COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2023 INTEGRATED RESOURCE	**)**	**CASE NO.**
PLAN OF BIG RIVERS ELECTRIC CORPORATION	**)**	**2023-00310**

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSES TO THE OFFICE OF THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION

Big Rivers Electric Corporation ("Big Rivers" or the "Company") by counsel, files its responses to the Office of the Attorney General's Supplemental Request for Information, issued in the above-captioned case on January 26, 2024.

FILED: February 16, 2024

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
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REQUEST NO. 2-1: ***Please provide separately tabbed responses to each and every data request, as required per Commission rules. Responses to initial data requests were not so tabbed.***

RESPONSE: Presumably this is a reference to 807 KAR 5:001 Section 8(4)(b), which provides that electronic submissions shall be, *inter alia*, "[b]ookmarked to distinguish sections of the paper, except that documents filed in response to requests for information need not be individually bookmarked[.]" These data request responses have been electronically bookmarked for ease of use, as requested.

Respondent: Counsel

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
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REQUEST NO. 2-2: ***Reference the response to AG-DR-1-14.***

a. ***Explain how the sequestration portion of the CCS project would be accomplished, and the specific location where captured carbon would be sequestered.***

b. ***Explain whether the Company has identified any potential obstacles to obtaining the 45Q tax credits over the life of the CCS project.***

c. ***Has BREC explored whether there may be a market for the carbon sequestered from the Wilson plant?***

d. ***Does BREC foresee any potential for a CO_2 pipeline being constructed in the region through which the Company could sequester the CO_2 captured from Wilson?***

e. ***Explain whether the power needed for the operation of both carbon capture and sequestration equipment would represent parasitic load on the Wilson plant. If not, why not? Include in your response whether any such parasitic load would represent costs to the member-owners, and if not, why not.***

f. ***Regarding the Company's response to subpart e., above, explain how any such parasitic load / costs would affect the ability of Wilson to compete against other generating units in the MISO footprint. Does BREC agree that:***

(i) ***additional costs attributed to Wilson would affect the unit's MISO economic dispatch rank;***

(ii) ***any such diminished economic dispatch rank could reduce revenues the unit earns in MISO, and thus would represent a cost to the member-owners; and***

(iii) ***based on the response to AG-DR-1-24, a lower average MISO dispatch level could contribute to a higher heat rate, which also would constitute a cost driver for the member-owners?***

RESPONSE:

a. Please see Big Rivers' response to Commission Staff's Request No. 2-44.

b. At this time, Big Rivers has not identified any potential obstacles to obtaining the 45Q tax credits over the life of the CCS project. Further analysis is needed to ensure appropriate tracking and reporting would be in place to meet all of the 45Q tax credit requirements to apply for the full credit, including bonus portions (e.g.: prevailing wage and apprenticeship requirements).

c. Big Rivers has not explored a market for the carbon sequestered at Wilson Station. Big Rivers' New ERA application anticipated the sequestration of the carbon and receipt of 45Q tax credits. The 45Q tax credits, as modeled, requires permanent storage.

d. Big Rivers does not foresee a CO_2 pipeline being constructed in the region because the CO_2 from Wilson Station is expected to be injected onsite.

e. The energy needed to operate the carbon capture and sequestration (CCS) equipment would reduce the net output of the Wilson Plant. This would result in the apparent heat rate of the Wilson unit increasing on a net output basis. This means that for every MWh of electrical energy produced by Wilson and delivered to the transmission system, more fuel will be used than current operations require. The costs for this additional fuel per MWh would increase the dispatch cost of the Wilson unit. Consequently, the operation of carbon capture and sequestration equipment would ultimately represent costs to the Big Rivers' Member-Owners.

f. Increasing the apparent heat rate of the Wilson unit could degrade its position in the economic dispatch rank among MISO units. It is impossible to predict with accuracy the final position that Wilson would have in the economic dispatch rank because actions that other MISO members will take are unknown. If other members all add CCS technology to their existing and new power plants, then the change in Wilson's position in the dispatch rank may be minimal. However, it is unlikely that all MISO power plants will have CCS technology by the mid-2030s.

i. Additional costs (increased fuel use, higher VOM, CO_2 transportation costs, etc.) would impact the position of Wilson in MISO's economic dispatch stack, assuming that all other MISO units do not have similar changes to their economic offers.

ii. A reduced dispatch rank could impact the MISO market revenues received by Wilson, assuming that the diminished rank resulted in a reduction of generation by the unit. If Wilson were to generate less, Big Rivers would be likely to receive less net revenue from the Wilson unit, which would reduce the amount of energy revenue used to offset fixed operation costs that are not recovered from the MISO market.

iii. As in the above response, a reduction in dispatch rank – in this case coupled with the addition of CCS technology – would contribute to a higher apparent heat rate on the Wilson unit.

Witnesses: Nathanial A. Berry (subparts a, c-f)

Talina R. Mathews (subpart b)

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REQUEST NO. 2-3: ***Reference IRP Report Table 4.3 (a), and the response to AG-DR-1-20. Provide the reason(s) for the 2027 drop in projected non-member sales.***

a. Explain also why no projection for non-member sales is provided beyond 2028.

RESPONSE: Please see Big Rivers' response to Commission Staff's Request No. 2-17. For IRP planning purposes, Non-Member sales were not projected beyond the current contract term.

Witness: Terry Wright, Jr.

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REQUEST NO. 2-4: ***Reference the response to AG-DR-1-25, which states that an attachment is provided. As no such attachment could be located, please provide the attachment. The Attorney General reserves the right to pose a follow-up data request based on this missing attachment.***

RESPONSE: A copy of the RUS letter, "SUBJECT: Recommended Accounting for Renewable Energy Credits (REC)," addressed to all RUS electric borrowers, dated April 16, 2009, is attached to this response.

Witness: Talina R. Mathews

United States Department of Agriculture
Rural Development

APR 16 2009

SUBJECT: Recommended Accounting for Renewable Energy Credits (RECs)

TO: All RUS Electric Borrowers

FROM: KENNETH M. ACKERMAN Kenneth M. Ackerman
Assistant Administrator
Program Accounting and Regulatory Analysis

On July 13, 2007, the Rural Utilities Service (RUS) published proposed revisions to 7 CFR Part 1767, Uniform System of Accounts – Electric (Part 1767). Comments were due on September 11, 2007. Among the many items addressed in the proposed revisions, was the first attempt at establishing accounting requirements for Renewable Energy Credits (REC). After reviewing the comments received regarding the accounting requirements for RECs, RUS made a decision to remove this particular provision from the final rule when it was published on May 27, 2008, pending further investigation and discussion.

RECs are created when renewable energy facilities, such as wind farms, biomass generators, and solar facilities, generate electricity. These RECs represent the environmental benefits of renewable energy. When a purchaser acquires RECs, the price represents the benefit of displacing non-renewable sources of generation, such as coal, oil or gas. Energy is generated and injected into the grid from a number of sources. Because electricity is a fungible commodity, energy being purchased from the grid cannot be specifically identified as to its source. To facilitate the sale of renewable energy nationally, a system has been created that separates energy generated from renewable resources into two parts; the energy itself and the benefits derived from displacing energy generated from non-renewable sources. These RECs overcome the issues of providing renewable energy to purchasers who are often geographically remote from the renewable generation facility. The REC can be sold in combination with the sale of electricity or may be sold independently of the sale of energy.

In an effort to achieve consensus on a unified approach to accounting for RECs, RUS established a working group to study the issue and provide recommendations. These recommendations have been vetted within RUS by operations, engineering and accounting and as a result, we are issuing the following guidance to be used in accounting for RECs.

Costing of Inventory

RECs may be created and/or received in conjunction with Purchase Power Agreements with renewable generating units. RECs acquired in this way are inventoried as units with the necessary vintage information associated but are not assigned values for accounting purposes.

RECs may also be purchased separately from their generation source and therefore have a cost associated with them at purchase. These RECs are inventoried as units with the necessary vintage information associated along with their cost.

RUS is establishing Account 159, Renewable Energy Credits, to be used for recording the purchase and sale of RECs. RUS recognized that RECs may be valued by using weighted average, first in first out (FIFO), or specific identification methods; however, we recommend the use of the weighted average method.

Sale of Renewable Energy Credits

Amounts received for the sale of RECs should be recorded as revenue. RECs sold should be removed from inventory at carrying value, if any, and charged against an expense account at the time of sale.

RUS is establishing Account 459, Revenue from the Sale of RECs, under the functional category Other Operating Revenues, and Account 559, Renewable Energy Credit Expenses.

Renewable Portfolio Standards (RPS)

RECs that are used to satisfy state or regional RPS should be removed from inventory at cost and an offsetting expense recorded if the RECs are being carried with an associated dollar value. RECs accounted for as units with no associated costs shall reduce the number available for sale but will result in no recordable income statement transaction.

Accounting Requirements

1. The following journal entry is to be used to record the purchase of Renewable Energy Credits:

Dr. 159, Renewable Energy Credits	XXX	
Cr. 131.1, Cash – General Funds		XXX
To record the purchase of Renewable Energy Credits.		

2. The following journal entry is to be used when recording the sale of Renewable Energy Credits held in inventory:

Dr. 131.1, Cash – General Funds		XXX
or		
Dr. 142/143, Accounts Receivable	XXX	
Cr. 459, Revenue from the Sale of RECs		XXX
Dr. 559, Renewable Energy Credit Expenses	XXX	
Cr. 159, Renewable Energy Credits		XXX
To record the sale of RECs and to reduce inventory accordingly.		

3. The following journal entry is to be used to record RECs used to satisfy Renewable Portfolio Standards (RPS):

Dr. 555, Purchased Power (may be subaccounted)	XXX	
Cr. 159, Renewable Energy Credits		XXX
To recognize the use of RECs to satisfy RPS.		

If RECs are being purchased and sold strictly for investment purposes, the accounting requirements found in Part 1767, Interpretation No. 629, Investments in Debt and Equity Securities, is appropriate.

If you have any questions regarding the accounting for renewable energy credits, please contact the Technical Accounting and Auditing Staff at 202-720-5227.

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REQUEST NO. 2-5: ***Reference: (i) IRP § 7.1.6; (ii) IRP Table 7.4.1 (a); and (iii) the response to PSC-DR-1-51. Confirm that due to MISO's new FERC-approved Seasonal Planning Reserve Margin Requirements, BREC*** [redacted] ***that will begin to manifest itself in*** [redacted]***. Provide a comprehensive explanation of all steps BREC is initiating*** [redacted]

a. ***Referring to the confidential version of Table 7.4.1 (a), explain why the*** [redacted] ***has its*** [redacted]

b. ***Will other MISO LSEs also be facing*** [redacted] ***during the same periods? If so, describe the impact BREC anticipates on capacity prices during those periods.***

c. ***Explain whether the Company believes the*** [redacted] ***will or could trigger the need to file for a base rate increase.***

RESPONSE: MISO's Seasonal Capacity construct includes an annual timeline beginning September 1 of the prior year and culminating with posting of Auction Results in April for the upcoming Planning Year. This timeline has a series of steps performed by Market Participants and MISO which incrementally clarify Load Serving Entities' load obligations and Generator Owners' accredited capacity. Big Rivers has timely completed its obligations to date, and MISO has posted partial results of the generator accreditation for Planning Year 2024/25. As of this filing, revisions by MISO have improved Big Rivers' Planning Year 2024/25 [redacted]. Please see Big Rivers' response to Commission Staff's Request No. 2-16 for Big Rivers' updated capacity position.

a. Confidential Table 7.4.1 (a) used information available in Summer 2023, which was before the current Planning Year's Seasonal Capacity timeline. The data has since been updated and Big Rivers' capacity position is showing [redacted].

b. Big Rivers does not have access to the expected capacity position of other MISO LSE's. In the event of a capacity shortage, Big Rivers would expect capacity prices to rise.

c. [redacted]

Witness: Terry Wright, Jr.

<u>REQUEST NO. 2-6:</u> ***Given the significant increase in seasonal primary reserves MISO is now requiring, explain whether BREC believes it would be prudent to re-examine its membership in MISO. Include in your explanation whether the Company will conduct new cost-benefit analyses as a result of this new requirement.***

<u>RESPONSE:</u> Pursuant to Case No. 2010-00043,[1] Big Rivers annually files a report to the Commission describing its current evaluation of available options for complying with NERC's contingency reserve requirement and its review of the short-term and long-term costs and benefits of continued membership in MISO. The latest report was filed September 29, 2023, and concluded that MISO membership remains the most cost-effective option for meeting contingency reserve requirements. Also as stated in the report, Big Rivers regularly evaluates whether it should maintain MISO membership or meet NERC Contingency Reserve requirements using an alternative approach.

Witness: Terry Wright, Jr.

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[1] *See, In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc*., P.S.C. Case No. 2010-00043 (Sep. 29, 2023). https://psc.ky.gov/PSCSCF/Post%20Case%20Referenced%20Correspondence/2010%20cases/2010-00043/20230929_Big%20Rivers%20Electric%20Corporation%20MISO%20Annual%20Cost%20Benefit%20Update%20Report.pdf

IN THE MATTER OF:
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REQUEST NO. 2-7: ***Provide the net capacity factor for all of the Company's renewable energy facilities, whether self-owned or from which the Company obtains power via a PPA, from their inception through the most recent date available.***

RESPONSE: Big Rivers does not presently own any renewable energy facilities, except with respect to seven small solar demonstration projects.

Witness: Terry Wright, Jr.

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
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REQUEST NO. 2-8: ***Provide the winter-time capacity factor (net for the months December – February) for all of the Company's renewable energy facilities, whether self-owned or from which the Company obtains power via a PPA, from their inception through the most recent date available.***

RESPONSE: Please see Big Rivers' response to the Office of the Attorney General's Request No. 2-7. Our SEPA Contract provides a guaranteed MWh per year, with monthly minimums and maximums.

Witness: Terry Wright, Jr.

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REQUEST NO. 2-9: ***For all renewable energy projects not yet completed, provide the projected capacity factor for each month once the project becomes commercially operable.***

RESPONSE: Please see the CONFIDENTIAL attachment to this response. The data is only for 1 year, as the shape is repeated throughout the study period.

Witness: Terry Wright, Jr.

BIG RIVERS ELECTRIC CORPORATION
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Unbridled Solar					
Max Capacity (MW)	Date	Month	Hours In the month	Generation	Capacity factor (%)
160	1/1/2023	1	744	[redacted]	[redacted]
	2/1/2023	2	672	[redacted]	[redacted]
	3/1/2023	3	744	[redacted]	[redacted]
	4/1/2023	4	720	[redacted]	[redacted]
	5/1/2023	5	744	[redacted]	[redacted]
	6/1/2023	6	720	[redacted]	[redacted]
	7/1/2023	7	744	[redacted]	[redacted]
	8/1/2023	8	744	[redacted]	[redacted]
	9/1/2023	9	720	[redacted]	[redacted]
	10/1/2023	10	744	[redacted]	[redacted]
	11/1/2023	11	720	[redacted]	[redacted]
	12/1/2023	12	744	[redacted]	[redacted]

PACE Solar					
Max Capacity(MW)	Date	Month	Hours In the month	Generation	Capacity factor (%)
100	1/1/2023	1	744	[redacted]	[redacted]
	2/1/2023	2	672	[redacted]	[redacted]
	3/1/2023	3	744	[redacted]	[redacted]
	4/1/2023	4	720	[redacted]	[redacted]
	5/1/2023	5	744	[redacted]	[redacted]
	6/1/2023	6	720	[redacted]	[redacted]
	7/1/2023	7	744	[redacted]	[redacted]
	8/1/2023	8	744	[redacted]	[redacted]
	9/1/2023	9	720	[redacted]	[redacted]
	10/1/2023	10	744	[redacted]	[redacted]
	11/1/2023	11	720	[redacted]	[redacted]
	12/1/2023	12	744	[redacted]	[redacted]

CONFIDENTIAL
Filed with Motion for
Confidential Treatment

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REQUEST NO. 2-10: ***Provide the winter-time capacity factor (net for the months December – February) for the Wilson, Reid and Green units for each of the past ten years.***

RESPONSE: Please see the table provided as an attachment to this response.

Witness: Nathanial A. Berry

BIG RIVERS ELECTRIC CORPORATION
Case No. 2023-00310
Winter-Time Capacity Factors

	NCF (%)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Wilson	January	[redacted]	91.08	75.34	89.57	93.67	58.50	63.91	94.75	81.33	72.91
	February	[redacted]	93.68	86.89	51.11	52.84	91.12	74.58	76.17	74.72	86.38
	December	98.18	73.24	88.06	93.36	-0.85	60.33	88.22	89.98	67.34	78.36

	NCF (%)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 1	January	[redacted]	90.77	60.65	78.30	60.24	81.51	22.05	30.08	60.99	-0.90
	February	[redacted]	93.60	60.31	21.61	56.95	88.82	48.65	68.68	25.05	-0.87
	December	93.24	65.42	89.81	59.57	97.28	28.16	34.74	36.31	21.52	2.88

	NCF (%)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 2	January	[redacted]	93.40	71.09	79.40	87.90	86.41	-1.07	-1.21	57.00	-0.94
	February	[redacted]	85.18	79.38	48.84	71.13	76.85	-0.74	51.85	15.38	-0.90
	December	93.55	57.37	90.22	73.23	86.57	-1.11	25.21	26.66	15.56	0.00

	NCF (%)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid CT	January	[redacted]	0.03	0.00	0.10	1.99	1.45	-0.24	-0.22	-0.06	0.10
	February	[redacted]	0.24	0.00	0.21	0.01	0.63	-0.02	0.03	0.00	-0.15
	December	-0.12	0.00	1.20	0.59	-0.11	-0.02	-0.07	1.03	-0.03	-0.16

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REQUEST NO. 2-11: ***Confirm that generating resources powered by fossil fuels provide the most reliable source of generation in comparison to alternative generating sources, excluding nuclear sources.***

RESPONSE: Big Rivers agrees that generating resources powered by fossil fuels are more reliable than alternative generating sources under most scenarios, mainly because they have a more dependable fuel supply that is typically not dependent on external conditions like wind or time of day. Fossil fuel generation is also dispatchable, as well as resilient and responsive to markets.

Witness: Nathanial A. Berry

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REQUEST NO. 2-12: ***Discuss BREC's history with respect to reliably serving its customers, and provide a breakdown of the types of generating resources (fuel source category) that were used to provide that reliability. Explain also whether the Company has ever had to institute rolling blackouts.***

RESPONSE: Ensuring the availability of safe, economic, and reliable power is Big Rivers' primary goal. In connection with these efforts, Big Rivers has historically relied, overwhelmingly, on its own coal- and gas-fired generation, as well as hydropower. Since transferring control of its generation and transmission resources to MISO in 2010, the dispatch of Big Rivers' resources has varied based upon both local and regional needs.

Big Rivers has been successful with respect to reliably serving its customers. The System Average Interruption Duration Index ("SAIDI") and the Customer Average Interruption Duration Index ("CAIDI") are key indices used by Big Rivers to measure reliability. SAIDI is the sum of all customer interruption durations divided by the total number of customers served. CAIDI is the sum of all customer interruption durations divided by the total number of customer interruptions. In addition, the availability of generation resources to meet the load requirements (e.g., absence of rolling blackouts) is another important measure of system reliability.

Recent reliability performance as measured by these indices has exceeded expectations. The 2023 year-end SAIDI value was 1.404 minutes with a CAIDI value of 41.377 minutes. Additionally, no rolling blackouts have been necessary to date.

Witness: Nathanial A. Berry

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<u>REQUEST NO. 2-13:</u> ***Reference the response to AG-DR-1-5. Given that "wind is not economically feasible due to intermittent operation in Big Rivers' service territory and risk of congestion cost outside of MISO zone 6," provide a cost estimate for serving 100% of BREC's load with solar resources.***

<u>RESPONSE:</u> See Big Rivers' response to the Office of the Attorney General's Request No 2-1, indicating that Big Rivers has not studied serving load with 100% renewables; therefore no such cost estimate is available.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
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REQUEST NO. 2-14: ***Given that solar resources are intermittent by nature, discuss the reliability impacts that would be experienced if BREC were to serve its load with 100% solar resources.***

RESPONSE: Big Rivers has neither anticipated nor studied the scenario of serving 100% of its load with solar resources. Please refer to Big Rivers' response to the Office of the Attorney General's Request No. 2-11, which discusses current reliability issues with alternative generating resources. Big Rivers' resource planning strikes the appropriate balance for our Members, providing safe, reliable power at the lowest reasonable cost, taking into account the benefits and risks of available resources.

Witness: Nathanial A. Berry

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REQUEST NO. 2-15: ***Confirm that, in order to reliably serve BREC's load with 100% renewable resources, BREC would be required to invest in renewable resources to be available to serve load in real time, battery resources to store energy for use when intermittent resources were unavailable and during periods of renewable underperformance, and separate renewable generating resources available to charge those batteries while the other generating resources were being used to serve load. If not confirmed, explain the response in detail.***

RESPONSE: Confirmed.

Witness: Nathanial A. Berry

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
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REQUEST NO. 2-16: ***Confirm that the commercially available and scalable energy storage device in service today is a 4-hour battery. Discuss how many layers of 4-hour batteries would be needed in order to serve load during the night if BREC operated utilizing renewables only, accounting for foreseeable periods of renewable underperformance which will certainly occur. If not confirmed, explain the response in detail.***

RESPONSE: The most commonly deployed storage technology is some form of Li-Ion-based battery typically configured to enable complete energy withdrawal over a 4-hour discharge window. Other, longer-duration storage technologies are in various stages of development and deployment stages, but have limited commercial deployment to date.

Projecting the amount of storage required to allow Big Rivers to operate entirely on renewables (solar and wind) would require a significant statistical study involving the behavior of Big Rivers' loads and potential renewable energy sources. However, historical time-aligned wind and solar production show that extremely low to no solar and wind periods have occurred in MISO and other markets for extended (multi-day) periods. Therefore, it would be reasonable to expect that attempting to run Big Rivers' system exclusively on wind, solar, and Li-Ion storage would require several days of continuous storage at close to or exceeding Big Rivers' peak hourly load.

Witness: Nathanial A. Berry

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REQUEST NO. 2-17: ***Discuss the performance of solar assets and renewable assets generally during winter storms.***

a. ***Discuss how this performance impacts the investments that would be needed if BREC intended to utilize 100% renewable generation sources.***

b. ***Explain also the capacity factor BREC ascribes to solar facilities during winter-time (December through February).***

RESPONSE: During winter storms, particularly those that increase cloud cover or result in precipitation (snow/ice) which may prevent solar facilities from capturing available sunlight, performance of solar assets is notably reduced.

a. See Big Rivers' response to the Office of the Attorney General's Request No. 2-13, indicating Big Rivers has not performed studies evaluating serving 100% load from renewables. However, utilization of batteries (the cost and capability of which are still being developed) would be necessary under such an assumption.

b. See Big Rivers' response to the Office of the Attorney General's Request No. 2-9, which indicates significantly lower capacity factors during winter-time.

Witness: Terry Wright, Jr.

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

<u>REQUEST NO. 2-18:</u> ***Discuss whether, even assuming transmission upgrades could be timely and economically achieved, BREC views reliance on out-of-state generating resources as a sound long-term generating plan.***

<u>RESPONSE:</u> Even assuming transmission upgrades could be timely and economically achieved, reliance on out-of-state generating resources carries risks that Big Rivers prefers to avoid in long-term generating planning, including congestion risks that would have to be mitigated via Auction Revenue Rights and Financial Transmission Rights. Other risks include transmission interruptions and other system events that cannot be fully mitigated through market redispatch. In the case of transmission interruption or a similar system event, import limitations could result in emergency curtailments of Big Rivers' system load. Additionally, if the generating resource is located outside the MISO footprint, Big Rivers would have to address the additional risks and costs of obtaining Firm Transmission.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

REQUEST NO. 2-19: ***Discuss the benefits to BREC and its customers of owning its own generating assets and operating those within its territory.***

RESPONSE: Owning generating assets reduces or avoids certain risks associated with other resource planning options. As discussed in Case No. 2021-00079, owned generation reduces the price risk to which Big Rivers would be subject if it relied on MISO market purchases for a significant portion of its capacity needs. Please also see Big Rivers' response to the Office of the Attorney General's Request No. 2-18 regarding out-of-state generating resources.

Witness: Nathanial A. Berry

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

REQUEST NO. 2-20: ***If, based on BREC's responses to the foregoing: (i) BREC historically has been able to provide reliable electric service utilizing primarily fossil fuel powered resources, and (ii) it is currently technically and/or economically unreasonable to generate 100% of electricity needed to serve BREC's customers using renewable resources, confirm that as a utility moves along a spectrum from 100% fossil fuel-powered, dispatchable resources to 100% intermittent, renewable resources, the system necessarily becomes less reliable. If not confirmed, explain the response in detail.***

a. If BREC's position is that some amount of renewable generation can be incorporated without reliability impacts, identify that amount and discuss reliability impacts between that value and 100% renewable resource based generation.

RESPONSE: Please see Big Rivers' response to the Office of the Attorney General's Request Nos. 2-11, 2-14, and 2-15. Also see attached to this response, a copy of MISO's 2021 report titled *Renewable Integration Impact Assessment* ("RIAA"), where MISO indicates that as renewable penetration increases, managing the system becomes more challenging.

a. The RIAA indicates that renewable penetration beyond 30% requires transformative thinking as significant challenges arise. While Big Rivers has not determined a specific percentage of renewable resource-based generation that could be incorporated without reliability impacts, we do agree with the RIAA's conclusion that impacts to grid performance increase sharply after 30% penetration. Additional regional studies are needed to determine the actual amount of renewable generation that can be incorporated without reliability impacts as well as optimal locations for renewable generation projects.

Witness: Nathanial A. Berry

MISO's Renewable Integration Impact Assessment (RIIA)

SUMMARY REPORT – FEBRUARY 2021

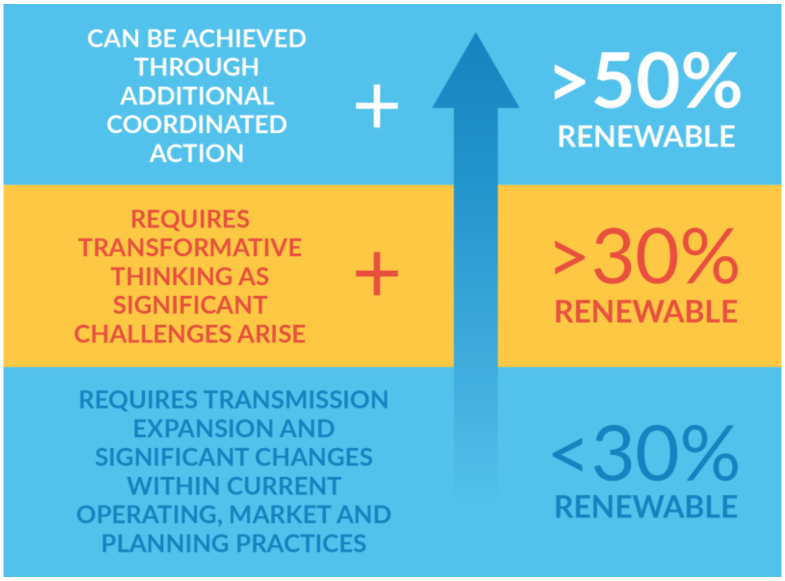
misoenergy.org

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.

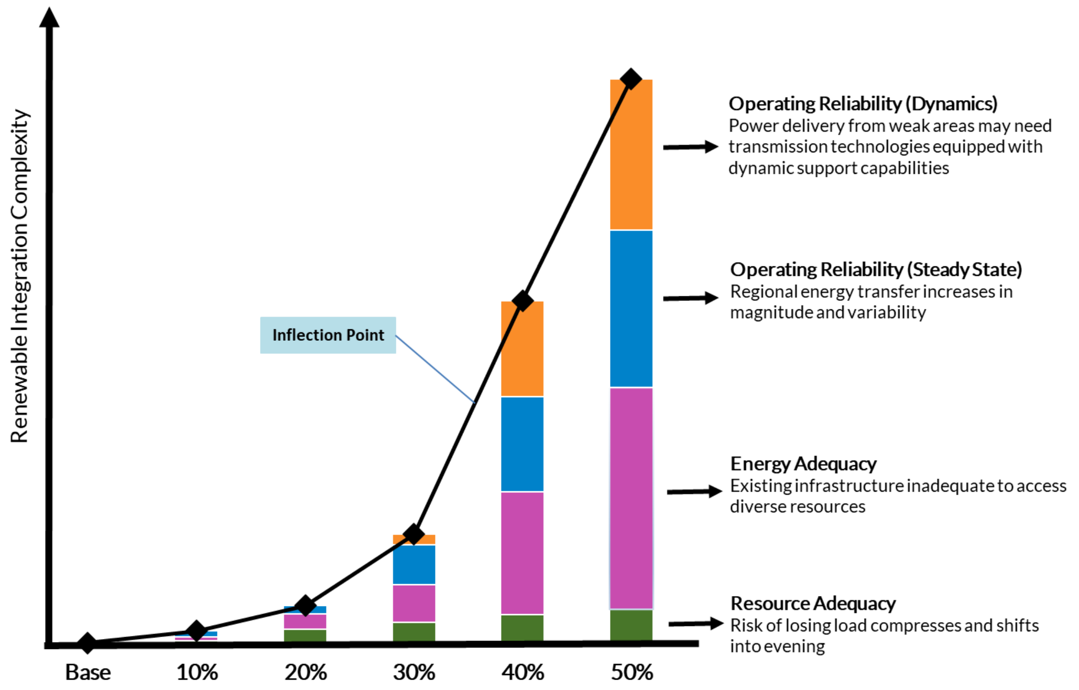


Figure 1: Increasing renewable penetration will significantly impact grid performance with complexity increasing sharply after 30% renewable penetration levels

> **"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.

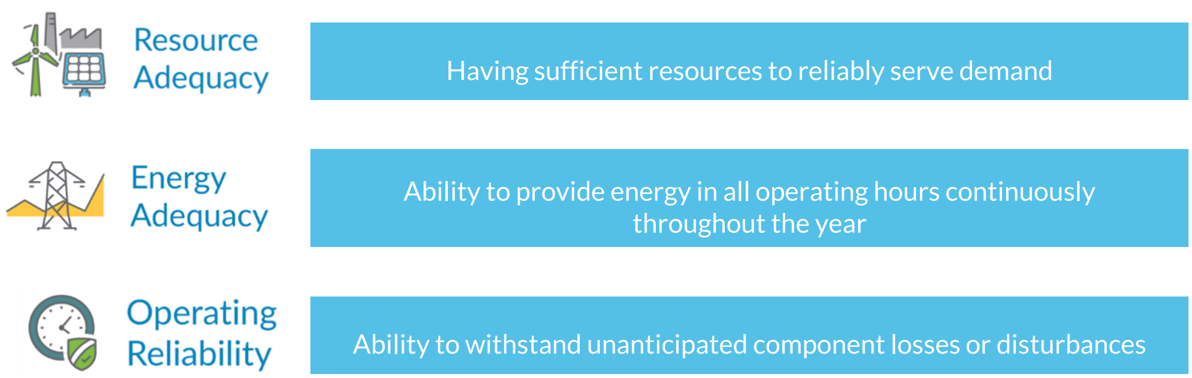
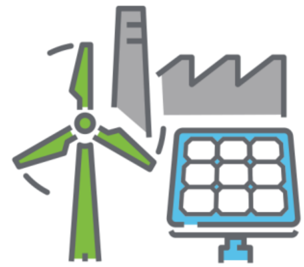


Figure 2: RIIA's three focus areas: Resource Adequacy, Energy Adequacy and Operating Reliability

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%.

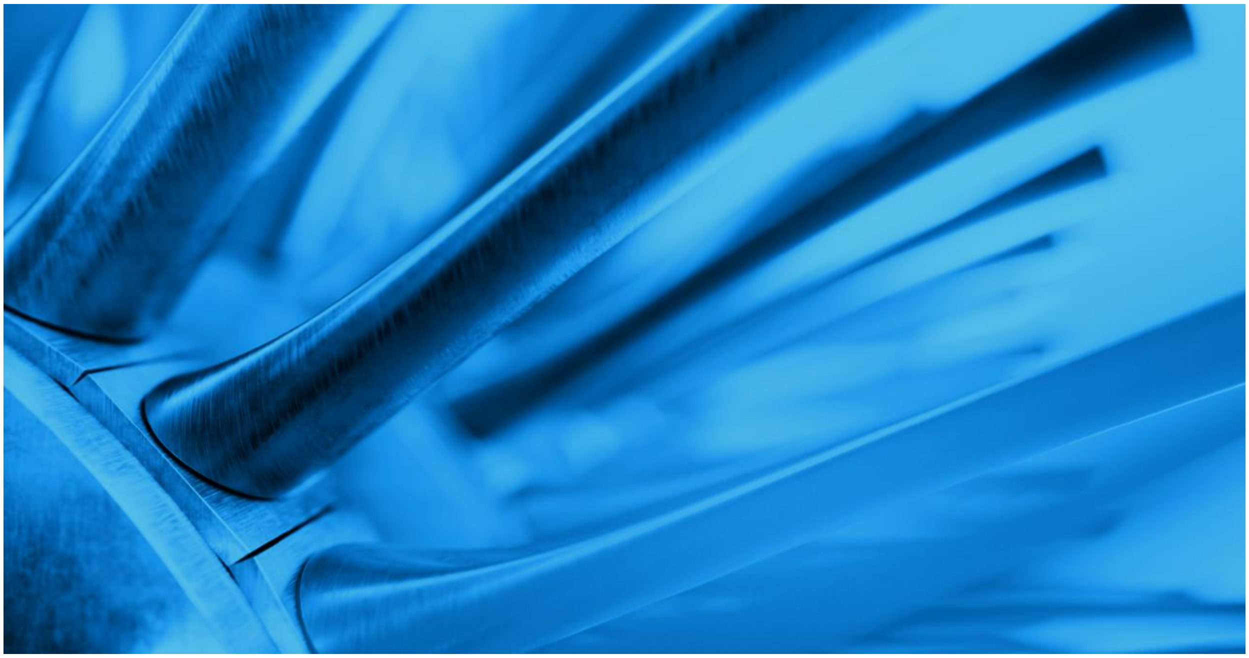
RESEARCH STEPS

- 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).

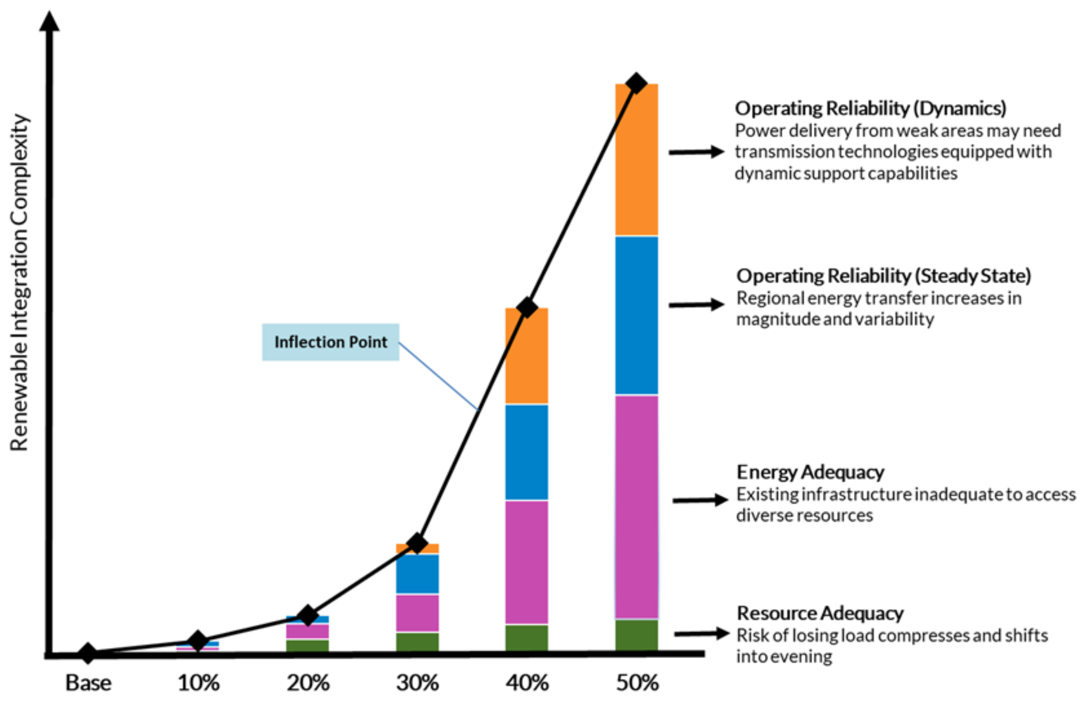


Figure UC-1: Inflection point of renewable integration complexity identified by RIIA

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:

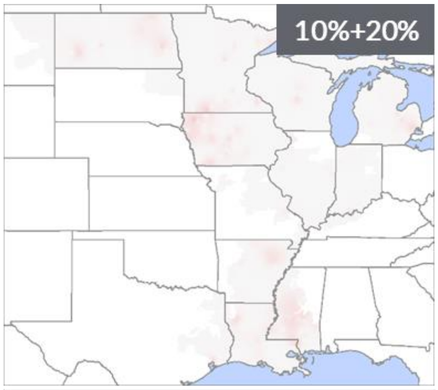
1) The costs to provide additional ramping
2) Software and operating practice changes needed to reliably and efficiently operate the system
3) New market product development, implementation, and market costs
4) The cost of preserving, or constructing new resources to allow for resource adequacy, even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

Solutions

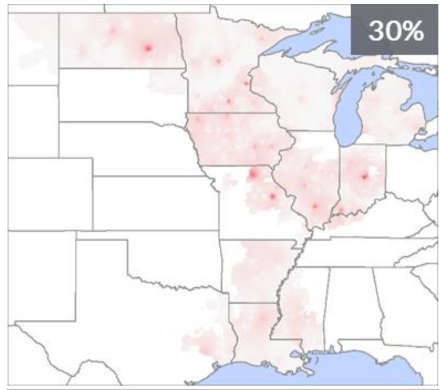
This section summarizes the RIIA data as to describe the type, location, and relative cost of solutions. This assessment is not meant to move forward particular solutions, and thus they are not presented in detail. The assessment focuses on the types and magnitude of risk that growing renewable energy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

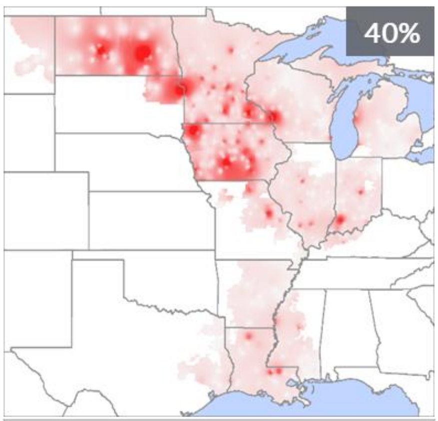
Key Findings



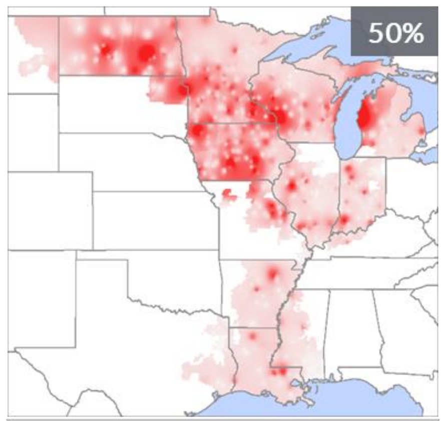
	161 & below	230	345 & above
Ckt*miles	1500	300	400



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.

