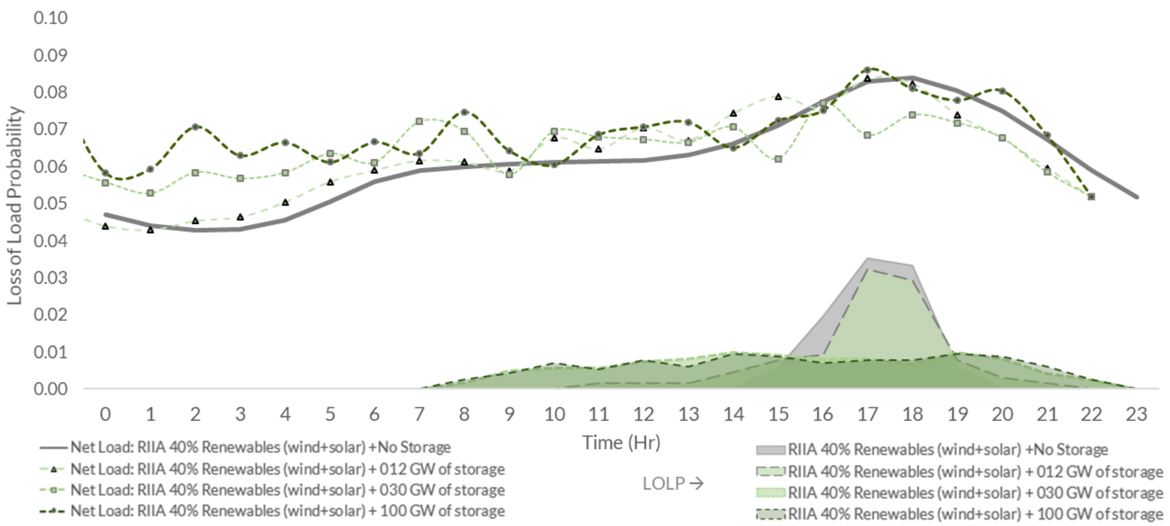


Figure RA-30: Hourly LOLP of a wind-heavy system by storage level

For the 40% penetration milestone (with 96 GW of installed renewable, most of which is wind), the addition of 12.1 GW of 6 hour duration storage raises the ELCC of renewables from 16.8% to 17% (Figure RA- 31). Further addition of storage increases the ELCC of renewables to 19.7%. Past this point, the addition of more storage has no meaningful impact on the ELCC and may reduce the ability of renewables to meet load at the risky periods. This behavior can best be understood by looking at the impact of storage on the net load curve.

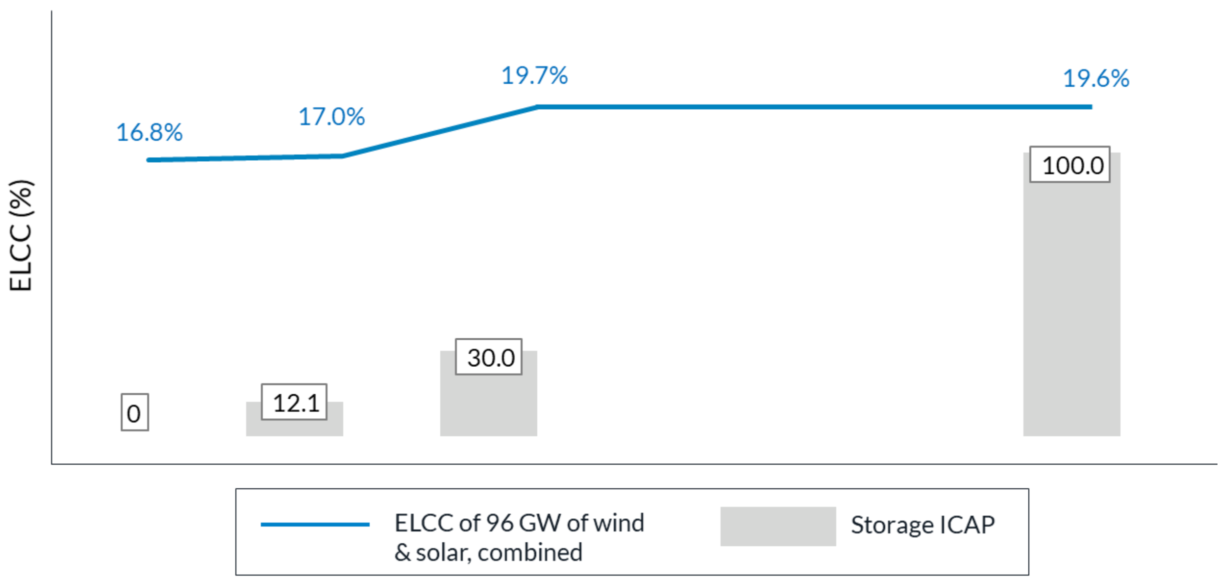


Figure RA- 31: ELCC benefit to a wind-heavy system from the addition of storage

In general, storage tends to flatten the net-load curve as it levels the peaks and fills the valleys. The flattening of the net-load curve, especially in the evening hours, allows renewables to better serve load in the new risky periods. An optimum amount of storage flattens out the net load curve and spreads-out the loss of load risk, which leads to an increase in the capacity contribution of the renewables. However, past the optimal point, the net-load curve is flattened out so much that the risk profile shifts to a much larger window (7 a.m. to 11 p.m.), making it more challenging for renewables to serve load at all these hours. Hence a leveling and possible decline in the ELCCs of renewables occurs.

An optimum amount of storage for a given system can increase the capacity contribution of the renewables. Additional storage past that point would have diminishing returns

The capacity contribution (ELCC) of storage alone decreases with an increase in installed storage(Figure RA-33). This phenomenon is similar to that observed for solar and wind, which like batteries, are energy-constrained resources. Without any renewables in the system, the initial ELCC of storage is relatively high and looks like a conventional unit due to its ability to be dispatched during high-risk periods. However, as 30 GW of storage is added to the system, the ELCC drops significantly to 64%. The rate of decline then reduces as the ELCC further drops to only 19% as up to 100 GW of storage is installed. This is due to the spreading of risk, as discussed earlier, and the energy-limited nature of storage.

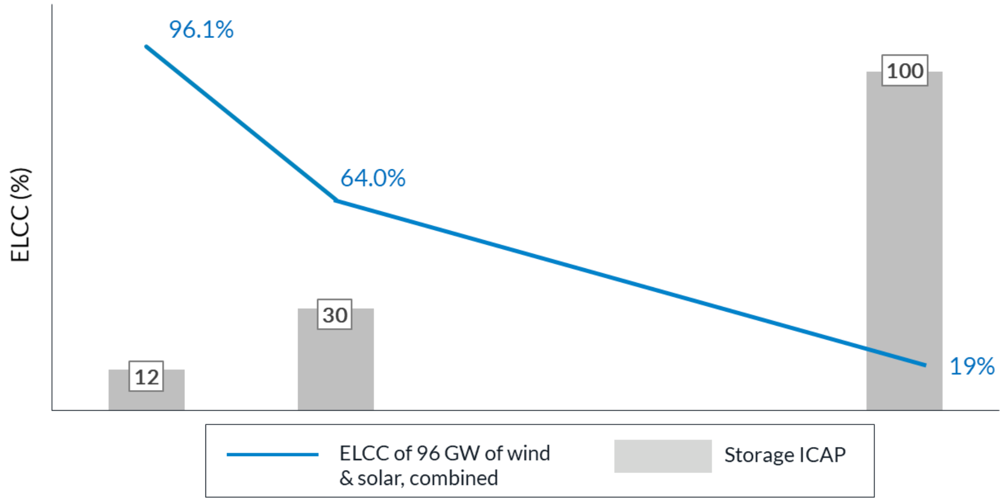


Figure RA-32: ELCC of storage as the penetration of storage increases

A similar impact on the ELCC of a "portfolio" of renewables and storage is observed as more storage is installed. The ELCC of "portfolio" is defined as the combined ELCC of wind, solar and storage (Figure RA-32). It is worth noting that the portfolio's capacity value may differ from that of a hybrid system; RIIA did not study a true hybrid system.

As the amount of installed storage increases, the ELCC of the portfolio initially improves; however, there is an optimal amount of storage, beyond which ELCC does not increase considerably from base. For a system with 96 GW of renewables, the addition of storage increases the portfolio ELCC to 25.8% from a base of 16.8%. The ELCC continues to increase, reaches a peak, and then starts to decline to levels close to the base ELCC. The decline can be attributed to the impacts of high levels of storage on the net-load profile.

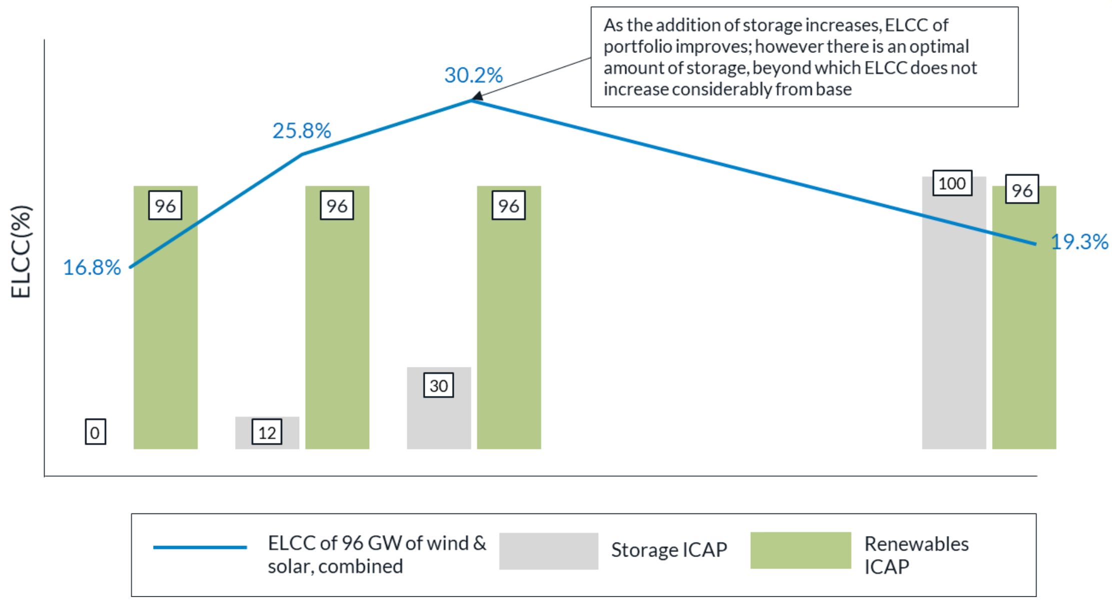


Figure RA-33: Change in ELCC on portfolio of wind, solar, and storage by storage penetration level

To further isolate how renewables impact storage, a series of simulations were run with various installed storage levels, with and without renewables. The results show that renewables improve the ELCC of storage (Figure RA-34). At all levels of installed capacity of storage, renewables' presence enhances the performance of storage as a capacity resource. However, the most significant effect of renewables on storage is at the aforementioned optimal point. At both the very low and very high levels of storage, renewables have a more modest impact on the ELCC of storage. However, in between these ranges, renewables could improve the ELCC of storage by up to 10 percentage points.

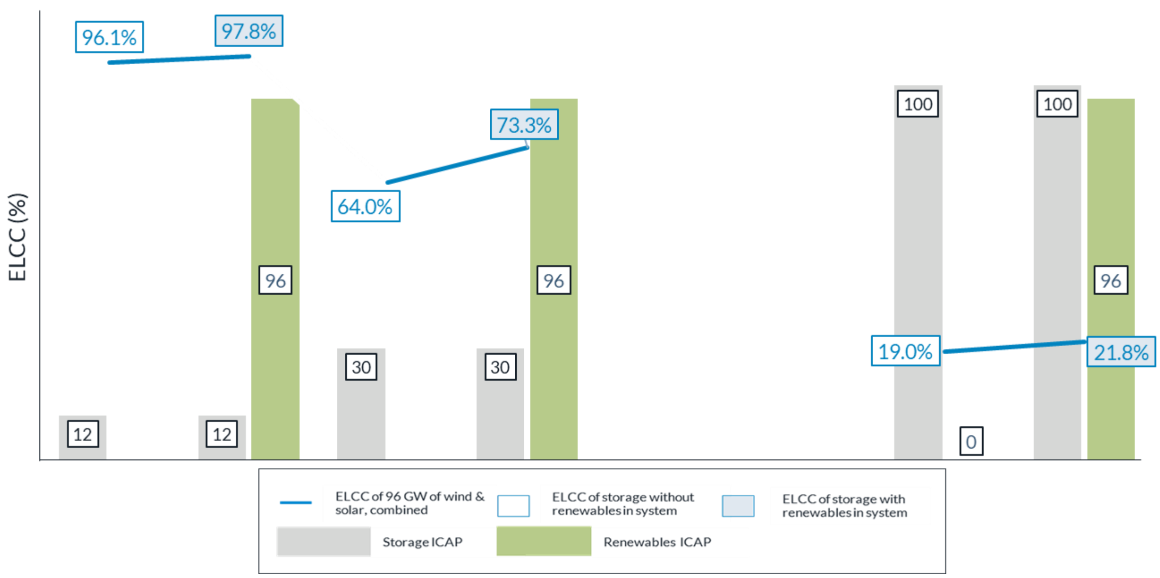


Figure RA-34: Comparison of ELCC of storage by renewable penetration level

Energy Adequacy — Planning

Overview

Energy Adequacy is defined as the electric system's ability to operate continuously to maintain and deliver energy every hour of the year to all locations within the footprint, meeting all demand in each hour reliably at the lowest cost. Using security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED), RIIA looks at both system and local level hourly renewable output levels, energy mix, ramping needs and provision, and transmission congestion. As the amount of low cost wind and solar resources increases significantly, RIIA looks at how the location, magnitude, and variability of these resources impact the flexibility requirements, operation of the existing fleet, and utilization of the transmission system. The key energy adequacy questions being addressed in RIIA include:

- Can the installed renewable energy be delivered to load every hour over the course of the entire year at each penetration level?
- How is the dispatch of the system affected by high levels of renewables?
- What system needs arise, and what, if any, actions are required to ensure energy delivery?

RIIA shows that online conventional generators must provide more ramping, when considering both the overall amount and the variations in that ramping, at renewable penetration levels above 40%. Although the assessment shows that the total generation and ramping needs from the existing generation fleet decrease, fewer traditional units remain to provide the generation and ramping capacity. This places greater importance on remaining traditional units.

RIIA also indicates a need for transmission grid expansion to accommodate higher levels of renewable penetration and respond to the associated system variability. In summary, RIIA Energy Adequacy analysis shows that:

- As renewable energy reaches 40% penetration, the transmission system is insufficient to further facilitate renewables and access the benefits of diversity in renewables and load
- Transmission solutions are developed starting at the 40% milestone to utilize the diverse, variable resources across the footprint, which impact curtailment, ramping, and power flows
- With transmission solutions, renewables continue displacing thermal generation across different times and locations, resulting in changes to power flows, thermal unit performance, and locational marginal prices

Key Findings

Finding: As renewable energy reaches 40% of annual energy, the transmission system requires upgrades to further facilitate renewables and access the benefits of diversity in renewables and load.

RIIA study considers four different transmission models summarized in Table EA-1. The "BaseT" model represents the actual maximum amount of interchange for the existing transmission system. "Start" model indicates the model with any incremental transmission improvements from the previous milestone. "Final" model includes all incremental transmission improvements through the current milestone. Lastly, the unconstrained model represents the theoretical maximum amount of interchange, assuming no limitations on the existing transmission system.

Transmission model	Explanation
BaseT	Base transmission included in the RIIA model
Start	Model includes base transmission (BaseT) as well as incremental transmission solutions identified by RIIA **through the previous milestone**. For example, a Start model for the 40% milestone includes any transmission solutions identified for the 30% and lower milestones.
Final	Model includes base transmission (BaseT) as well as all incremental transmission solutions identified by RIIA **through the current milestone**. For example, a Final model for the 40% milestone includes any transmission solutions for the 40% milestone in addition to any transmission solutions identified at earlier milestones.
Unconstrained	Uses the base transmission model (BaseT), but each transmission path is assumed to have unlimited flow capacity. In other words, the line ratings are not respected for unconstrained models.

Table EA-1: Explanation of transmission models used for Energy Adequacy analysis

By the 40% penetration milestone, massive transmission system upgrades are needed.

RIIA finds that, by the 40% penetration milestone, the energy penetration targets could not be reached without the massive deployment of transmission solutions (Figure EA-1). When gradually adding renewable generation capacity into the production cost model, starting with the Base model and reaching the 30% milestone, it was found that study penetration targets are achievable with incremental adjustment of unit commitment and dispatch. However, at the 40% milestone, renewable energy is curtailed in markedly higher amounts (shown in Figure EA-1). An array of solutions must be deployed to achieve the 40% study penetration target. To get to the 50% penetration target, more solutions are needed beyond what has been deployed to reach the 40% milestone.

Figure EA-2 shows the generation capacity for the MISO region from the Base to 50% milestones, broken down by type and region. For all milestones, most of the thermal fleet is assumed to be available, with only around 17 GW being retired. On the other hand, a total of around 100 GW of renewable capacity is added to the MISO system by the 50% milestone. Figure EA-3 further breaks down the production of energy by fuel type in the three MISO regions, i.e. Central, North and South. This breakdown reveals that most curtailment is from wind resources in the North region, driven by transmission limitations. As described in the Technical Assumptions Summary, a notable amount of wind capacity was placed in the North region as part of the RIIA model building process (Figure EA-2). Without deploying transmission solutions, the existing infrastructure must be upgraded to further facilitate the integration of renewables that are far from load centers and, by doing so, access the benefits of diversity between renewables and load.