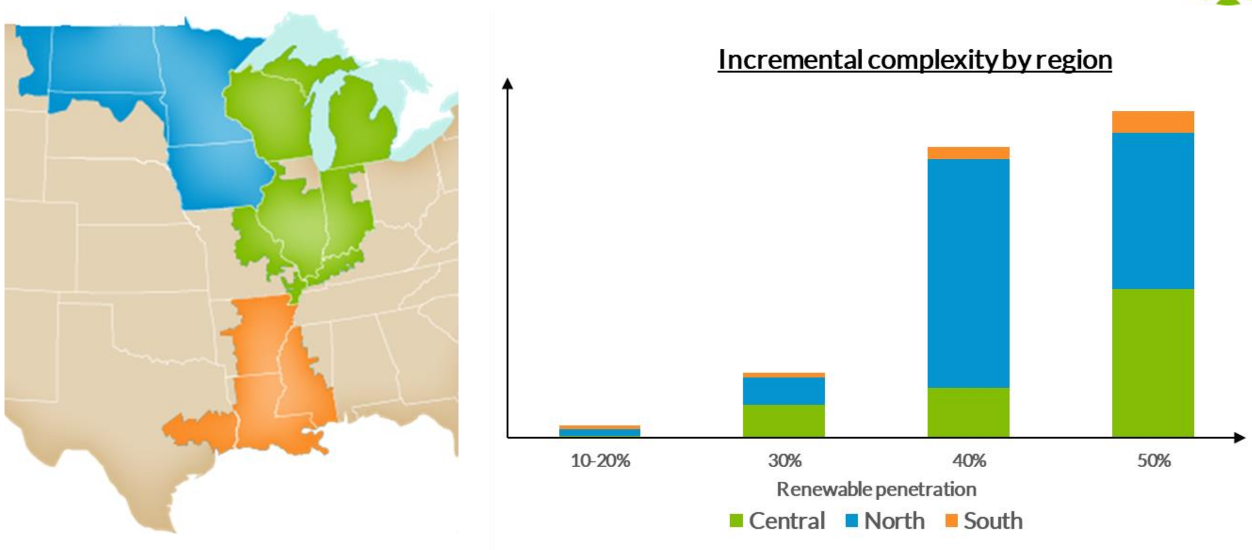


Figure UC-3: Regional distribution of incremental complexity at renewable milestones

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.

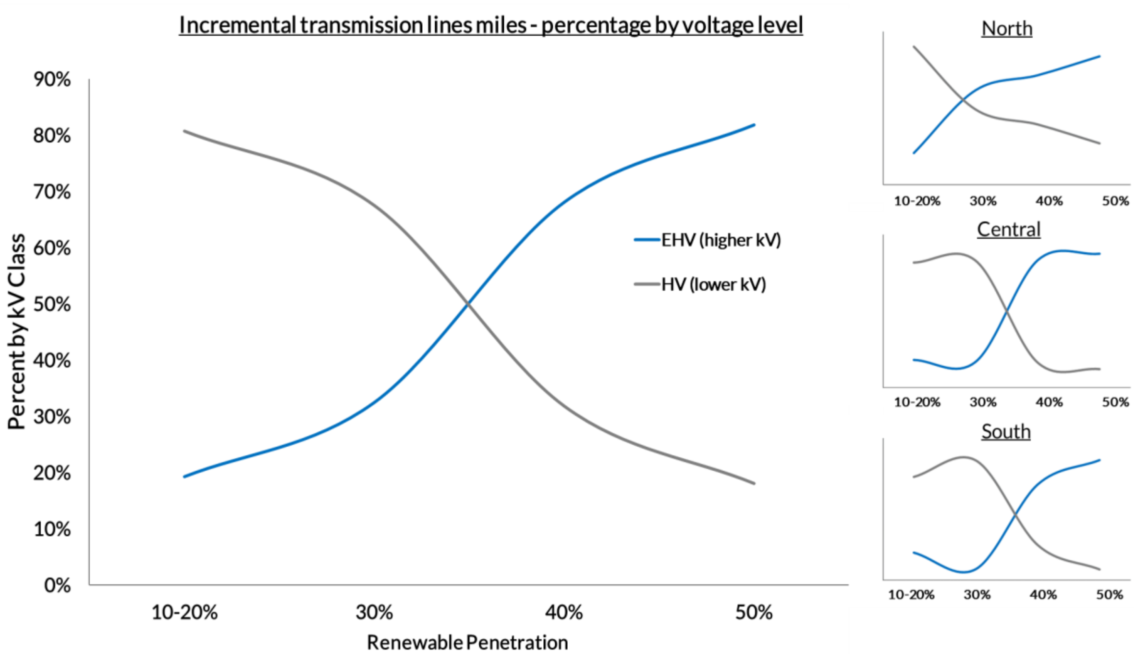


Figure UC-4: Ratio of incremental High Voltage (230 kV and below) and Extra High Voltage (345 kV and above) transmission at each renewable penetration level

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.

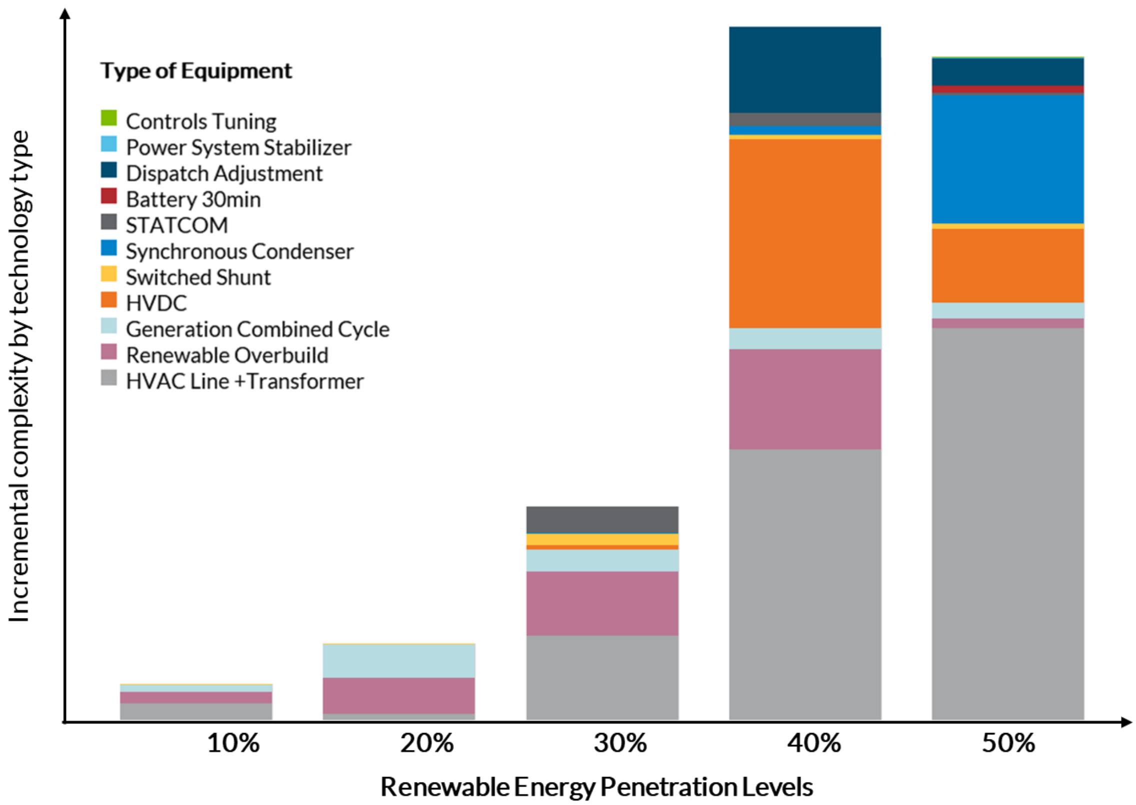


Figure UC-5: Incremental complexity by technology for each renewable penetration milestone

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.

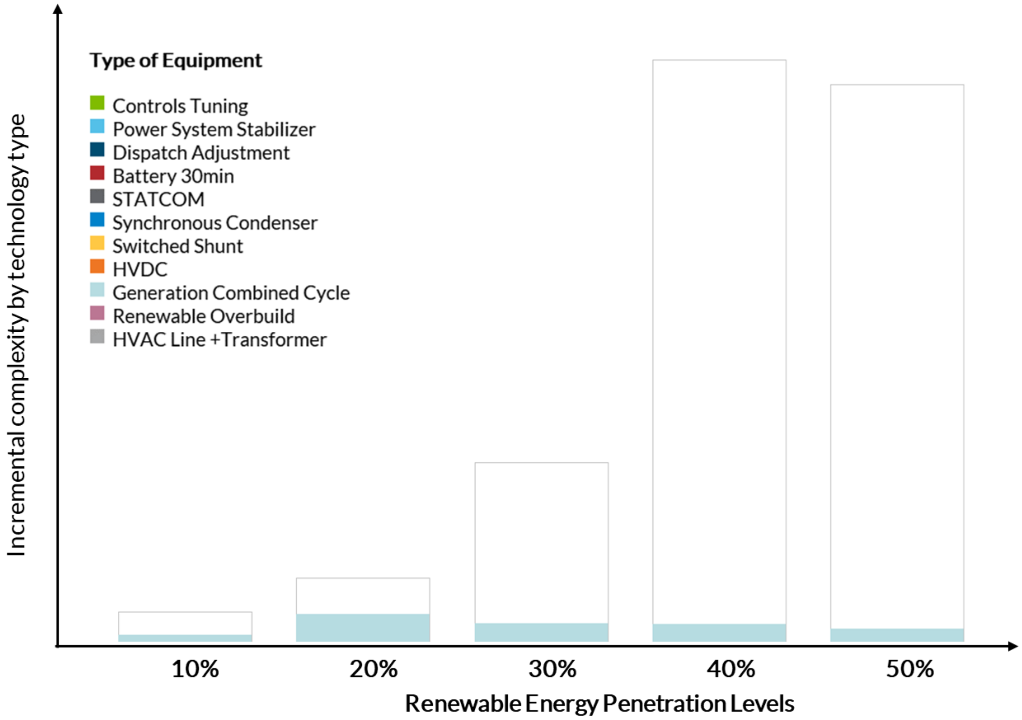
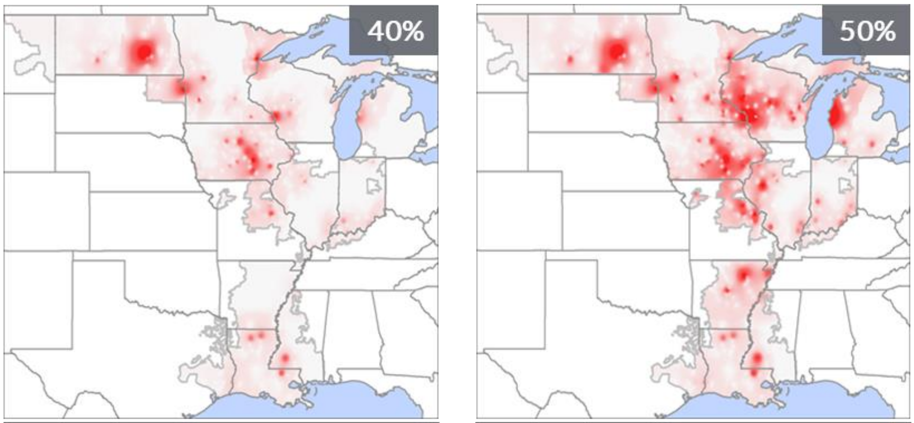


Figure UC-6: Resource adequacy solutions - incremental complexity by technology for each renewable penetration milestone

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

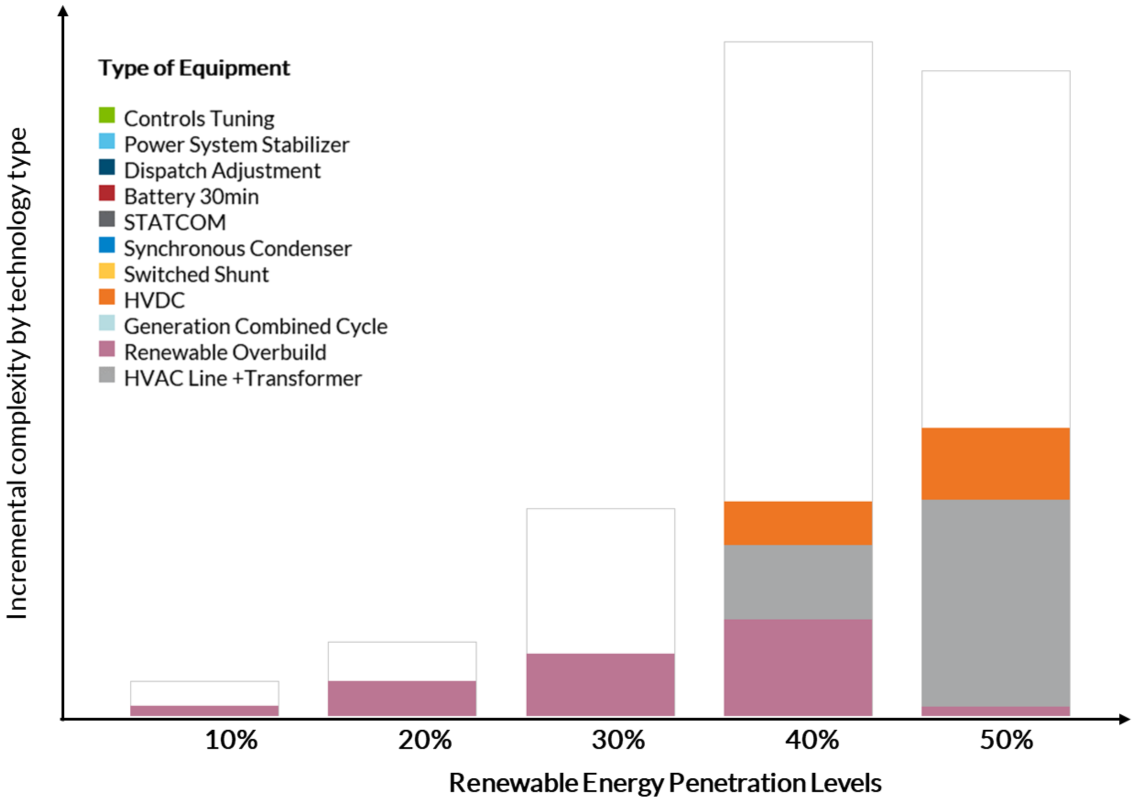
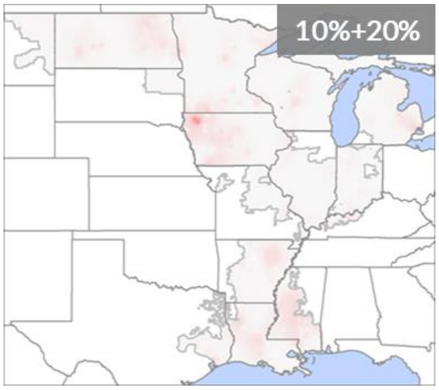
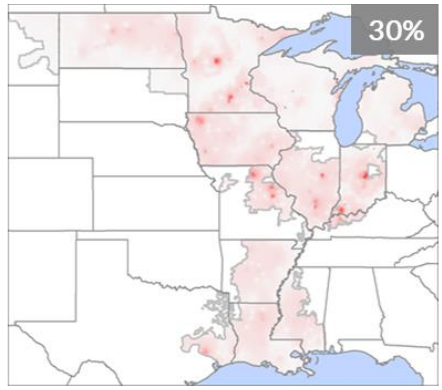


Figure UC-8: Energy adequacy solutions - incremental complexity by technology for each renewable penetration milestone

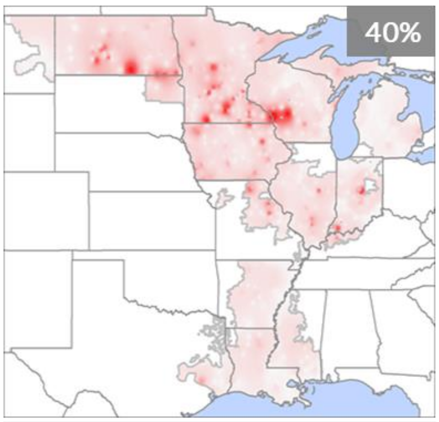
Figure UC-7 presents the Energy Adequacy (EA) assessment solutions. Before the 40% milestone, no transmission solutions were needed for Energy Adequacy; the energy targets were met in part by an over-build of wind and solar capacity. However, past the 30% level, the penetration targets could not be met 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.



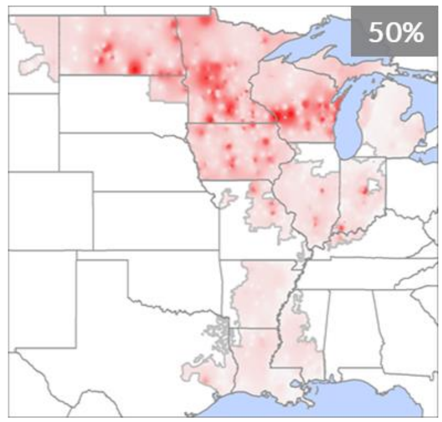
	161 & below	230	345 & above
Ckt*miles	1500	300	400



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.

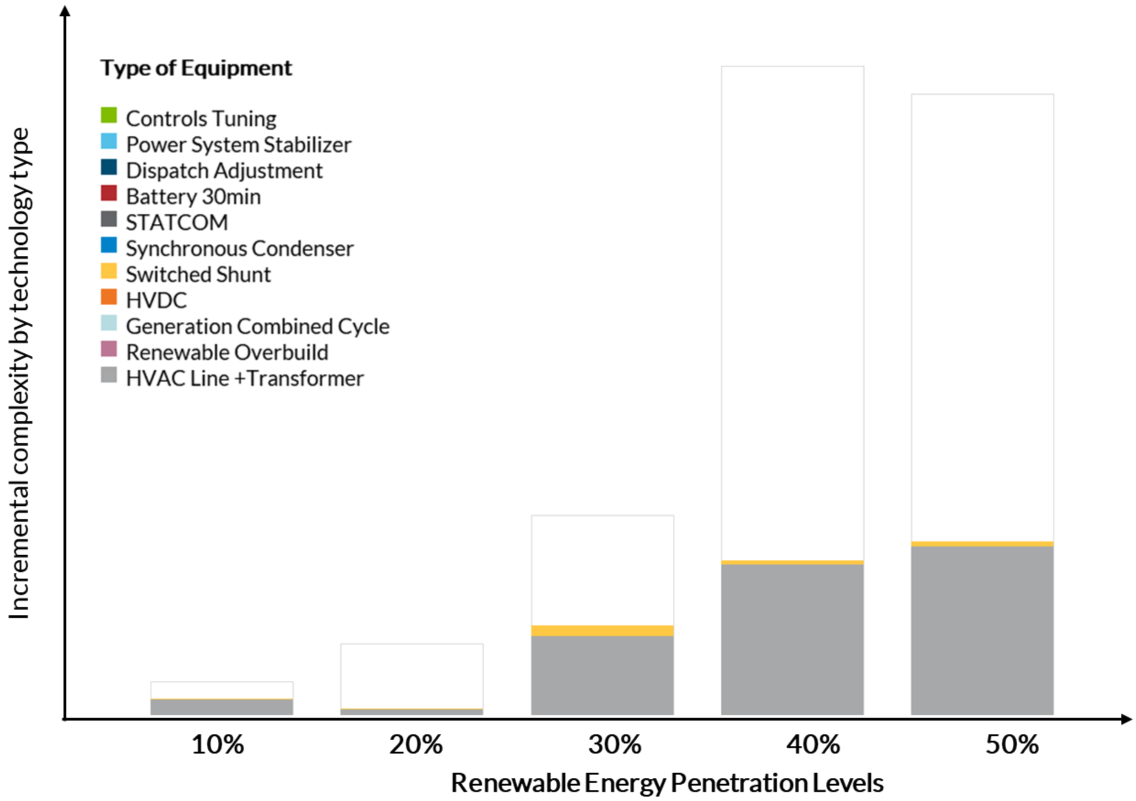
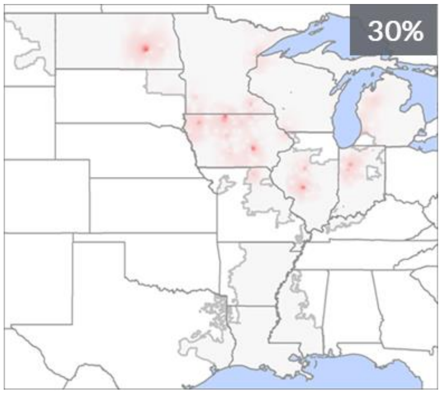


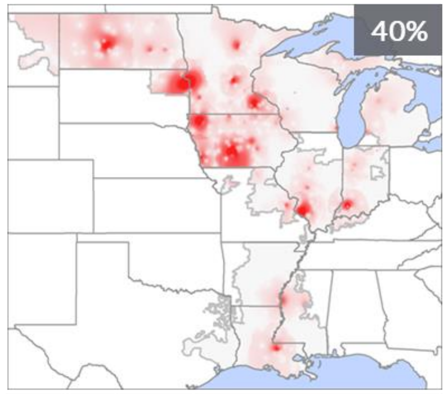
Figure UC-10: Steady state solutions - incremental complexity by technology for each renewable penetration milestone

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.

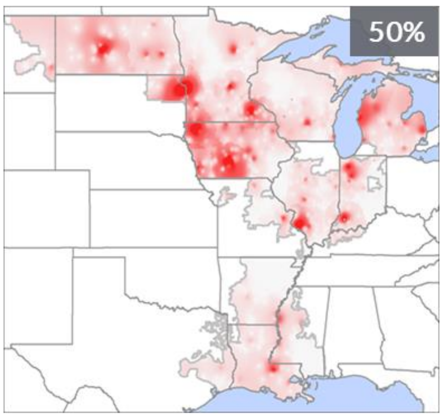
These solutions increased renewable energy delivery and mitigated thermal overloads on the bulk electric system, 100 kV and above. However, since RIIA used a bottom-up planning approach to upgrade the existing facilities for operating reliability, there is an opportunity to optimize transmission planning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

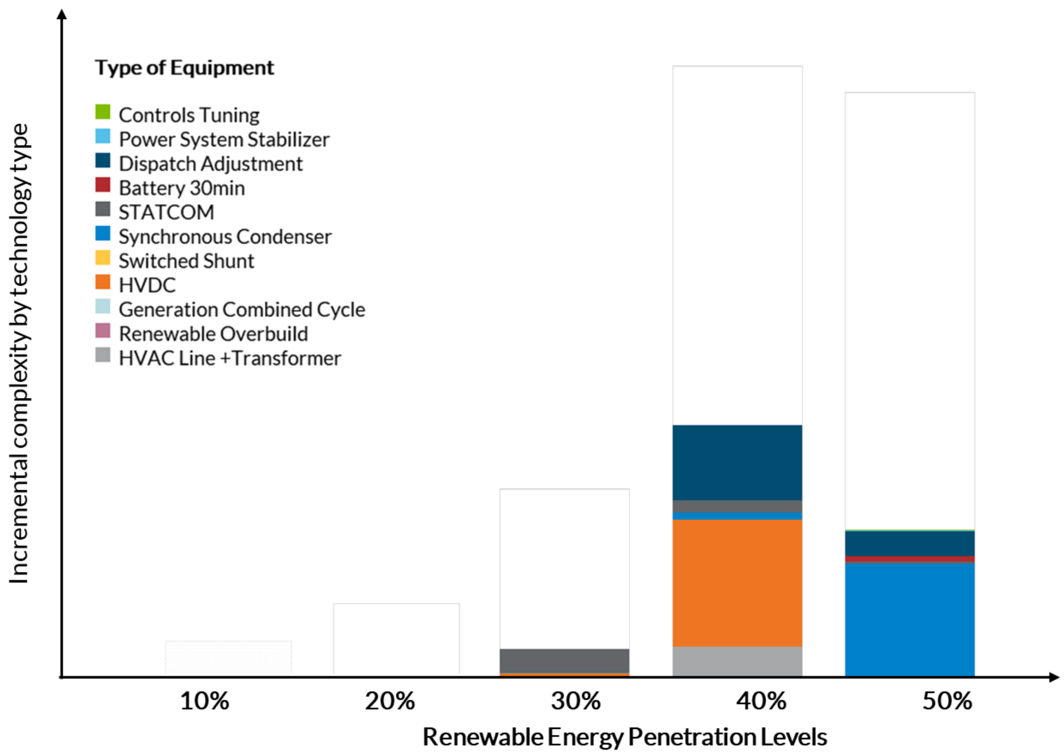


Figure UC-12: Dynamic stability solutions - incremental complexity by technology for each renewable penetration milestone

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).

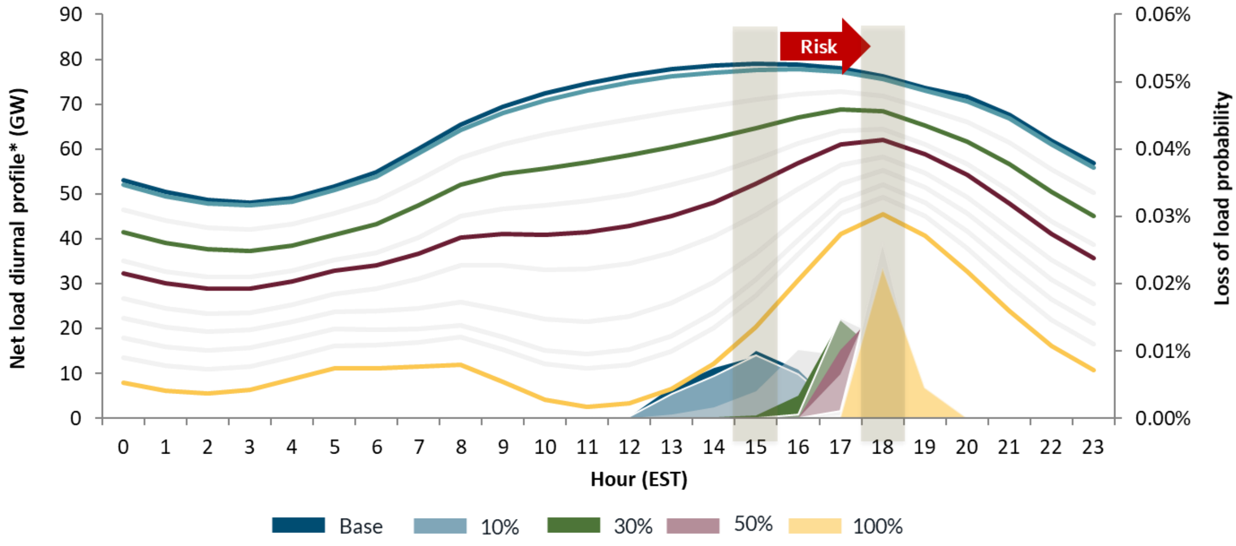


Figure RA-1: Shift in LOLP risk profile

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.

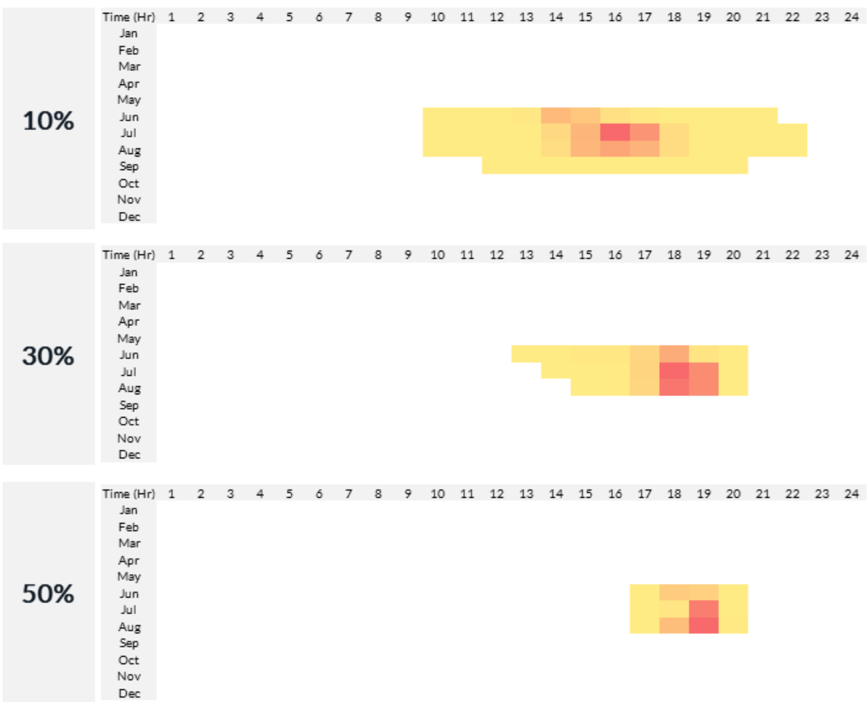


Figure RA-2: Heatmap of EUE by time period and milestone

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

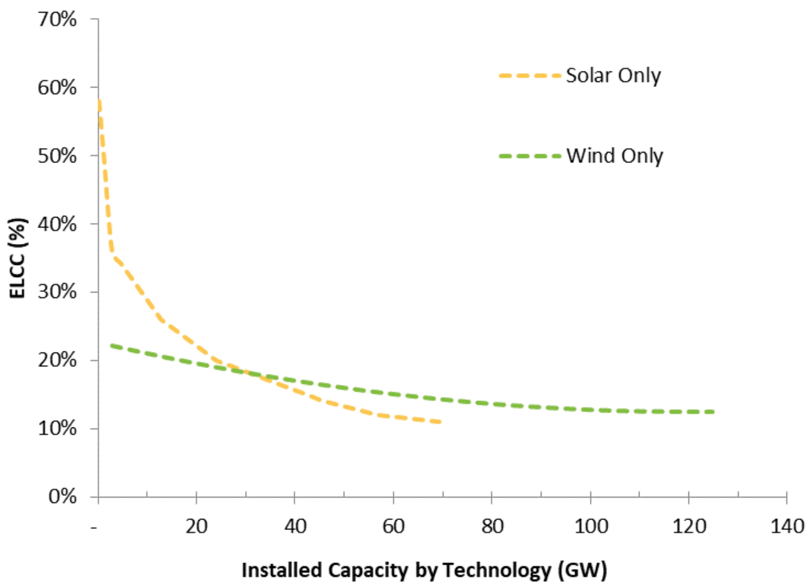


Figure RA-3: Change in ELCC as a function of installed capacity

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.

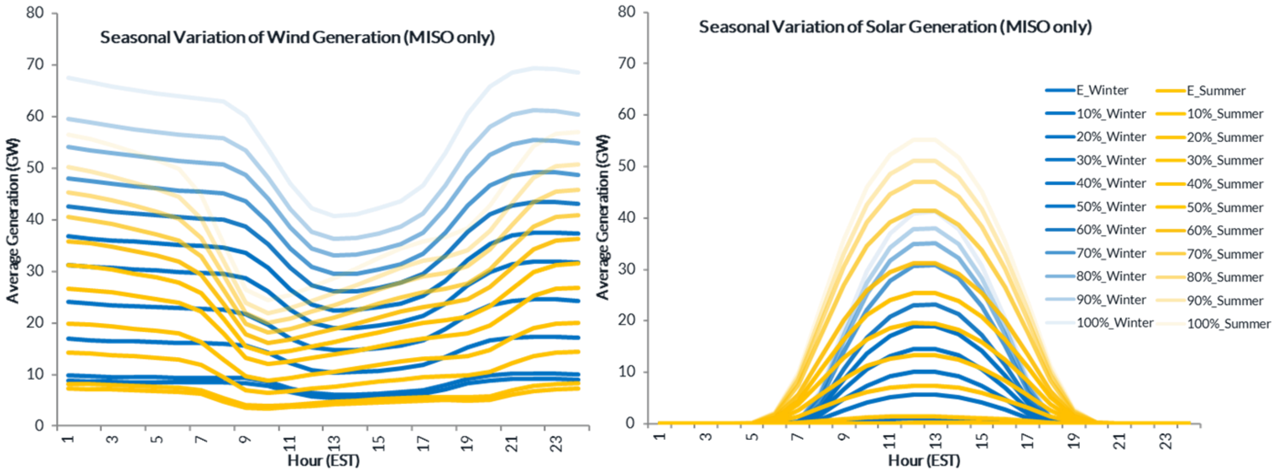


Figure RA-4: Availability of wind and solar by the time of day and season

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.

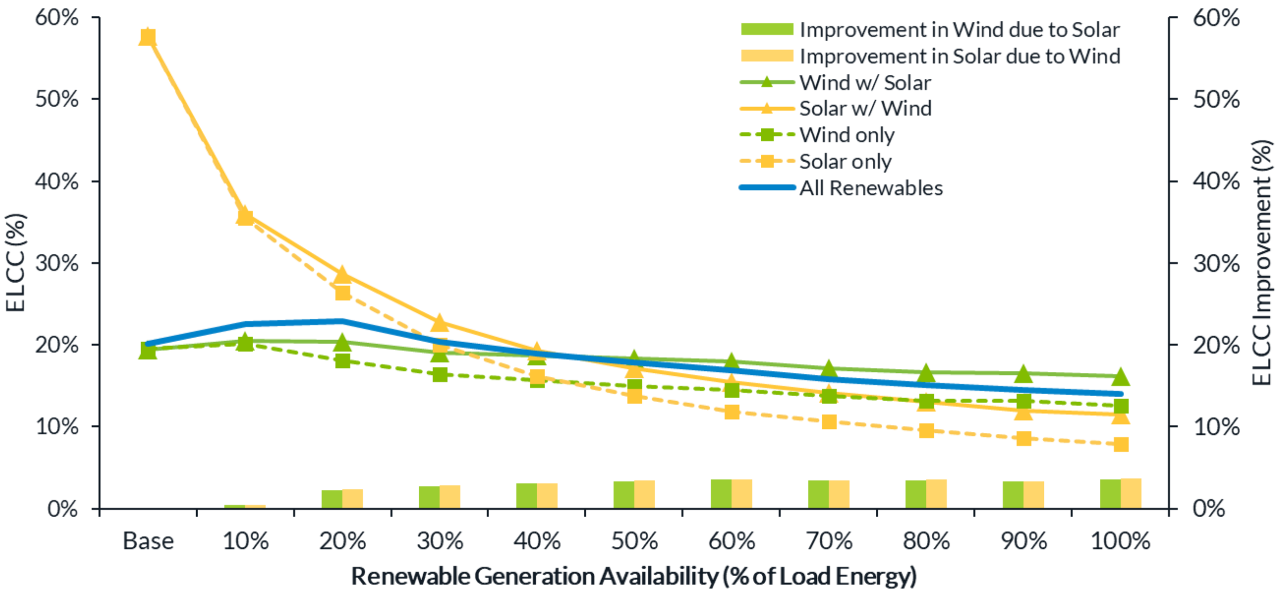


Figure RA-5: Change in ELCC with technology diversity

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.

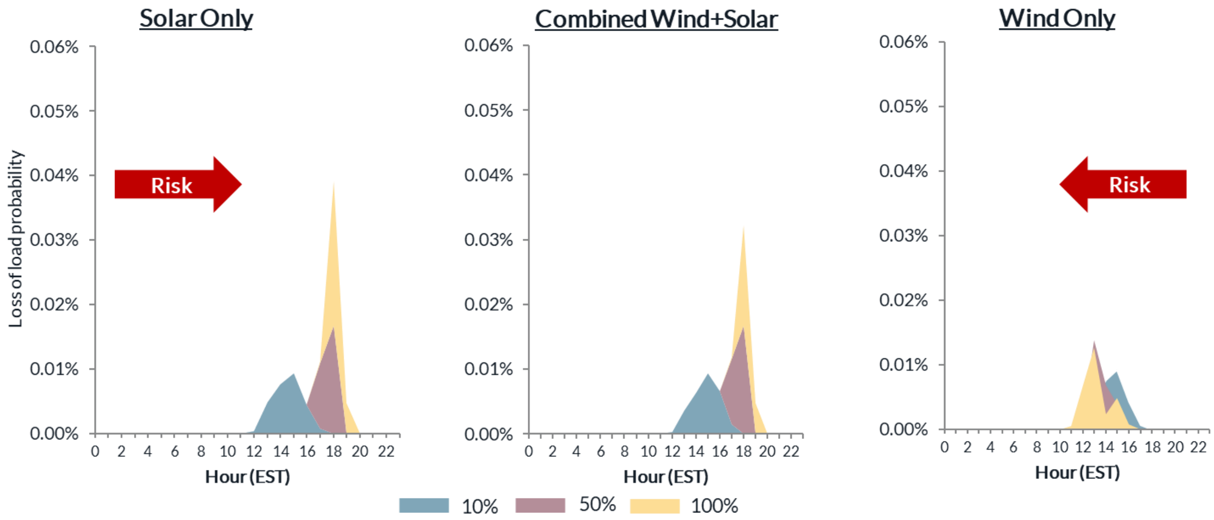
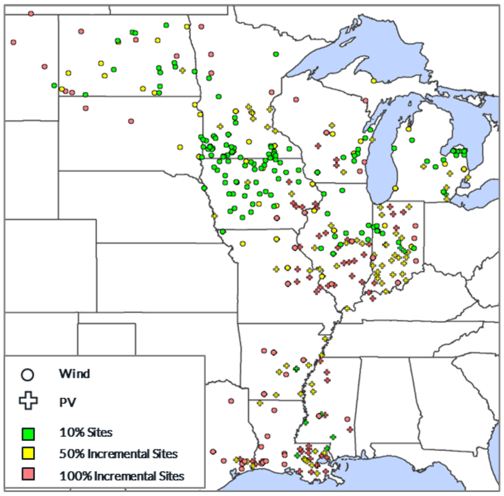


Figure RA-6: Change in LOLP by technology and milestone

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.

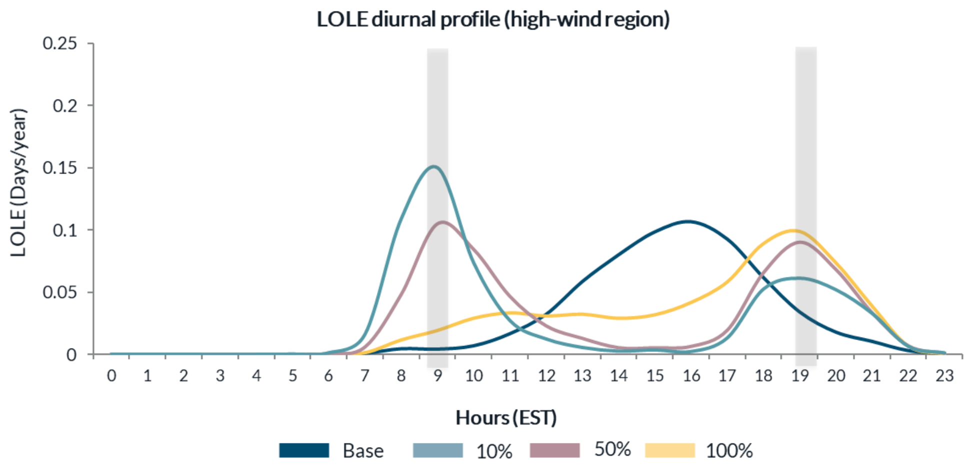


Figure RA- 8: Hourly LOLE in high wind northern region

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.

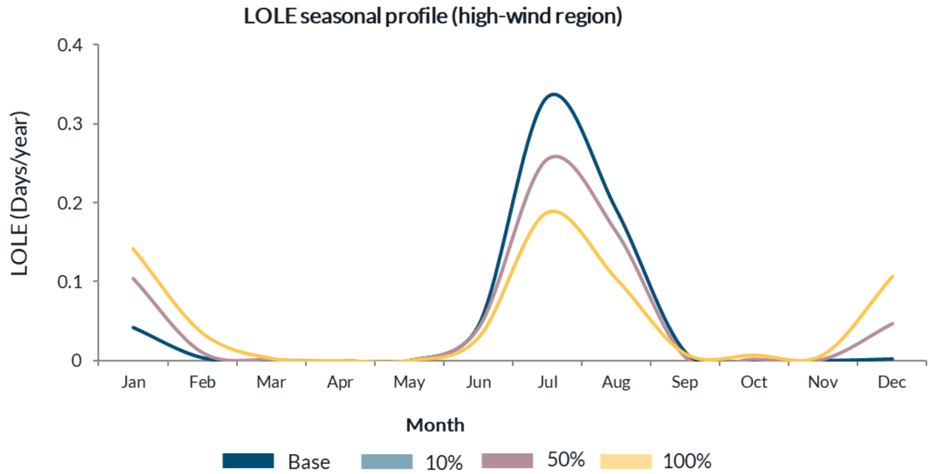


Figure RA-9: Monthly LOLE in high wind northern region

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)

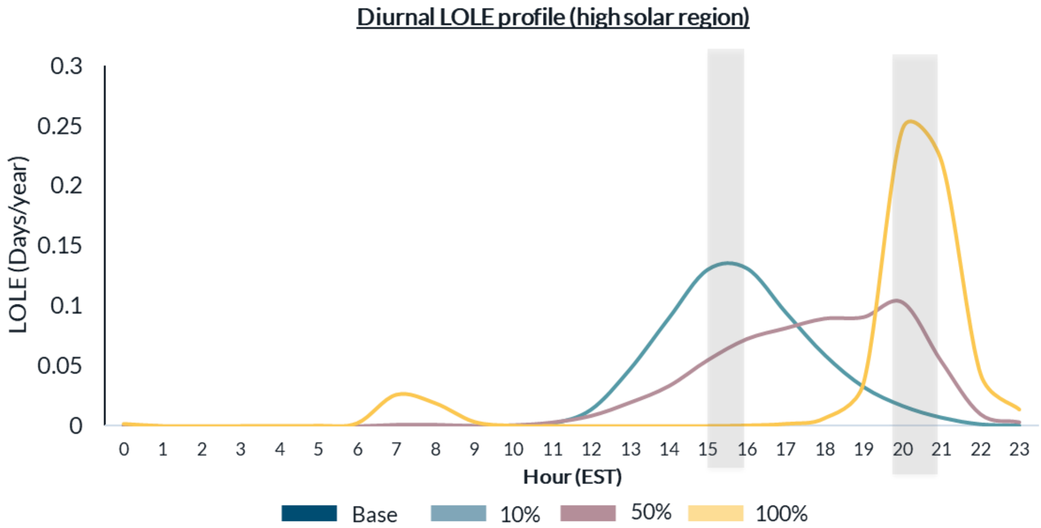
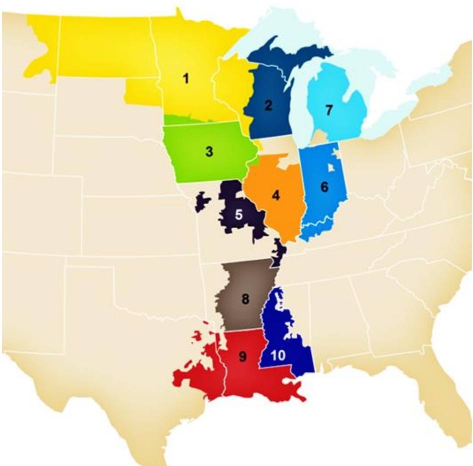


Figure RA-10: Hourly LOLE in high solar southern region

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.



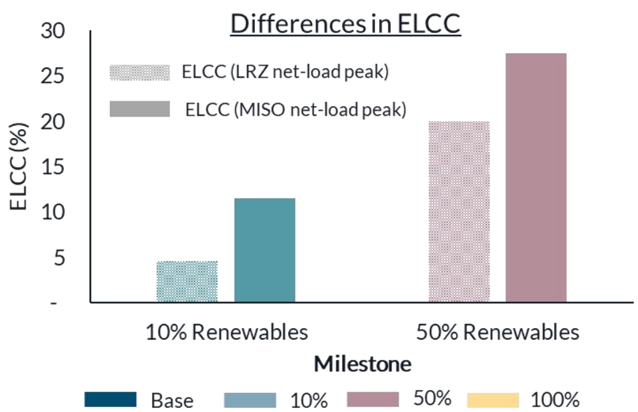


Figure RA-11: Change in ELCC by region size (MISO LRZ vs. MISO)

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.

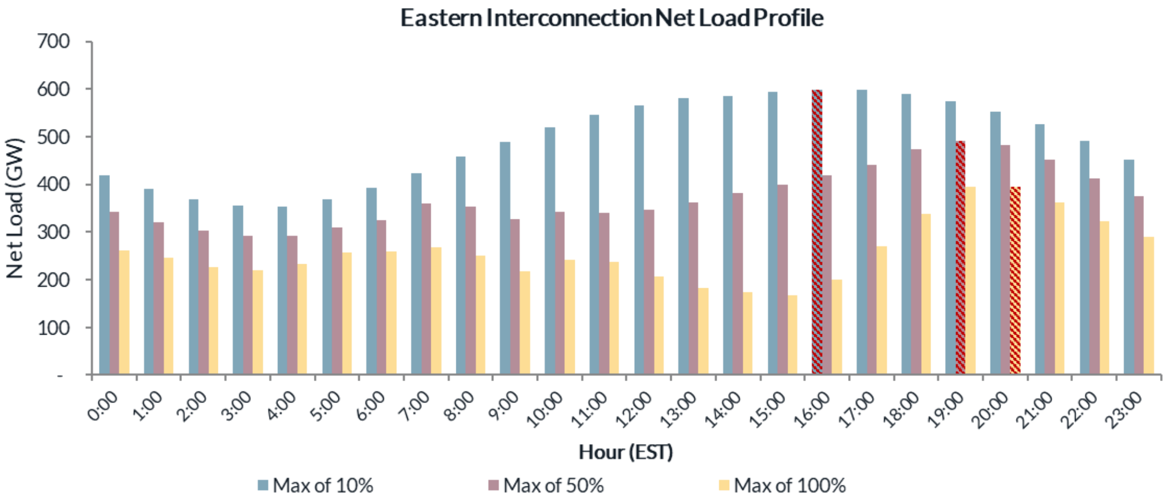


Figure RA-12: Eastern Interconnection Net Load Profile; peak net-load for each penetration level is highlighted.

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.

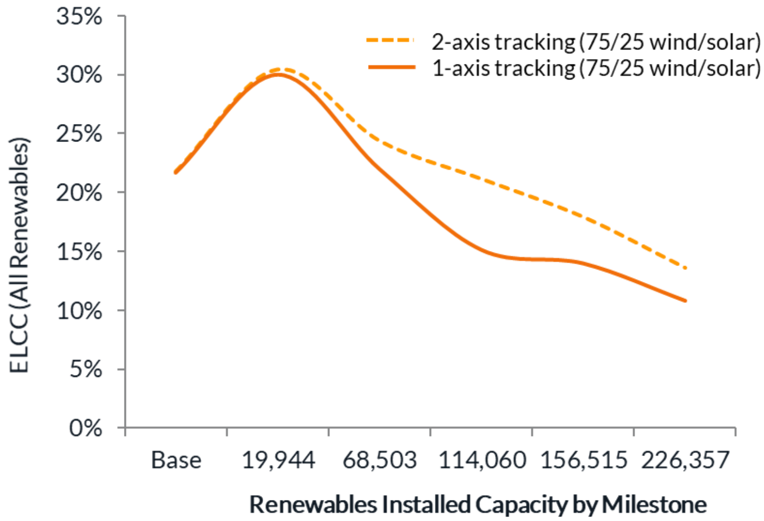


Figure RA-13: ELCC comparison of 2-axis vs. 1-axis solar

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.

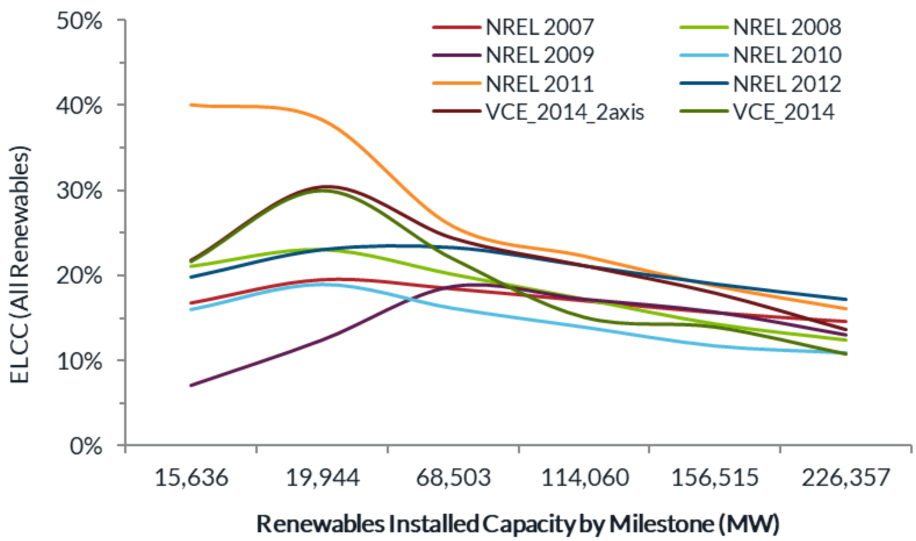


Figure RA-14: Change in ELCC by installed capacity per weather year

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.

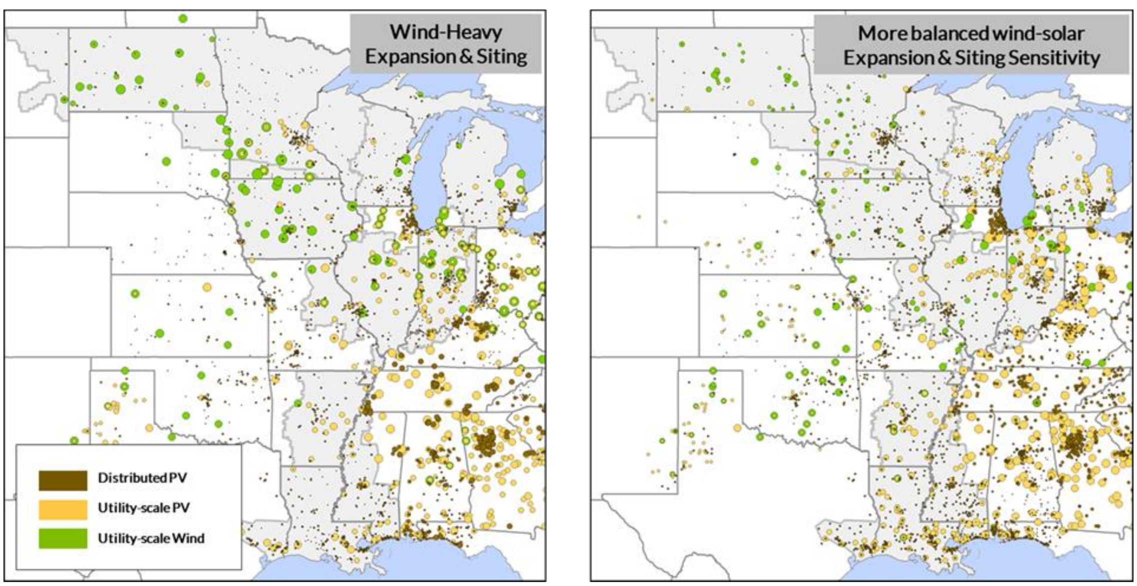


Figure RA-15: Wind and solar siting sensitivity

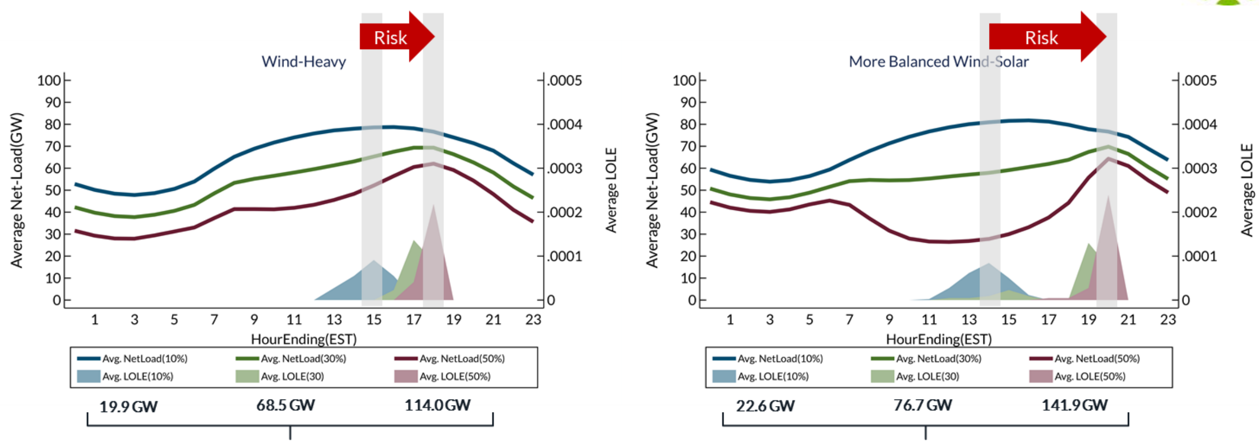


Figure RA-16: LOLE of wind-heavy resource deployment vs. balanced deployment

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.

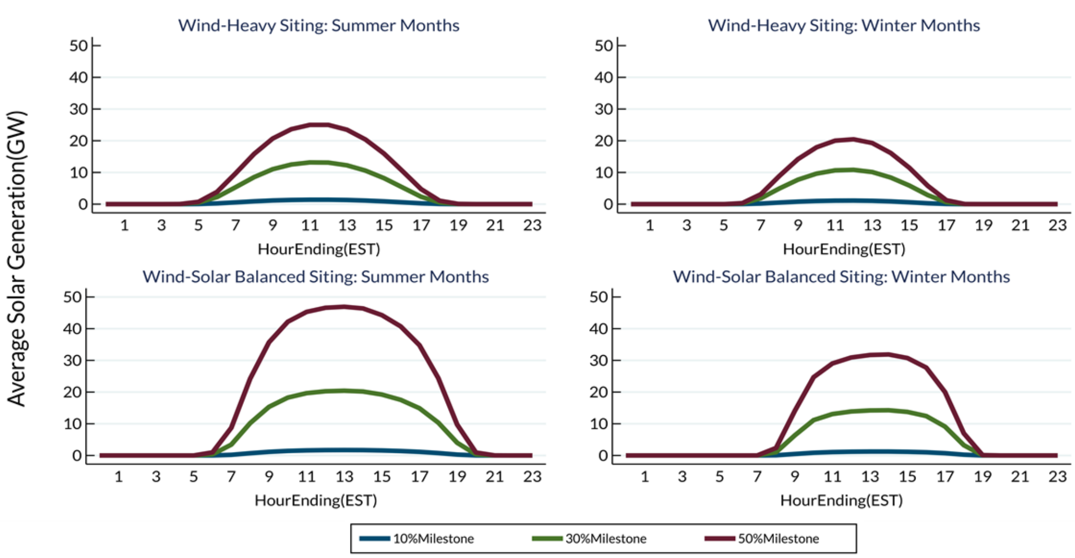
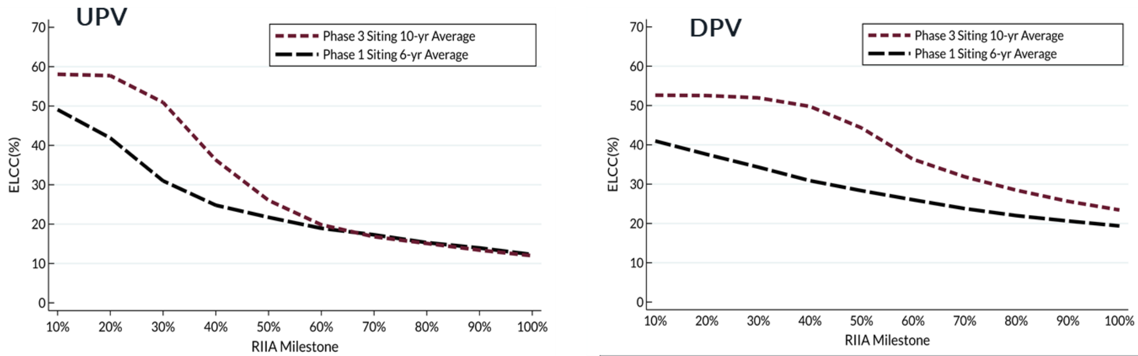


Figure RA-17: Average solar generation of siting sensitivity

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.

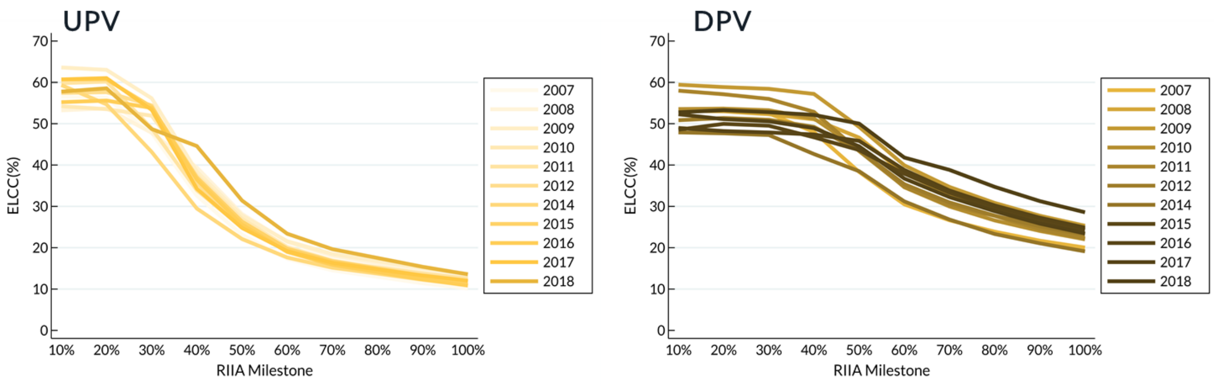
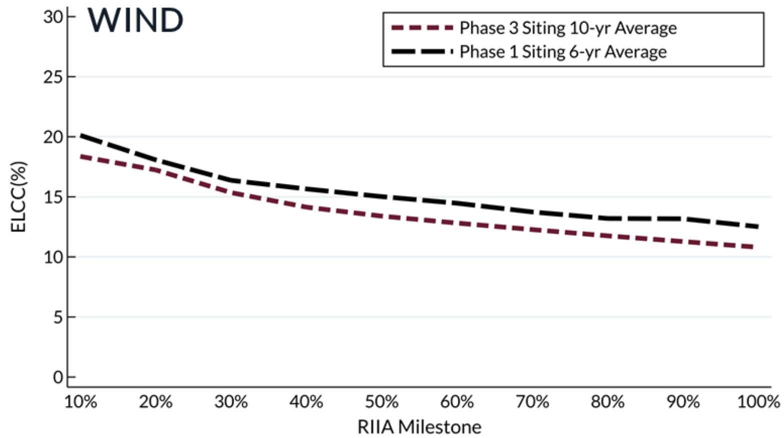


Figure RA-19: ELCC of solar by weather year

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.

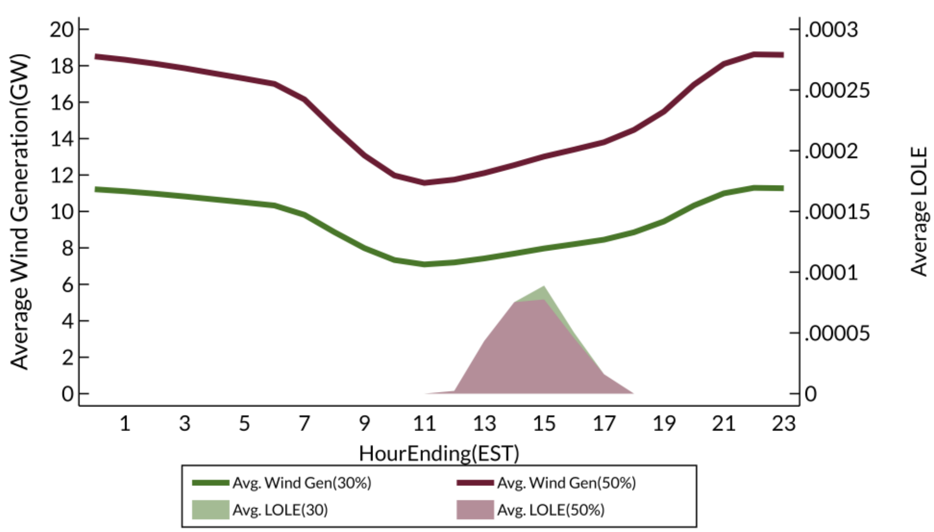


Figure RA-21: LOLE of wind at 30% vs. 50% penetration

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.

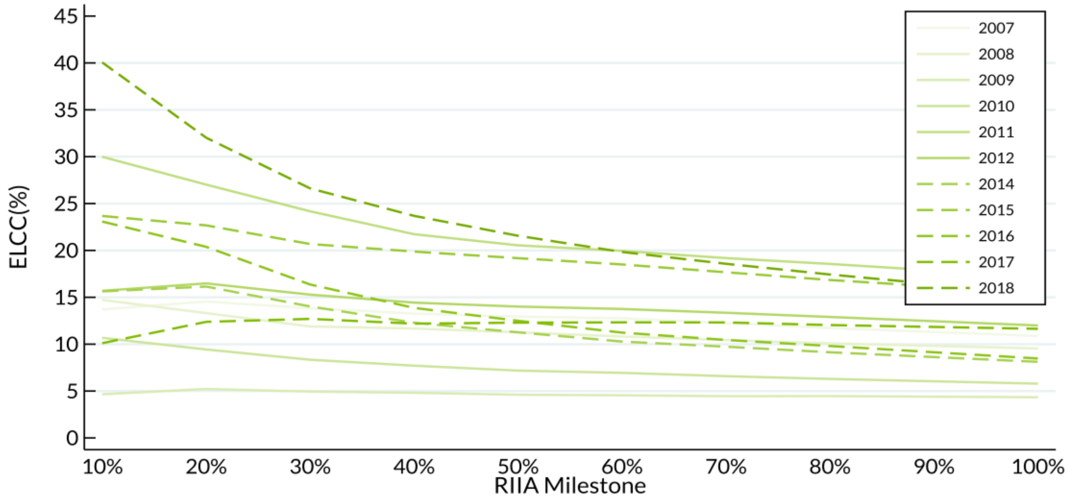


Figure RA-22: ELCC of wind by weather year

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).

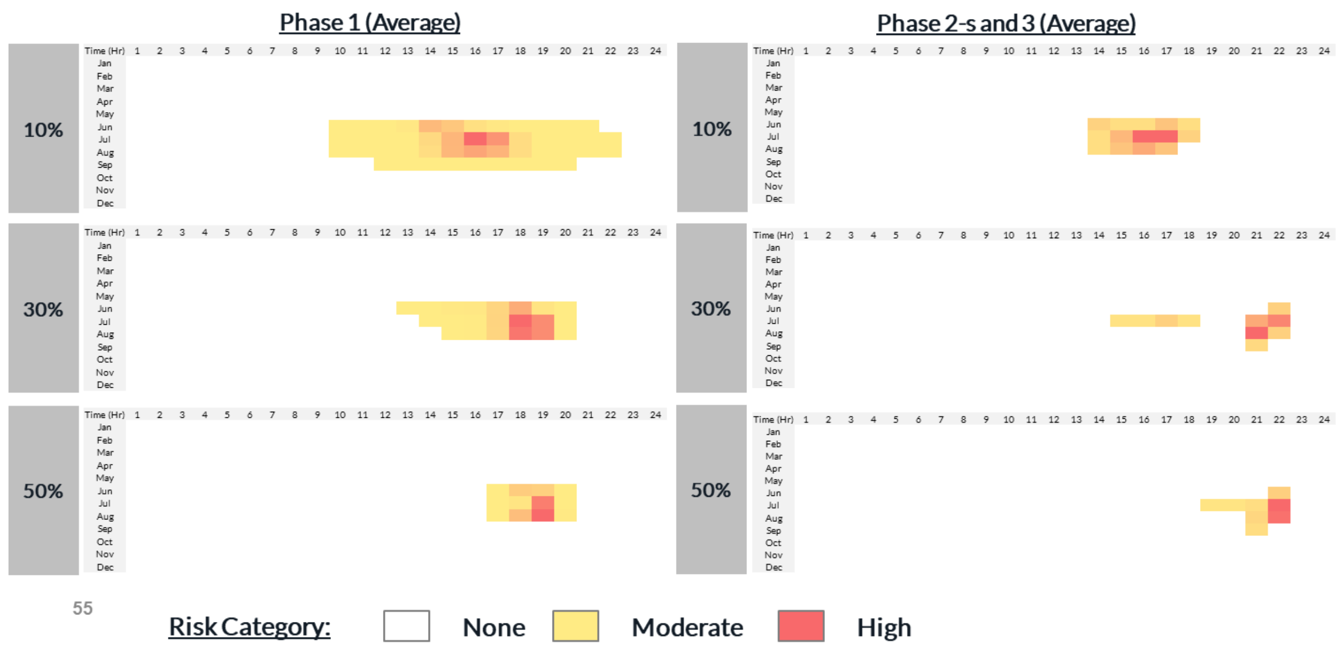


Figure RA-23: Average EUE by sensitivity and milestone

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.

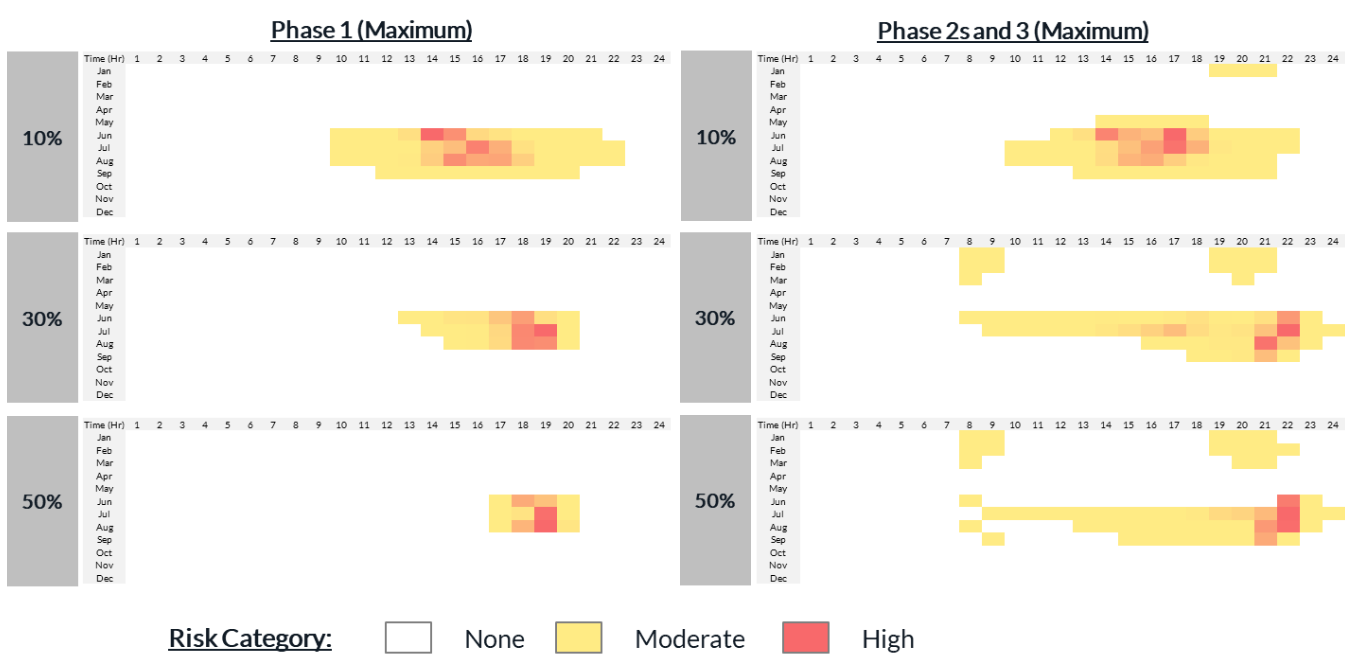


Figure RA-24: Maximum yearly EUE by sensitivity and milestone

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.

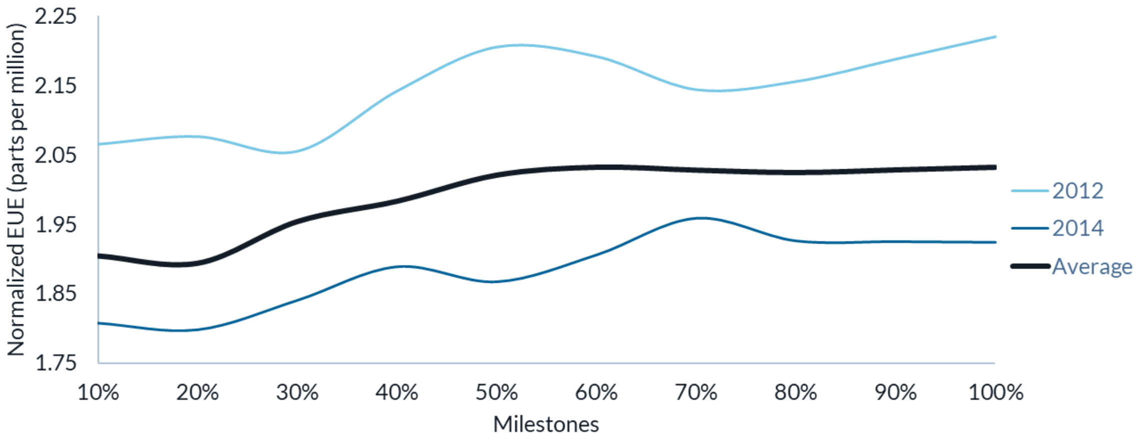


Figure RA-26: Change in normalized EUE by weather year and milestone. The 'average' respresents 11 weather years

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

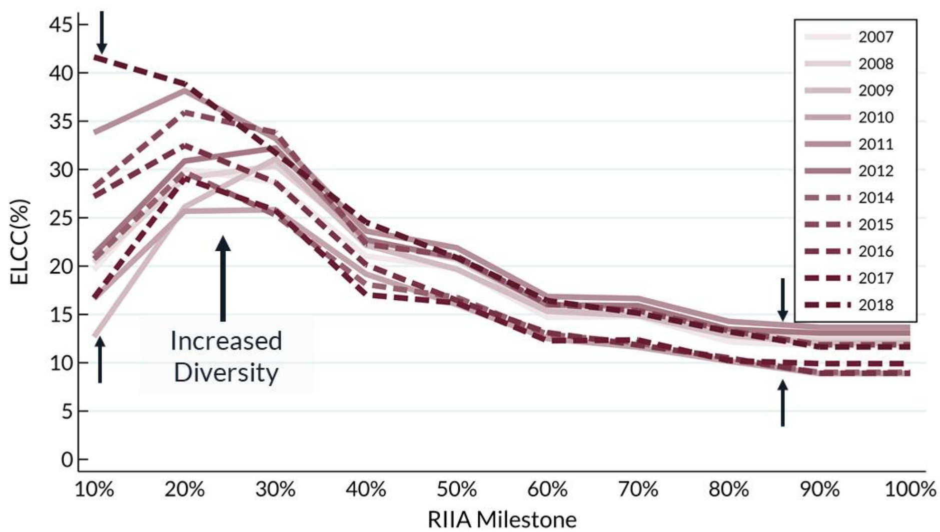
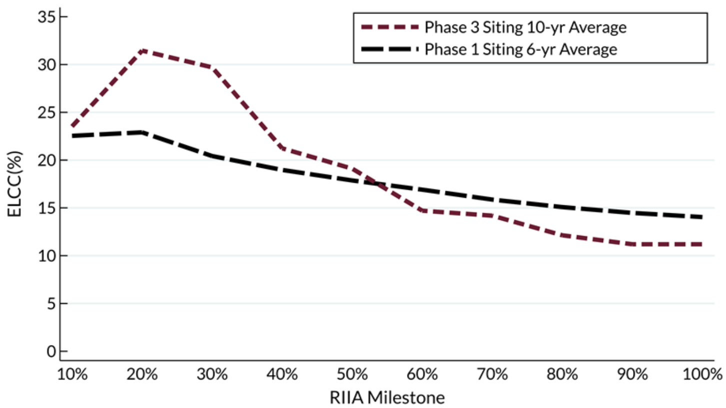


Figure RA-27: Change in ELCC due to diversity and weather year

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.