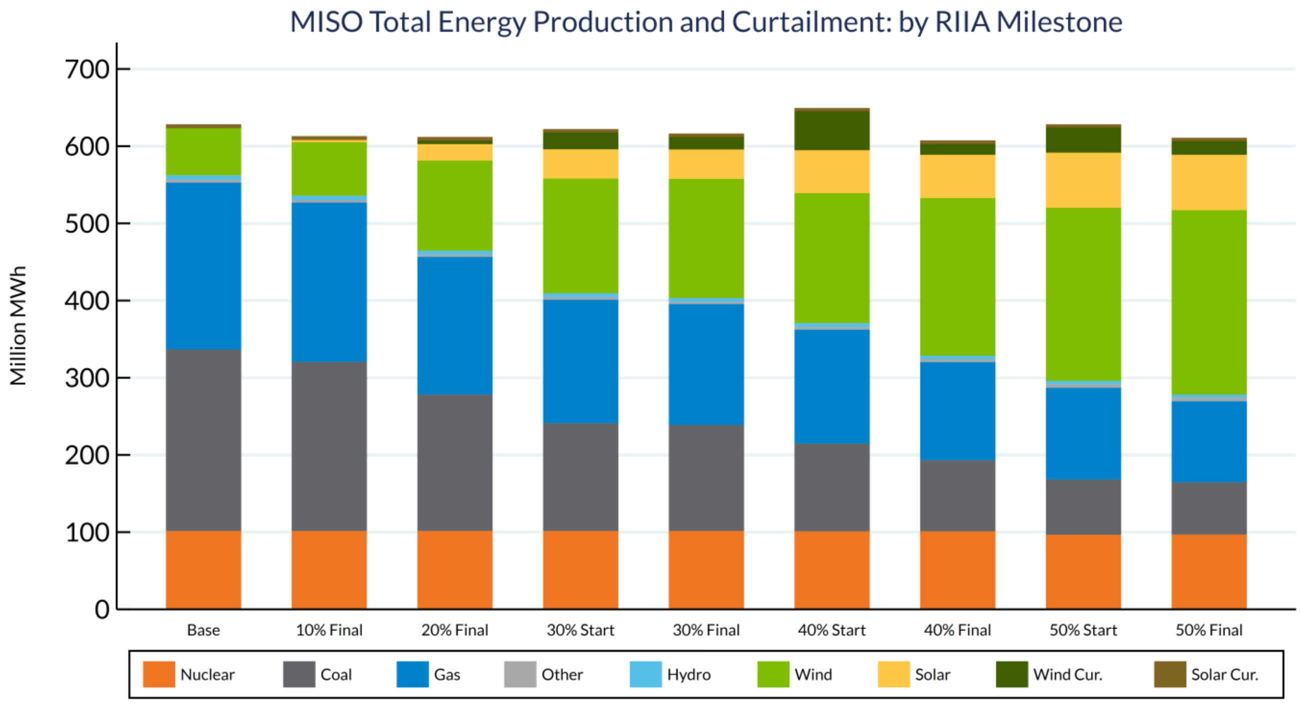
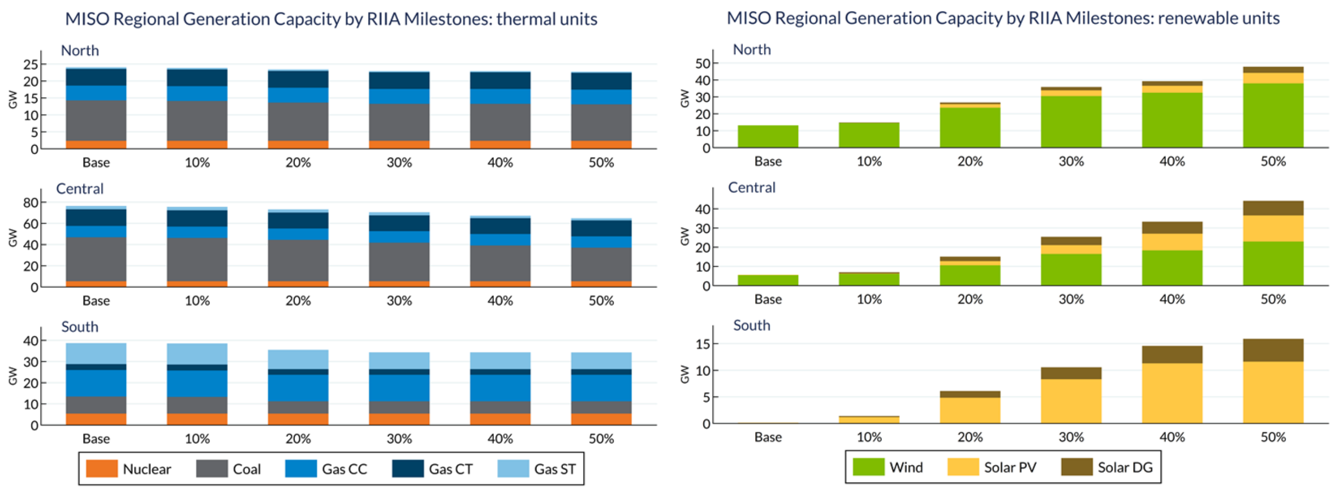


Figure EA-1: Fuel mix in RIIA milestones. "Start" indicates the addition of all renewables for the current milestone, plus any incremental transmission improvements from the previous milestone. "Final" indicates the addition of all renewables and any incremental improvements for the current milestone. The 30% model required transmission upgrades to meet OR performance requirements.



* Different Y-axis scales.

Figure EA-2: RIIA generation capacity assumptions, regional breakdown

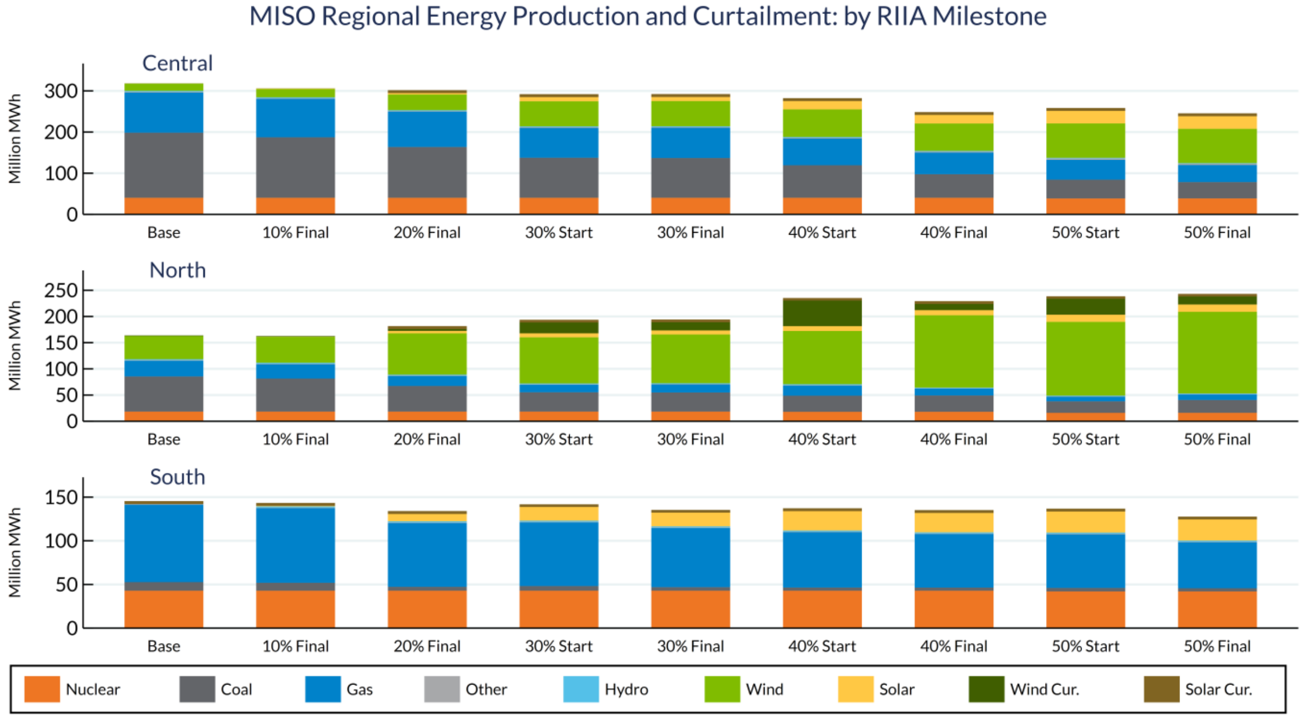


Figure EA-3: Fuel mix in RIIA milestones, regional breakdown

Starting at the 40% milestone, transmission solutions were developed to enable the delivery of resources across the footprint.

Transmission solutions are developed to facilitate energy delivery starting at the 40% milestone, enabling the use of diverse, variable resources across the footprint and impacting curtailment, ramping, and power flows

Finding: Transmission Solutions Reduce Renewable Energy Curtailment

Transmission solutions significantly reduce wind energy curtailment at both the 40% and 50% milestones, when comparing the Final model with the Start model (red box, Figure EA-4). Interestingly, the impact of transmission solutions on reducing curtailment is lower at the 50% penetration level, suggesting potential diminishing returns of solutions at higher penetration scenarios. In the Start models, curtailment is more pronounced during the night in the shoulder months (left panel, Figure EA-5), when load is at its minimum and wind production tends toward its maximum.

The right panel in Figure EA-5, on the other hand, illustrates how curtailment changes after including transmission solutions; the negative magnitude reflects the fact that curtailment decreases between the Start and Final models. The time periods with the largest reduction of curtailment align with the high curtailment periods in the left panel, peaking during the night in shoulder months. By comparing the magnitudes of curtailment between 40% and 50% milestones in the right panel, it is also obvious that the curtailment reduction is smaller at 50% milestone for all months.

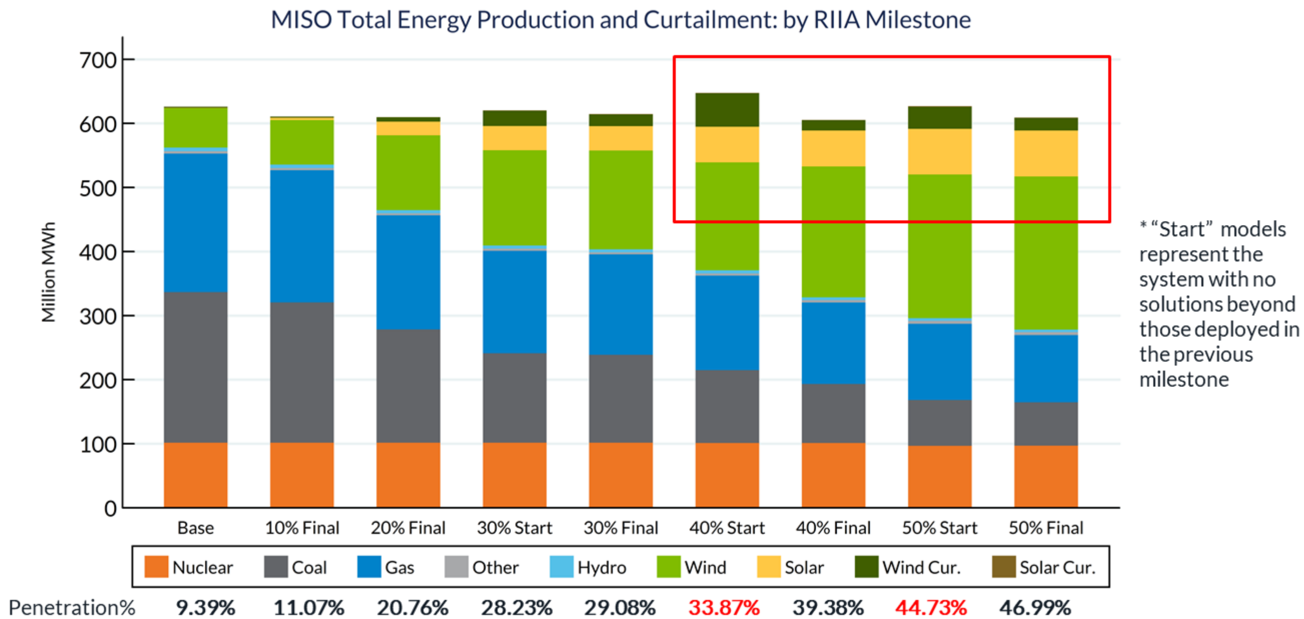


Figure EA-4: Transmission solutions and their effect on renewable penetration for all RIIA milestones

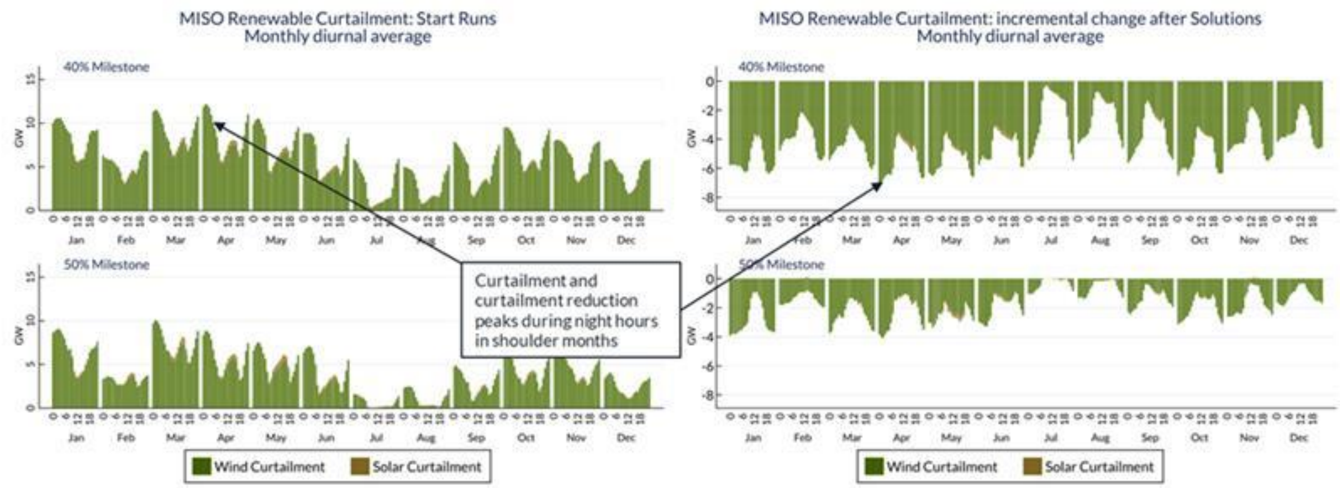


Figure EA-5: Monthly diurnal average of renewable energy curtailment for the 40% and 50% milestones

Finding: Transmission Solutions Enable Economic Ramping and Commitment of Thermal Units Ramping and Commitment

Figure EA-6 shows the change in annual aggregation of ramping for coal and gas combined-cycle (CC) units between Start and Final models. The most notable effect of adding transmission is reducing the ramping from coal units at the 40% milestone and beyond. For gas CC units, adding transmission solutions also slows the escalation of its ramping, but not as dramatically as the reduction of the coal units. At hourly granularity, Figure EA-7 shows that the variation of one-hour ramp magnitude decreases for coal units after including transmission solutions. On the other hand, transmission solutions facilitate the use of gas CC units for ramping, shown by the increased magnitudes of one-hour ramp variation.

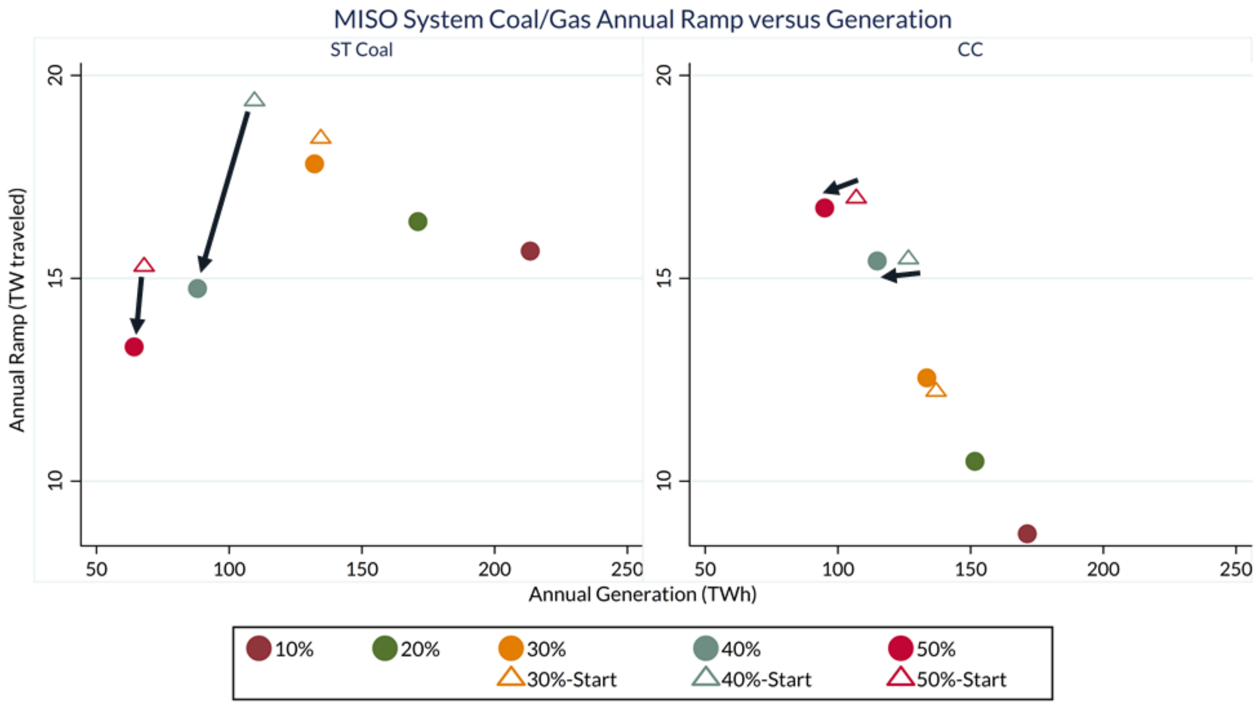


Figure EA-6: Effect of transmission solutions on thermal unit ramping for RIIA milestones

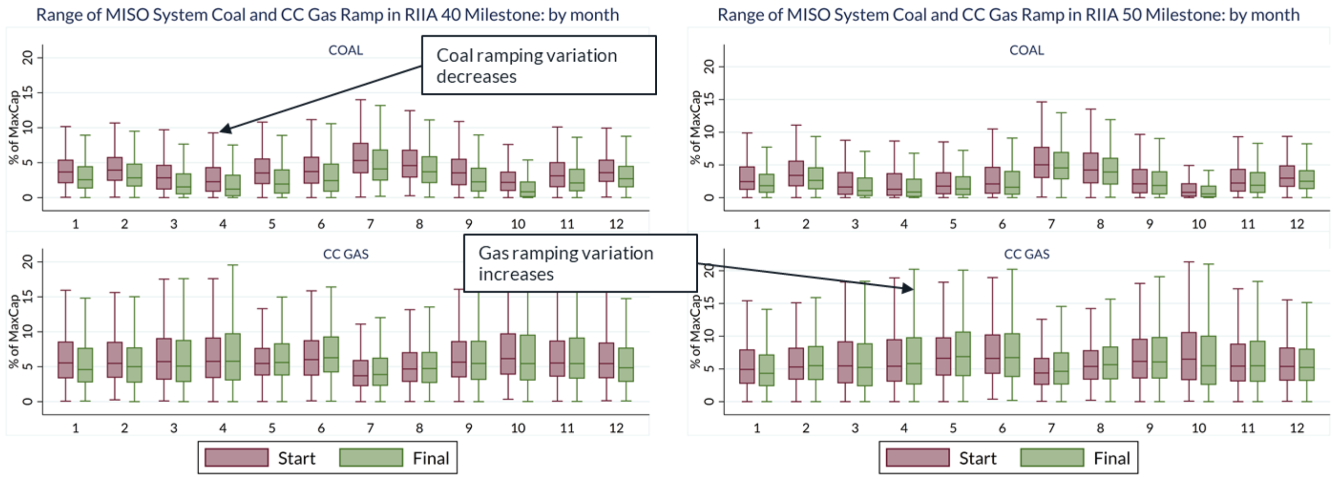


Figure EA-7: One-hour ramp variability of coal and gas units for the RIIA 40% and 50% milestones

To further illustrate the trend of ramping across five RIIA milestones and the relationship to transmission solutions, Figure EA-8 through Figure EA-10 compare three different models. The first model is an unconstrained model, in which no RIIA transmission solutions are included and the ratings of all line are ignored (Figure EA-8). In other words, the unconstrained model represents an ideal transmission constraint-free world based on the current infrastructure. The most notable trend of ramping in Figure EA-8 is the increased contribution of gas CC units to meeting ramping needs from the 10% to 50% milestone, while the ramping support provided by all other types of thermal units decrease. Unit commitment and dispatch decisions are based on the relative economics and generator flexibility of different types of thermal generation and the unconstrained case offers insight into the ideal operation of the fleet if transmission were not limited by current ratings.

The second model represents a case where transmission constraints have been reintroduced, but no RIIA-identified solutions have yet been included, the so-called "base transmission" or "BaseT" model (Figure EA-9). In this BaseT model, the ramping trends for gas CC and gas steam turbine (ST) units are similar to those of the unconstrained model: increasing or decreasing with renewable penetration, respectively. However, the need of ramping from coal and gas combustion turbine (CT) units increases, particularly at higher penetration milestones.

Lastly, in the Final model (Figure EA-10), where RIIA transmission solutions are included and transmission constraints are considered, the ramping needs from coal and CT gas units are reduced. In the pattern of ramping for the coal units, it is clear that the inclusion of RIIA transmission solutions after the 30% milestone particularly enables this reduction in ramping contribution.

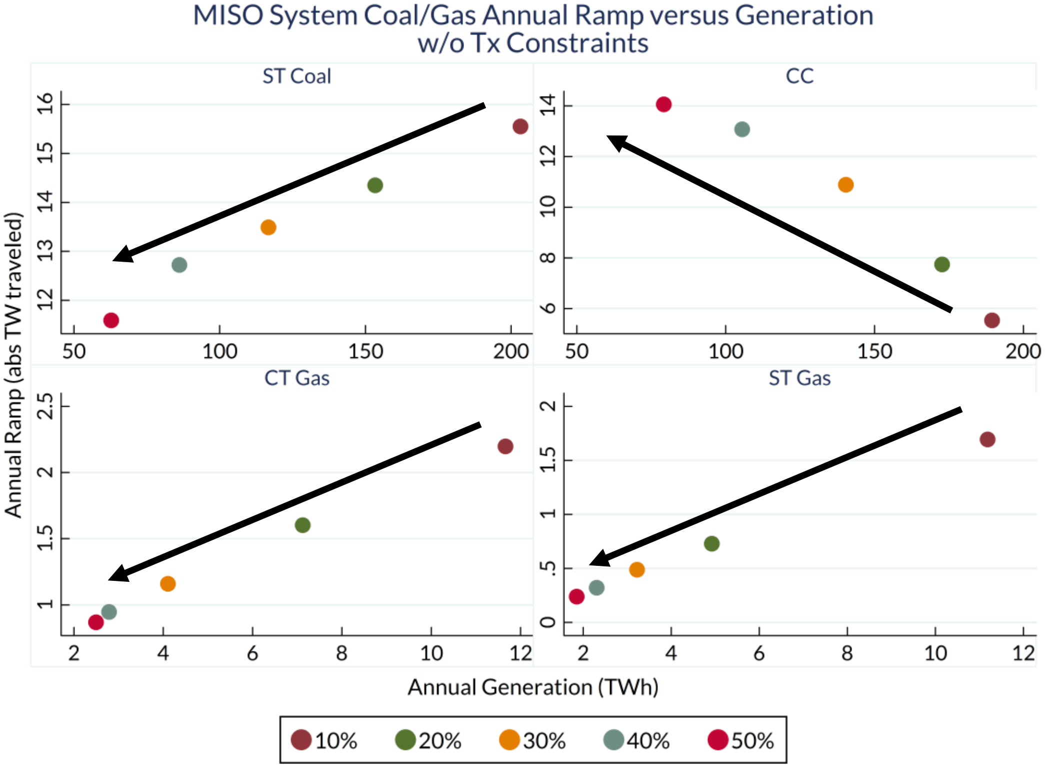


Figure EA-8: Thermal unit ramping in RIIA milestones, ignoring transmission constraints

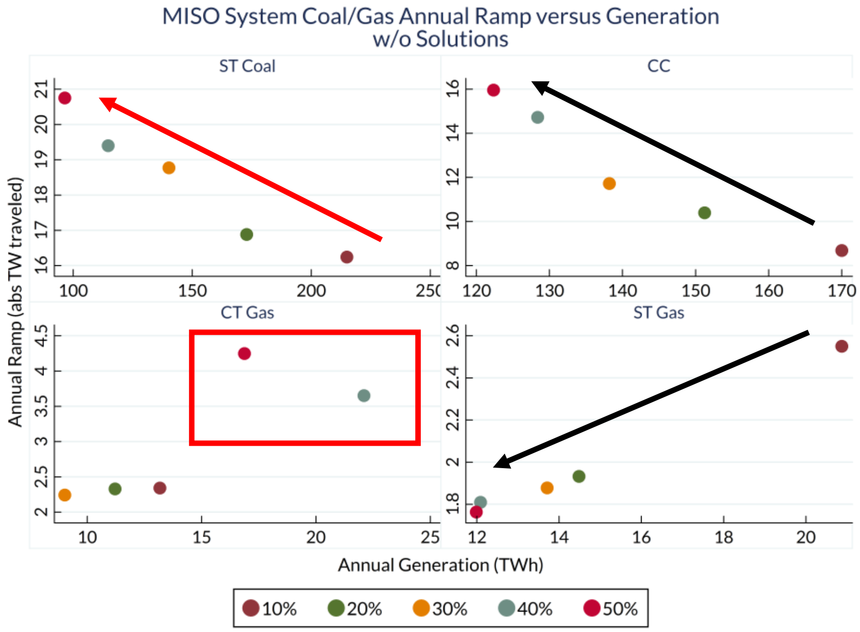


Figure EA-9: Thermal unit ramping in RIIA milestones for the "BaseT" model, which includes transmission constraints, but no RIIA transmission solutions

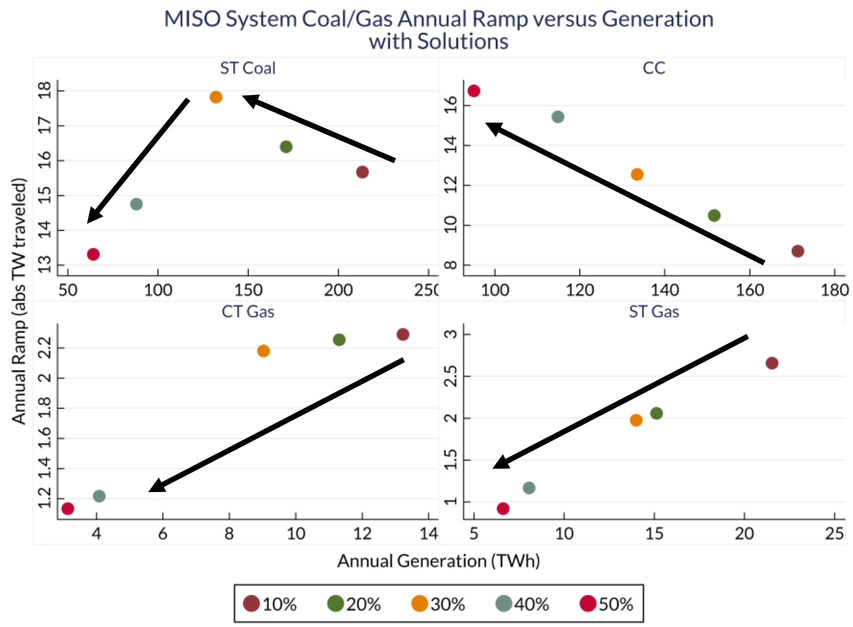


Figure EA-10: Thermal unit ramping in RIIA milestones for the Final model, which includes transmission constraints and RIIA-identified transmission solutions

Transmission solutions also help to reduce the number of thermal units that are committed (Figure EA-11). As wind and solar increase after transmission solutions are added, smaller uneconomical conventional assets are not being dispatched. This thins out the flexibility stack and moves ramping to larger, more economic units.

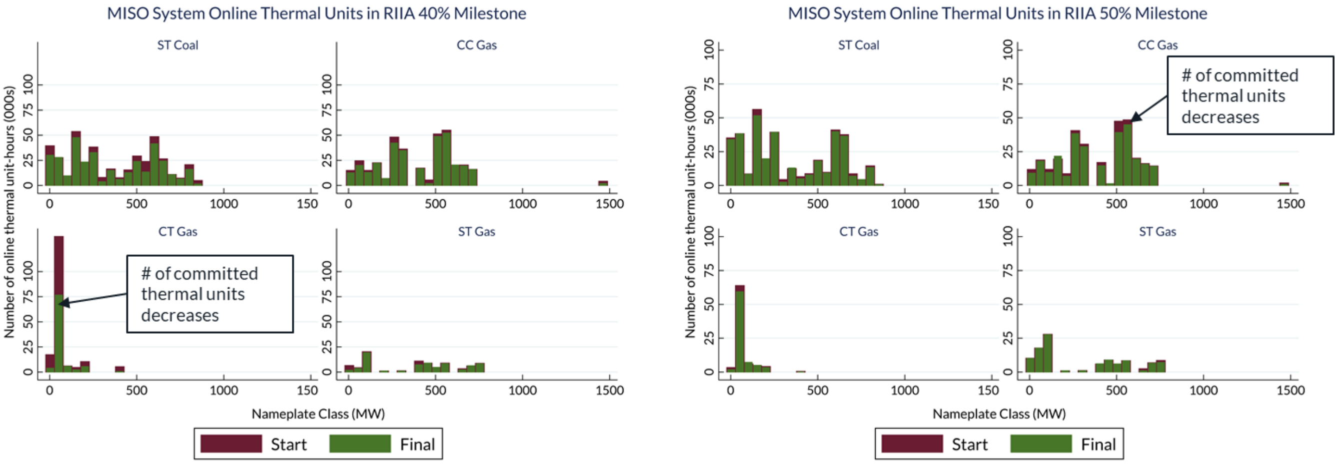


Figure EA-11: Commitment of coal and gas units in the RIIA 40% and 50% milestones

Finally, to reinforce the fact that ramping behavior is driven primarily by the relative economics between different fuels and technologies, an additional scenario assuming unlimited ramping capabilities of all thermal units in the model was tested. The right panel of Figure EA-12 (unlimited ramping), shows more gas CC units are consistently committed and dispatched in the production cost model to meet ramping needs from 30% to 50% milestones. This is true even when all types of conventional technology are assumed to have unlimited ramping capabilities, suggesting that the dispatch is based on economics.

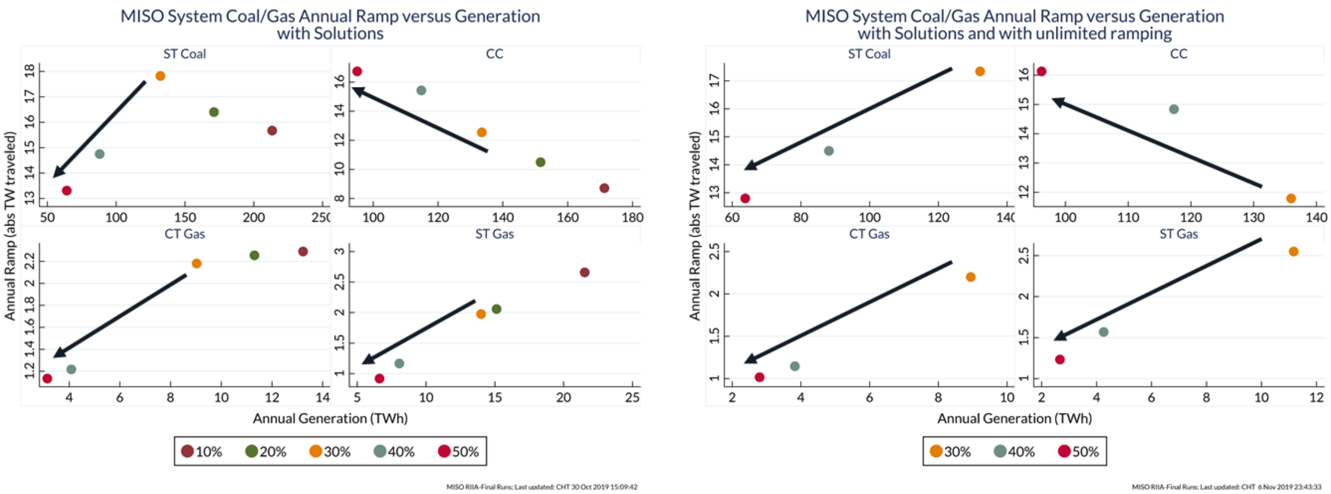


Figure EA-12: Thermal unit ramping in RIIA milestones, assuming unlimited ramping capabilities for all thermal units

Finding: Transmission Solutions Enable More Power Interchange, Using Diverse, Variable Resources from Across the Footprint

The intra-MISO powerflow increases in magnitude and becomes more variable with transmission solutions (Figure EA-13). Adequate transmission enables the production cost model to use diverse, variable resources across the footprint. The powerflow on MISO lines varies more, changes more quickly, and is more bi-directional once transmission solutions are included for the 40% and 50% milestones (Table EA-2).

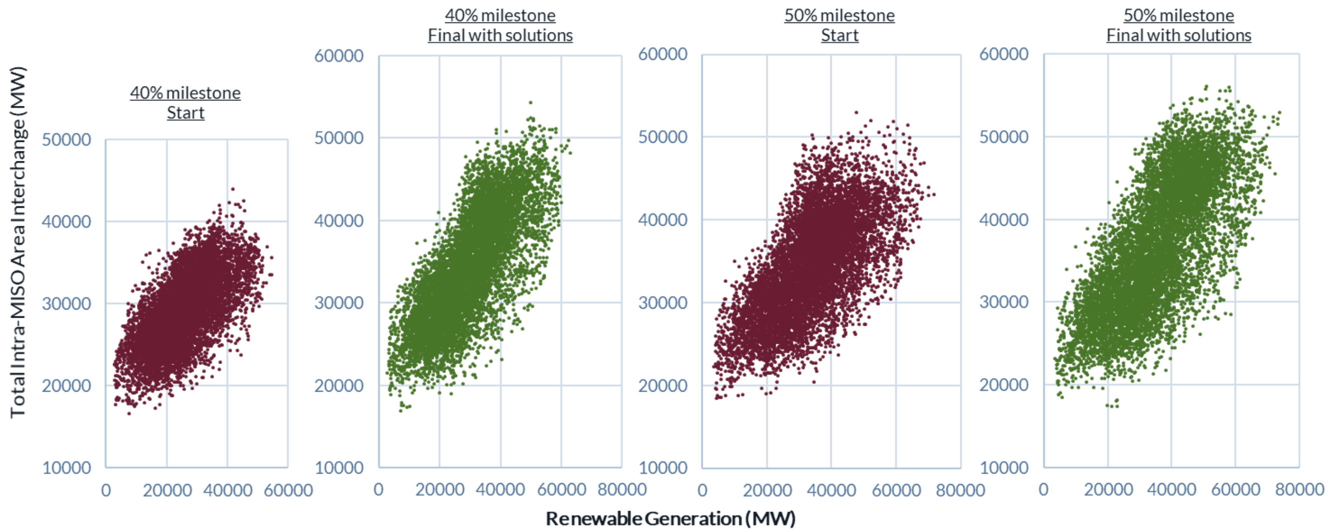


Figure EA-13: Intra-MISO power flow at RIIA 40% and 50% milestones before and after transmission solutions

Milestone	40%				50%			
Voltage class (kV)	345 and below	500	HVDC	765	345	500	HVDC	765
Pos (+) flow direction (hr. %)	55%	89%	77%	50%	61%	44%	56%	57%
Neg (-) flow direction (hr. %)	38%	11%	23%	50%	35%	56%	44%	40%
Pos (+) flow direction (MW %)	56%	96%	83%	48%	61%	41%	57%	59%
Neg (-) flow direction (MW %)	37%	4%	17%	52%	34%	59%	43%	38%
Standard deviation	256	467	1407	449	83	156	575	556
Average flow ramp / MW / hr	3%	2%	5%	2%	1%	1%	3%	1%
Ramp up max / MW	3%	19%	33%	8%	2%	4%	19%	2%
Ramp down max / MW	-4%	-19%	-34%	-8%	-3%	-4%	-22%	-2%

Table EA-2: Change of power flow direction and ramping

Lastly, MISO's energy interchange with neighboring Balancing Authorities (BAs) also increases after including transmission solutions, suggesting better utilization of the available and diverse resources across the entire Eastern Interconnection (Figure EA-14). The fact that new transmission enables this increase is illustrated by comparing the "BaseT", "Start," "Final," and "Unconstrained" models (as described in Table EA-1). The unconstrained model (right-most for both panels) represents the theoretical maximum amount of interchange, assuming no limitations on the existing transmission system. The BaseT model (left-most for both panels) represents the actual maximum amount of interchange for the existing system. By including incremental transmission solutions (Start and Final), it is seen that the interchange ranges increase, although they do not reach the levels seen in the unconstrained model. The increase from Start to Final is also larger seen in the 40% milestone but less obvious in the 50% milestone, suggesting the effect of incremental transmission solutions would diminish at higher penetration level.