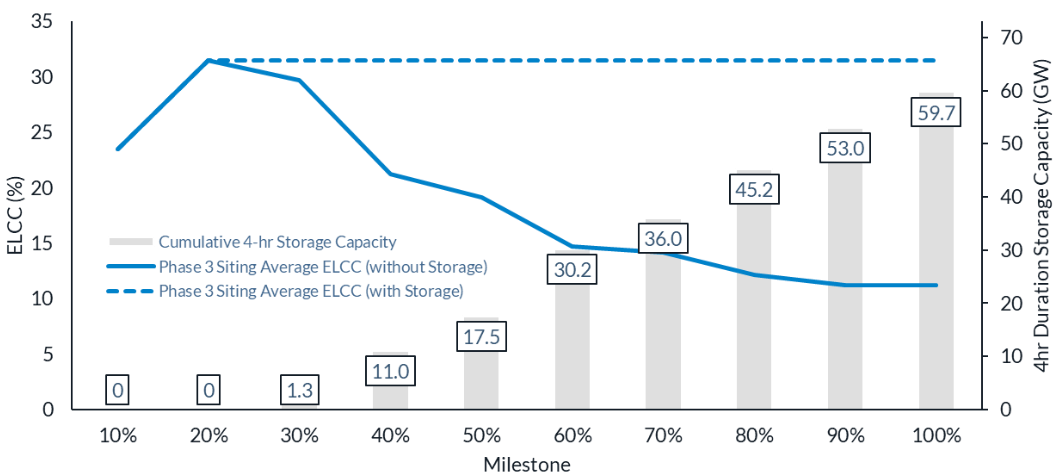


Figure RA-29: Amount of battery storage needed to maintain a constant ELCC

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.

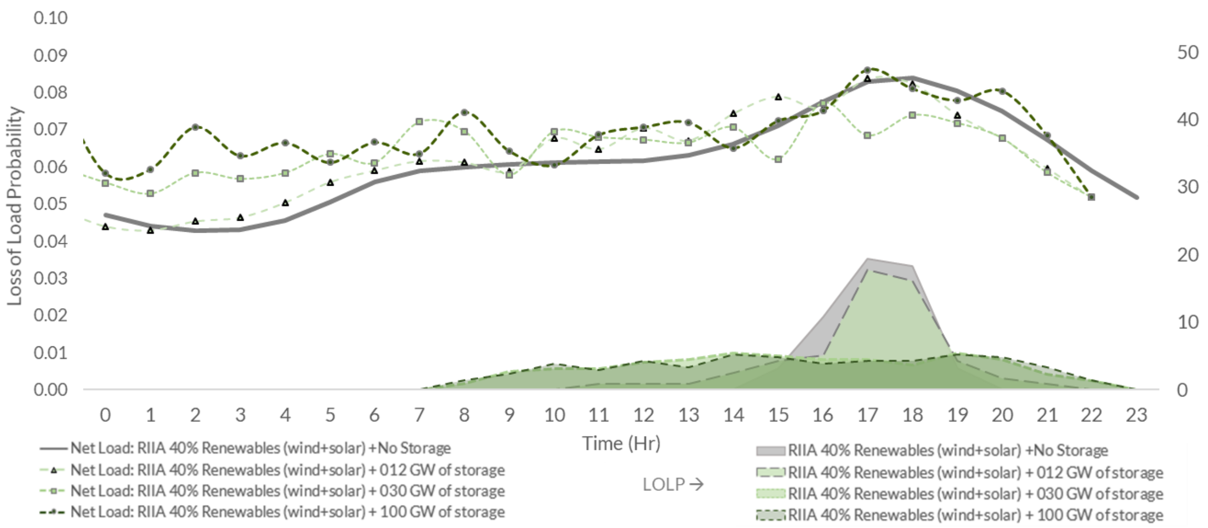


Figure RA-30: Hourly LOLP of a wind-heavy system by storage level

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.

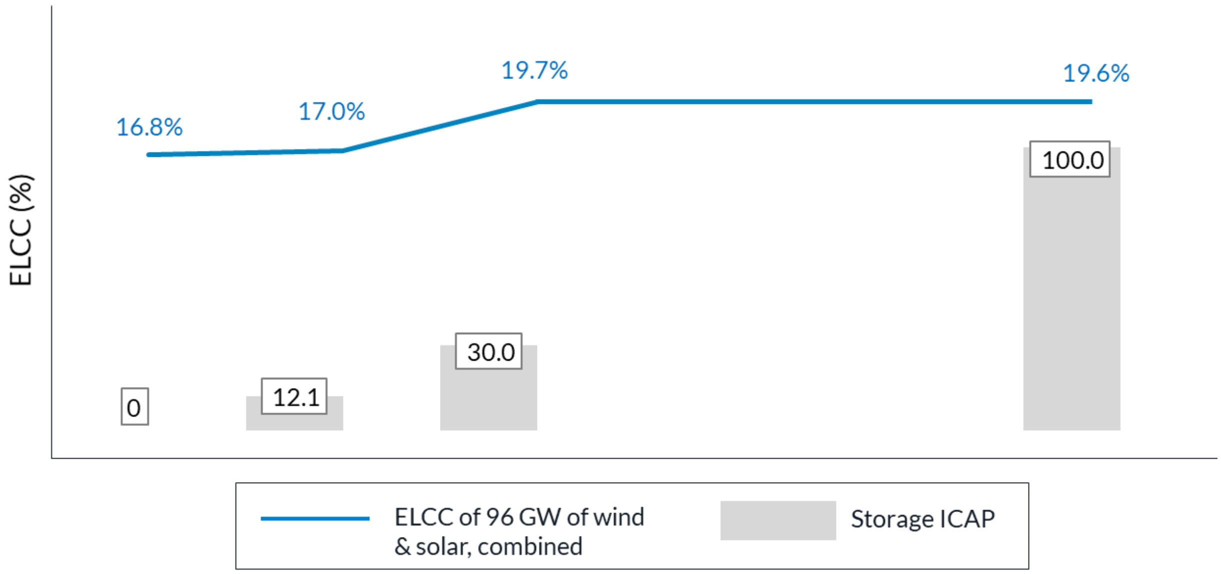


Figure RA- 31: ELCC benefit to a wind-heavy system from the addition of storage

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.

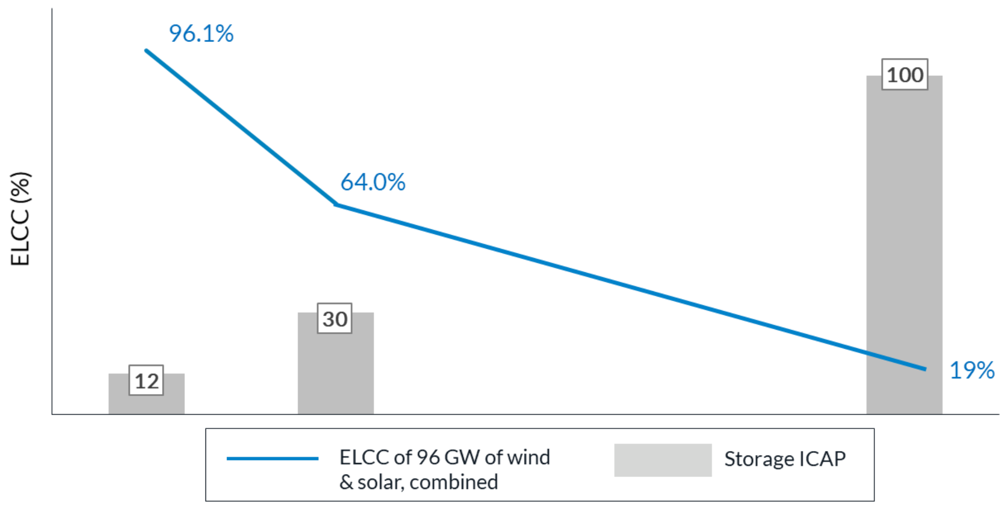


Figure RA-32: ELCC of storage as the penetration of storage increases

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.

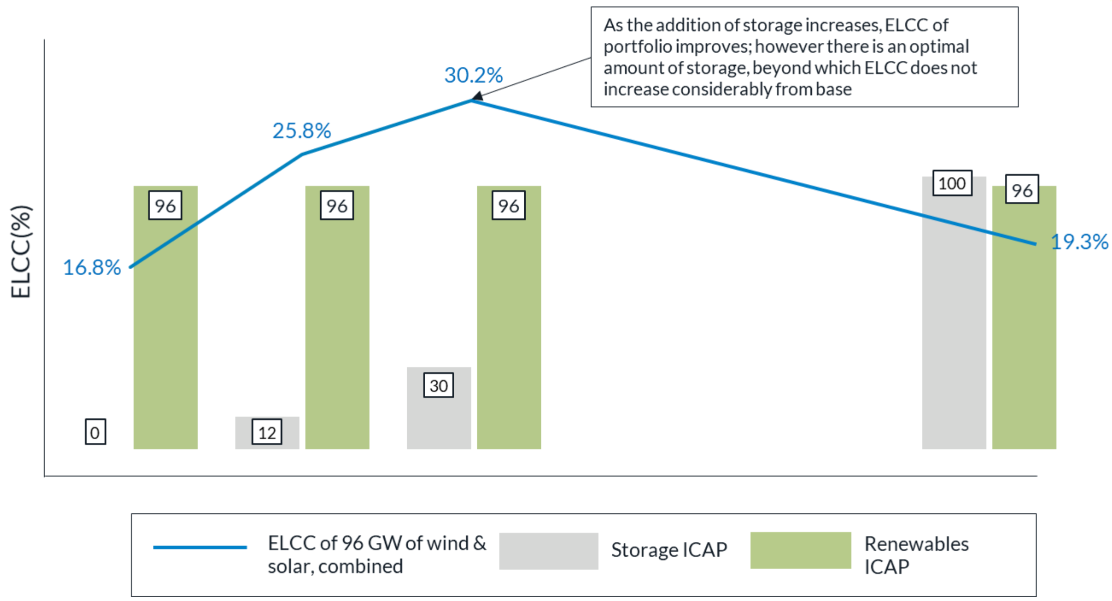


Figure RA-33: Change in ELCC on portfolio of wind, solar, and storage by storage penetration level

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.

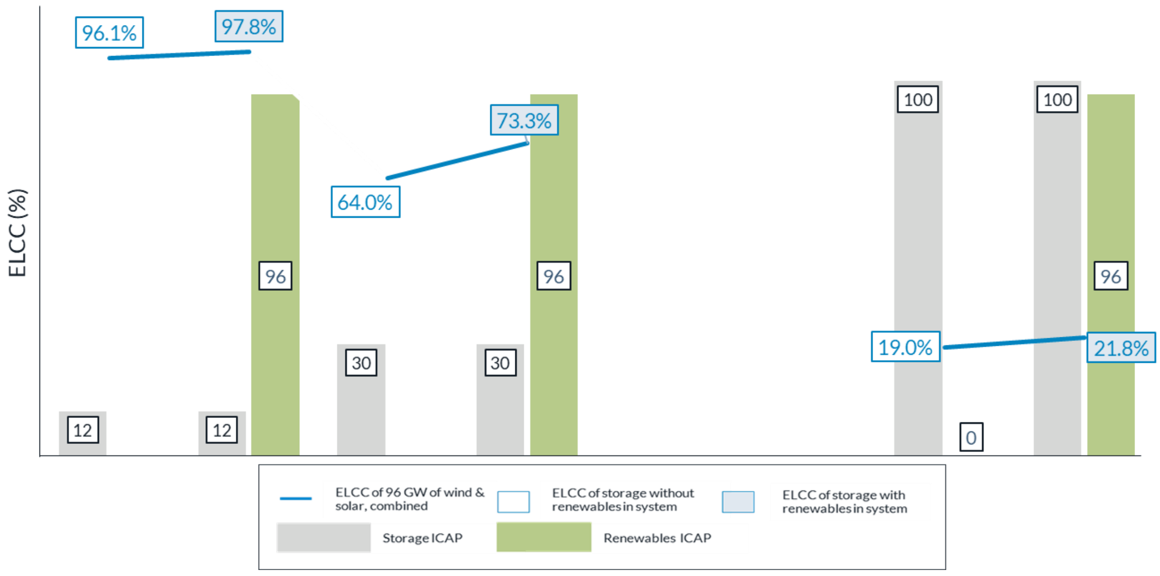


Figure RA-34: Comparison of ELCC of storage by renewable penetration level

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.

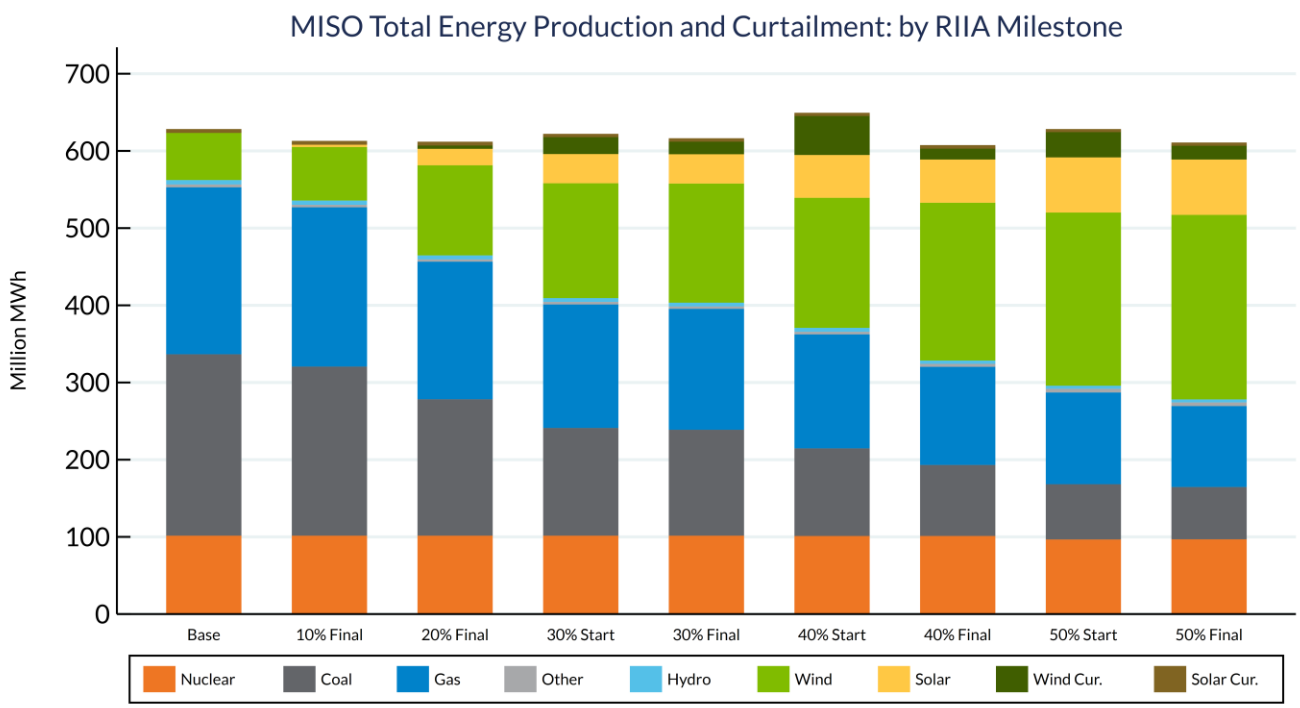
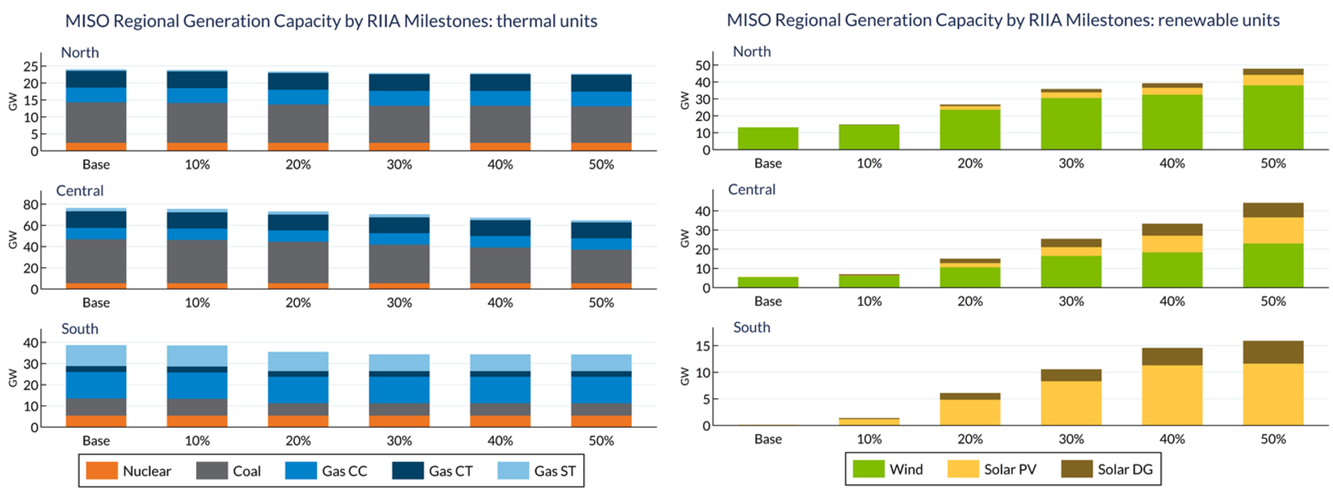


Figure EA-1: Fuel mix in RIIA milestones. "Start" indicates the addition of all renewables for the current milestone, plus any incremental transmission improvements from the previous milestone. "Final" indicates the addition of all renewables and any incremental improvements for the current milestone.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



* Different Y-axis scales.

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

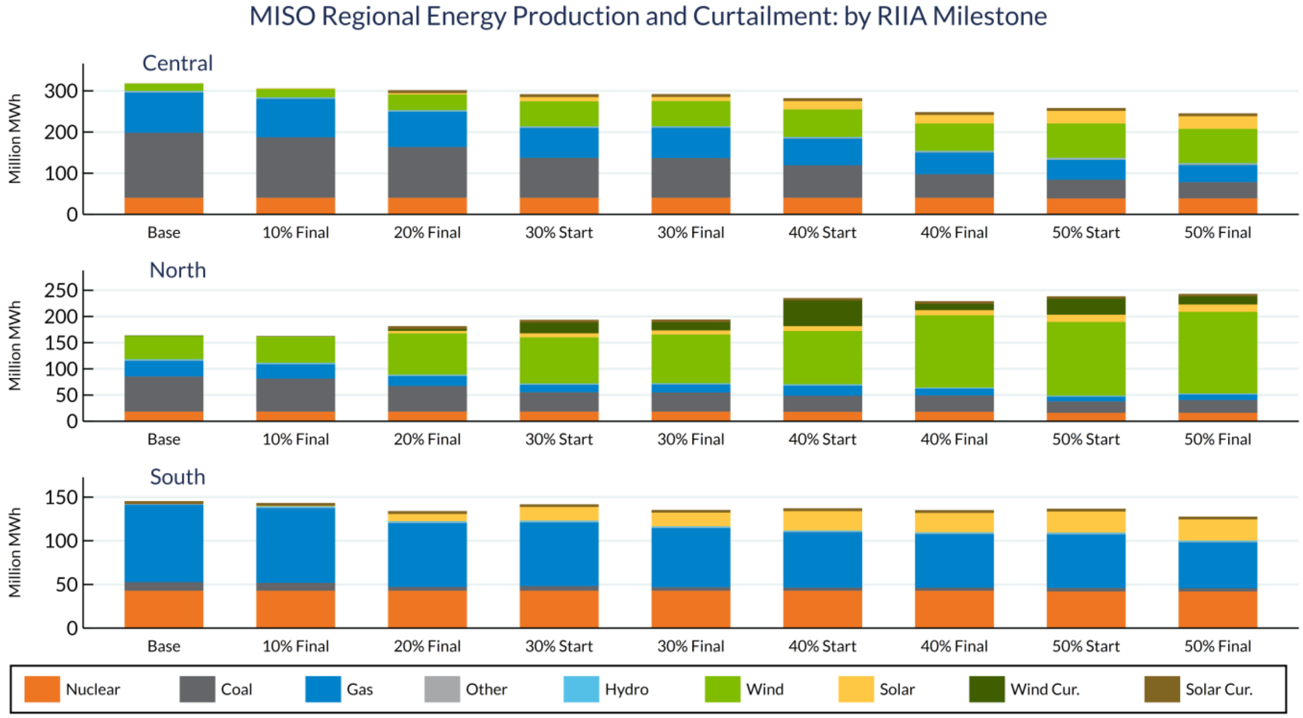


Figure EA-3: Fuel mix in RIIA milestones, regional breakdown

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.

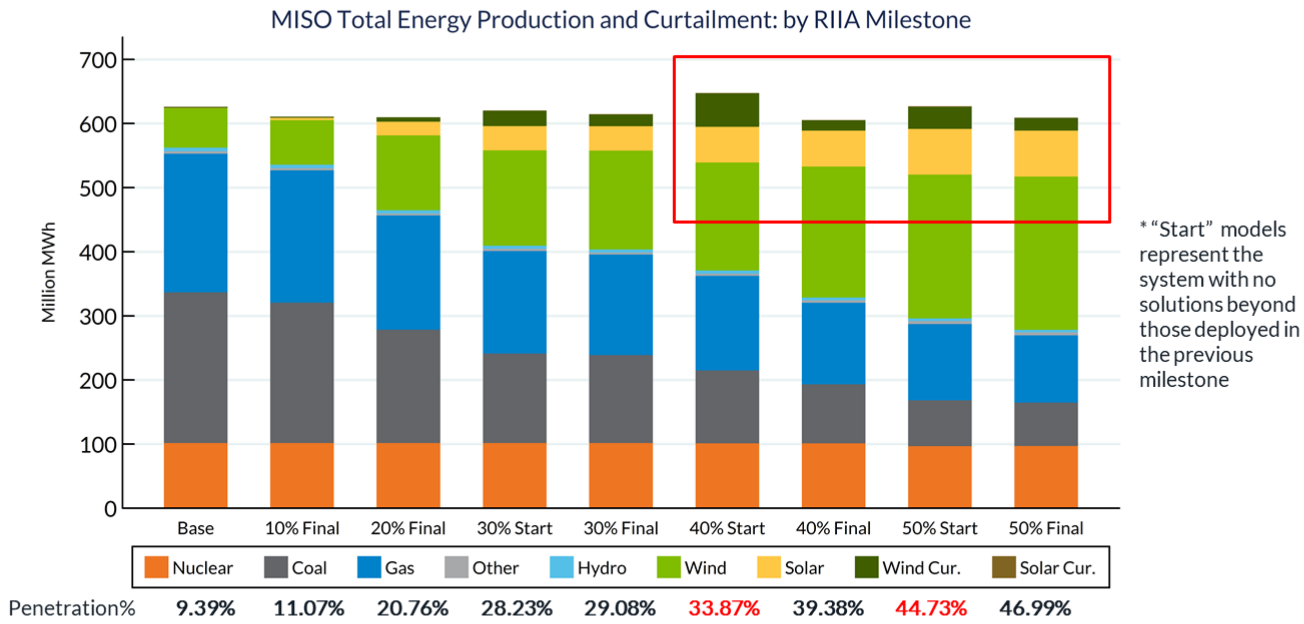


Figure EA-4: Transmission solutions and their effect on renewable penetration for all RIIA milestones

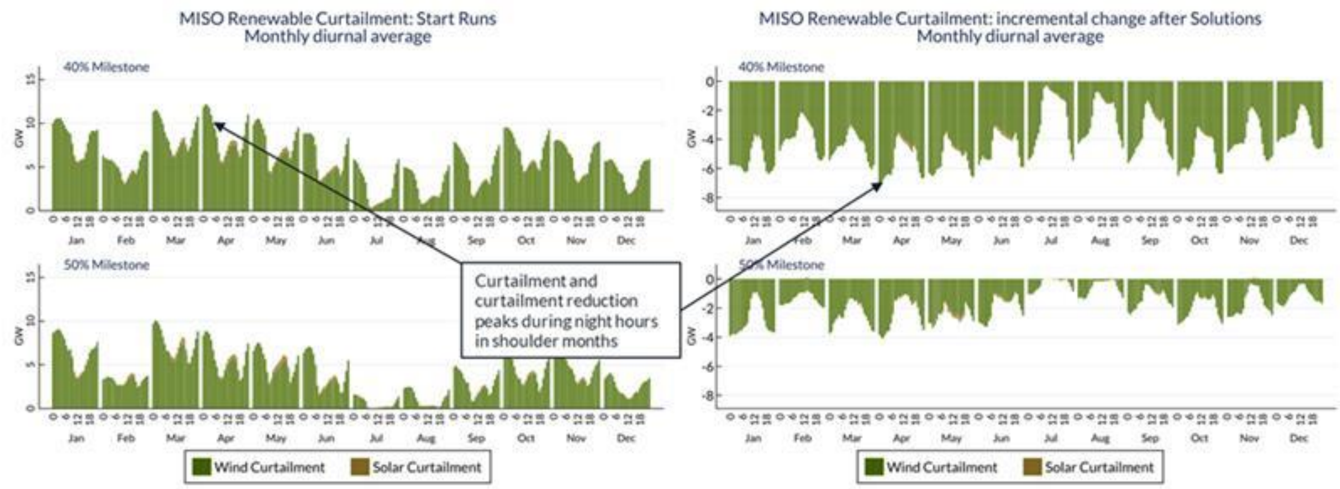


Figure EA-5: Monthly diurnal average of renewable energy curtailment for the 40% and 50% milestones

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.

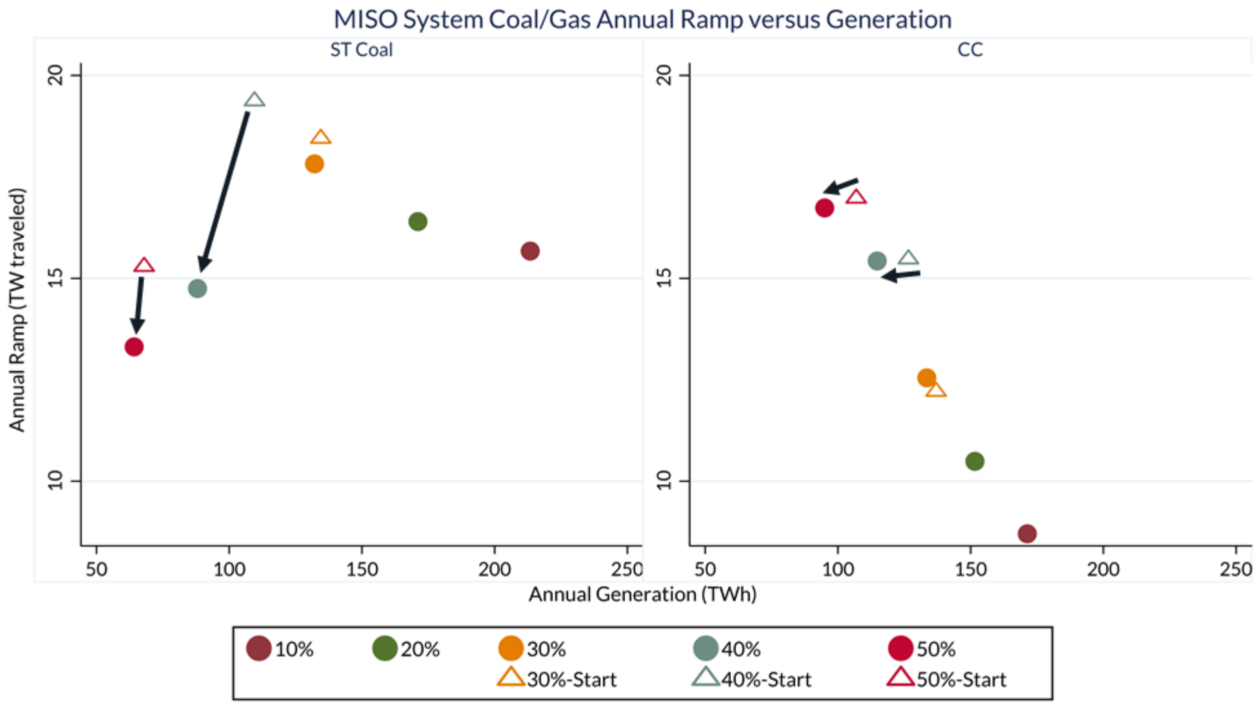


Figure EA-6: Effect of transmission solutions on thermal unit ramping for RIIA milestones

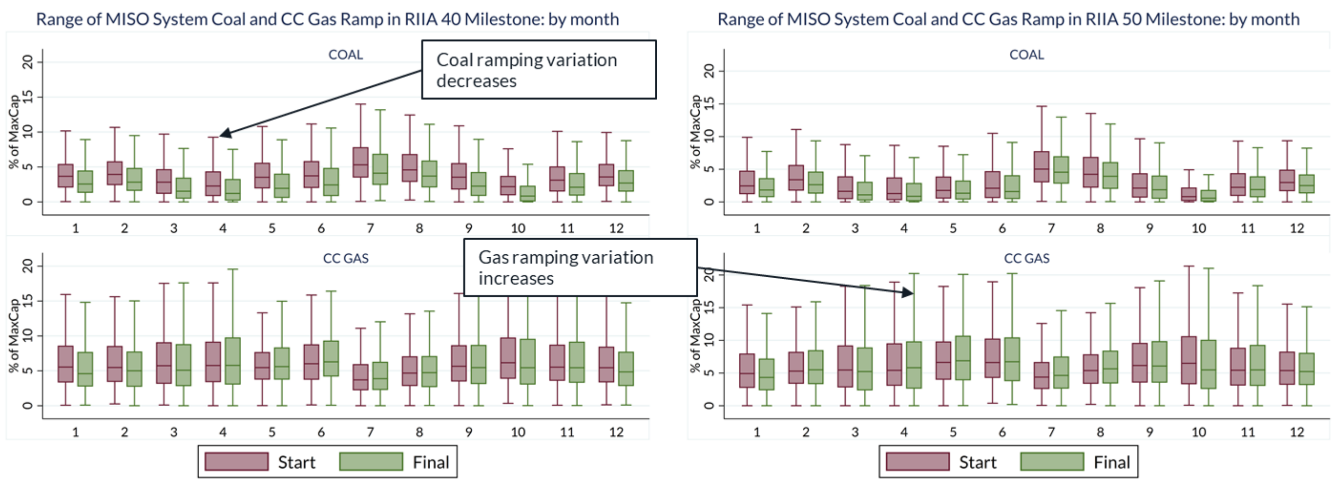


Figure EA-7: One-hour ramp variability of coal and gas units for the RIIA 40% and 50% milestones

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.

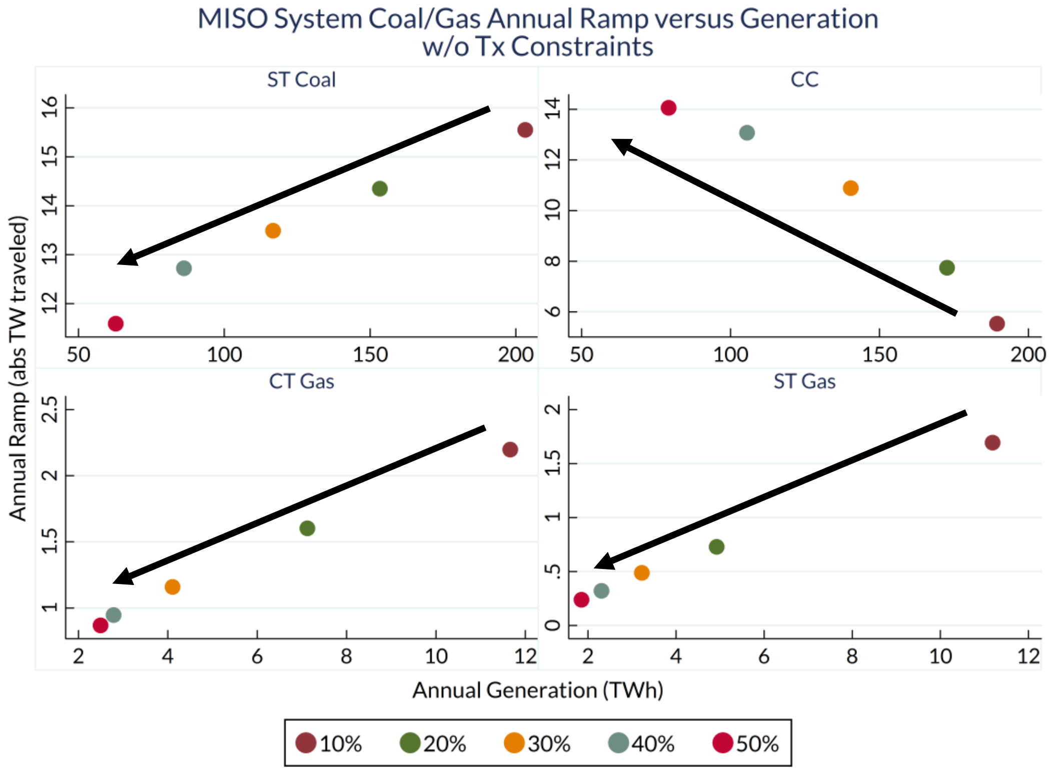


Figure EA-8: Thermal unit ramping in RIIA milestones, ignoring transmission constraints

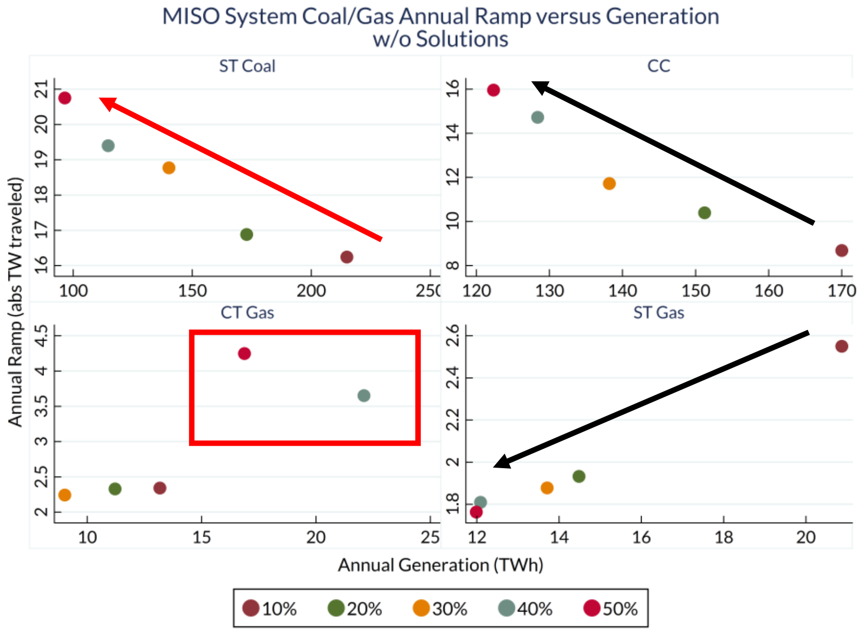


Figure EA-9: Thermal unit ramping in RIIA milestones for the "BaseT" model, which includes transmission constraints, but no RIIA transmission solutions

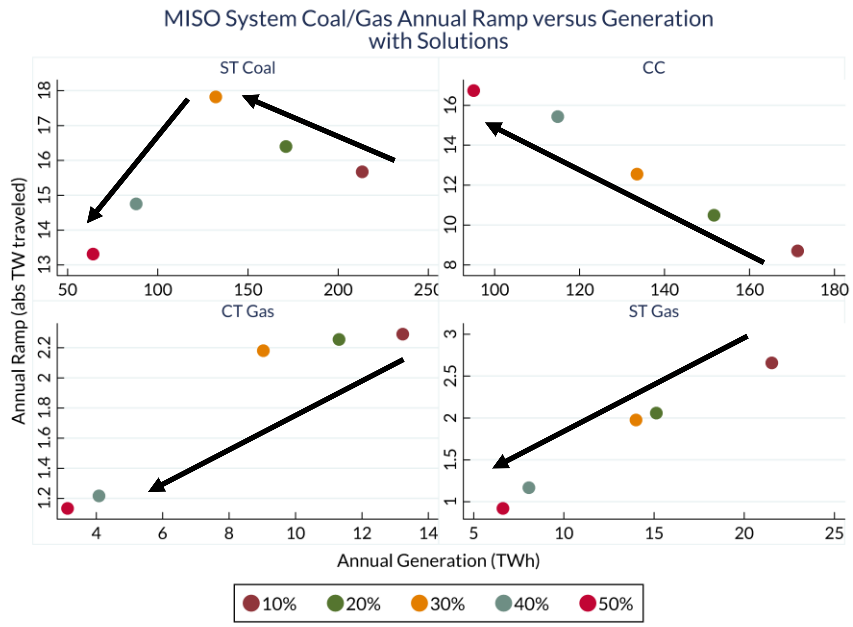


Figure EA-10: Thermal unit ramping in RIIA milestones for the Final model, which includes transmission constraints and RIIA-identified transmission solutions

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.