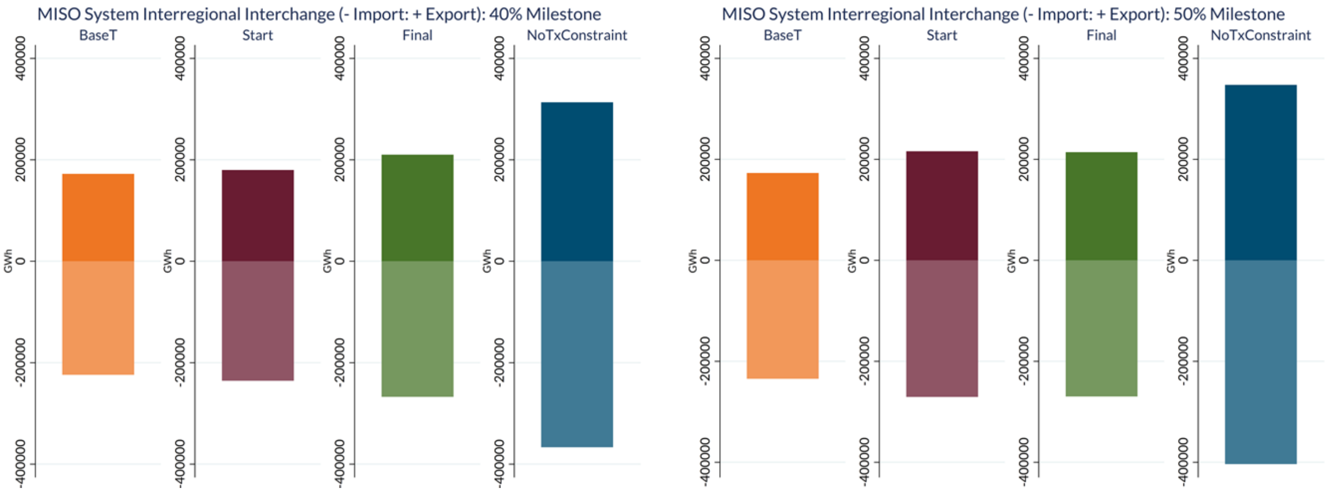


Figure EA-14: MISO interchange with neighboring BAs at RIIA 40% and 50% milestones for different models.

Finding: With transmission solutions, renewables continue displacing thermal generation across different times and locations, resulting in changes to power flows, thermal unit performance, and locational marginal prices.

Renewable energy displaces thermal generation as penetration level increases

Renewables displace thermal generation across different times and locations (Figure EA-15). This displacement is particularly notable in the North region, which is assumed to have a significant amount of wind generation capacity. Compared with the Base milestone, the conventional generation of the North region decreases sharply by the 50% milestone in all hours of the day, and in all months of the year. The same phenomenon is also seen in the Central region, where wind and solar together act to displace thermal generation. Lastly, in the South region, solar generation replaces gas in the middle of the day. It is also interesting to note that the total energy production in the South stays about the same between the Base and 50% milestone, suggesting that Southern solar production mostly replaces Southern thermal generation. In contrast, the Northern wind generation far exceeds its own load and, subsequently, acts to replace thermal generation in the Central region.

While focusing on daily peak hour (i.e. peak hour of each day; 365 data points in a model year), Figure EA-16 shows that wind has a notable contribution during the shoulder months, while solar contributes mostly in summer. This is because MISO daily peak-load hours during winter months often occur in early morning or early evening, and solar production is typically low in the morning or evening hours. In the Sensitivity section, the use of energy storage to shift solar production into evening hours will be evaluated.

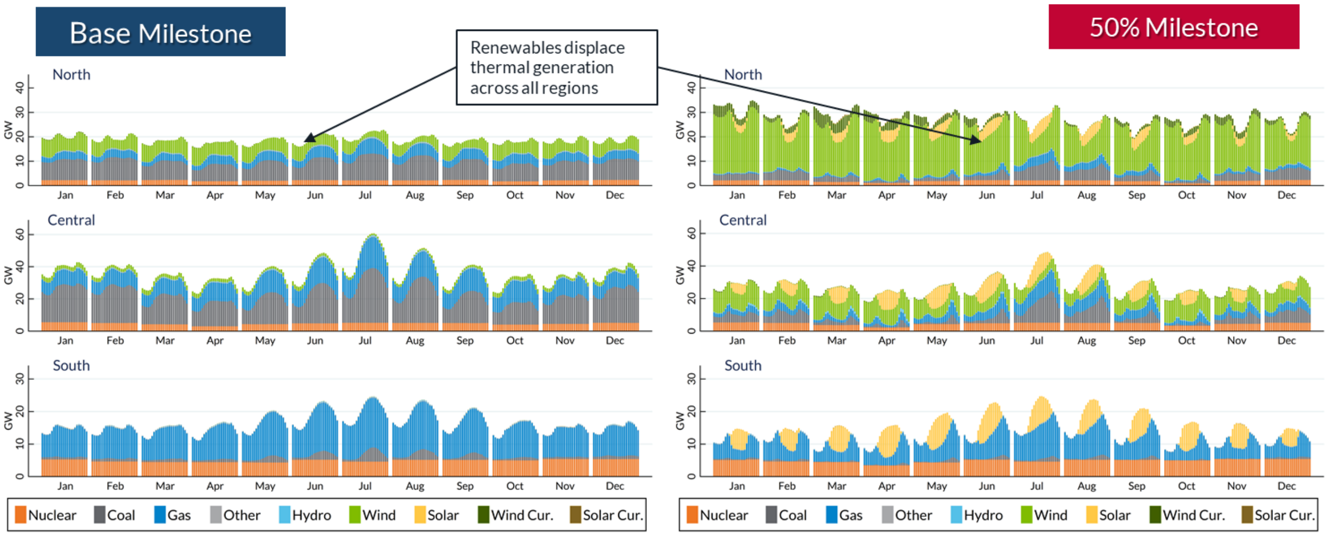


Figure EA-15: Monthly diurnal average of fuel mix at RIIA Base and 50% milestones

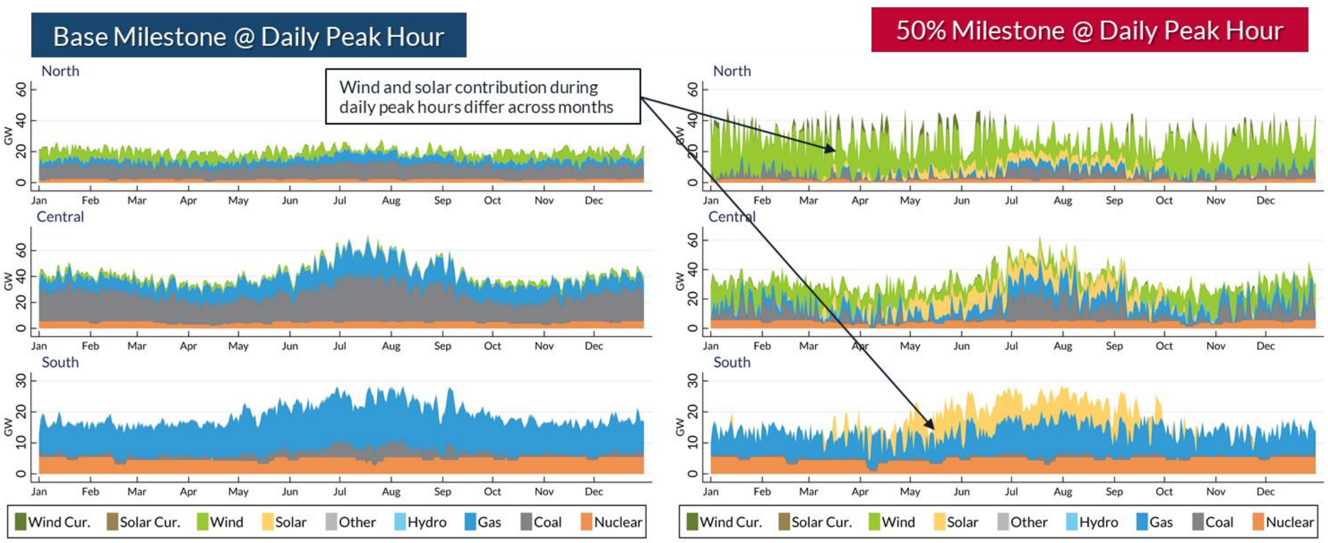


Figure EA-16: Daily peak hour of fuel mix at RIIA Base and 50% milestones

In the next three figures (Figure EA-17 through Figure EA-19), the incremental change of fuel mix between milestones is explored. The increase in wind curtailment in North region between the 20% and 30% milestones is notable in almost all months and hours, yet the target energy penetration is met (Figure EA-17). The incremental increase in renewable energy (excluding curtailment) is about the same magnitude as the incremental decrease in thermal generation output in most months, except during shoulder months in the Central region.

Moving between the 30% and 40% milestones and including transmission solutions (Figure EA-18), it is seen that the incremental increase in wind generation in the North far exceeds the incremental decrease of its thermal generation. Hence, excess North wind flows into the Central region and replaces Central's thermal output. In contrast, the increase in solar energy in the South impacts primarily the South thermal output, seen in the similar values and shapes between the solar incremental increase and thermal incremental decrease.

Lastly from the 40% to the 50% milestones (Figure EA-19), the sheer increase in wind and solar generation begins to reduce nuclear generation in shoulder months in both the North and South regions. Figure EA-20 shows a detailed hourly fuel mix for the month of April at the 50% milestone. When renewable energy production is high during low load months, as illustrated by April, nuclear units are dispatched down in favor of more flexible thermal units, which make up most of the remaining capacity in the South. Although the production cost modeling chose to turn nuclear units off for several days at a time, it is not expected that most nuclear units can provide such flexibility in operation.

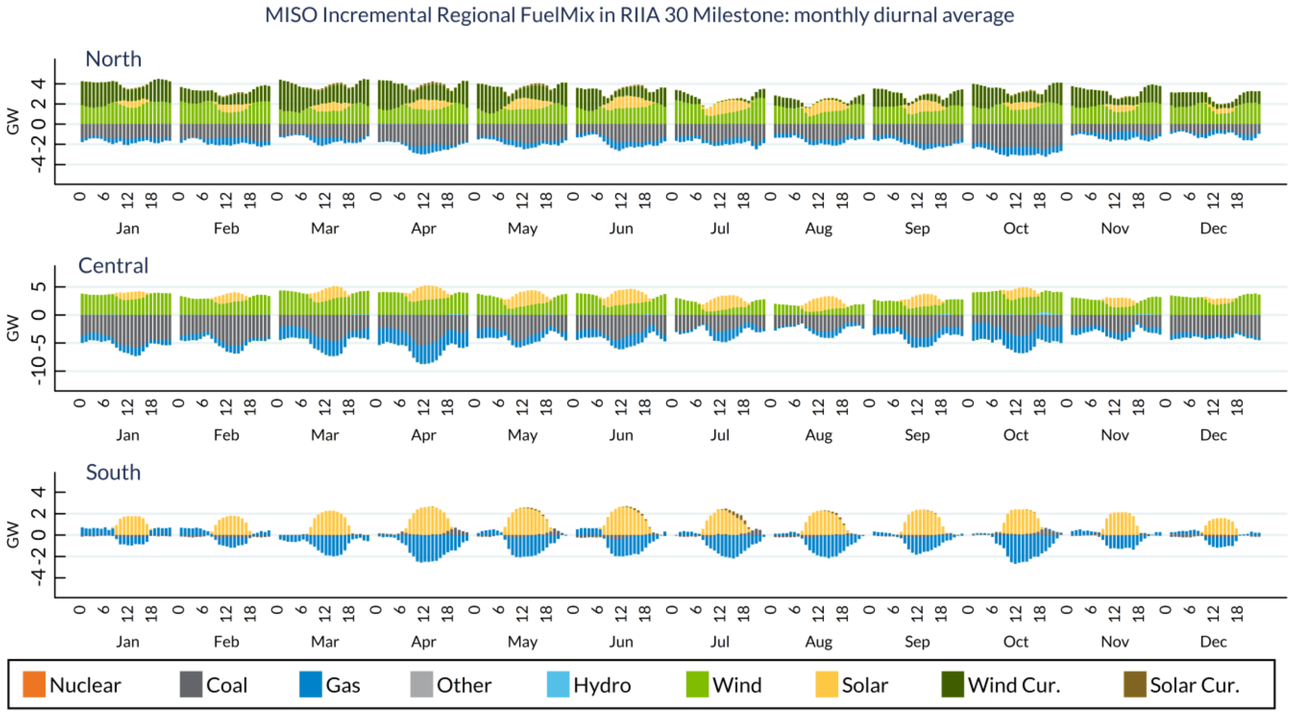


Figure EA-17: Monthly diurnal average of fuel mix, incremental change from the 20% milestone to the 30% milestone. Positive numbers indicate incremental increase, while negative numbers indicate incremental decrease.

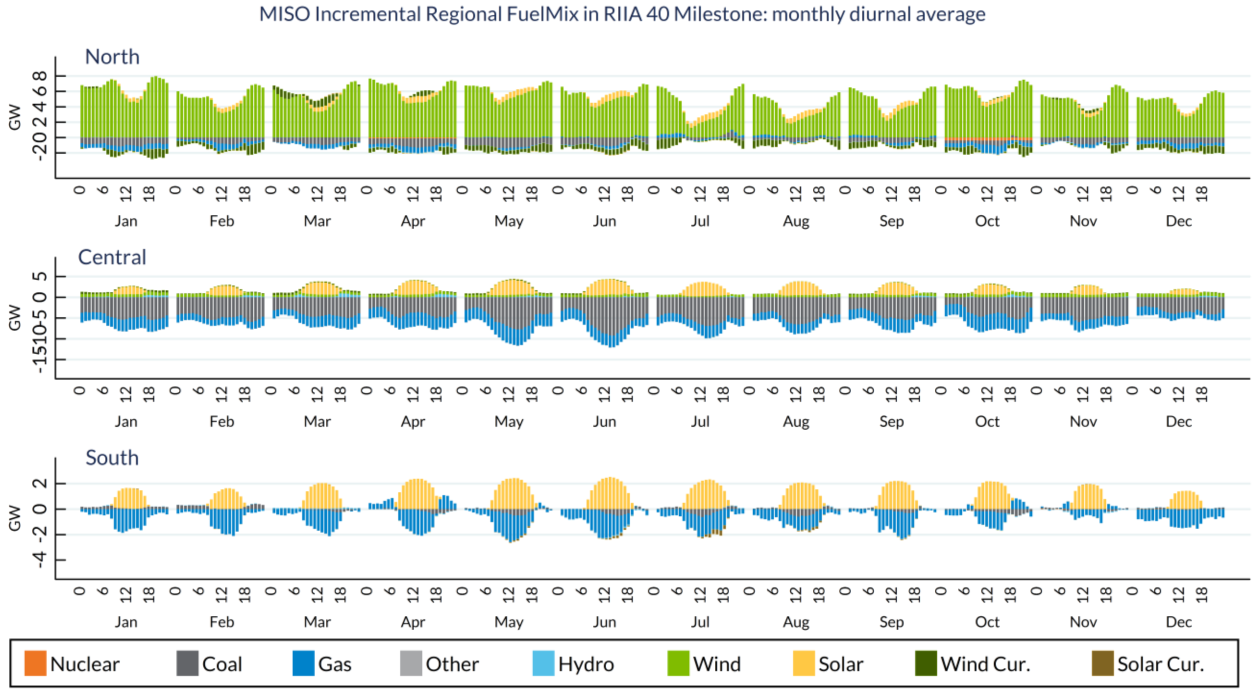


Figure EA-18: Monthly diurnal average of fuel mix, incremental change from the 30% milestone to the 40% milestone

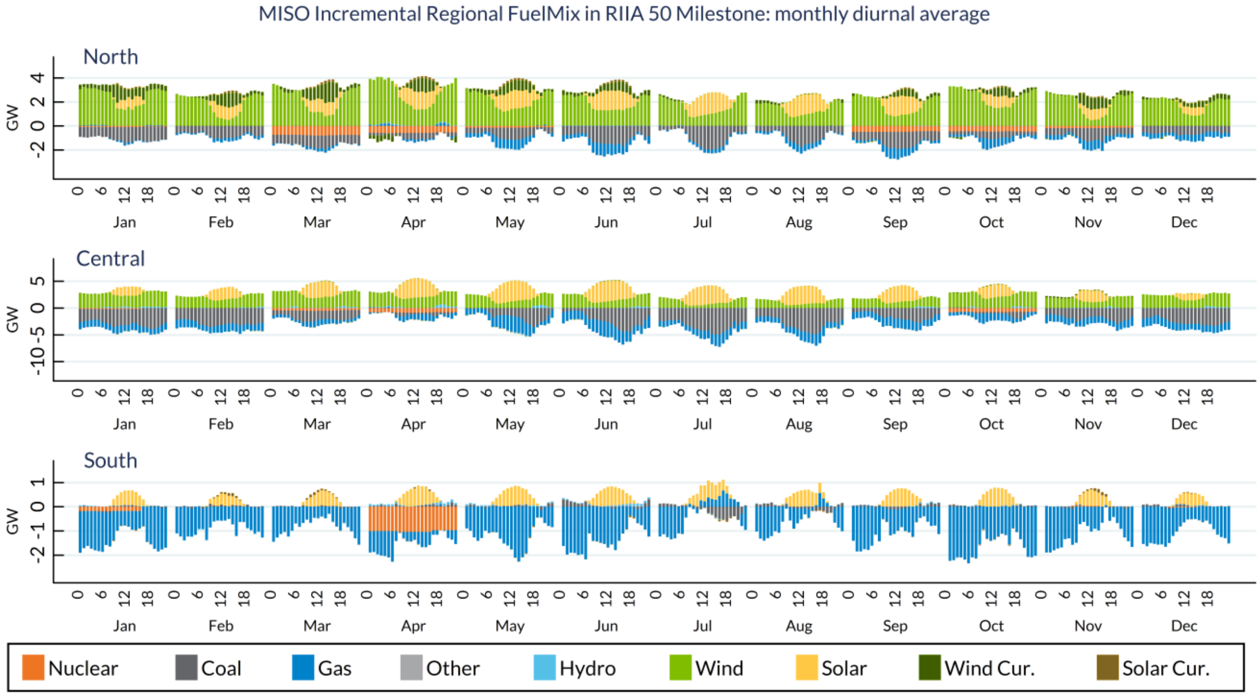


Figure EA-19: Monthly diurnal average of fuel mix, incremental change from the 40% milestone to the 50% milestone

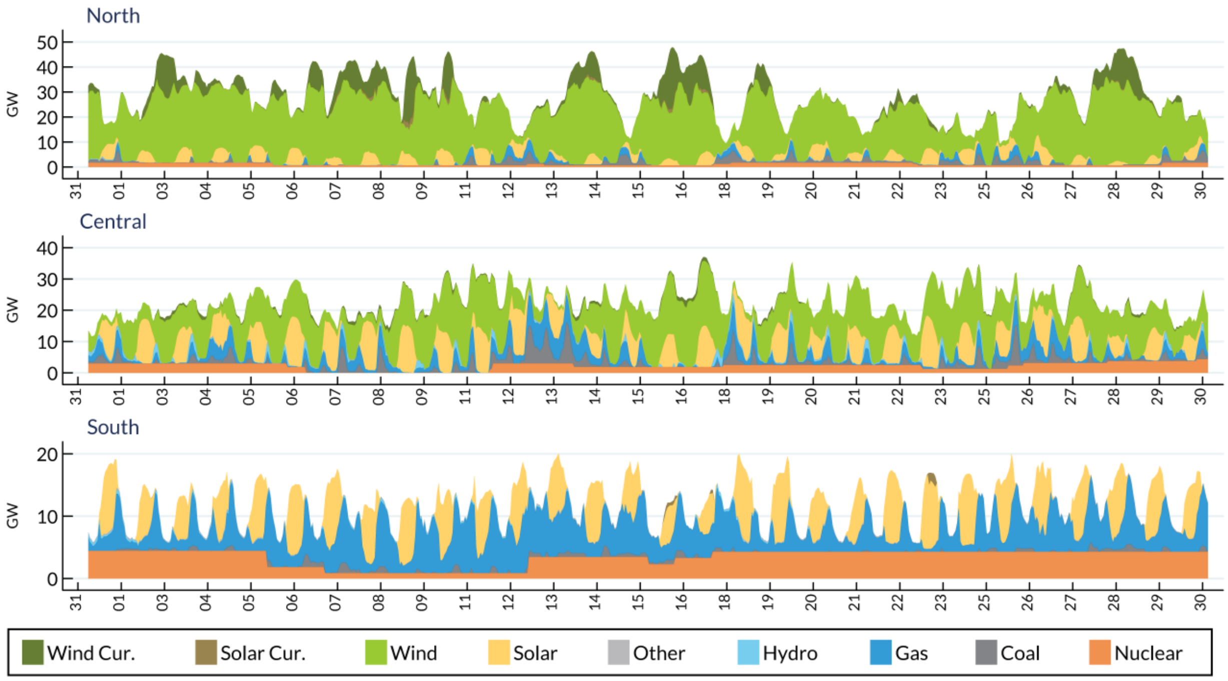


Figure EA-20: Hourly fuel mix in April for the RIIA 50% milestone

Finding: Increasing system renewable energy increases the magnitude and variability of interchanges within and external to MISO

As described in previous section, transmission solutions facilitate renewable integration and access to diverse resources across the entire footprint. Intra-MISO power flows increase accordingly in magnitude and become more variable as renewable penetration increases (Figure EA-21). This figure shows the intra-MISO interchange with respect to the instantaneous renewable generation; the height of the cloud of points indicates greater magnitudes of interchange, and the greater variability is illustrated by the fact that the lower bound of the cloud does not really shift upwards.

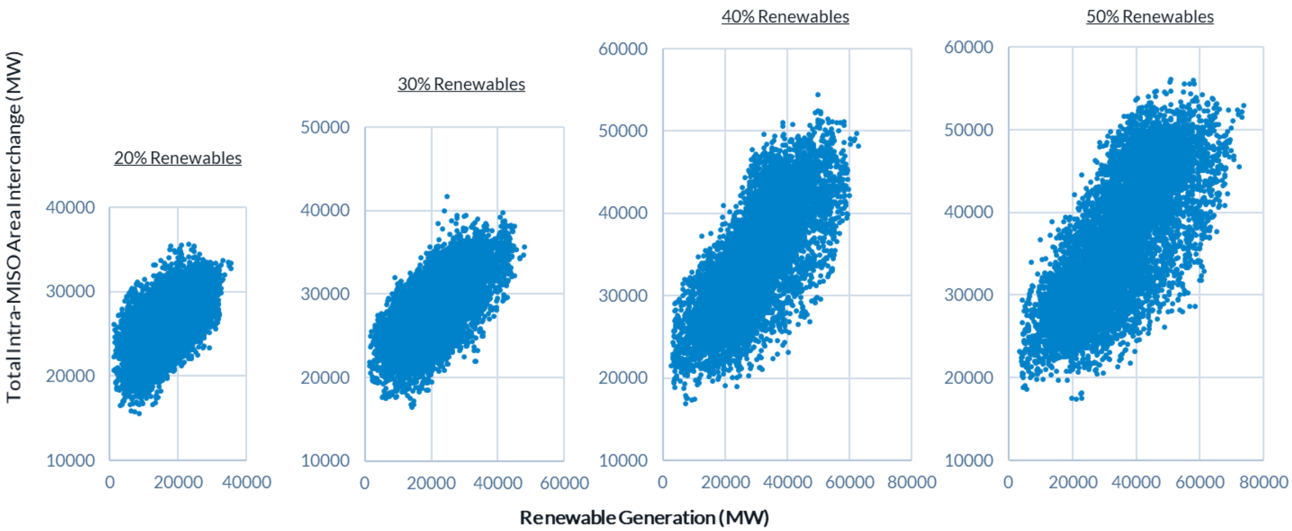


Figure EA-21: Intra-MISO interchange from RIIA 20% to 50% milestones. The increasing upper limit of the cloud of points indicates increased interchanges, while the increasing height of the cloud indicates increased variability

When looking into the patterns of power flow between the MISO North-Central and South regions, it is seen that the net South-to-North power flow increases during the middle of the day when solar is peaking in the South (Figure EA-22). On the other hand, MISO continues to increase imports from neighboring BAs (Figure EA-23); according to RIIA modeling assumptions, renewable capacity grows throughout the entire Eastern Interconnection (Figure EA-24). This indicates that the system may be able to take advantage of geographical diversity in renewable outputs and load.

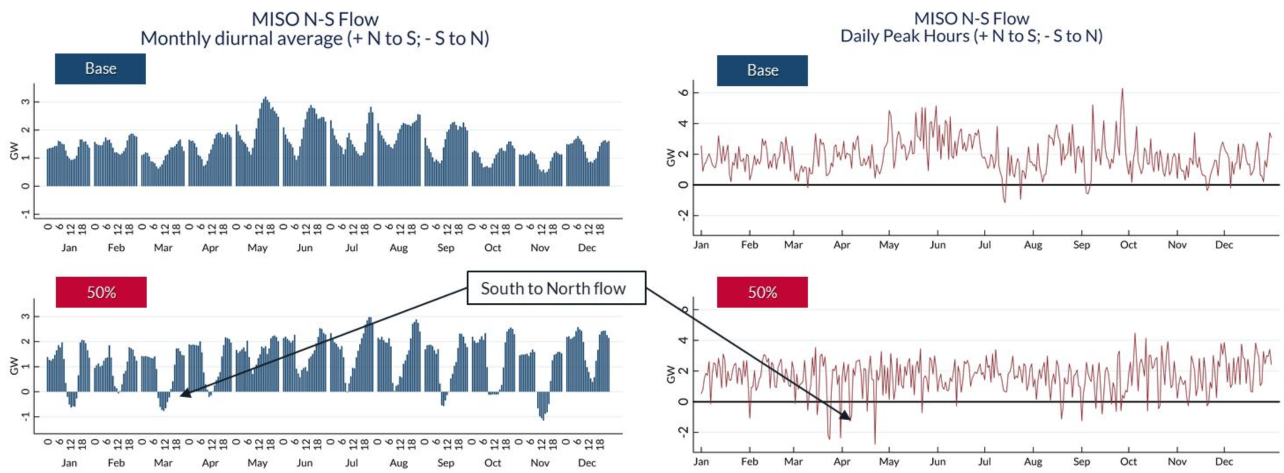


Figure EA-22: MISO North-South flow for the RIIA Base case and 50% milestone

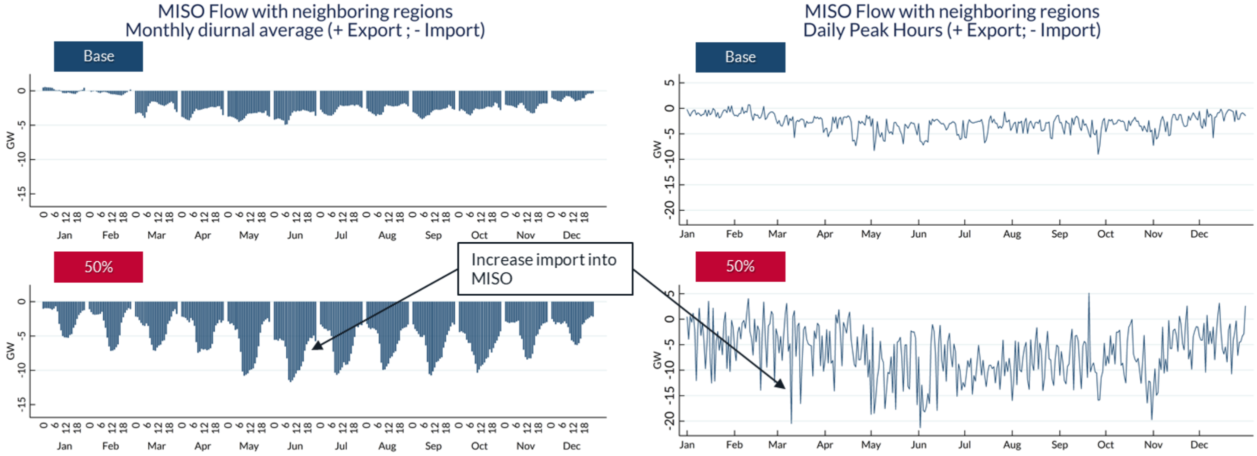


Figure EA-23: MISO flow with neighboring BAs for the RIIA Base case and 50% milestone

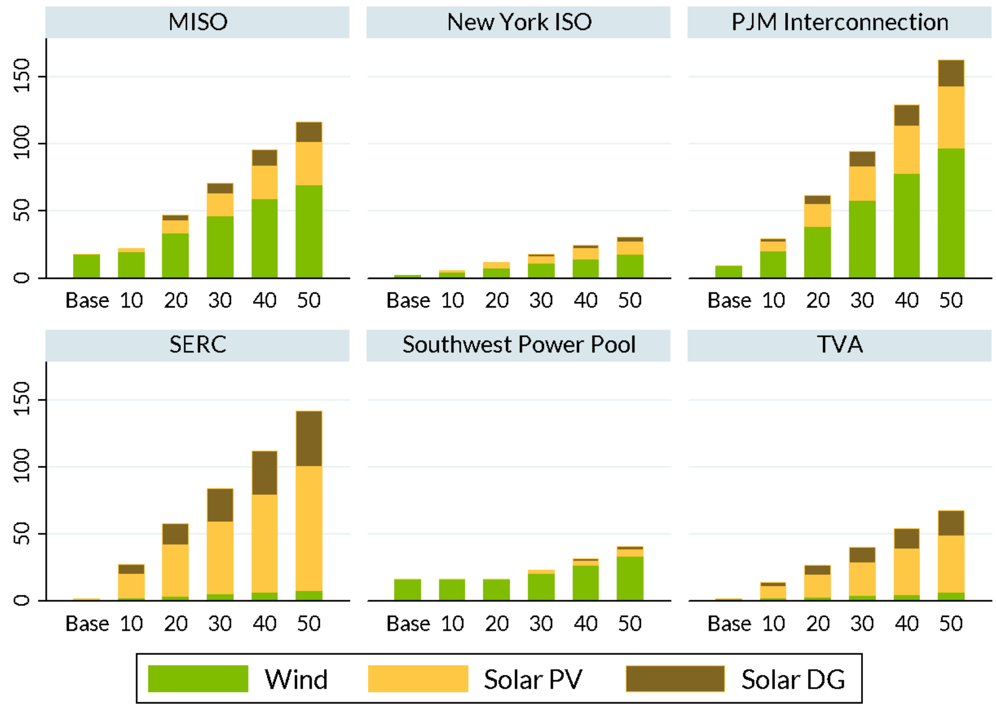


Figure EA-24: RIIA assumptions for renewable capacity expansion (GW) in the Eastern Interconnection

Because renewable capacity expansion was assumed to increase across the entire Eastern Interconnection, the next three figures (Figure EA-25 to Figure EA-27) will examine the relationship between MISO's system fuel mix and its interchange with neighboring BAs. Figure EA-25 shows the incremental change between the 20% to 30% milestones for the fuel mix (top panel) and interchange with neighboring BAs (bottom panel). The top panel of this figure shows that the incremental increase in renewable energy in MISO is smaller than the incremental decrease in MISO's thermal generation output, 10 GW to 14 GW, respectively. When cross-referenced with the bottom panel, it is clear that increased energy import from neighboring BAs is used to serve the load. In the 30% and 40% milestones when MISO wind production is abundant during shoulder months and off-peak hours, Figure EA-26 shows that MISO incrementally reduces energy imports during these time periods, while generally increasing the incremental import during middle of the day in all months. Lastly, when comparing the incremental changes between the 40% to 50% milestones, further increases in renewables in the shoulder months continues to reduce energy imports (Figure EA-27).

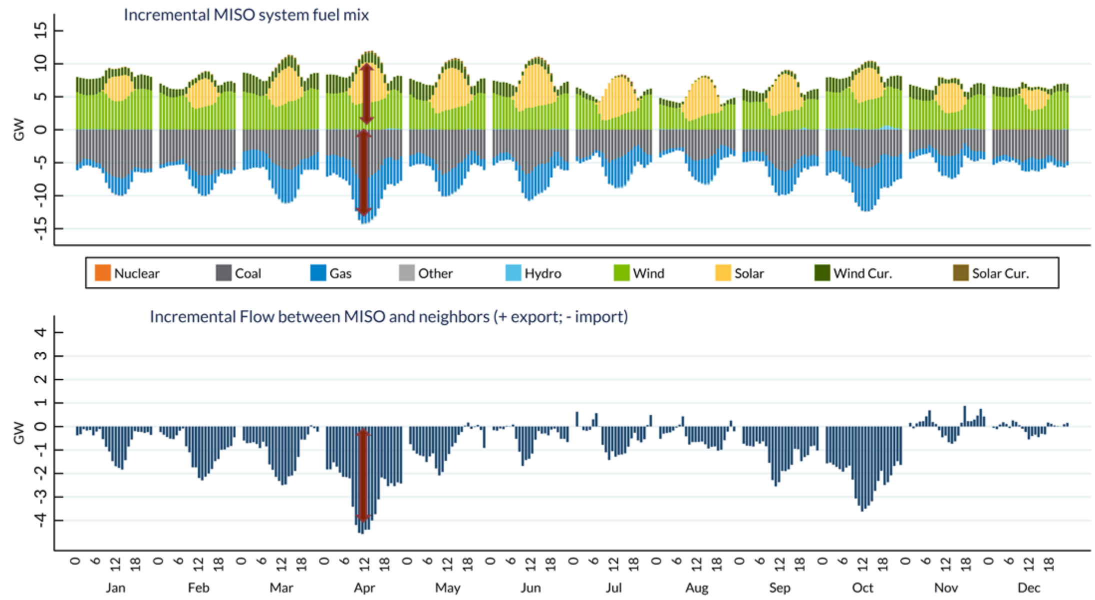


Figure EA-25: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 20% to 30% milestones

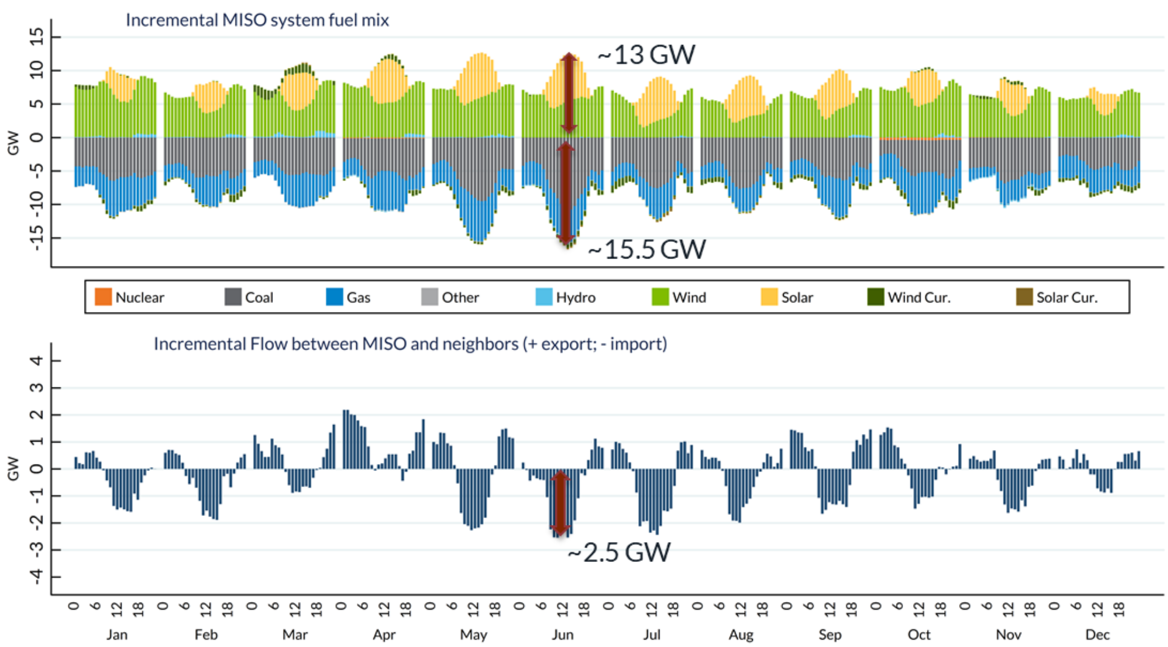


Figure EA-26: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 30% and 40% milestones

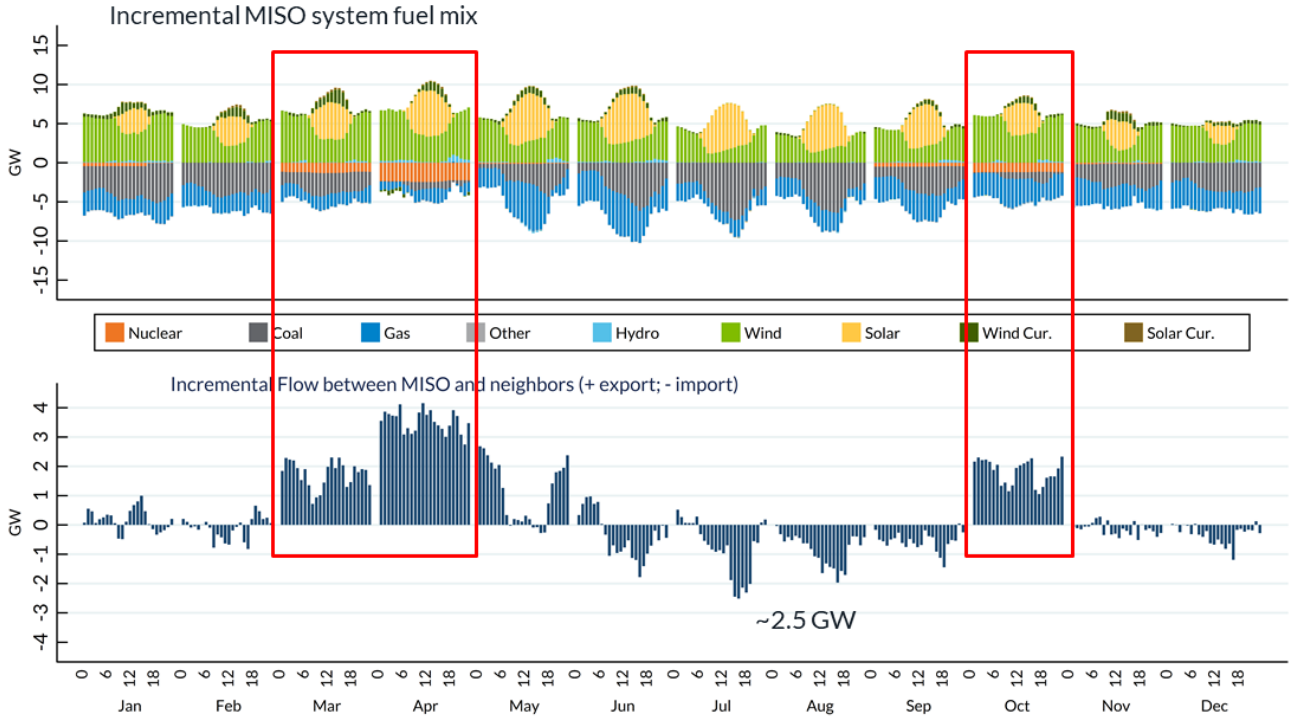


Figure EA-27: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 40% and 50% milestones

Finding: With higher renewable penetration, CC gas units fulfill system ramping needs, while the ramp demand for other types of thermal units decreases

Flexible units are needed to fulfill system need of ramping

In this section, attention is turned to the diurnal ramping pattern of thermal units, both system-wide and regionally. Figure EA-10 shows that CC gas units provide the majority of the new ramping needs as the ramp requirements from thermal units increase from the Base model up to the 50% milestone. This trend is also evident when comparing the diurnal ramping pattern of all four types of thermal generators. System-wide ramping from CC units increases consistently over most hours and months in the 50% milestone compared to the Base model (Figure EA-28). CT gas and ST gas are used to a lesser extent for the summertime evening ramps. The regional difference of diurnal ramping patterns are examined in Figure EA-29 through Figure EA-31. In the Central region (Figure EA-29), the largest coal unit ramp-ups decrease to approximately 2,000 MW and shift to primarily off-peak hours by the 50% milestone, while CC gas ramps increase in both directions by the 50% milestone. In the North region (Figure EA-30), the need for coal and CC gas ramping at higher penetrations increases during off-peak hours. Lastly in the South region (Figure EA-31), the CC gas and ST gas units are able to meet much of the system-wide flexibility need shown in Figure EA-28. In Figure EA-28, the system-wide CC gas ramping needs range from -4000 MW to 4000 MW and the South CC gas units can provide up to 3000 MW ramping in both directions (Figure EA-31).