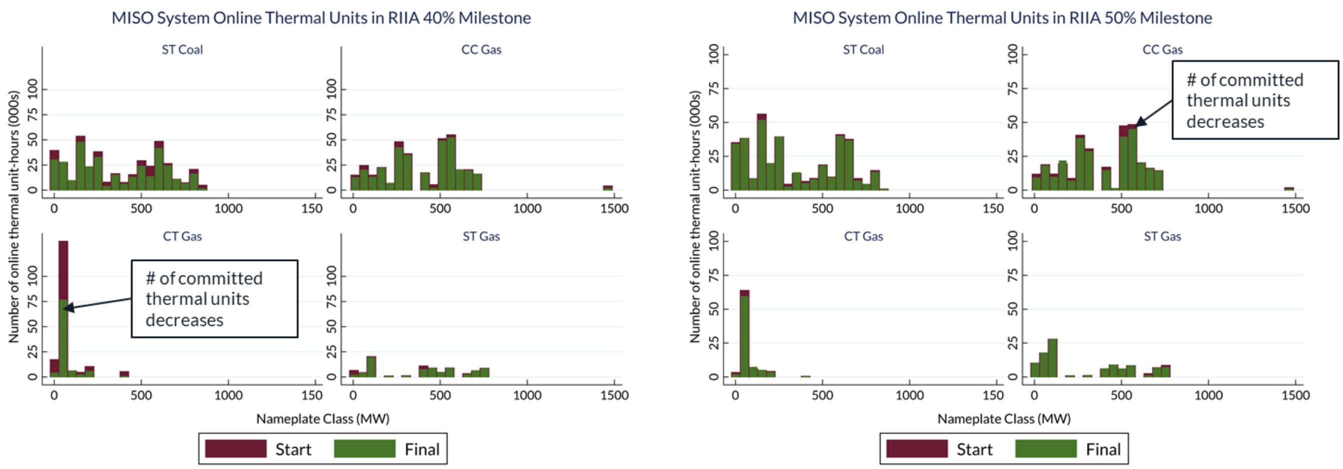


Figure EA-11: Commitment of coal and gas units in the RIIA 40% and 50% milestones

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.

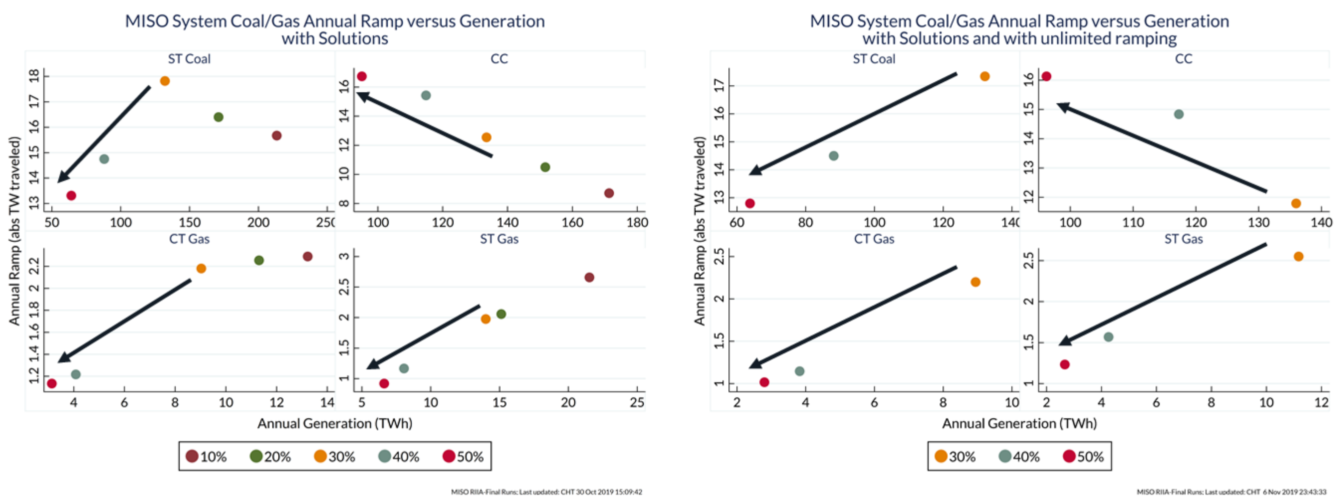


Figure EA-12: Thermal unit ramping in RIIA milestones, assuming unlimited ramping capabilities for all thermal units

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).

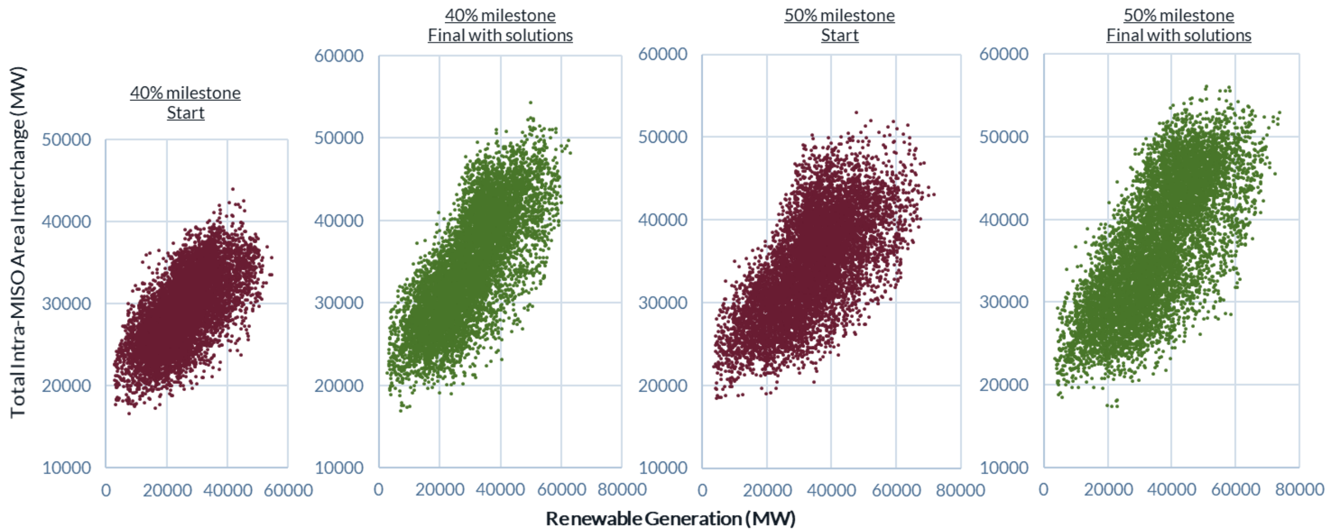


Figure EA-13: Intra-MISO power flow at RIIA 40% and 50% milestones before and after transmission solutions

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.

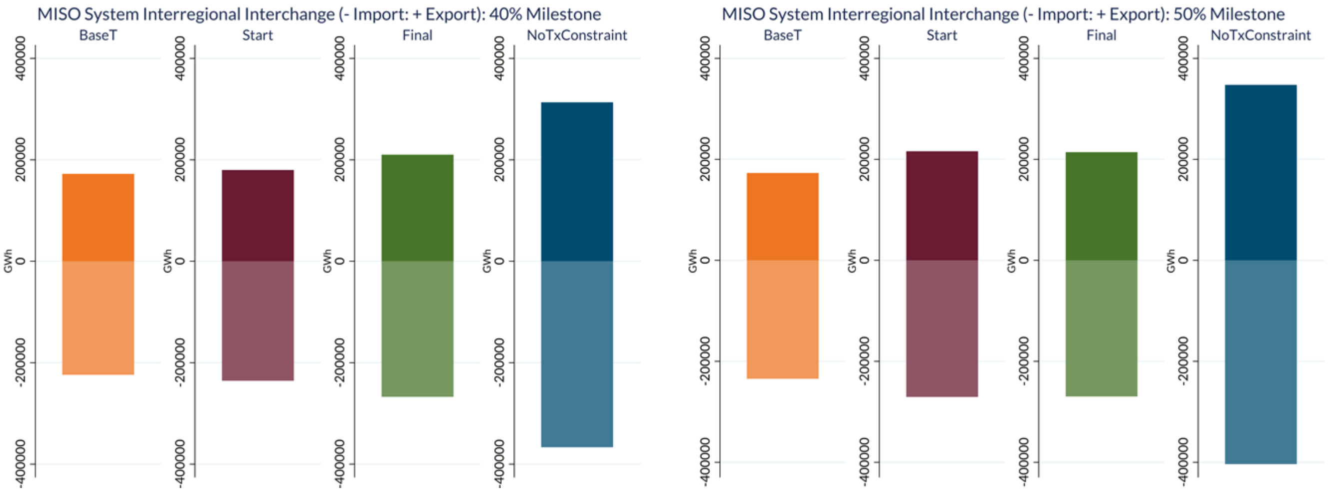


Figure EA-14: MISO interchange with neighboring BAs at RIIA 40% and 50% milestones for different models.

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.

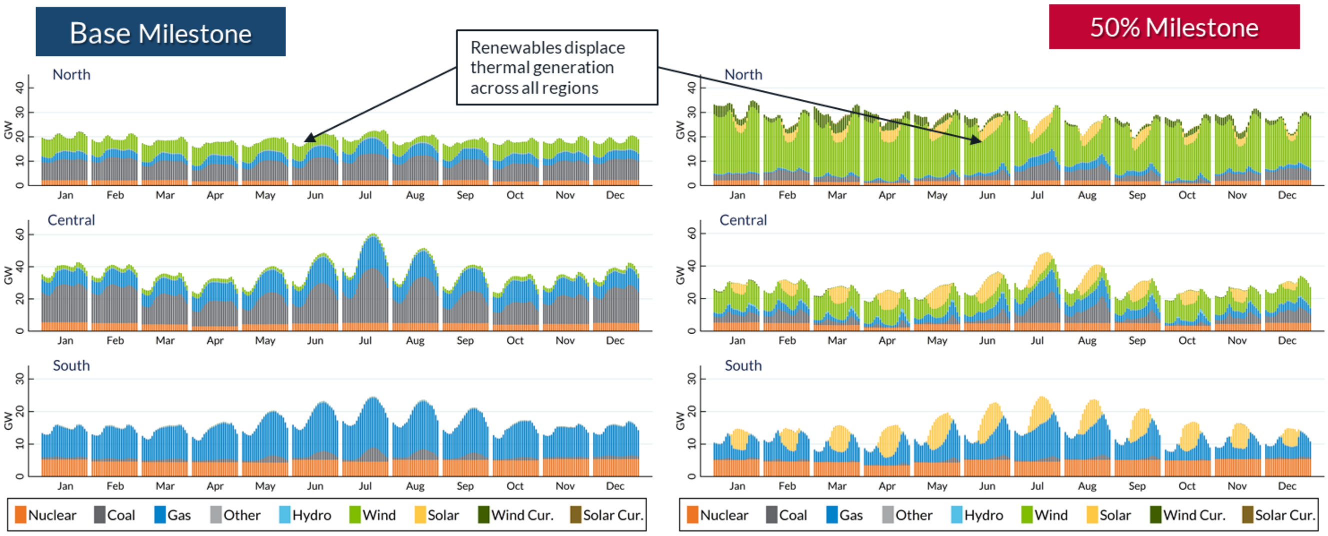


Figure EA-15: Monthly diurnal average of fuel mix at RIIA Base and 50% milestones

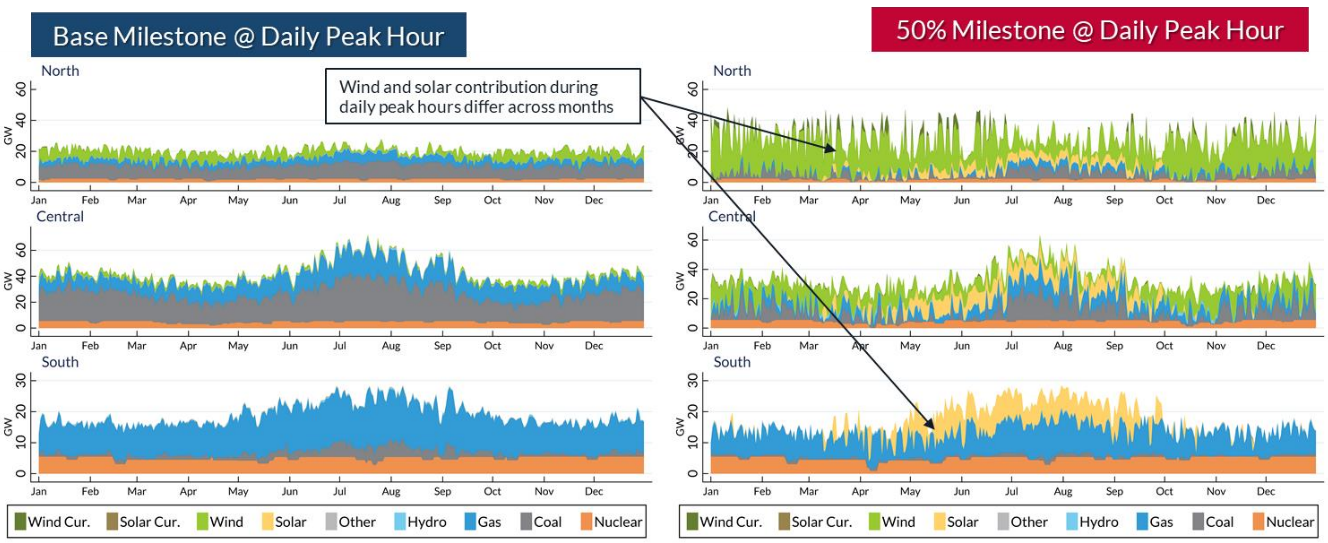


Figure EA-16: Daily peak hour of fuel mix at RIIA Base and 50% milestones

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.

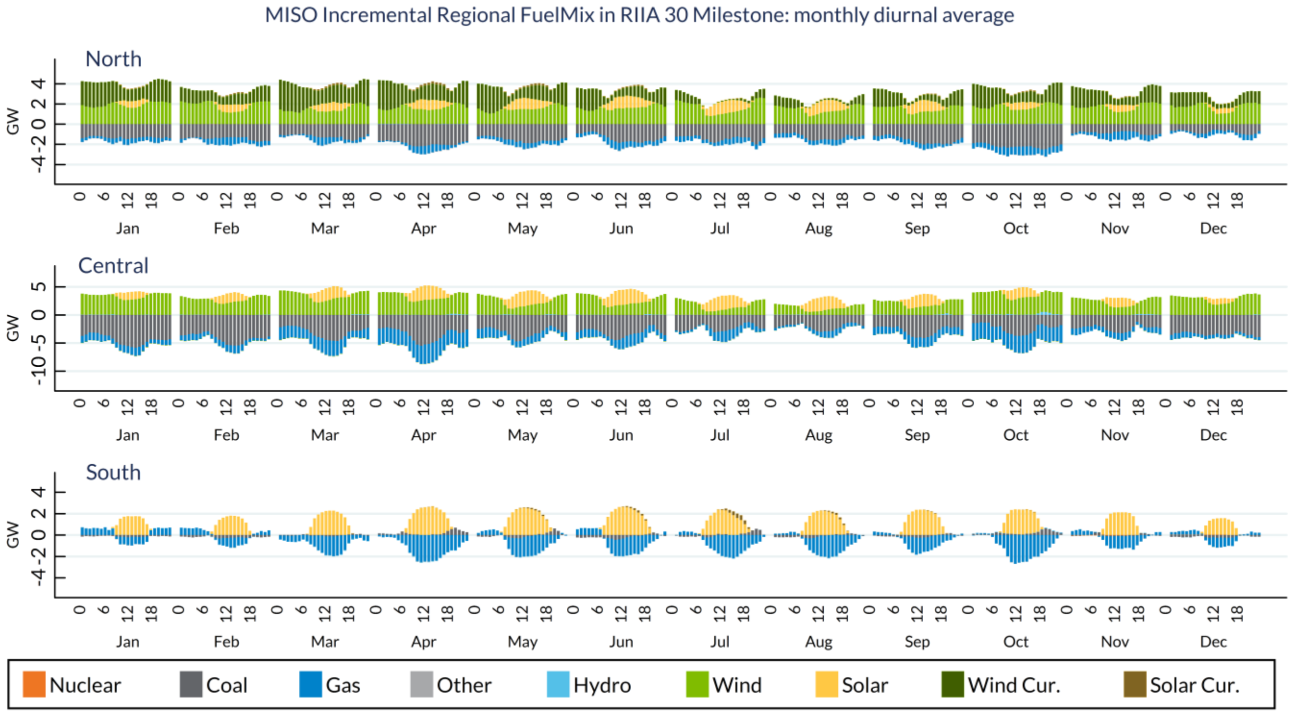


Figure EA-17: Monthly diurnal average of fuel mix, incremental change from the 20% milestone to the 30% milestone. Positive numbers indicate incremental increase, while negative numbers indicate incremental decrease.

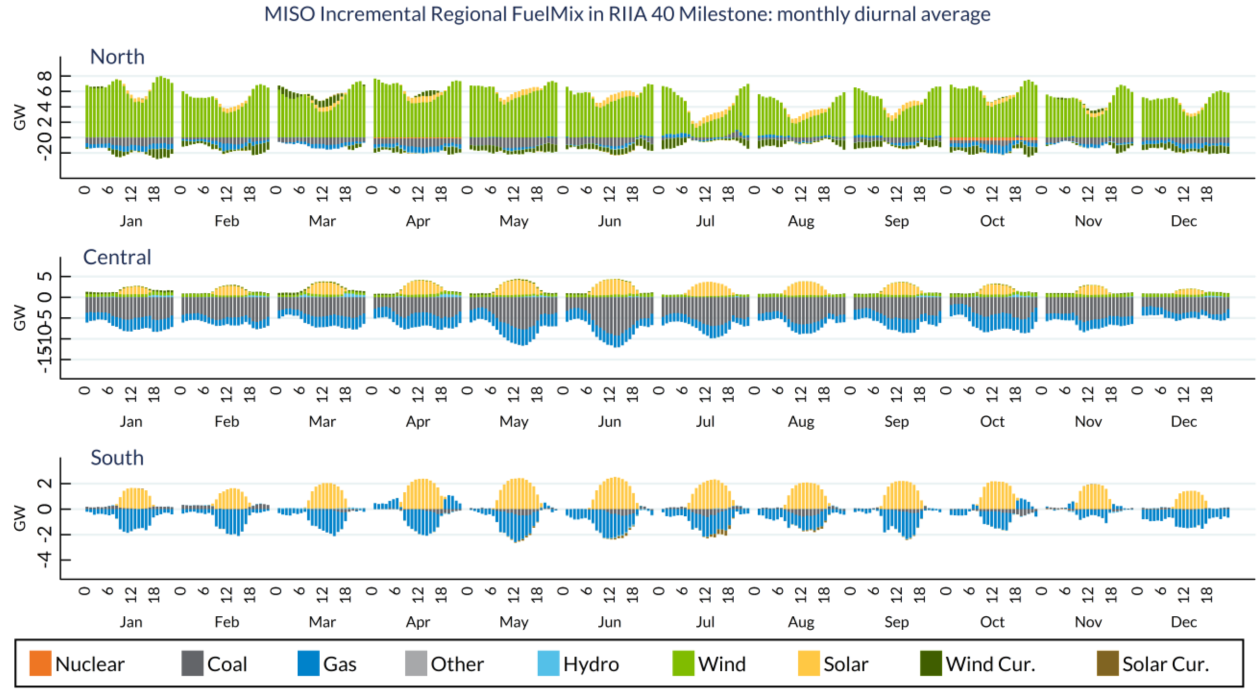


Figure EA-18: Monthly diurnal average of fuel mix, incremental change from the 30% milestone to the 40% milestone

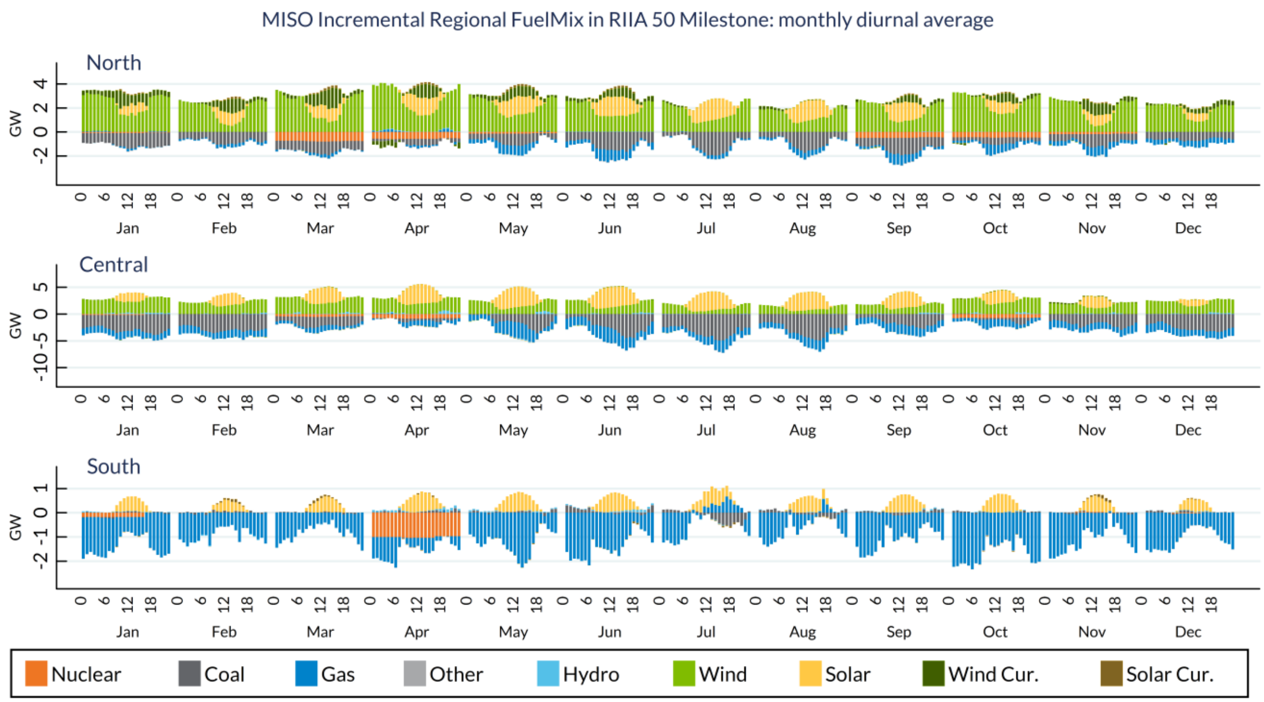


Figure EA-19: Monthly diurnal average of fuel mix, incremental change from the 40% milestone to the 50% milestone

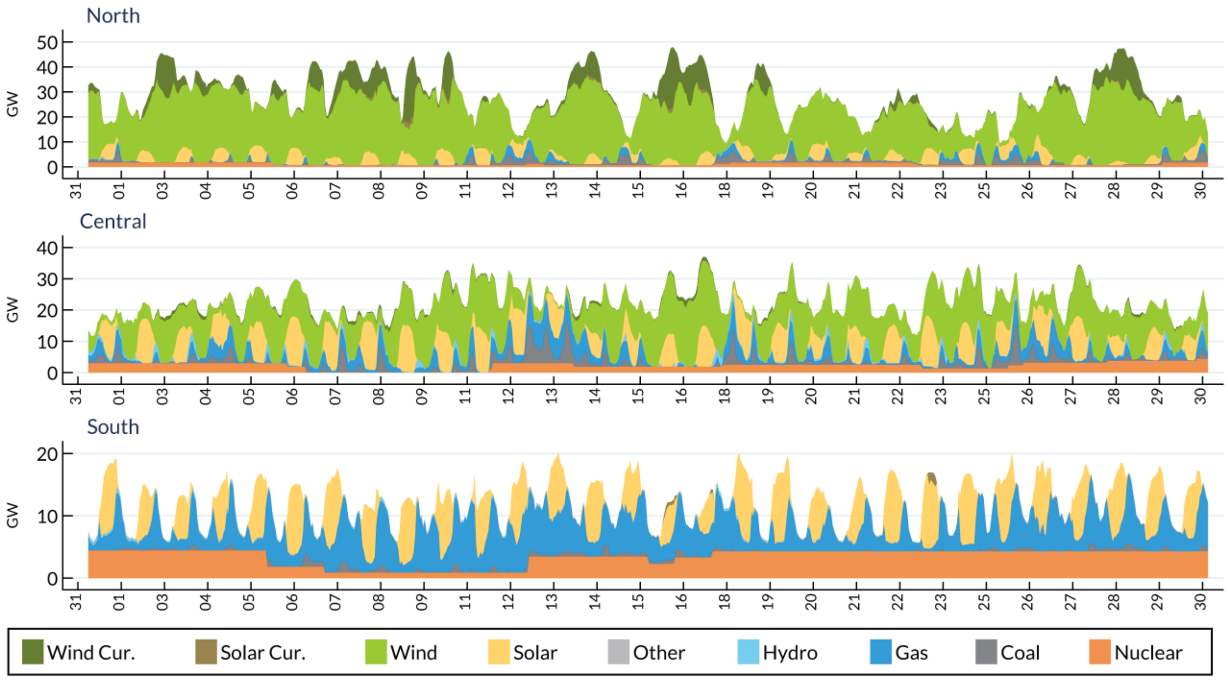


Figure EA-20: Hourly fuel mix in April for the RIIA 50% milestone

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.

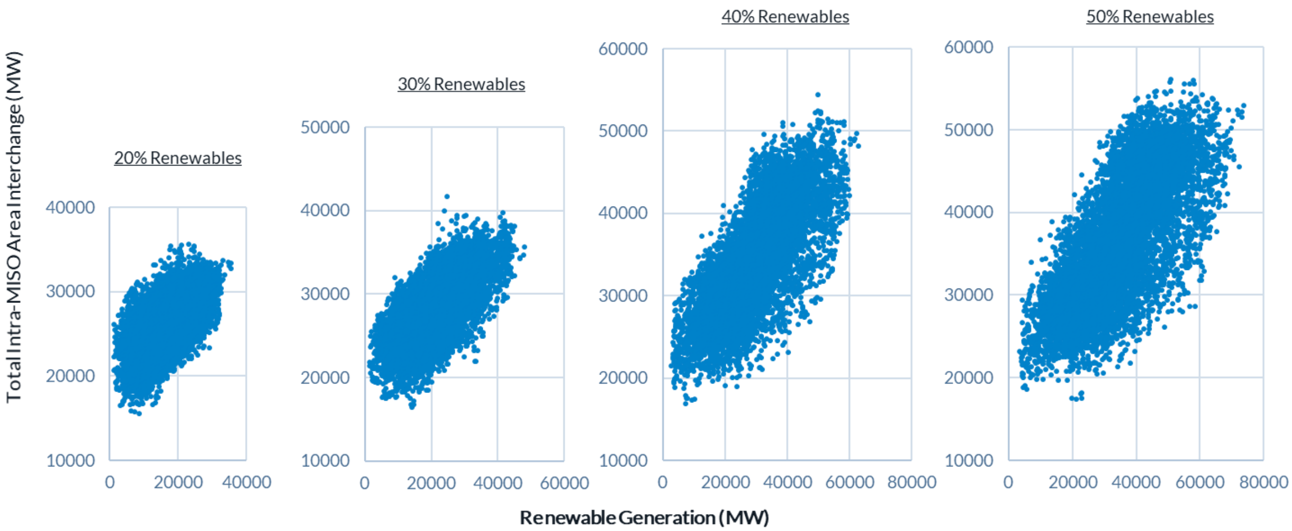


Figure EA-21: Intra-MISO interchange from RIIA 20% to 50% milestones. The increasing upper limit of the cloud of points indicates increased interchanges, while the increasing height of the cloud indicates increased variability

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.

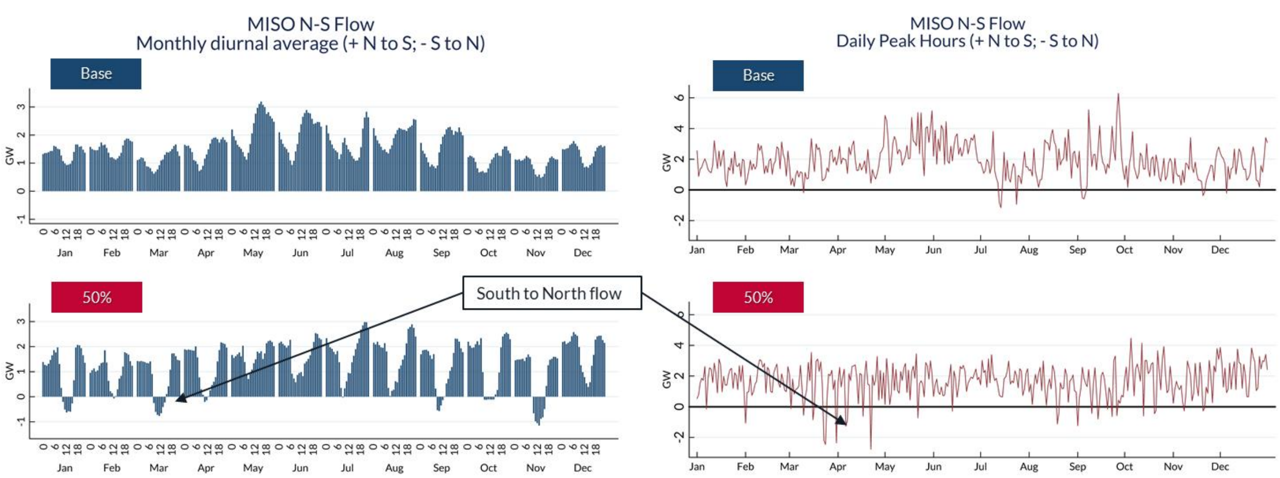


Figure EA-22: MISO North-South flow for the RIIA Base case and 50% milestone

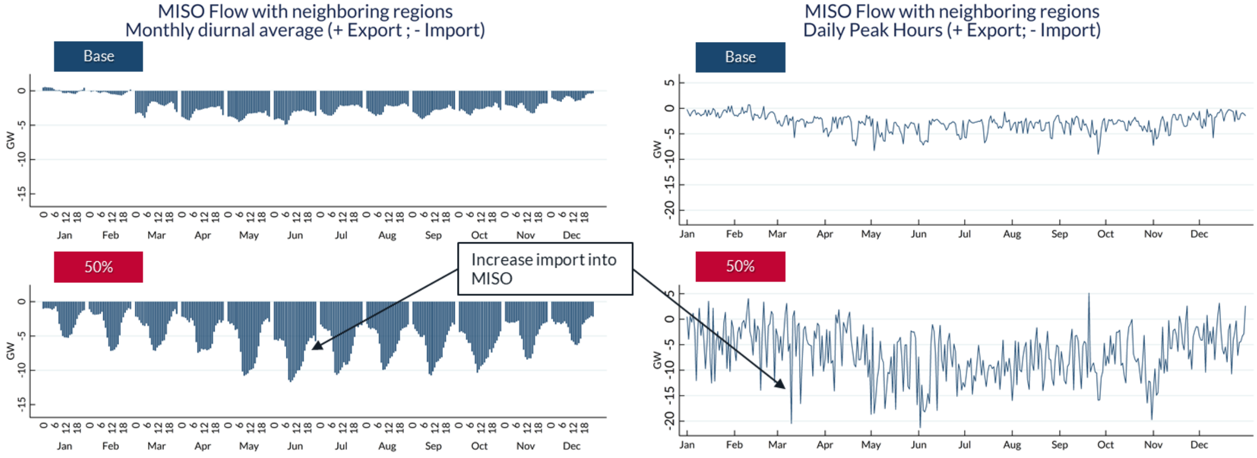


Figure EA-23: MISO flow with neighboring BAs for the RIIA Base case and 50% milestone

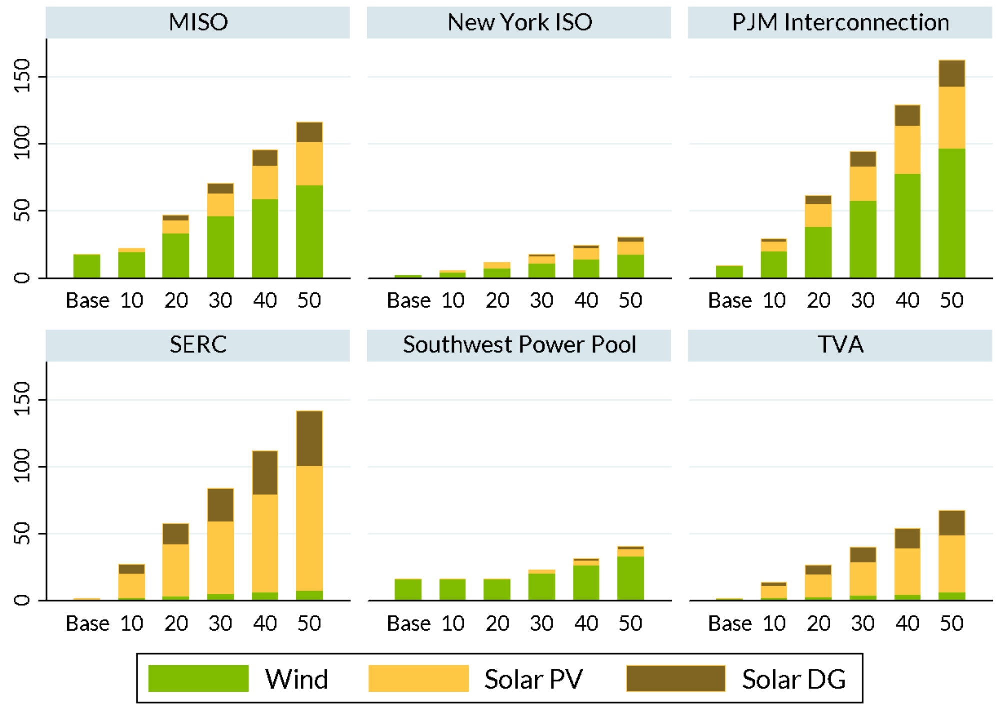


Figure EA-24: RIIA assumptions for renewable capacity expansion (GW) in the Eastern Interconnection

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).