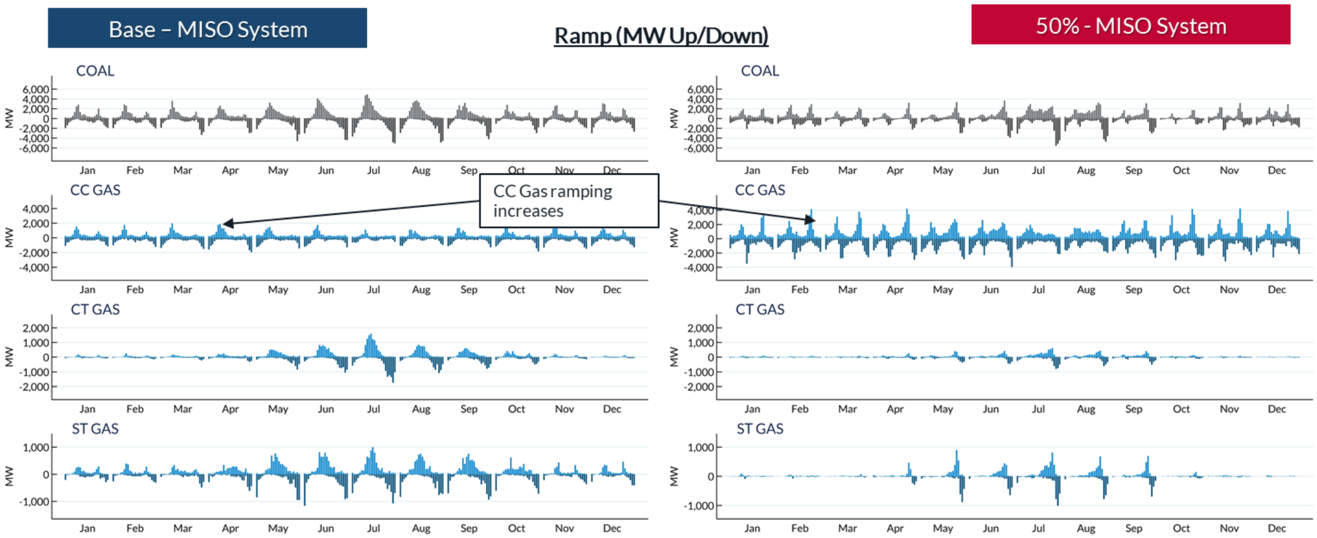


Figure EA-28: Monthly diurnal average of MISO system thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

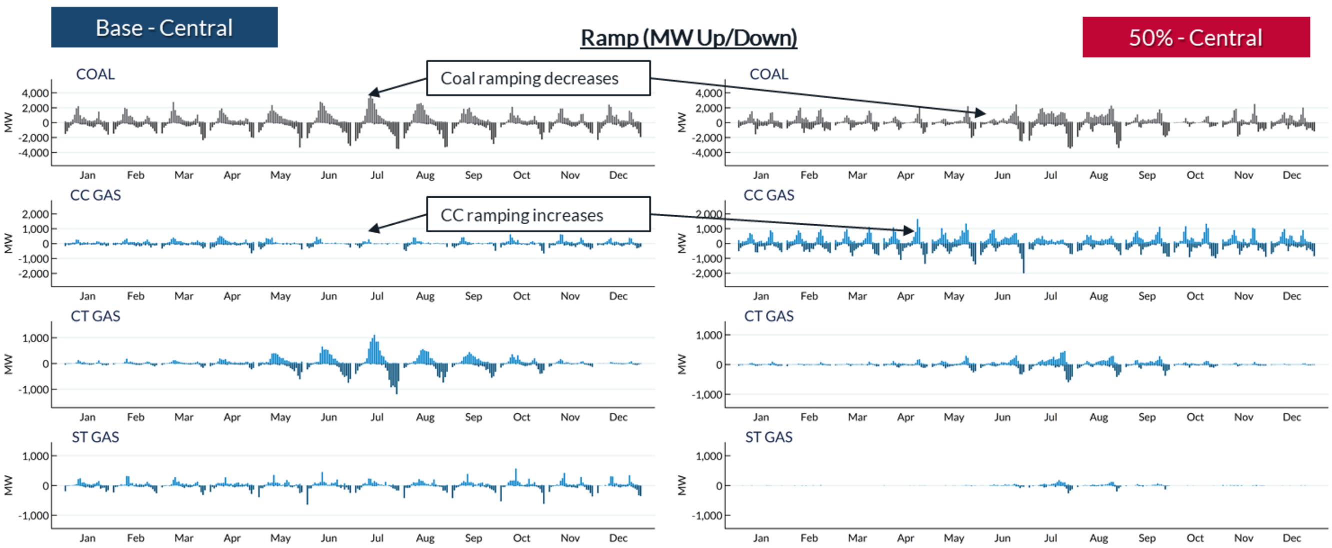


Figure EA-29: Monthly diurnal average of MISO Central thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

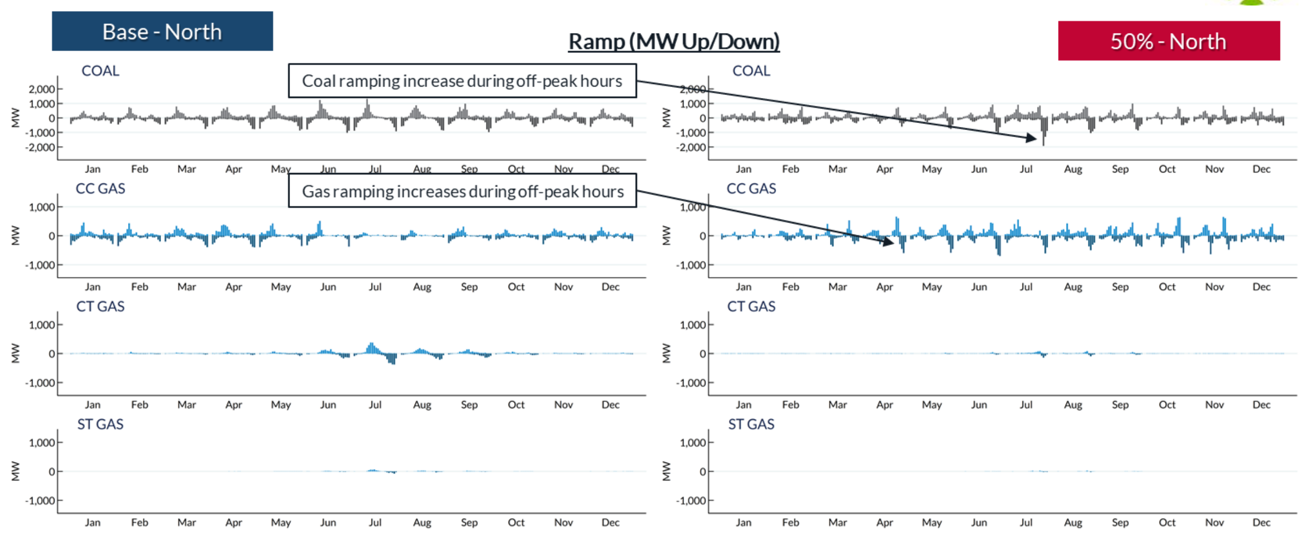


Figure EA-30: Monthly diurnal average of MISO North thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

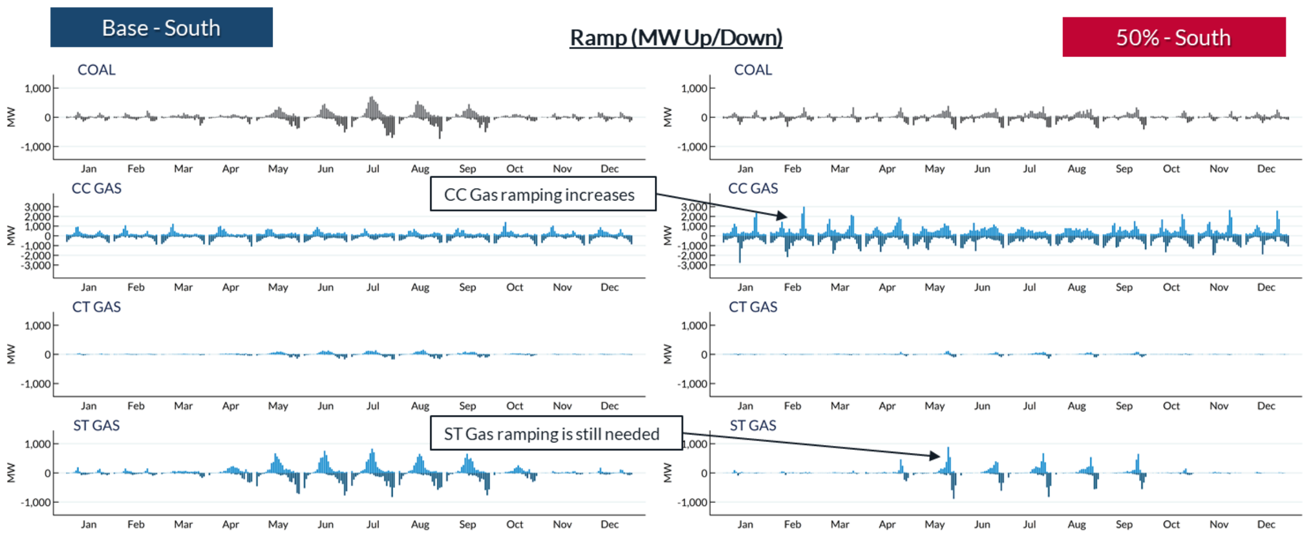


Figure EA-31: Monthly diurnal average of MISO South thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

Finding: Thermal unit commitment increases and develops two daily peaks

Since thermal unit ramping must be supplied by either online units or through committing offline units, this section explores the diurnal pattern of thermal unit commitment, i.e. ramping from zero output. Figure EA-32 shows that the greatest need to commit units for ramping shifts from the summer to the shoulder months. A new pattern of two daily peaks for commitment appears the shoulder months to accommodate rapid changes in renewable generation during early morning and late afternoon hours.

When looking into the differences between the commitment for the four major types of thermal units, Figure EA-33 shows that CC gas and coal units are consistently committed to meet the double-peak net-load pattern at the 50%

milestone. This represents a significant change from the Base model, where unit commitment for ramping was clustered into just one peak for meeting the traditional afternoon peak.

The regional differences in thermal unit commitment were also explored (Figure EA-34 through Figure EA-36). In both the Central and North regions (Figure EA-34 and Figure EA-35), coal and CC gas units were increasingly needed in the off-peak hours of shoulder months by the 50% milestone, compared to the Base model. However, the capacity of committed units in the North region is lower than in the other regions, suggesting that the North is benefiting from flexibility provided by other MISO regions. This inference seems borne out by the fact that CC gas units in the South provide a notable share of the capacity committed to meet system flexibility needs.

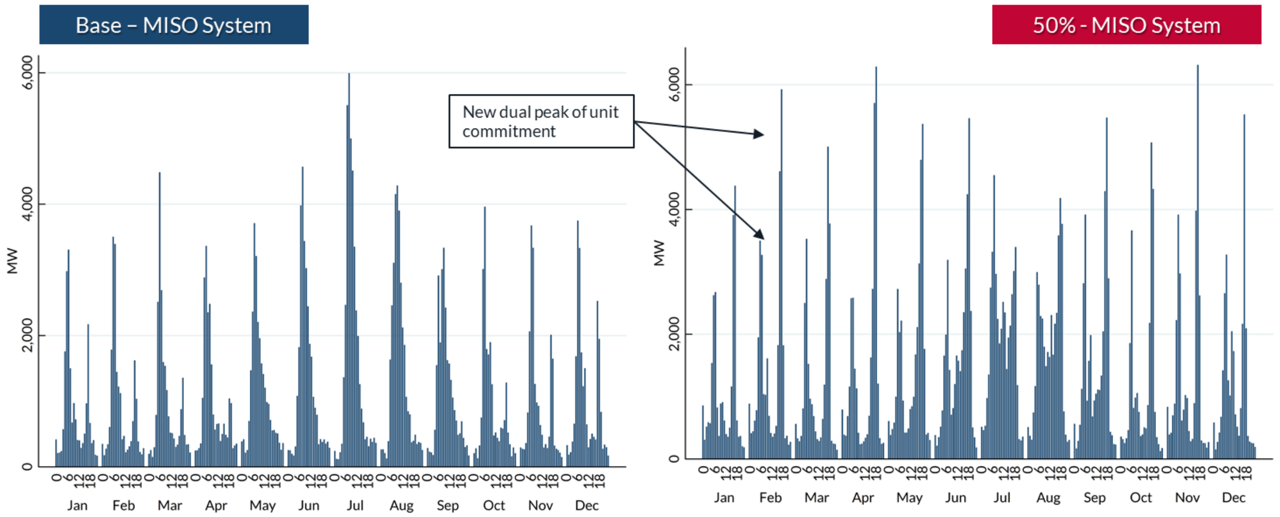


Figure EA-32: Monthly diurnal average of MISO system-wide thermal units commitment for RIIA Base model (left) and 50% milestone (right)

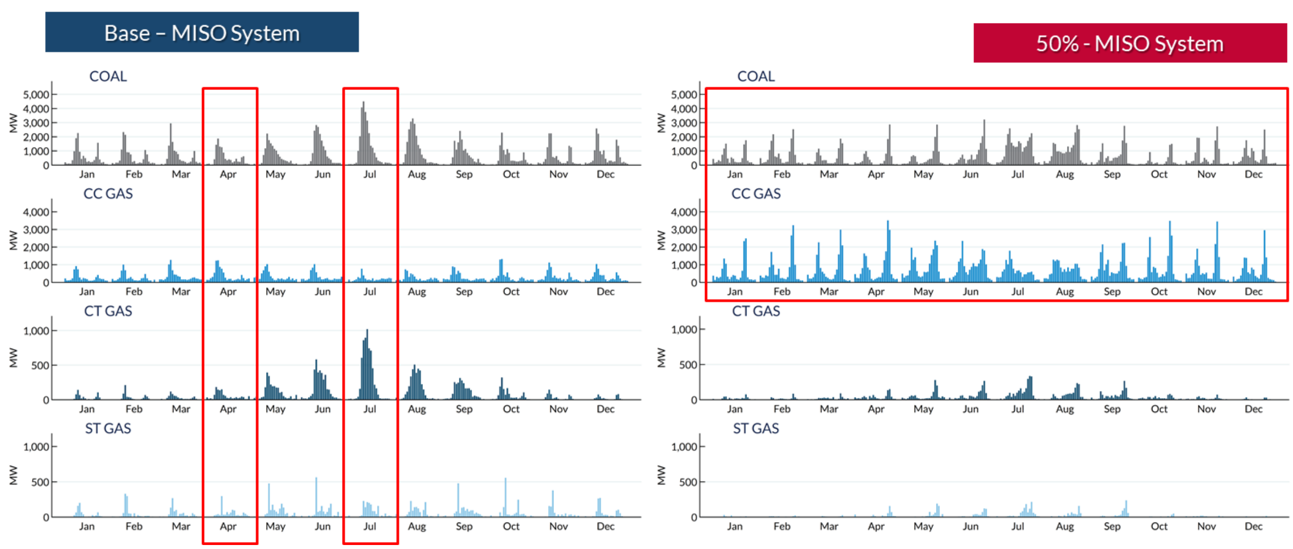


Figure EA-33: Monthly diurnal average of MISO system thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

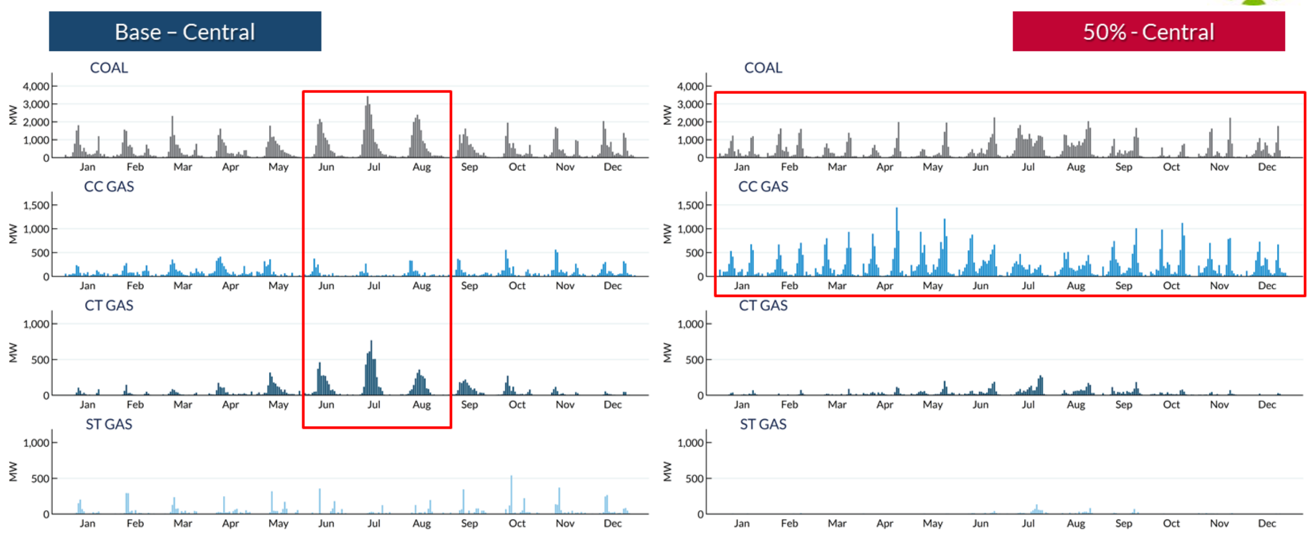


Figure EA-34: Monthly diurnal average of MISO Central thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

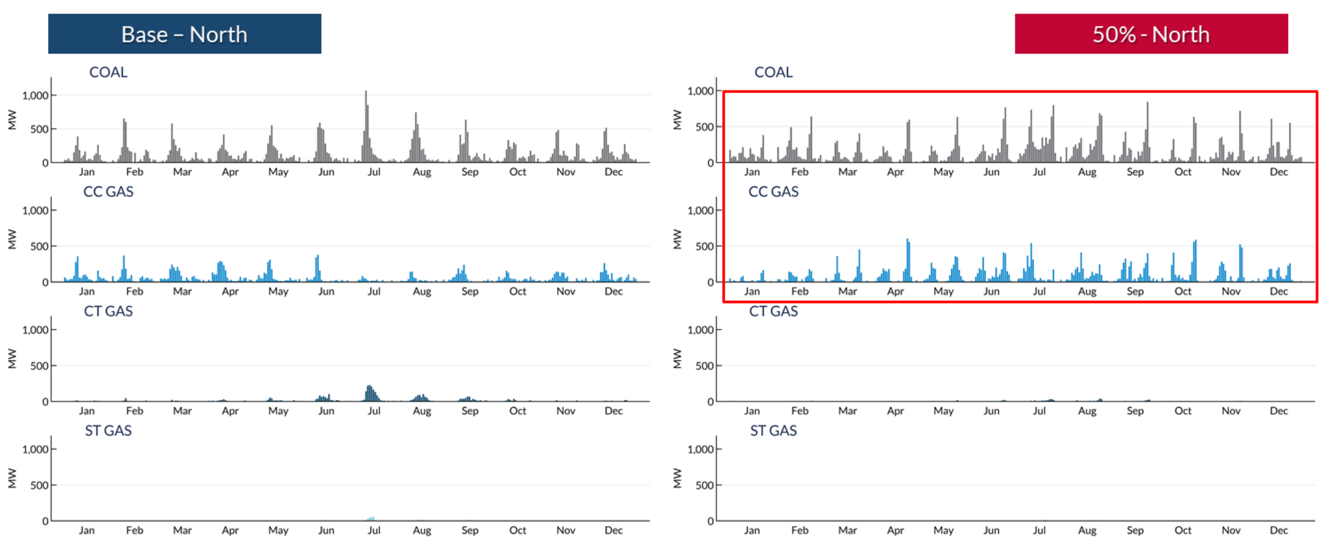


Figure EA-35: Monthly diurnal average of MISO North thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

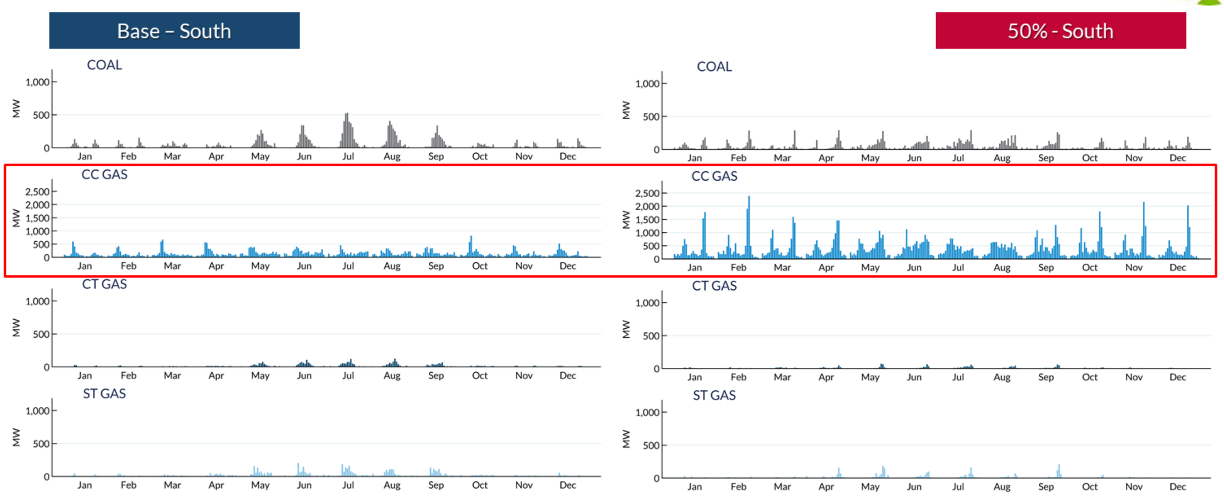


Figure EA-36: Monthly diurnal average of MISO South thermal units commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

Finding: Increasing renewables changes locational marginal prices of renewable locations

Increased renewable electricity generation and decreased natural gas prices across the United States have led to concurrent changes in electricity prices, and such price decreases influence not only the economics of incumbent thermal units, but also the value of renewable electricity. Using the results of the RIIA production cost simulation combined with regression-based analysis methods, the average price impact ($/MWh) per 1 GW of renewable generation was calculated for each penetration milestone. The data in Figure EA-37 suggest that increasing renewable resources impact the LMPs at wind and solar locations more than the LMPs at thermal unit locations. As a rich literature has examined the empirical effect of increasing renewable generation on system-wide wholesale electricity price based on historical data, this study sheds light on how the electricity price may continue to change in a world with high renewable penetration. When evaluating the average price impact, the important comparison is between each of the technology types and not to compare across milestones. For example, it is clearly seen that wind has the largest decrease in price per GW; it is approximately twice as large as the decrease seen for all other technologies at the 20% milestone.

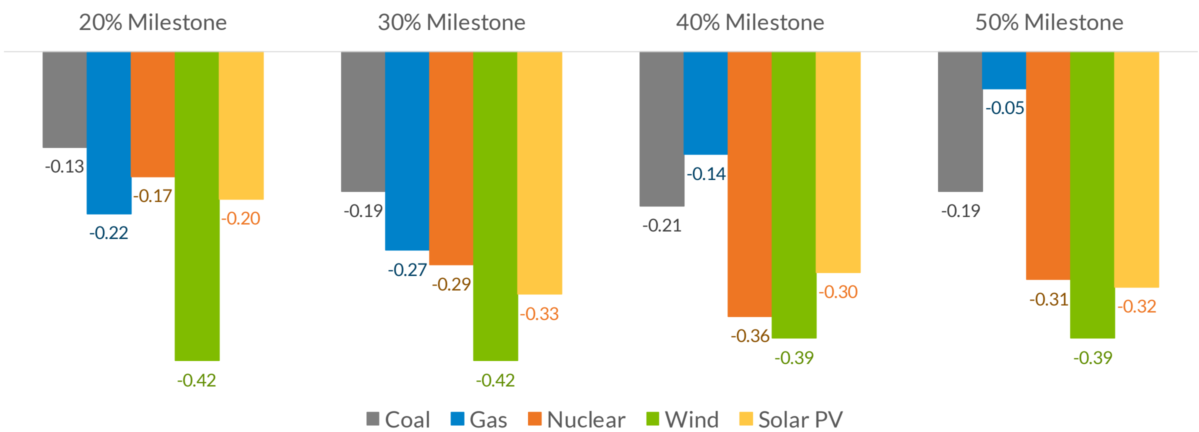


Figure EA-37: Average price impact* ($/MWh) per 1 GW of renewable generation within each milestone**

*** Average price impact through all hours in each RIIA milestone**

**** Regression-based methods were used to identify average price impact ($/MWh) per 1 GW renewable generation.**

Energy Adequacy – Planning: Sensitivity Analysis

Sensitivity analysis is a technique to test model assumptions individually and determine the impact that they may have on the conclusions reached in previous analysis. The results of the previous section following the assumptions outlined in the Technical Assumptions Chapter. In testing the impact of these assumptions on the study finding, the following key questions were considered:

- Can the renewable penetration targets be met in all sensitivities, when key model assumptions have been modified?
- How would the following metrics change due to different assumptions?
  - Fuel mix
  - Locational marginal price (LMP)
  - Thermal unit ramping
  - Power flows
- For each sensitivity, are there any changes to key system operating points that may warrant further analysis?

Table EA-3 lists the key model assumptions that were changed as a part of the sensitivity analysis. Four primary areas of assumptions were changed and each of these is referred to as a "sensitivity": fuel price, generator characteristics, generator retirements, and siting. The column titled "Phase 2 Assumption" describes the assumptions used for the analysis in the previous sections; the column titled "Phase 2s Assumption" describes the assumptions used for the sensitivity analysis.

The first sensitivity is related to fuel price assumption. The original RIIA work used fuel price parameters from the 2017 MISO Transmission Expansion Planning Study (MTEP17), which is the year RIIA began. In the fuel price sensitivity, future out-year fuel prices from MTEP19 were used. The second sensitivity is related to generator operating parameters used in production cost modeling, such as ramp rates, start-up time, etc. In the generator characteristics sensitivity, those assumptions were modified based on actual parameters offered into the MISO Energy and Operating Reserve markets, instead of using numbers developed by data vendors. Because the assumptions of this sensitivity come from the MISO Market, it is called the "market data" sensitivity.

The third and fourth sensitivities addresses thermal generation resource retirement and two different cases were tested: a no retirement case, i.e. all thermal generating units are available, and a high retirement case, i.e. thermal units have accelerated retirement. In the final sensitivity, the capacity mix between wind and solar resources was changed to reflect recent trends in the MISO Generation Interconnection Queue, where more and more capacity applying for interconnection is solar.

Sensitivity	Phase 2 Assumption	Phase 2s Assumption
Fuel price	MTEP17 fuel prices	MTEP19 Accelerated Fleet Change (AFC) Future out-year prices
Generator characteristics	Generator characteristics sourced from ABB and NREL	Generator characteristics from MISO proprietary data
Generator retirements	Use net revenue Net Present Value (NPV) to determine which units to retire Capacity value of renewables based on Resource Adequacy work	Zero retirements High retirements (based on MTEP19 AFC Future assumption) Capacity value of renewables from Phase 2 calculations (unchanged)
Siting	Wind and Solar 75:25 Siting and expansion at the entire system level	Wind and Solar ~50:50 at 50% milestone Localized expansion and siting by LRZ load ratio

Table EA-3: Key assumptions for sensitivity analysis

Finding: Renewable penetration targets are met for most sensitivities when all the RIIA Phase 2 transmission solutions are included.

Table EA-4 lists the penetration levels reached in all sensitivities for all milestones, when the transmission solutions from the initial work were included. Thus, the ability of transmission solutions to enable the target penetration levels is not greatly impacted by the changes to input assumptions for all five sensitivities. The high retirement sensitivity at the 50% milestone is the sensitivity that falls short of penetration target, suggesting aggressive thermal unit retirement may lead to insufficient capacity for meeting the flexibility needs in high renewable penetration scenario.

Figure EA-38 shows the annual fuel mix for the original work (Phase II-Final) and all five sensitivities. From this figure, the most notable difference when compared with Phase II-Final is seen in the fuel price and siting sensitivities. This is a result of the different fuel price and the modified wind and solar capacity mix. In the next section, how the key metrics change due to different assumptions in each sensitivity will be discussed.

	RIIA milestone	10%	20%	30%	40%	50%
	Phase II Final with solutions	**11.07%**	**20.87%**	**29.08%**	**39.38%**	**46.99%**
	Fuel price sensitivity	11.14%	21.28%	29.29%	40.76%	48.15%
	Market data sensitivity	11.14%	21.05%	29.40%	39.67%	47.37%
	No retirements sensitivity	11.15%	20.95%	29.28%	39.46%	47.11%
	High retirements sensitivity	11.15%	20.88%	28.97%	39.36%	45.97%
	Siting sensitivity	11.42%	21.07%	31.38%	41.44%	50.84%
	Phase II Final with solutions	**73.22**	**137.99**	**192.27**	**260.36**	**310.72**
	Fuel price sensitivity	73.69	140.74	193.67	269.52	318.37
	Market data sensitivity	73.67	139.19	194.41	262.33	313.23
	No retirements sensitivity	73.73	138.54	193.62	260.91	311.52
	High retirements sensitivity	73.73	138.09	191.57	260.25	303.99
	Siting sensitivity	75.48	139.31	207.47	274.00	336.19

Table EA-4: Renewable energy production and penetration in sensitivity analysis for all RIIA milestones. Penetration levels that come within 95% of the target value are classified as "meeting" the target.

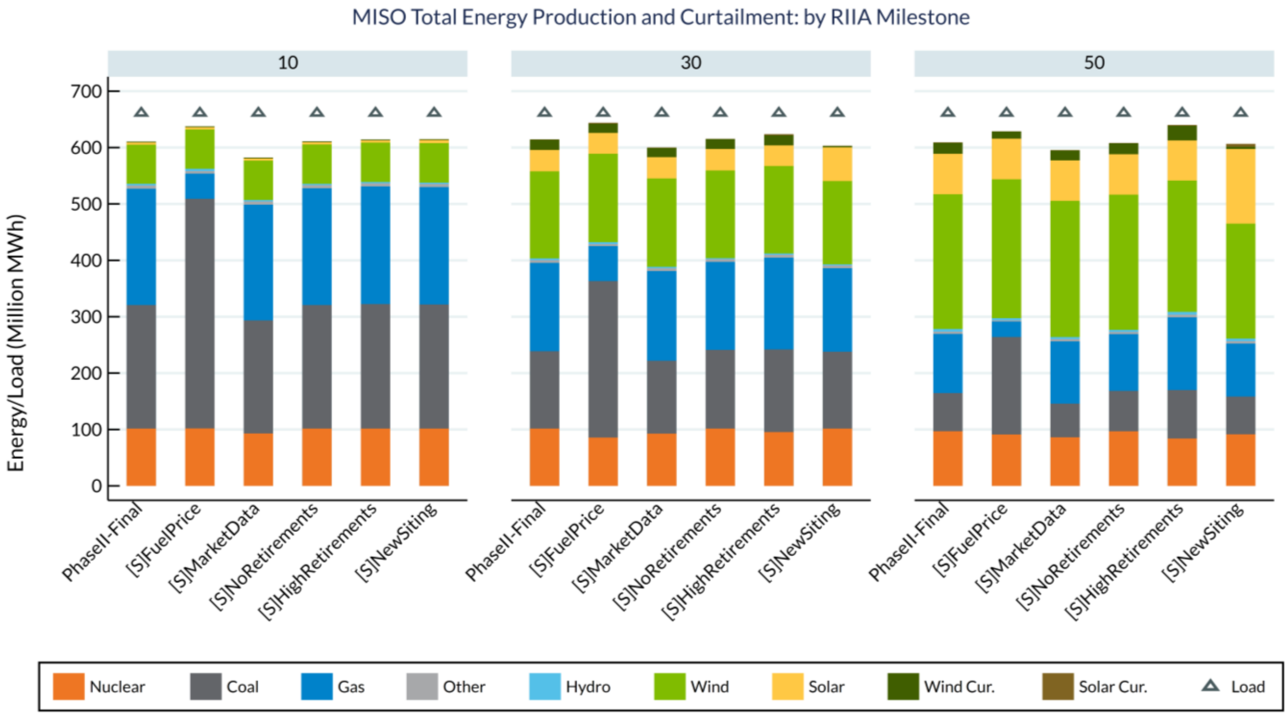


Figure EA-38: Annual energy production by fuel type for the 10%, 30%, and 50% milestones for sensitivity analysis; sensitivities are indicated by [S]

(A) Fuel price sensitivity

In the fuel price sensitivity, the out-year fuel prices from MTEP19 were used. Most prices decreased (Figure EA-39). The notable exception was the gas price, which more than doubled from an average of $2.53/MBtu in the Phase II-Final model to $5.56/MBtu in the sensitivity.

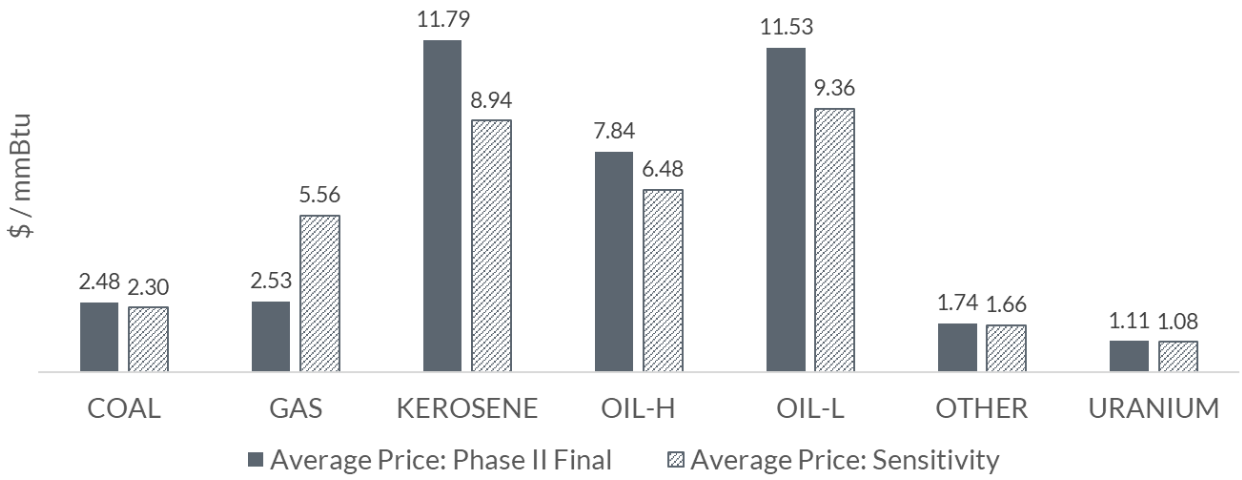


Figure EA-39: Fuel price assumptions in fuel price sensitivity

As expected, the relatively high gas price assumption in the fuel price sensitivity resulted in coal units being dispatched more than gas units. High gas prices drive the switch from gas generation to coal generation, while the system as a whole still meets the renewable penetration milestone (Figure EA-40). The high gas prices also increase the system average LMP, as the gas units are often the margin-clearing generators.