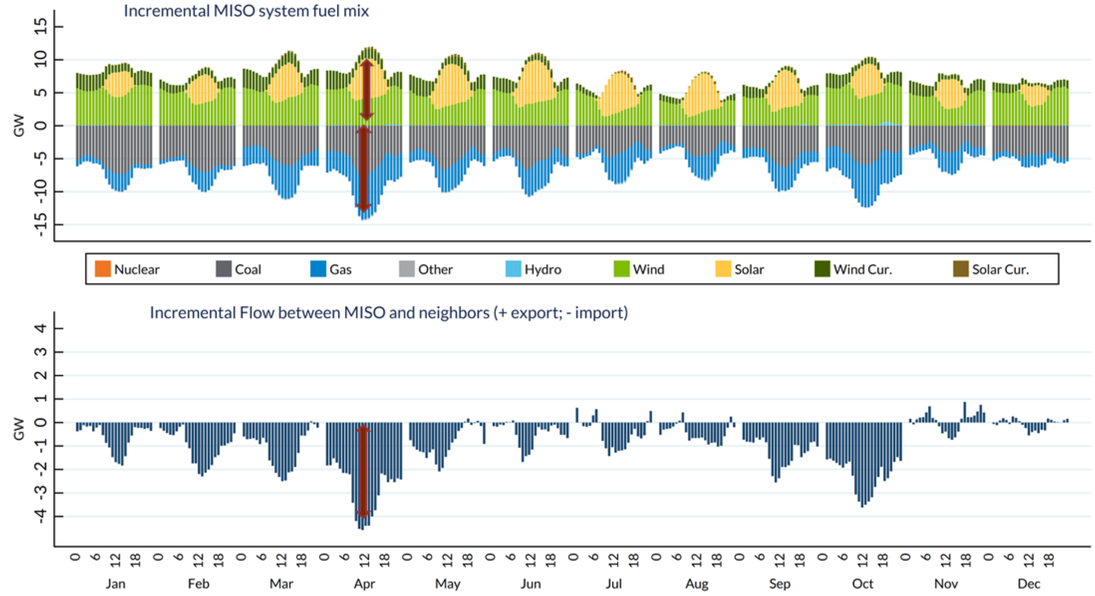


Figure EA-25: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 20% to 30% milestones

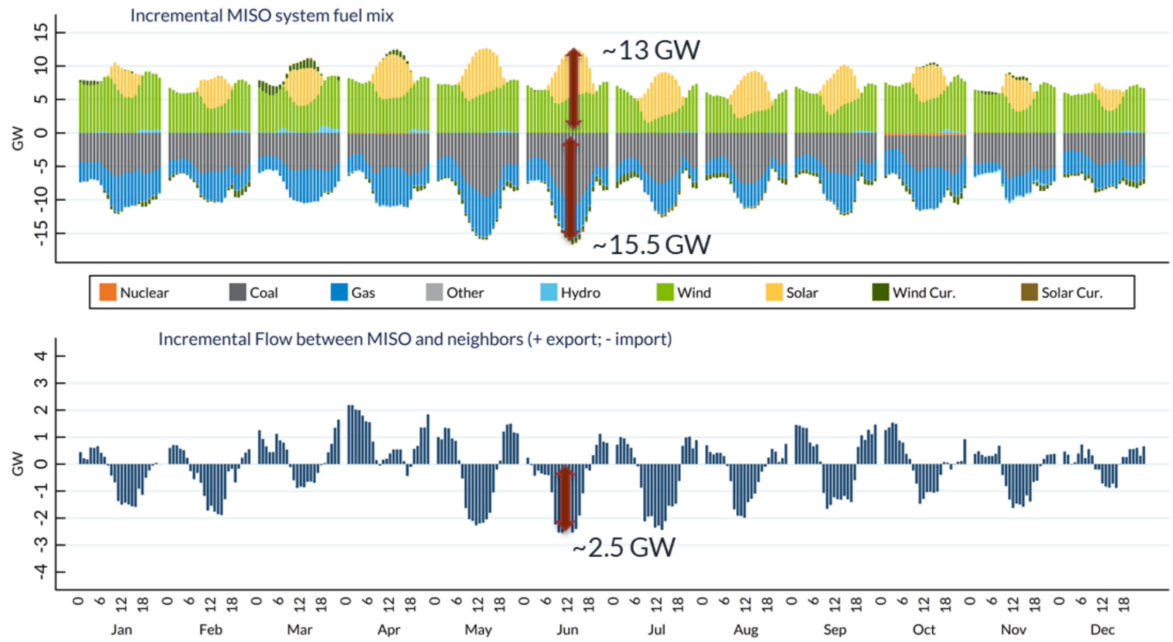


Figure EA-26: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 30% and 40% milestones

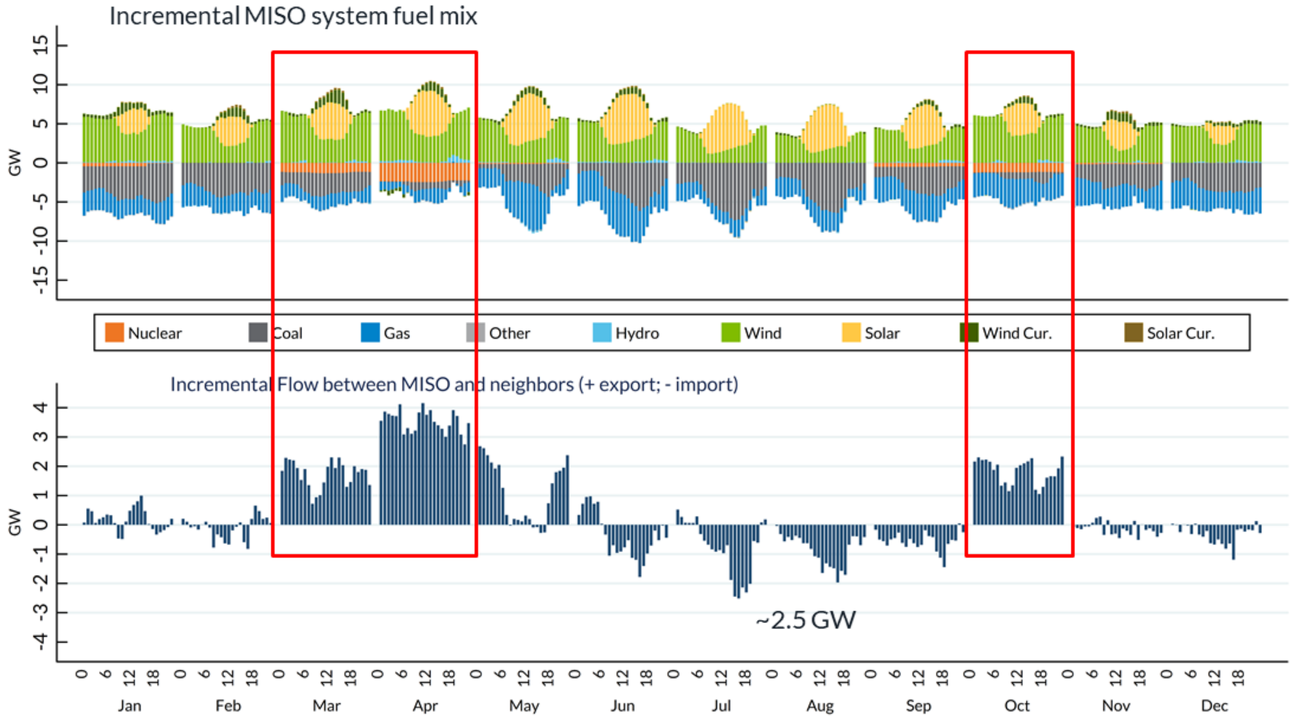


Figure EA-27: Monthly diurnal average of MISO fuel mix and interchange with neighboring BAs, incremental change between the RIIA 40% and 50% milestones

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).

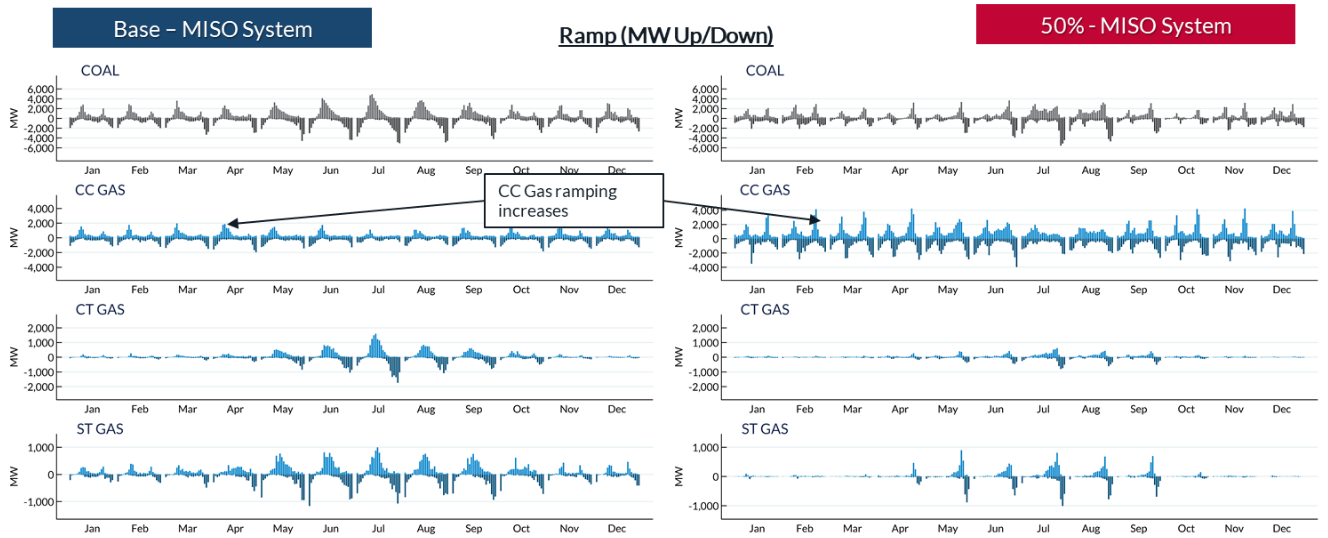


Figure EA-28: Monthly diurnal average of MISO system thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

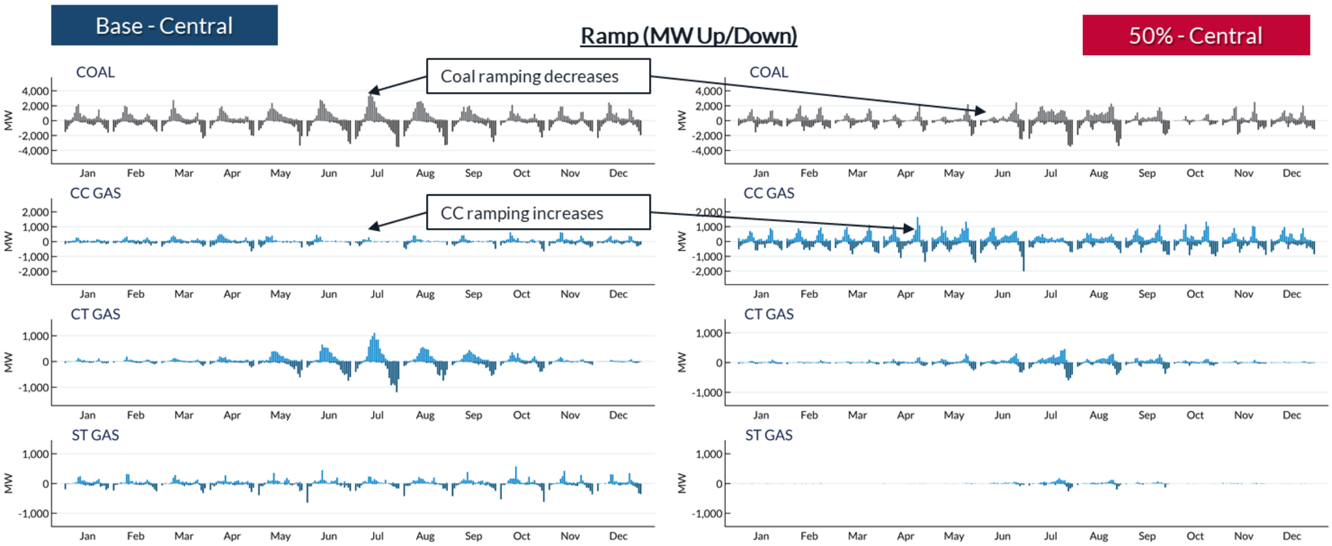


Figure EA-29: Monthly diurnal average of MISO Central thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

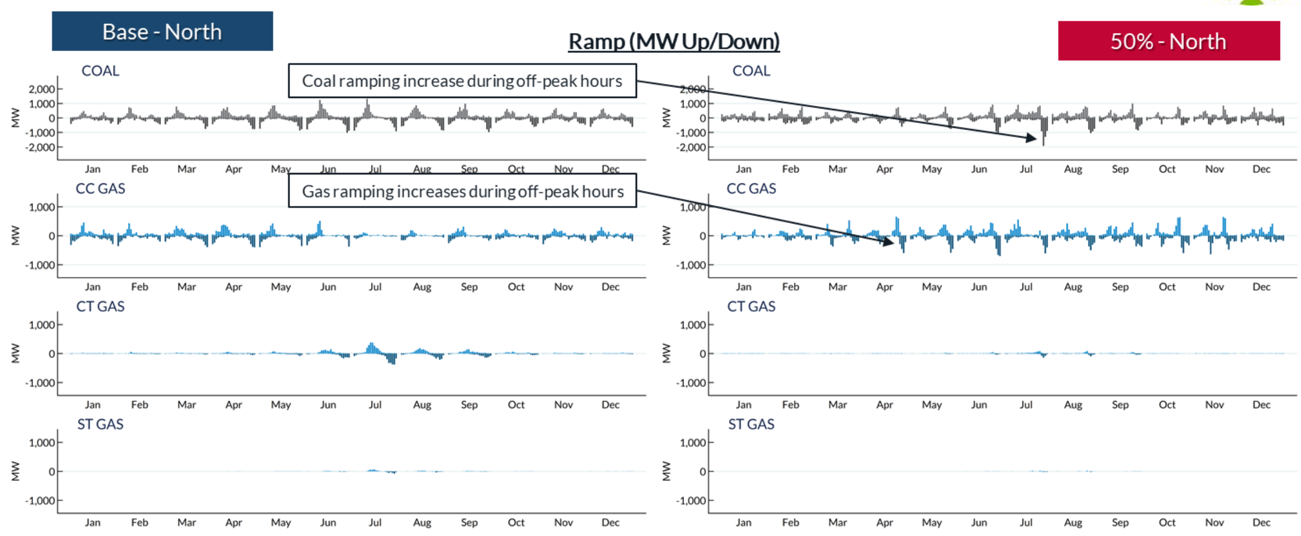


Figure EA-30: Monthly diurnal average of MISO North thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

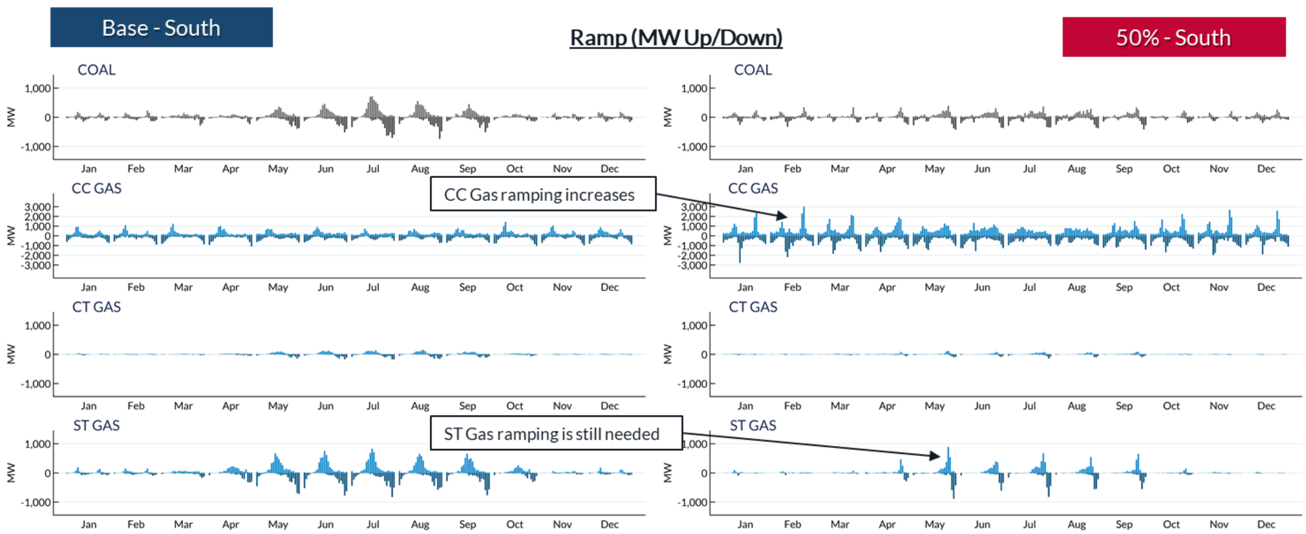


Figure EA-31: Monthly diurnal average of MISO South thermal unit ramping for RIIA Base model (left) and 50% milestone (right)

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.

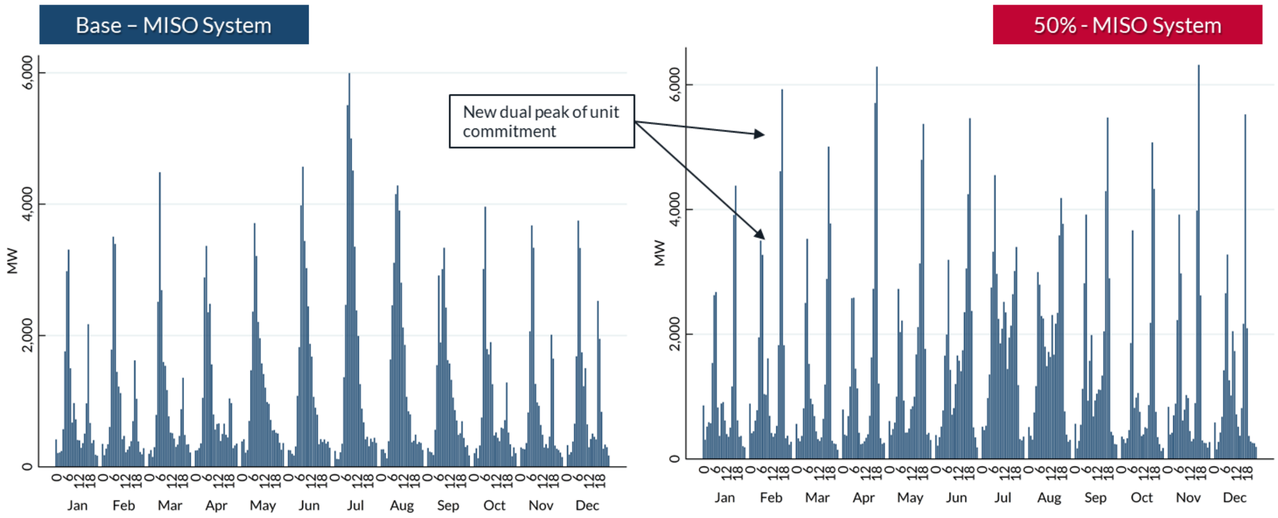


Figure EA-32: Monthly diurnal average of MISO system-wide thermal units commitment for RIIA Base model (left) and 50% milestone (right)

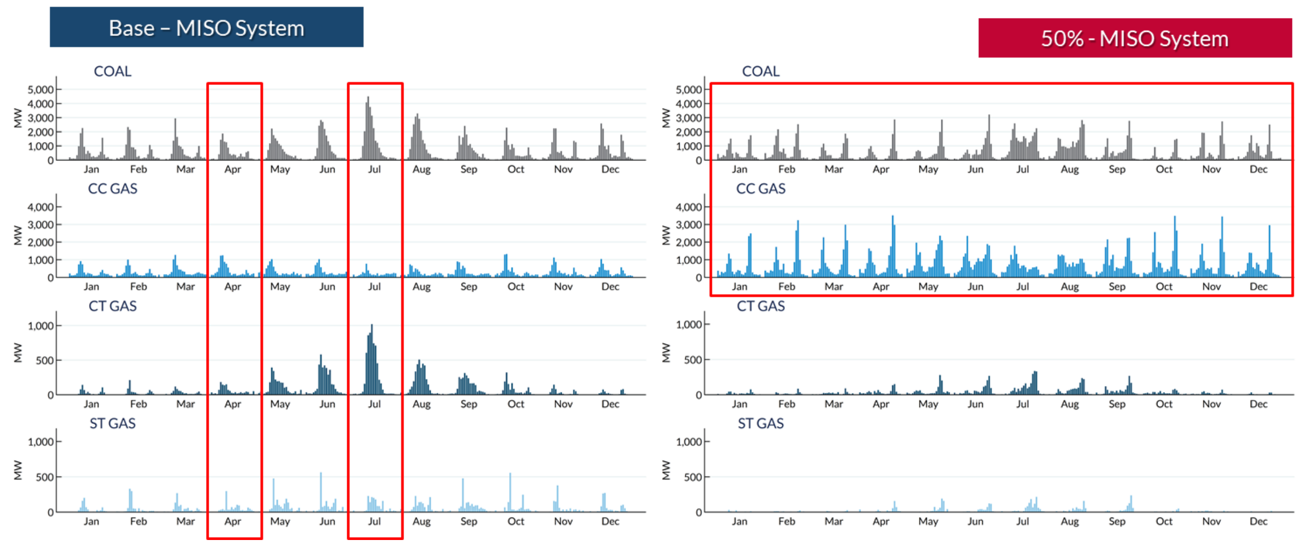


Figure EA-33: Monthly diurnal average of MISO system thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

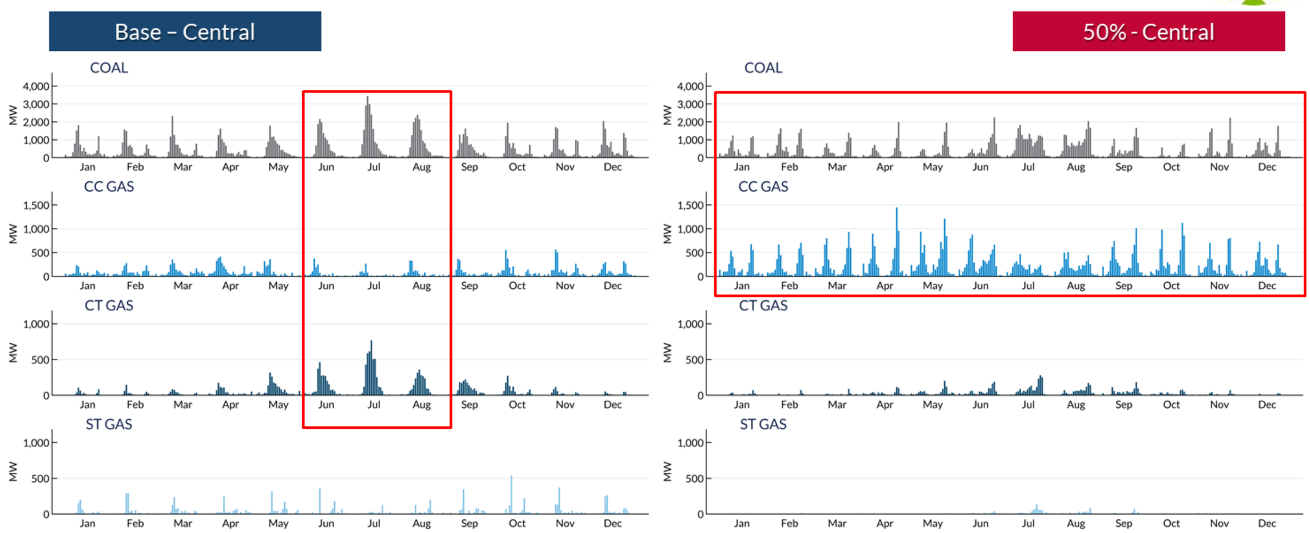


Figure EA-34: Monthly diurnal average of MISO Central thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

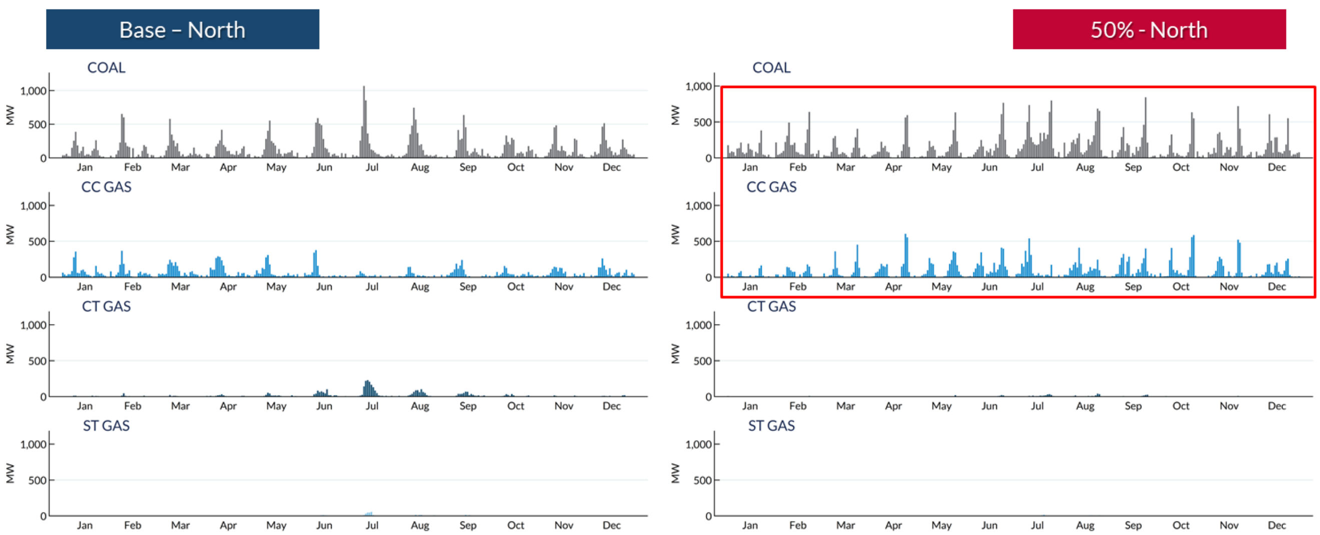


Figure EA-35: Monthly diurnal average of MISO North thermal unit commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

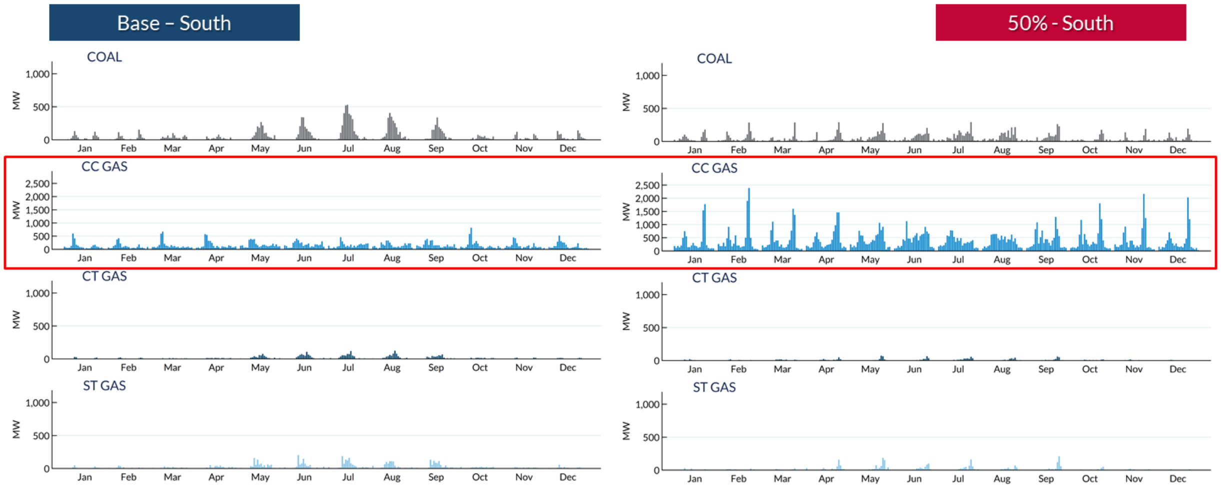


Figure EA-36: Monthly diurnal average of MISO South thermal units commitment by technology and fuel for RIIA Base model (left) and 50% milestone (right)

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.

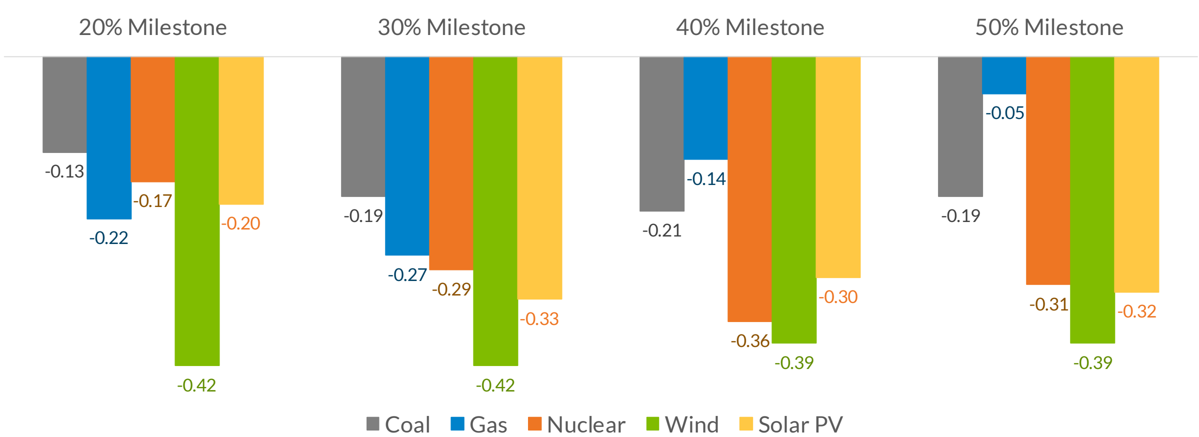


Figure EA-37: Average price impact* ($/MWh) per 1 GW of renewable generation within each milestone**

*** 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.

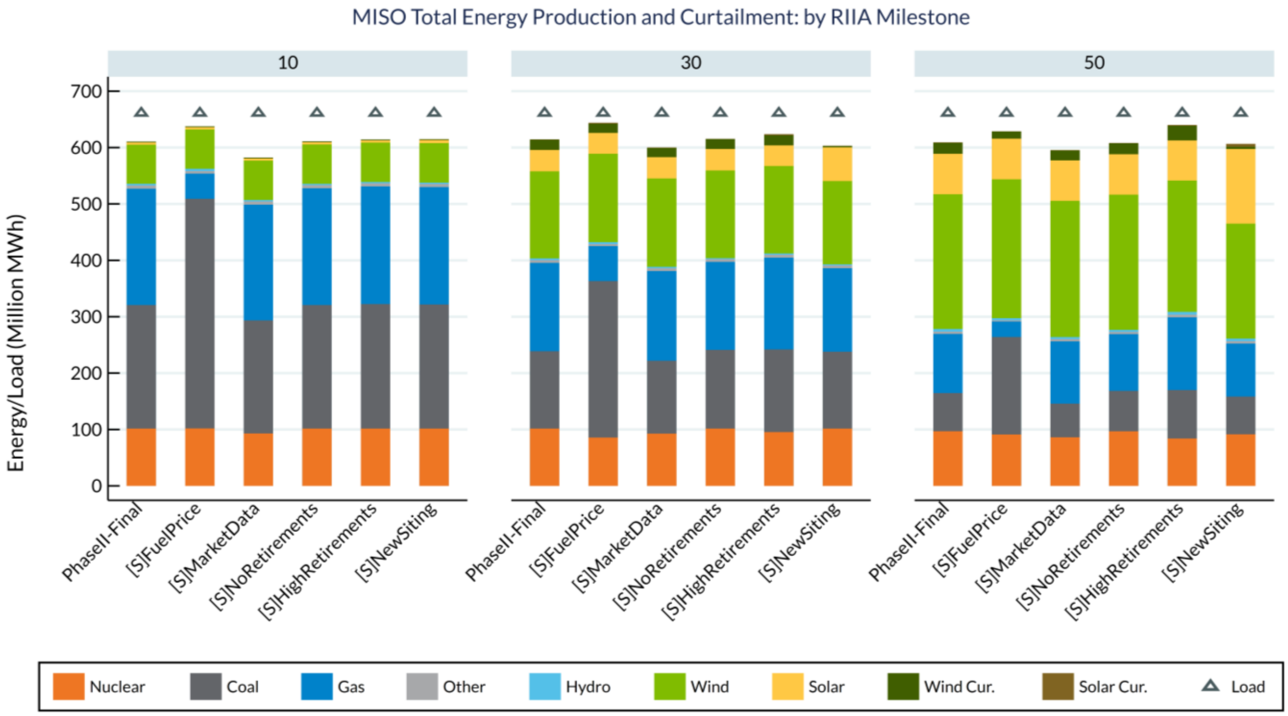


Figure EA-38: Annual energy production by fuel type for the 10%, 30%, and 50% milestones for sensitivity analysis; sensitivities are indicated by [S]

(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.

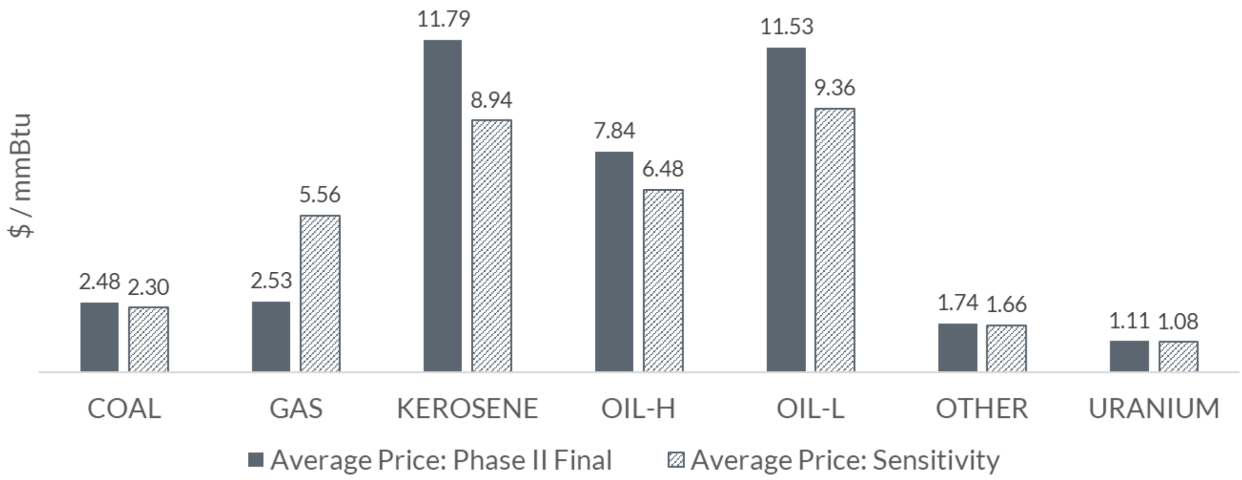


Figure EA-39: Fuel price assumptions in fuel price sensitivity

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.

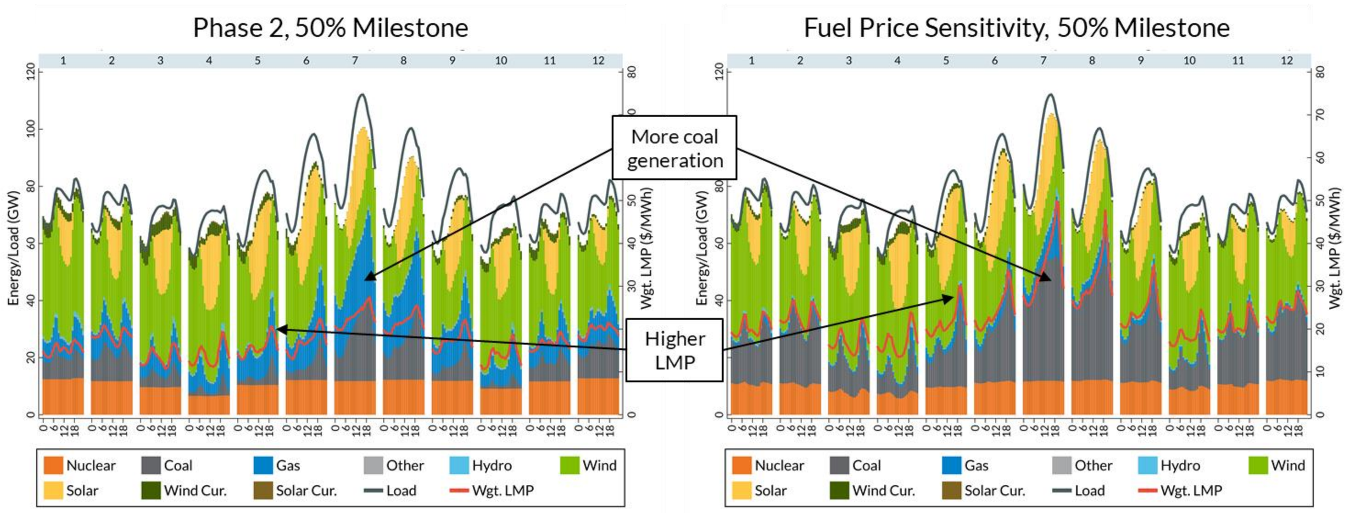


Figure EA-40: Monthly diurnal average of fuel mix and LMP in the fuel price sensitivity (right), compared to the previous assumptions (left)

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.

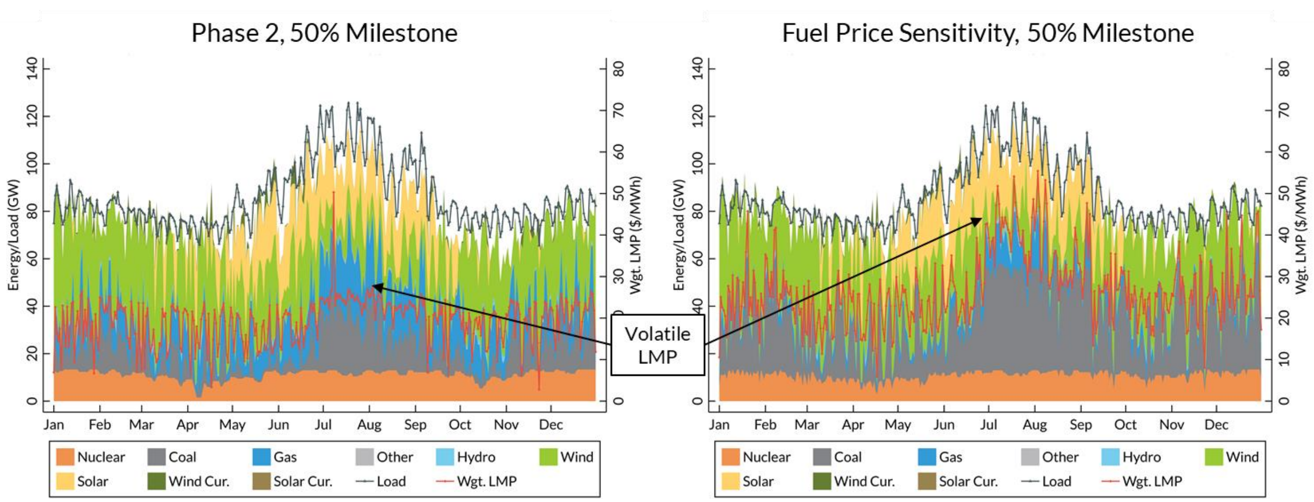


Figure EA-41: Daily peak hour fuel mix and LMP in the fuel price sensitivity (right), compared to the previous assumptions (left)

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.

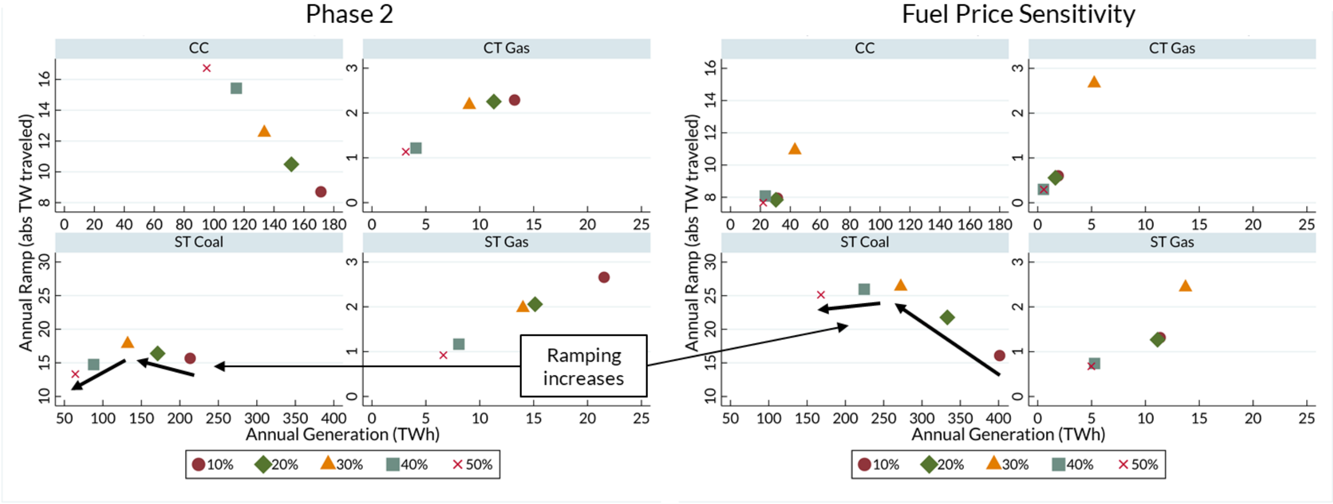


Figure EA-42: Thermal unit ramping in the fuel price sensitivity (right), compared to the previous assumptions (left)

(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.

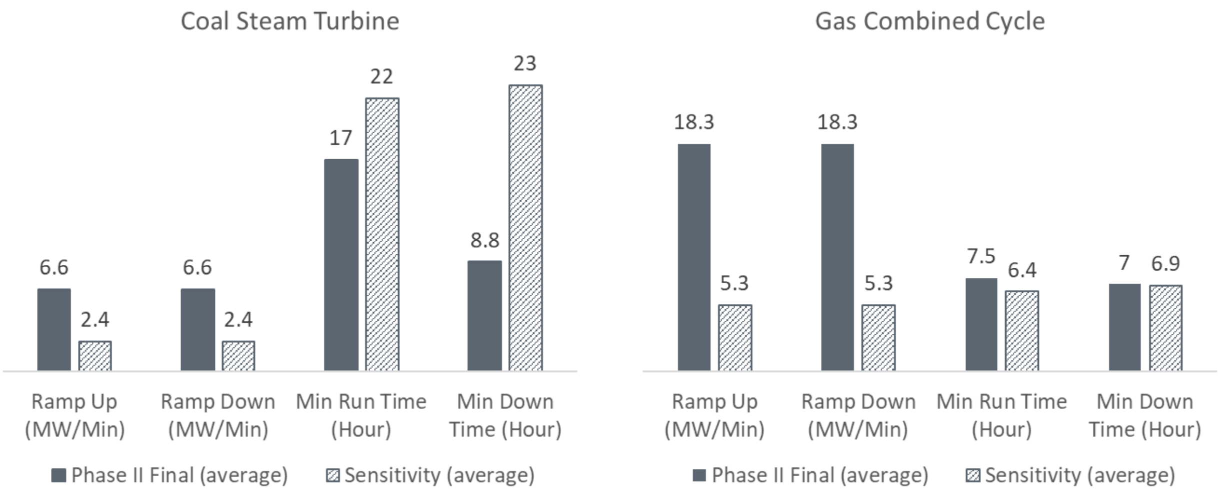


Figure EA-43: Generator operating parameter assumptions for the market data sensitivity

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).

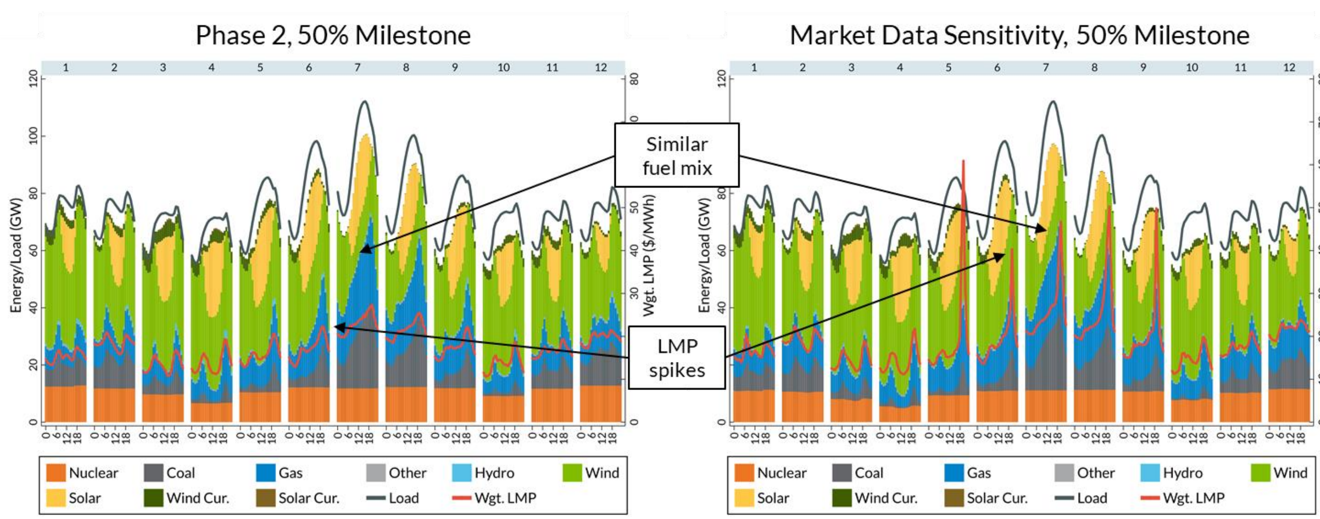


Figure EA-44: Monthly diurnal average of fuel mix and LMP for the market data sensitivity

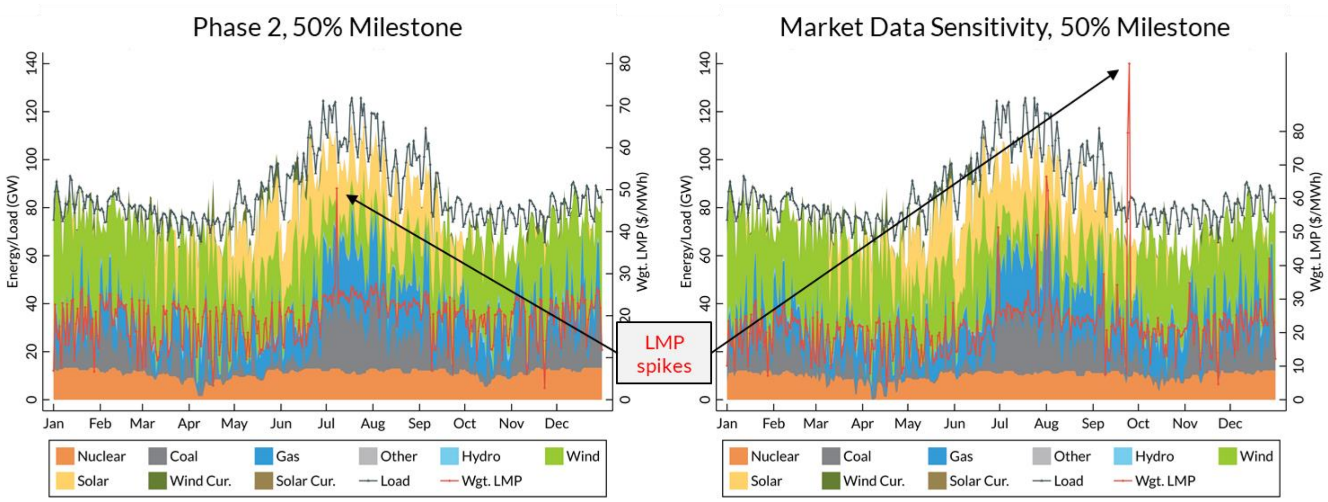


Figure EA-45: Daily peak hour fuel mix and LMP for market data sensitivity

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.

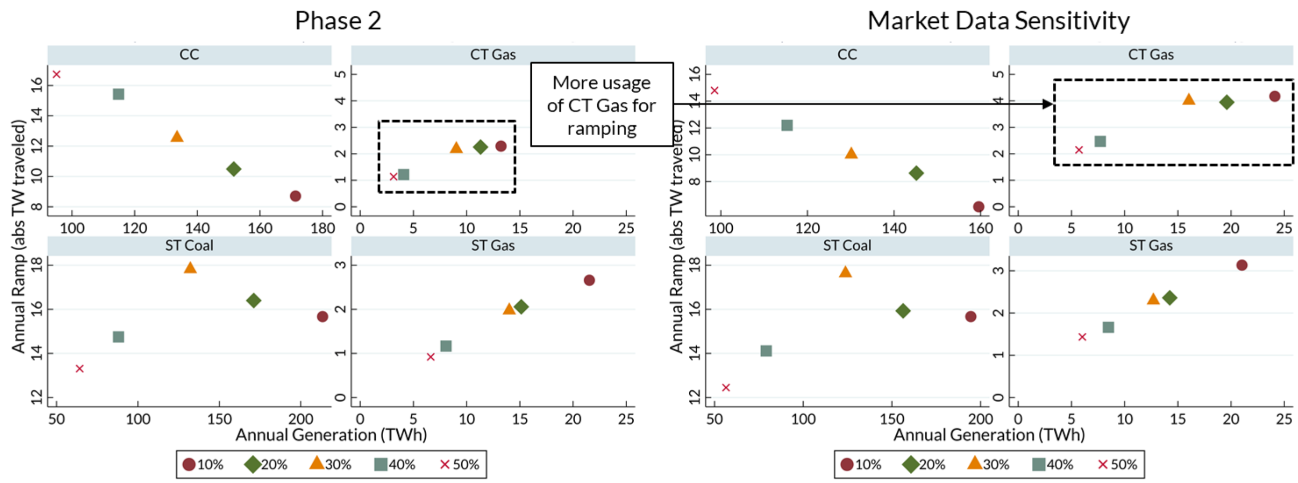
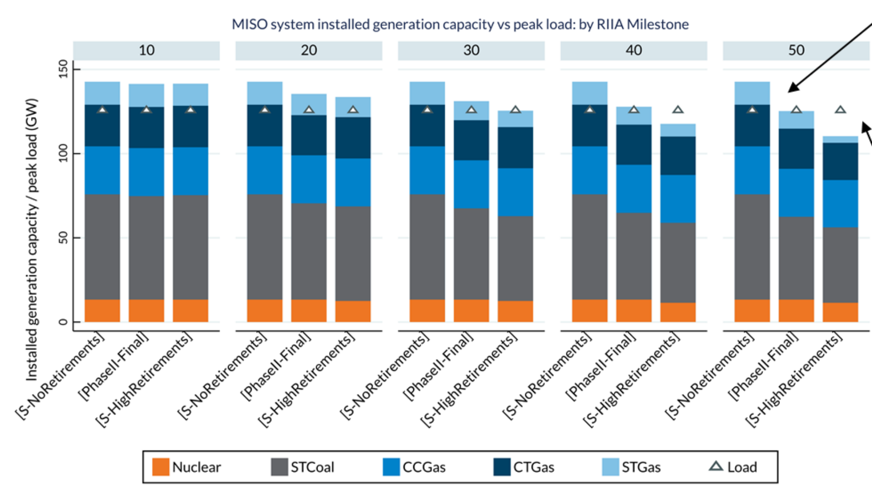


Figure EA-46: Thermal unit ramping for the market data sensitivity

(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.



+17.4 GW

	ST Coal	CC Gas	CT Gas	ST Gas
Central	9.9	0.0	0.7	1.1
North	1.2	0.0	0.0	0.1
South	2.2	0.0	0.2	2.0

-13 GW

	ST Coal	CC Gas	CT Gas	ST Gas
Central	-4.7	-0.1	-0.5	-0.6
North	-1.7	-0.1	-1.3	-0.1
South	2.0	-0.2	0.1	-5.8

Figure EA-47: Thermal units retirement assumptions in the no retirements (left) and high retirements (right) sensitivities, compared to the original work (Phase II-Final, center of clustered bars)

Despite having an additional 17.4 GW of thermal generating capacity available in the model, the simulation results of the no retirements sensitivity did not differ notably from the Phase II-Final model. This holds true whether examining the annual renewable production and penetration (Table EA-4), fuel mix and LMPs (Figure EA-48 and Figure EA-49), or thermal unit ramping (Figure EA-50). These results provide additional evidence supporting the previous conclusion that transmission constraints are the primary factor preventing increases in renewable penetration, rather than lack of thermal unit support for ramping needs or flexibility, based on the current model assumptions.

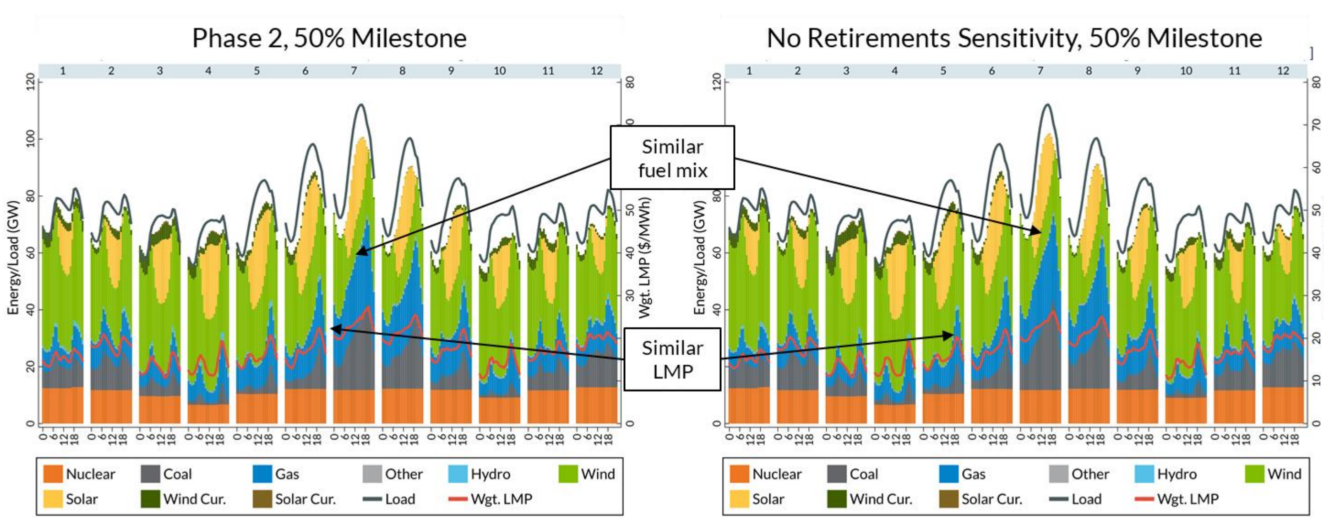


Figure EA-48: Monthly diurnal average of fuel mix and LMP in the no retirements sensitivity

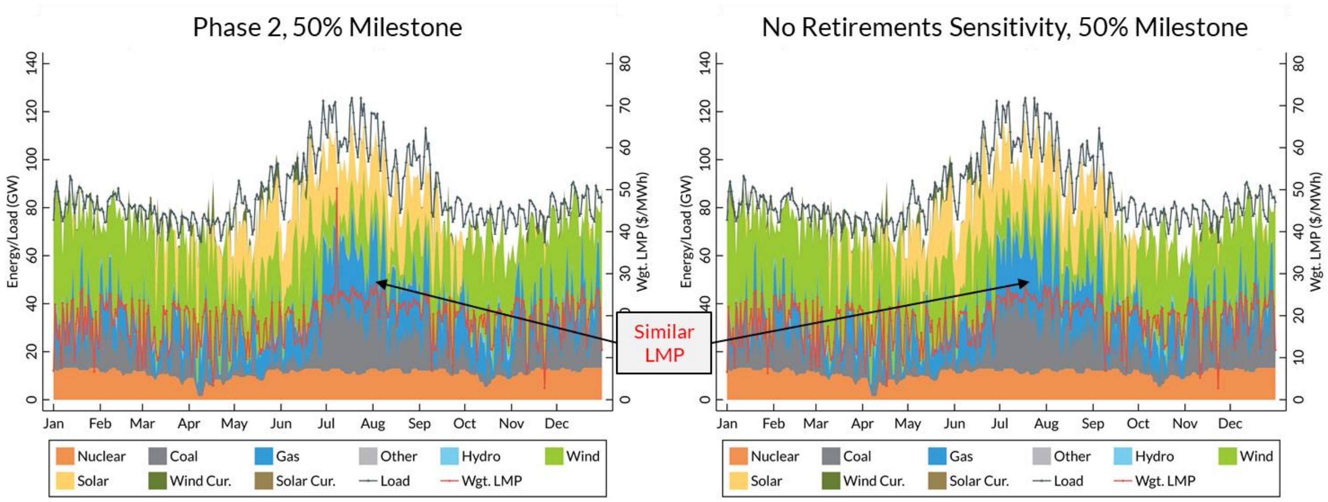
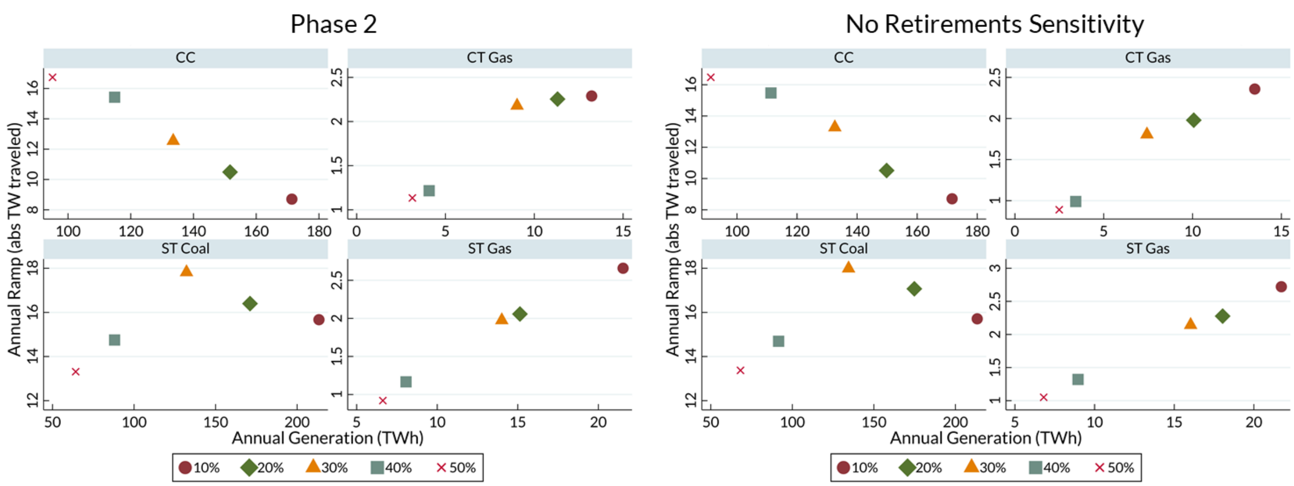


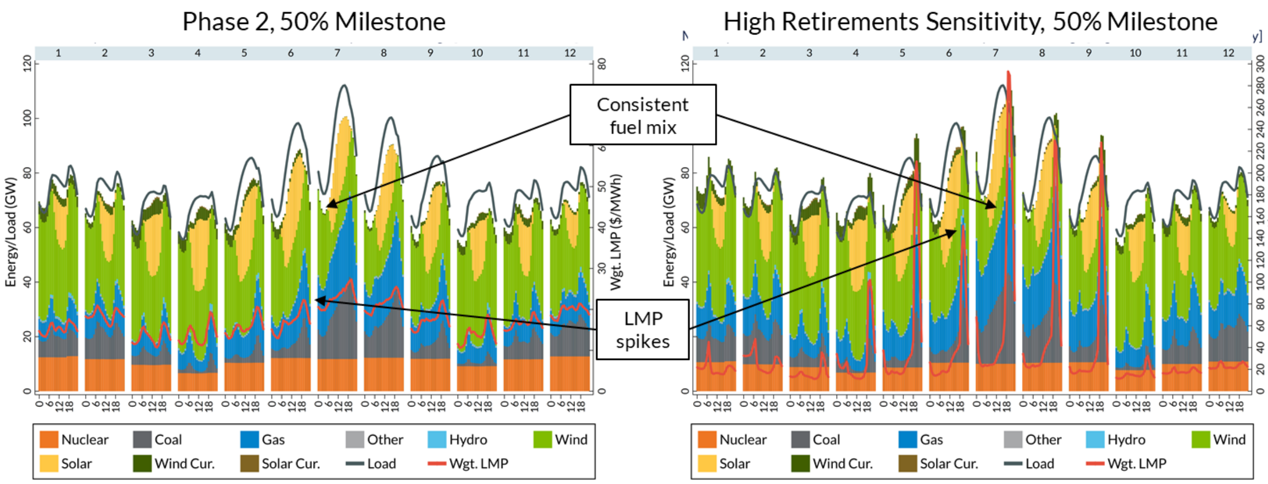
Figure EA-49: Daily peak hour of fuel mix and LMP in the no retirements sensitivity



*Different scales in both x-axis and y-axis

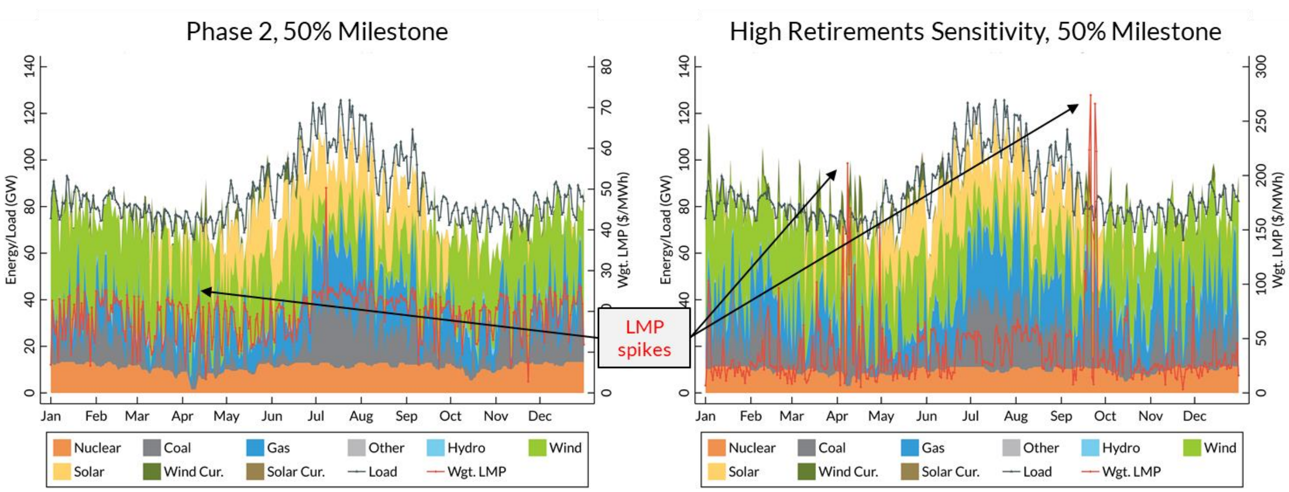
Figure EA-50: Thermal unit ramping in the no retirements sensitivity

On the other hand, when an accelerated pace of thermal unit retirement (as in the high retirements sensitivity), the lack of thermal unit support for system ramping becomes an issue. In Table EA-4, the high retirements sensitivity has the lowest penetration and annual renewable production compared to the Phase II-Final model and other sensitivities. Despite the fact that the fuel mix does not change significantly, the system average LMPs spike during evening hours (Figure EA-51) and during daily peak-load hours (Figure EA-52). This illustrates the reduced thermal capacity available in the system to support ramping.



*Different scales in LMP y-axis

Figure EA-51: Monthly diurnal average of fuel mix and LMP in the high retirements sensitivity



*Different scales in LMP y-axis

Figure EA-52: Daily peak hour of fuel mix and LMP in the high retirements sensitivity

Figure EA-53 shows the contribution of different technologies and fuels to ramping. Because less thermal capacity is available in the system for the high retirements sensitivity, the remaining coal and CT gas units need to provide more ramping between the 40% and 50% milestones to accommodate the increased variability of renewable energy production.

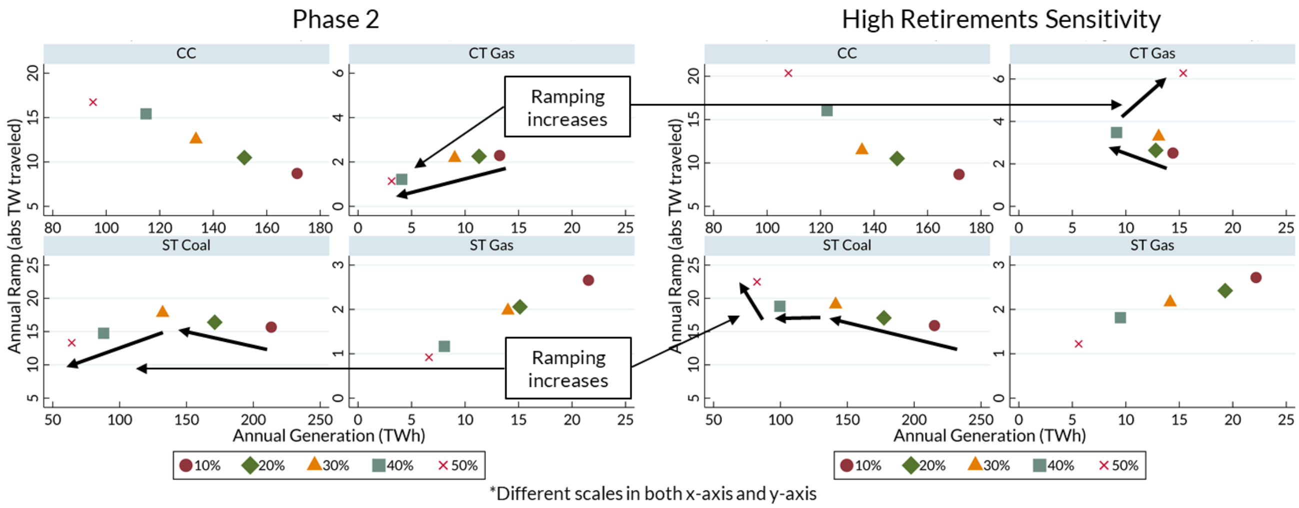


Figure EA-53: Thermal unit ramping in the high retirements sensitivity

(D) Siting sensitivity

In years since the RIIA study began, the MISO Interconnection Queue has begun to shift to include more and more solar units, evaluating the impacts of renewable mix and siting locations through sensitivity analysis sheds light into an alternative path of renewable development. For the siting sensitivities, the renewable capacity expansion included more solar capacity relative to wind. Because wind comprises the majority of installed renewable generating capacity in the current MISO system, the siting] sensitivity gradually increased the installed solar capacity across milestones, such that the available energy production from wind and solar resources approached an even split by the 50% penetration milestone, compared to the 75:25 split in the Phase II-Final model (Figure EA-54). Furthermore, a localized renewable capacity expansion was used to choose sites at each Local Resource Zone. As a result, more solar is sited in the Central and South regions, while less wind capacity is added to the North (Figure EA-55).

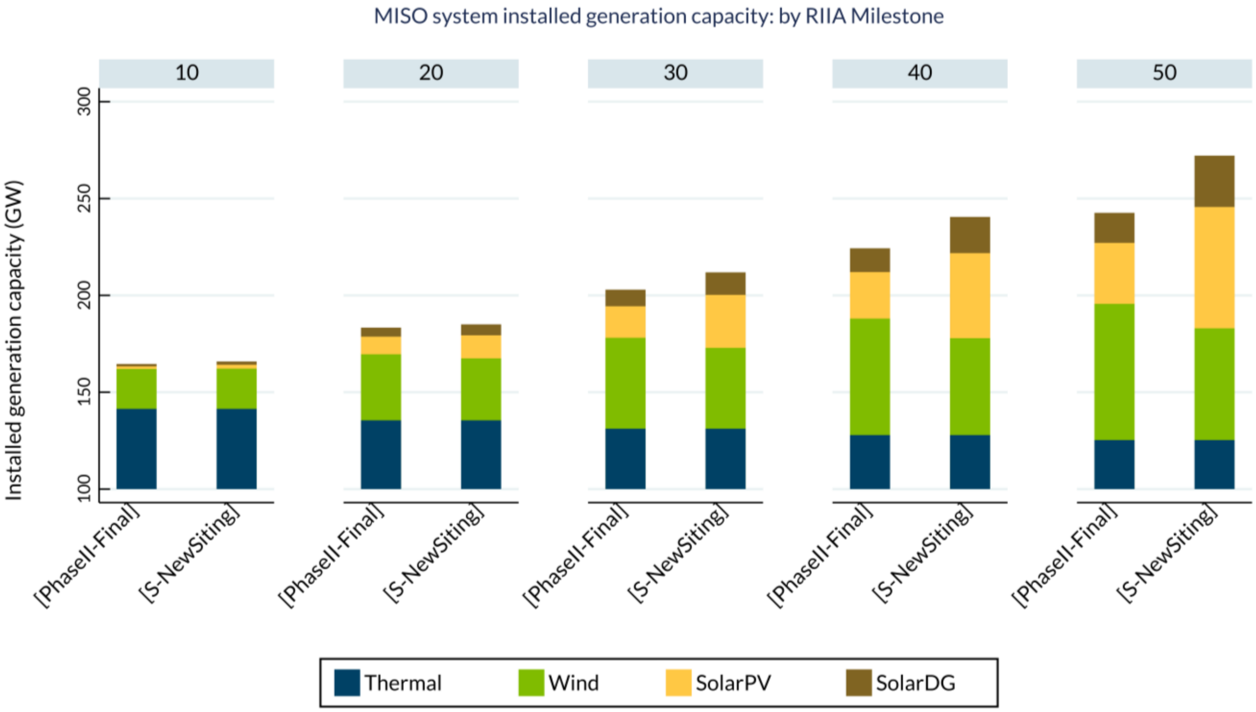


Figure EA-54: Wind and solar capacity expansion assumptions for the siting sensitivity

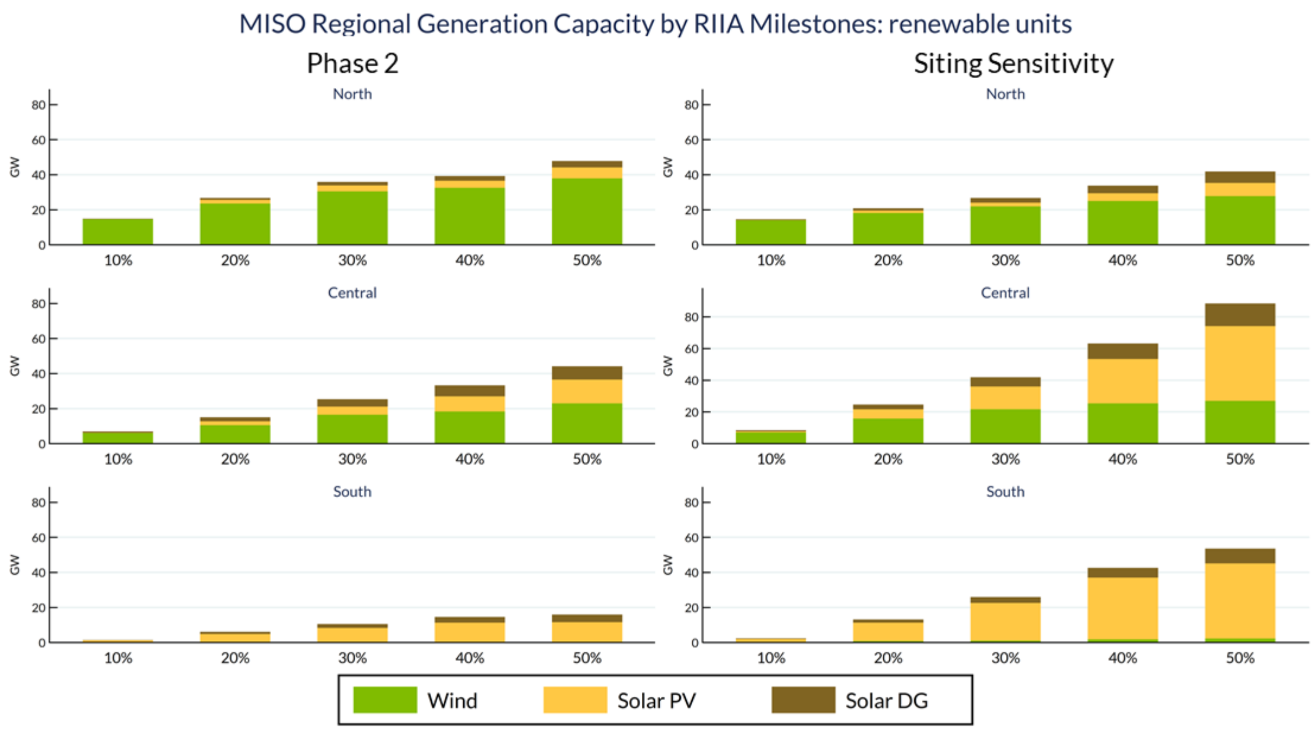


Figure EA-55: Regional breakdown of assumed wind and solar capacity expansion for the siting sensitivity

Because more solar capacity was assumed in the siting sensitivity, the middle of the day shows increased solar generation and reduced average LMPs and price volatility during peak-load hours (Figure EA-56 and Figure EA-57). Interestingly, curtailment of solar energy showed up in shoulder months, usually around midday. Since the original transmission solutions were developed to mostly facilitate wind energy delivery, it is not expected that they would have a large impact on reducing solar curtailment. The new siting of solar capacity for this sensitivity may have created new local congestion, however no new solutions were developed as a part of the sensitivity analysis. Regardless of the solar curtailment, the penetration target is achieved in the siting sensitivity.

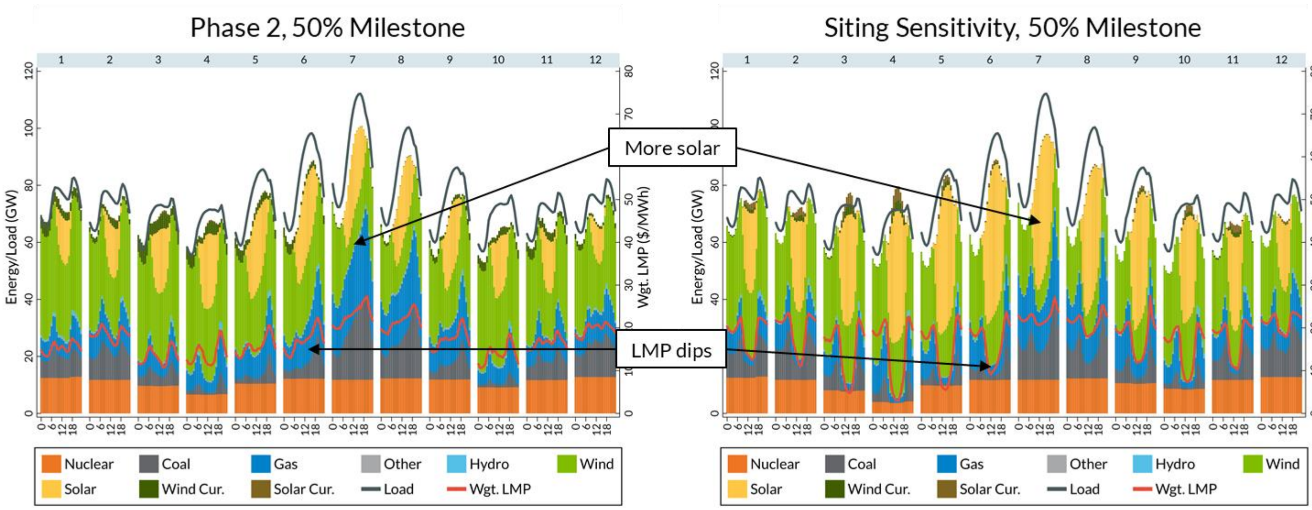


Figure EA-56: Monthly diurnal average of fuel mix and LMP in the siting sensitivity

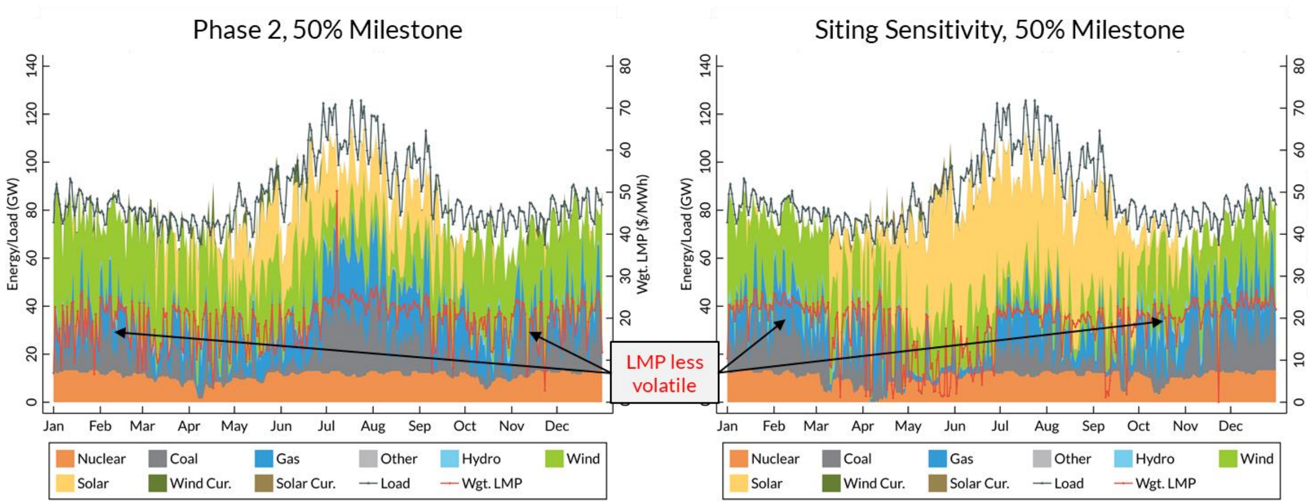


Figure EA-57: Daily peak hour of fuel mix and LMP in the siting sensitivity

Due to the increased solar production, more system ramping is needed from thermal units in the morning hours when the sun rises and during the evening hours when the sun sets. As a result, coal and CT gas units are needed to provide more ramping in the 40% and 50% milestones (Figure EA-58) to accommodate the “duck curve” induced by the solar production profile in the siting sensitivity. In particular, North coal units and Central CT gas units increase their ramping between the 40% and 50% milestones.