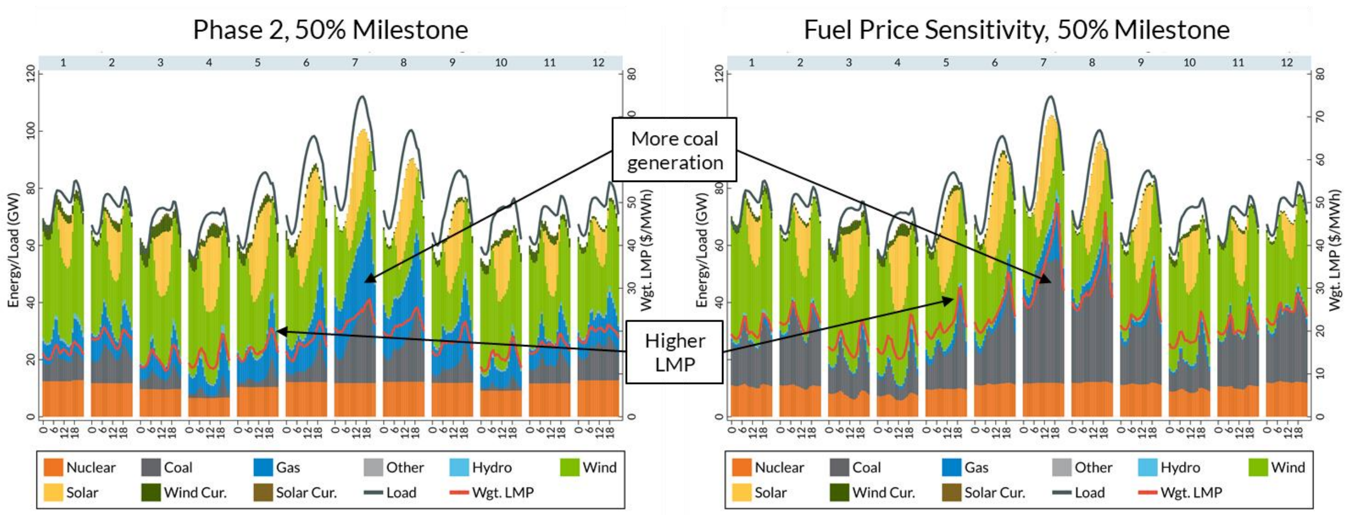


Figure EA-40: Monthly diurnal average of fuel mix and LMP in the fuel price sensitivity (right), compared to the previous assumptions (left)

With the high gas price assumption in the fuel price sensitivity, the increases in system LMPs are notable at the daily peak load hours. The LMPs in the fuel price sensitivity (right panel) are higher in almost all peak hours than the LMPs in Phase II-Final model (left panel) (Figure EA-41). The price volatility also increases, particularly during the summer months.

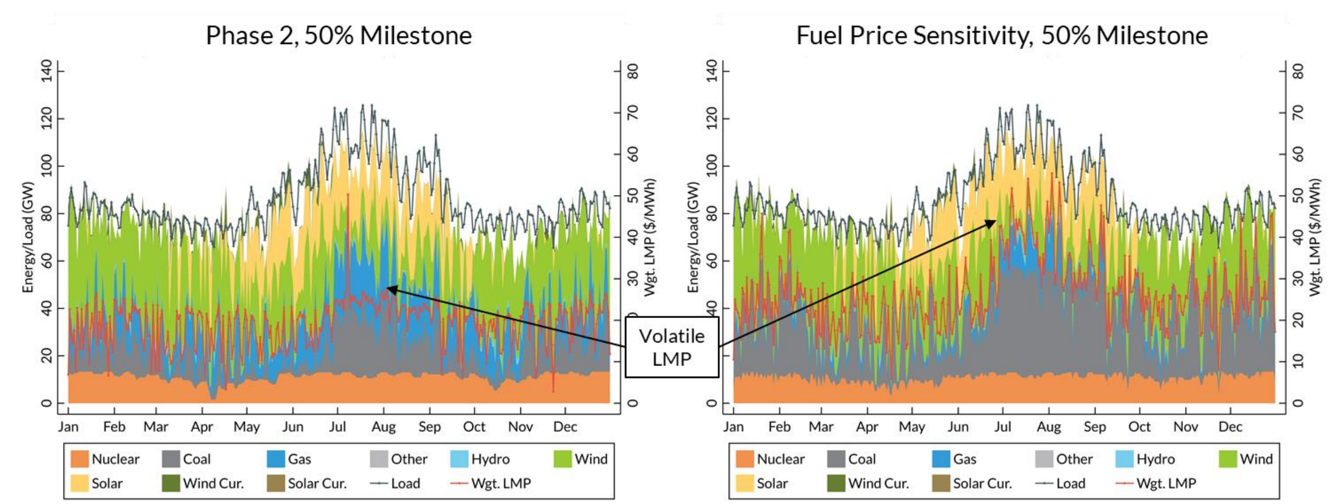


Figure EA-41: Daily peak hour fuel mix and LMP in the fuel price sensitivity (right), compared to the previous assumptions (left)

Because coal units displace gas generation due to pricing, most ramping needs in the fuel price sensitivity are supplied by coal ST units, instead of gas CC units (Figure EA-42). This finding suggests that based on the current operating assumptions, coal units are capable of supporting system flexibility needs.

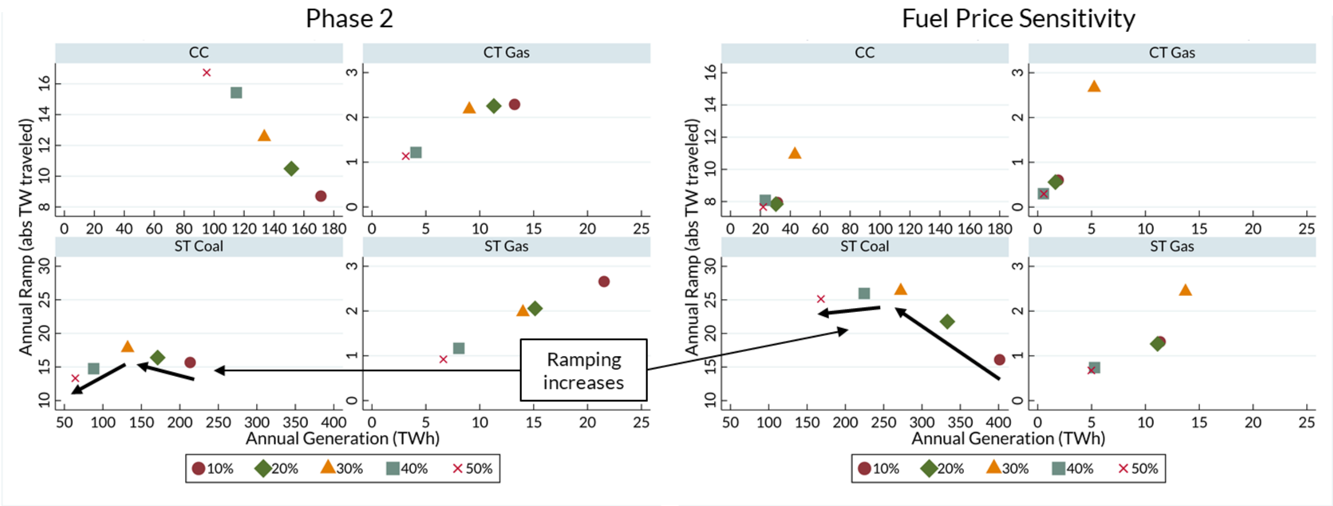


Figure EA-42: Thermal unit ramping in the fuel price sensitivity (right), compared to the previous assumptions (left)

(B) Market data sensitivity

Following the fuel price sensitivity, in which coal and gas generation units were dispatched and committed based on their relative economics as a function of fuel price input, in the market data sensitivity used the operating parameters actually offered by MISO market participants into the Energy and Operating Reserve Market. For MISO generation, there is a one-to-one match between the RIIA production cost model and the MISO market model. For the thermal units in other parts of the Eastern Interconnection in the RIIA production cost model, the average offer of the MISO units based on generation technology and capacity class was used as a proxy. Figure EA-43 compares the key generator parameters between vendor-developed data (used in Phase II-Final model) and MISO market data (used in Sensitivity). For coal generators, the operation flexibility decreases when using MISO market data as the ramp rates are lower and the minimum run time and down time are both longer. In terms of gas CC units, using MISO market data also suggests less flexibility in terms of ramp rates.

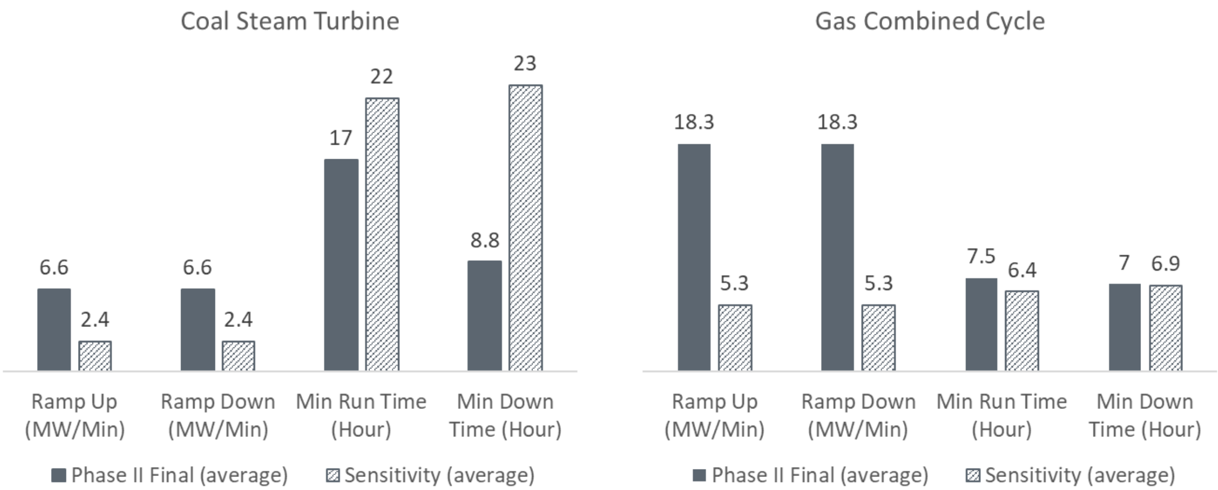


Figure EA-43: Generator operating parameter assumptions for the market data sensitivity

Figure EA-44 presents the diurnal average of fuel mix and system LMPs by twelve months for the market data sensitivity. The most notable difference is the increase in LMPs during the evening hours, driven by the relatively lower operational flexibility of coal and gas CC units. This reduction subsequently increases the usage of gas peaking units for ramping needs. Nonetheless, the system fuel mix remains more-or-less unchanged. During the daily peaks, there are also only a few additional price spikes, again driven by the inability of coal and gas CC units to provide flexibility and higher utilization of gas peaking units (Figure EA-45).

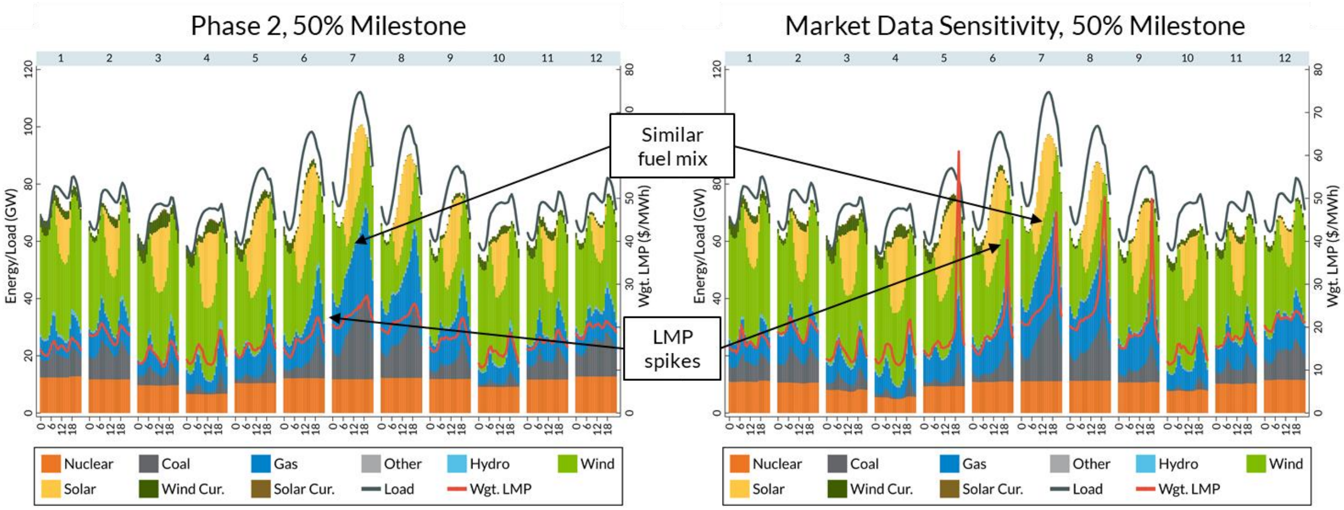


Figure EA-44: Monthly diurnal average of fuel mix and LMP for the market data sensitivity

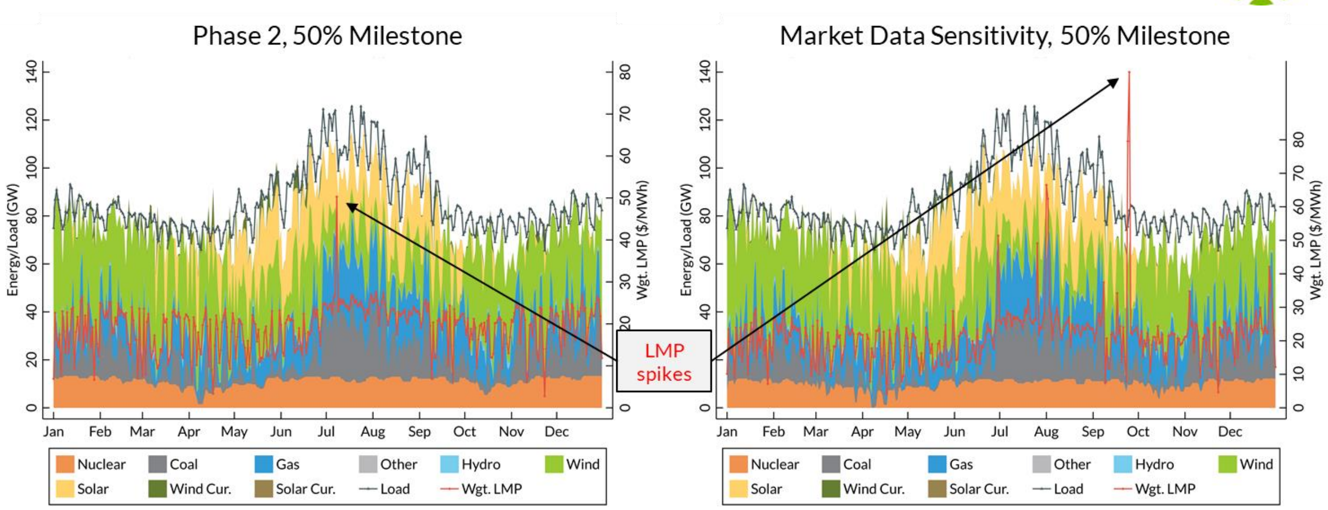


Figure EA-45: Daily peak hour fuel mix and LMP for market data sensitivity

Because of the increased use of gas peaking units for ramping (Figure EA-46), both the annual generation and ramping provided by gas Combustion Turbine (CT) increased in the market sensitivity. This result is due to the reduced ramp rates assumed for gas CC and coal ST units, as described earlier.

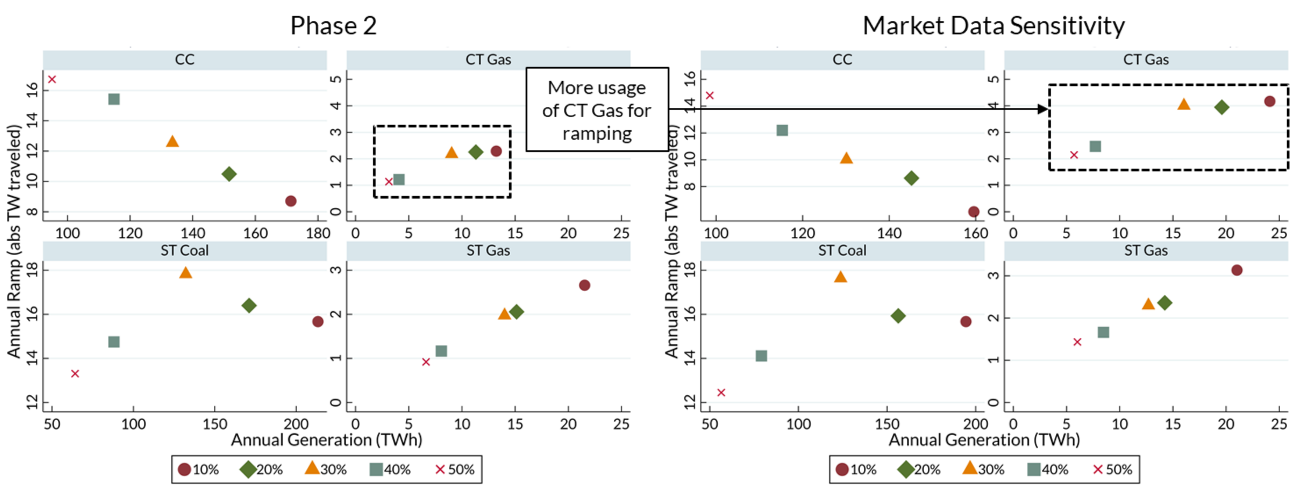


Figure EA-46: Thermal unit ramping for the market data sensitivity

(C) No retirements and high retirements sensitivities

In the sensitivities related to thermal unit retirements, the two scenarios illustrated in Figure EA-47 were examined. In the no retirements] sensitivity, no conventional thermal units were retired, and all thermal generating capacity is available for all the milestones. As a result, an additional 17.4 GW of thermal generating capacity was preserved at the 50% penetration milestone, compared to the retirements assumed for the same milestone in the Phase II-Final model. On the other hand, in the high-retirements sensitivity, an accelerated pace of thermal unit retirement was assumed, and, by the 50% milestone, an additional 13 GW of conventional thermal units were retired.