The increased solar production also affects the diurnal flow pattern on transmission lines. The percentage of lines with changing flow direction increases to accommodate solar production profiles. Such power flow flips are particularly notable among higher voltage lines (Figure EA-59).

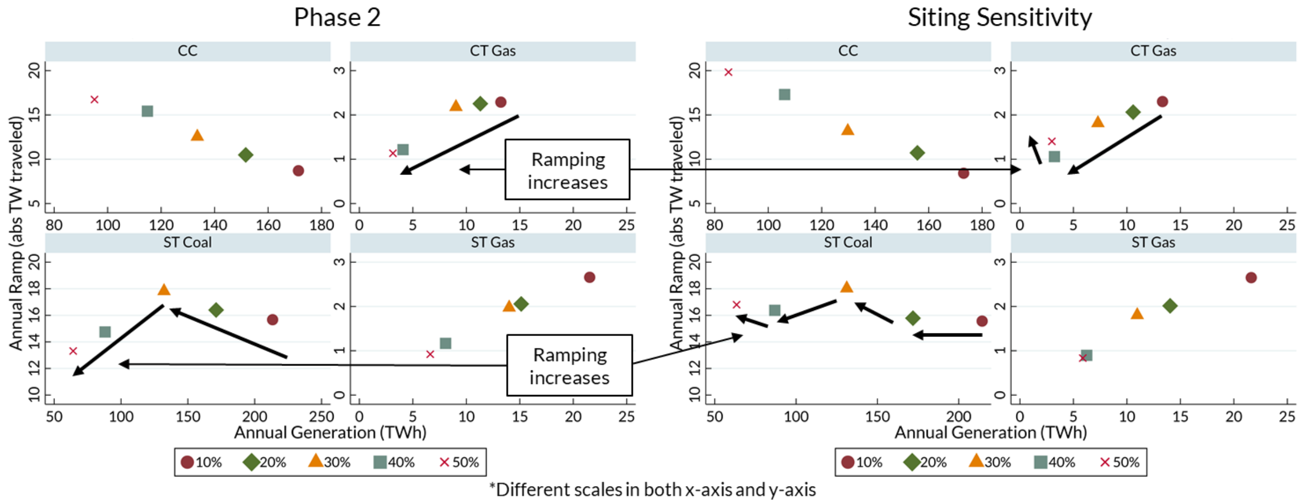


Figure EA-58: Thermal unit ramping for the siting sensitivity

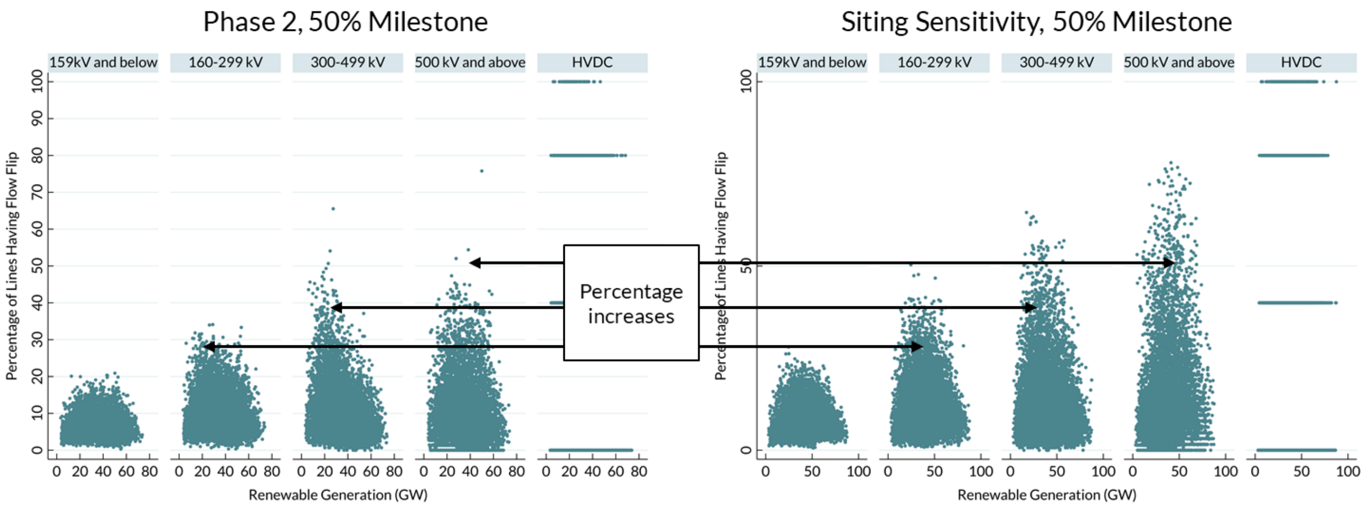


Figure EA-59: Percentage of transmission lines where the flow changes direction for the siting sensitivity (right), compared to the original work (left)

Finding: Increased solar capacity in the siting sensitivity creates a new stressed operating point during the shoulder load periods, which may need further review in Operating Reliability.

The last metric examined in the sensitivity analysis was system operating points. The analysis investigated whether there were any changes that might warrant further analysis. A new potential stress point was found in the siting sensitivity at the 50% milestone, called here "shoulder load, high renewable (SLHR)" (Figure EA-60). This new potential stress point appears in June (darker points in Figure EA-61). In June, load is increasing but remains less than the annual peak load, yet a notable amount of solar generation shows up in the system. Figure EA-61 illustrates this SLHR zone, which may need further review under the focus area of Operating Reliability.

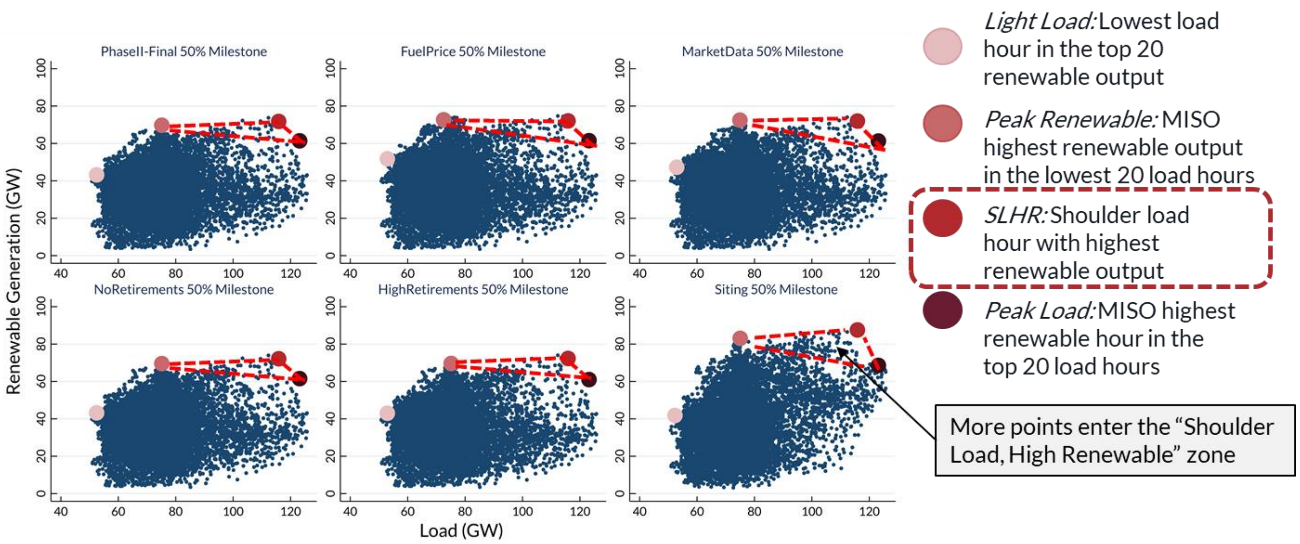


Figure EA-60: System stress points for the fuel price, market data, no retirements, high retirements, and siting sensitivities

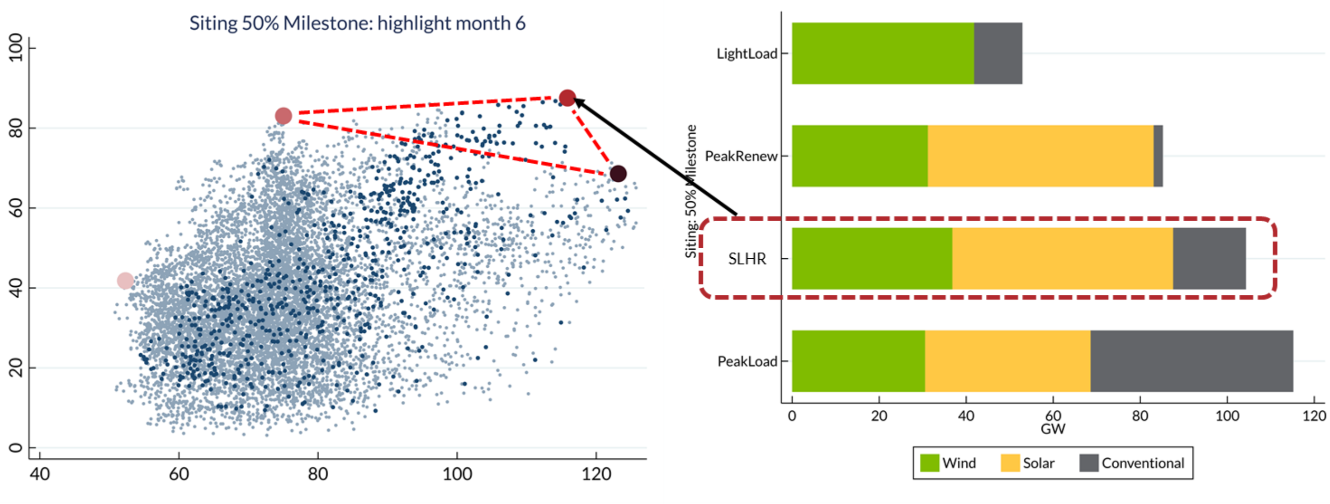


Figure EA-61: The shoulder load, high renewable (SLHR) zone appears for the siting sensitivity

(E) Energy Storage Sensitivity

The objective of the energy storage sensitivity is to explore how energy storage can contribute to renewable integration. Simulations were performed to discover whether energy storage can be used to facilitate meeting the renewable penetration target by maximizing renewable energy delivery. Analysis was focused on the Phase II-Final model at the 40% penetration milestone, with 60 GW of installed wind capacity, 24 GW of utility-scale solar PV, and 12 GW of distributed solar.

Please note that the scope of the energy storage sensitivity does not include the following:

a. Evaluating storage at every penetration milestone
b. Determining optimal mode of operation for energy storage
c. Studying detailed financial feasibility of individual storage locations
d. Studying stacked-benefit of storage
e. Studying storage under the existing MISO Storage Aa Transmission Only Asset (SATOA) construct

Table EA-5 lists the scenarios and assumptions of the energy storage sensitivity. In the first scenario, "heuristic", a total of 30 GW of energy storage was included in the model. This 30 GW of energy storage capacity was sourced from a separate MISO storage study, which utilized a multi-step approach to determine the location and quantity of energy storage by Local Resource Zone (LRZ) in the MISO footprint. In the heuristic scenario, most of the energy storage capacity is sited near load centers (left panel, Figure EA-62).

In the second scenario, "co-location or hybrid", 6 GW and 12.1 GW of battery storage were assumed to be located at the same node as solar generation resources and wind resources, respectively (central panel, Figure EA-62). Detailed assumptions of these co-located batteries are described in Table EA-6.

The third scenario is "MISO-developed optimization," where storage was included as a solution candidate. When both storage and transmission are solution candidates, the optimization process selects only 0.5 GW of battery storage (Run 1). However, if storage is the only solution candidate, the optimization process selects 16 GW of storage (Run 2), and the locations of that 16 GW (right panel, Figure EA-62).

Scenario	Assumption	Total Storage (GW)
Heuristic	• Storage capacity sourced from another MISO storage study • Phase 2 solutions are NOT included	30
Co-location or hybrid	Assume batteries co-located with wind and solar resources	
	Solar sites: batteries with fixed charging and discharging profiles	6
	Wind sites: batteries are price responsive	12.1
	Phase 2 solutions up to 30% milestone are included	
MISO-developed optimization	Storage as solution candidate in optimized solution development	
	Run 1: Both transmission and storage as solution candidates	0.5
	Run 2: Only storage as solution candidate	16
	Phase 2 solutions up to 30% milestone are included	

Table EA-5: Scenarios and assumptions of the energy storage sensitivity

Charging-Discharging Philosophy	Primary Purposes	Locations	Size Details
Pre-programmed, fixed profile: Utility-scale photovoltaic (PV) • Storing 10% of available solar energy (every day) from hour 10:00 to 15:00; • Discharge energy stored equally from hour 17:00 to 19:00; maintain 85% or 80% efficiency Distributed PV • Storing 25% of available solar energy (every day) from hour 10:00 to 15:00 • Discharge energy stored equally from hour 17:00 to 19:00; maintain 85% or 80% efficiency	• Increase capacity credit of utility-scale solar • Distributed storage modelled per Solar Energy Industries Association (SEIA) report	• All PV siting	• Inverter Max MW rating varies per location • MWh rating = 2 hours x Max MW • Total utility-scale PV: 2.4 GW • Total distributed: 3.9 GW
Energy arbitrage: • Store energy during curtailment (low locational marginal price), discharge during higher price • Production cost model determines the time of charging and discharging • No limit on the number of cycles • Minimum charge level is 5%	• Increasing wind energy delivery by reducing curtailment • Energy arbitrage	• Top 30 sites with highest curtailment and with most effective energy storage performance • Top 30 sites with most effective energy storage performance	• Inverter Max MW rating varies per location • MWh rating = 6 hours x MW • Total reducing curtailment: 8.1 GW • Total energy arbitrage: 3.3 GW
50% participate in energy-arbitrage, 50% reserved for frequency and small signal (not storage as a transmission-only asset [SATOA]) • Store energy during low prices, discharge during higher • Production cost model determines the time of charging and discharging • No limit on the number of cycles • Minimum charge level 50%	• Frequency response and small signal support	• Sites identified during 50% RIIA Phase 2 operating reliability-dynamics studies	• Inverter Max MW rating varies per location • MWh rating = 1 hour x MW • None for RIIA 40% milestone

Table EA-6: Detailed assumptions of energy storage operation and siting for the co-location scenario

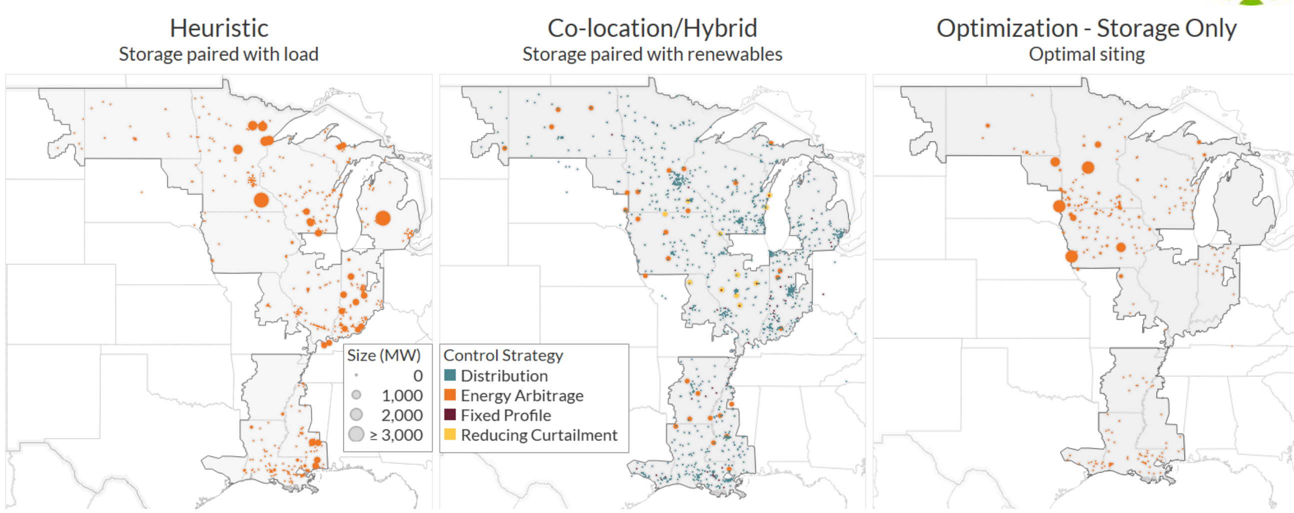


Figure EA-62: Location of energy storage and control strategy for the energy storage scenarios examined

Finding: Storage, without adequate transmission capacity in the system, may help increase renewable energy delivery but may not sufficiently aid in meeting penetration targets

In Table EA-7, the results of all scenarios for the energy storage sensitivity are summarized. None of the scenarios reached the 38% penetration target; the 'balanced' optimization run, where both storage and transmission were available as solution candidates, comes closest to reaching the study penetration target. These results suggest that storage alone, without adequate transmission capacity in the bulk electric system, may not be sufficient to reach renewable penetration targets. In the following sections, each scenario is discussed in more detail.

Storage alone, without adequate transmission capacity in the bulk electric system, may not be sufficient for meeting renewable penetration targets

Scenario	Heuristic	Co-location or Hybrid	Optimization Run 'Balanced'	Optimization Run 'Storage Only'
40% renewable penetration level	32.3%	35.9%	37.3%	36.2%
Storage location	Storage sited near load	Storage paired with renewables	Optimized expansion of transmission and storage	Expansion of only storage
Comment	No additional transmission	With RIIA transmission solutions up to 30%	With RIIA transmission solutions up to 30%	With RIIA transmission solutions up to 30%

Table EA-7: Summary of simulation results for the energy storage sensitivity

Heuristic: In Figure EA-63, the annual fuel mix and renewable curtailment were compared before and after adding 30 GW of energy storage, but without including any RIIA transmission solutions (i.e. BaseT model). Without adequate transmission capacity in the system, renewable energy is significantly curtailed due to transmission constraints and the maximum penetration level is 31.9% (the bottom horizontal stacked bar). After including 30 GW of energy storage near loads in the system, the storage increased renewable energy delivery, which is reflected in a 0.4% increase in the renewable energy penetration level. However, this small increase is not enough to meet the renewable penetration target for the 40% milestone.

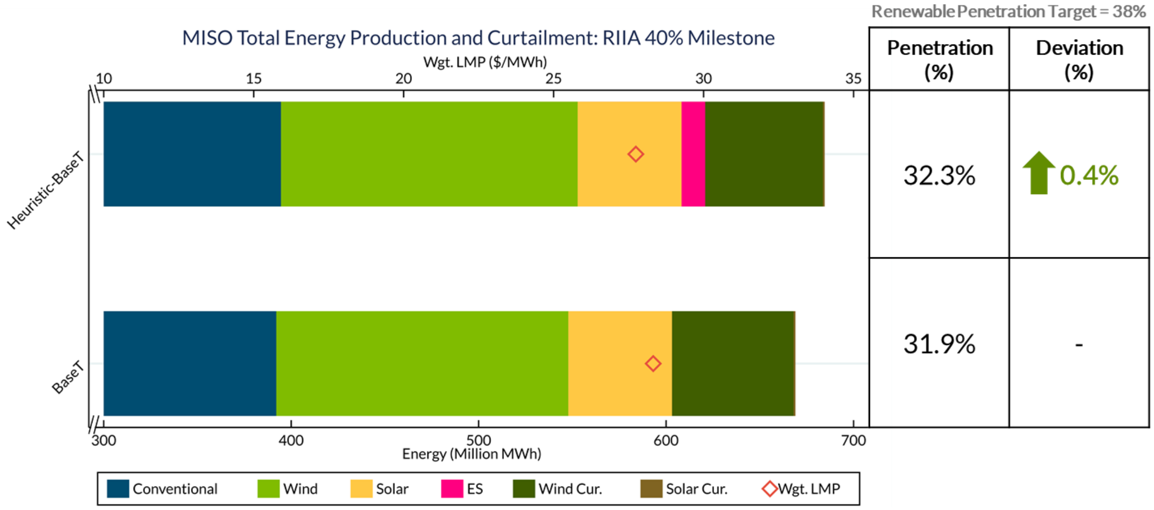


Figure EA-63: Fuel mix of the heuristic scenario of the energy storage sensitivity, assuming the base transmission (BaseT) model

In Figure EA-64, the same heuristic scenario was examined with the inclusion of all RIIA transmission solutions up to 40% milestone (Phase II-Final model). Interestingly, even with adequate transmission capacity in the system, including 30 GW of storage near load only increases renewable energy delivery by 0.5% of the annual energy.

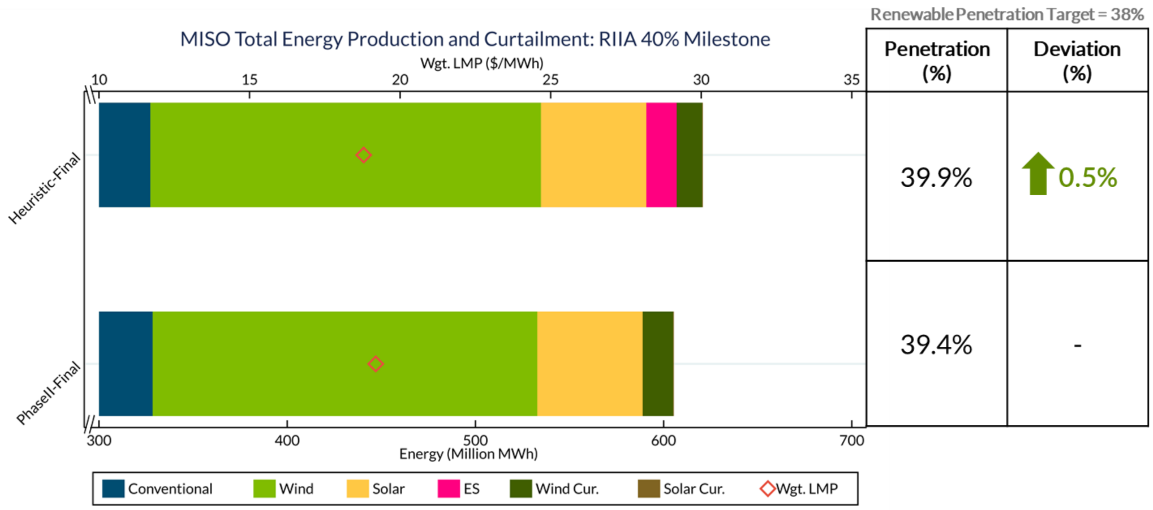


Figure EA-64: Fuel mix of the heuristic scenario of the energy storage sensitivity, assuming RIIA transmission solutions through the 40% milestone (Final model)

Nonetheless, transmission solutions do provide synergy for the efficient operation of storage. When adequate transmission capacity is available in the system, the average charging and discharging of battery storage is notably higher (the right panel of Figure EA-65). Please note that battery charging and discharging shown in Figure EA-65 is consistent with the simulation settings: charging during low LMP hours and discharging during high LMP hours.

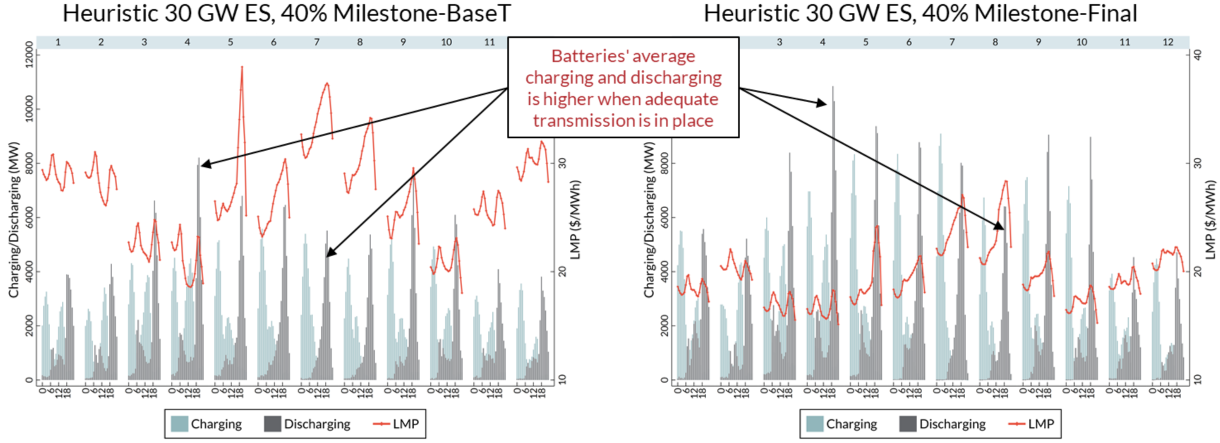


Figure EA-65: Monthly diurnal average of battery charging and discharging in the heuristic scenario of the energy storage sensitivity, with base transmission (BaseT, left) and RIIA transmission solutions (Final, right)

Finding: Storage paired with renewables is more effective in increasing renewable energy delivery than when it is paired with load

Co-location: In Figure EA-66, the annual fuel mix and renewable curtailment are compared before and after including 6 GW of energy storage co-located with solar sites and 12.1 GW of storage co-located with wind sites. Both simulations include RIIA transmission solutions up to the 30% milestone (i.e. Start model). Compared with the heuristic scenario, the co-located batteries are more effective at increasing renewable delivery; the penetration level increased by 2% after including 18.1 GW of co-located battery storage (top of Figure EA-66) compared to the case without battery storage (bottom). In a later section, it will be shown that the MISO-developed optimization also chooses to site energy storage mostly near renewable resources instead of near load (Figure EA-70), which reinforces the finding here.

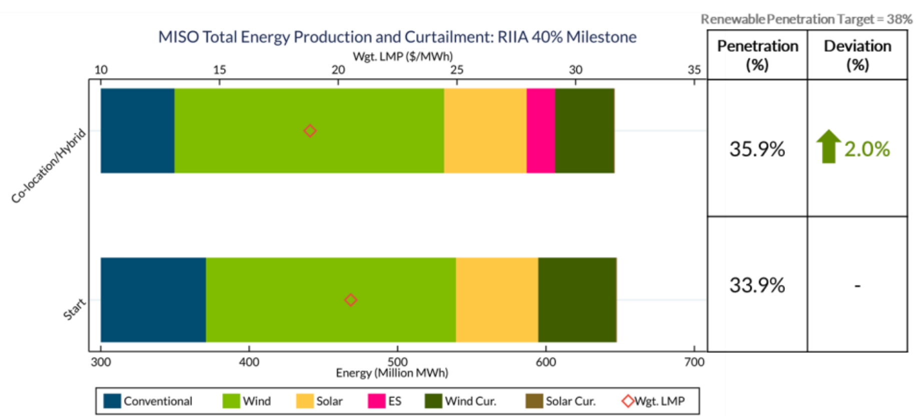


Figure EA-66: Fuel mix of co-location scenario of the energy storage sensitivity for the 40% milestone, with RIIA transmission solutions through the 30% milestone added (Start)

Finding: Computer-aided optimized expansion demonstrates a combination of storage and transmission is an effective way to meet renewable targets

In both the heuristic and co-location scenarios discussed in previous sections, the choice of energy storage quantity and location is primarily based on engineering judgement and no costs were considered. Hence, in the MISO-developed optimization scenario, a computer-aided optimization technique was used to explore "optimal" or "balanced" solutions to reach renewable penetration targets. This computer-aided optimization technique included the capital costs of transmission and energy storage as well as system production cost. In Figure EA-67, the total cost varies across different expansion scenarios, from a transmission-only solution (on the left) to a storage-only solution (on the right). Figure EA-67 provides two key observations. First, transmission is more cost effective than storage at increasing the renewable energy penetration, as the total cost of (1), the transmission-only solution, is much lower than the total cost of (5), the storage-only solution. Second, transmission and storage together may achieve the best overall value, as (2) had the lowest total cost.

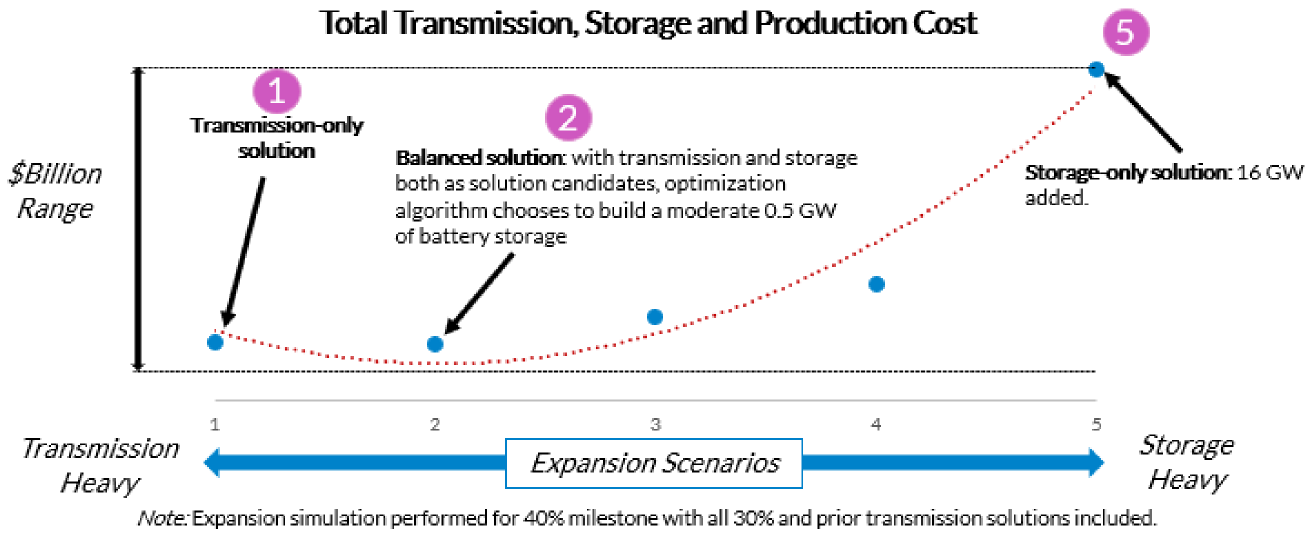


Figure EA-67: Total cost of transmission, storage, and production for different combinations of transmission and storage in the MISO-developed optimization scenario of the energy storage sensitivity

When considering renewable energy delivery, Figure EA-68 shows that transmission is necessary to facilitate the transfer of renewable energy to load. When including transmission as a candidate solution (1 and 2), renewable energy penetration comes very close to the target for the 40% milestone while the storage-only scenario (3) with 16 GW of storage cannot reach the same penetration level as solutions with transmission.

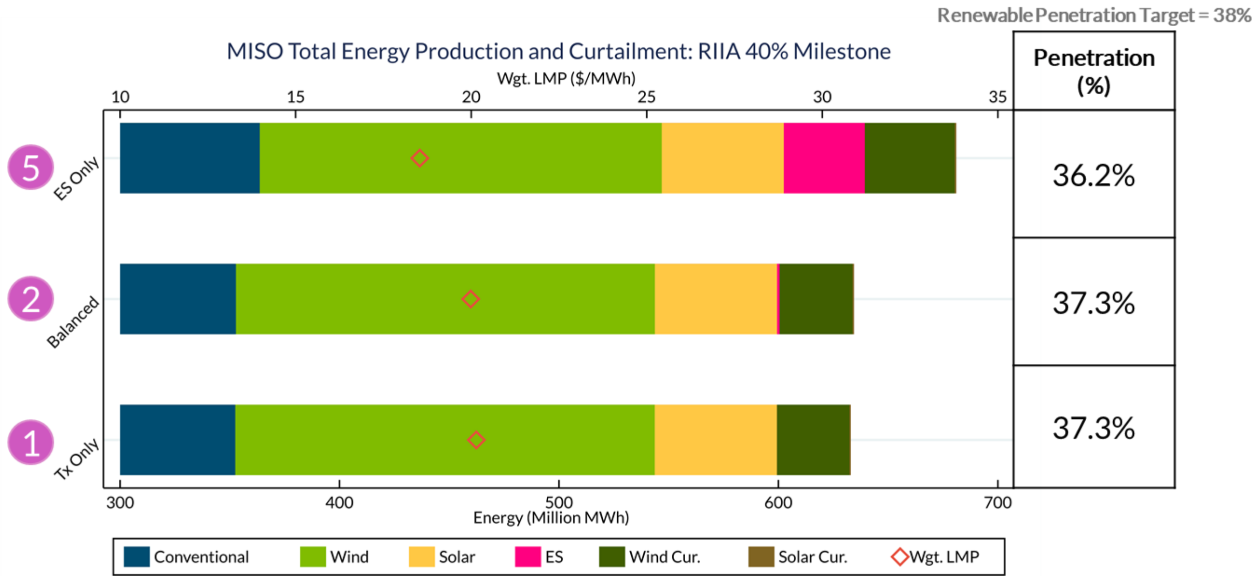


Figure EA-68: Fuel mix and renewable energy penetration of the MISO-developed optimization scenario of the energy storage sensitivity

Similar to the finding illustrated in Figure EA-65, the MISO-developed optimization scenario found that storage participation in the balanced scenario (2) is higher than in the storage-only scenario (5), measured by utilization rate or capacity factor of battery storage (Figure EA-69). This suggests that storage and transmission may mutually benefit each other, depending on the relative magnitudes of transmission line rating, generation, and load. If the transmission rating is smaller than the minimum of the load or the maximum power from variable generation paired with the battery, building more transmission may reduce congestion and increase battery utilization. However, when the line rating is greater than the minimum of the load MW or the maximum power from variable generation, adding more batteries could be a cost-effective measure to increase renewable penetration and increase flow on transmission lines.

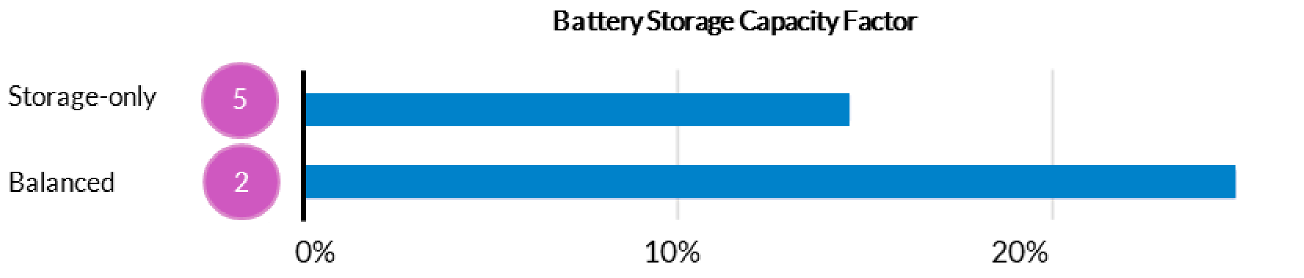


Figure EA-69: Utilization of battery storage in the MISO-developed optimization scenario of the energy storage sensitivity

Finding: Storage is more cost-efficient to mitigate short-duration congestion of moderate severity

In the MISO-developed optimization scenario, it is possible to examine the types of batteries chosen and their locations in order to make additional conclusions about the role that energy storage might play in a high-renewable future. The top two charts of Figure EA-70 compare the number of installations for each MISO region for the two different optimization solutions. In both cases (storage-only and balanced), shorter duration batteries are shown to be preferred for most locations, comprising approximately 85% of the selected batteries. In the bottom two charts of Figure EA-70, the locations of the storage installations are compared for the three MISO regions. For both the storage-only and balanced optimizations, most storage is sited near renewable resources instead of near load (99% and 93%, respectively). This suggests that storage is a cost-efficient way to mitigate short-duration congestion driven by renewable output.

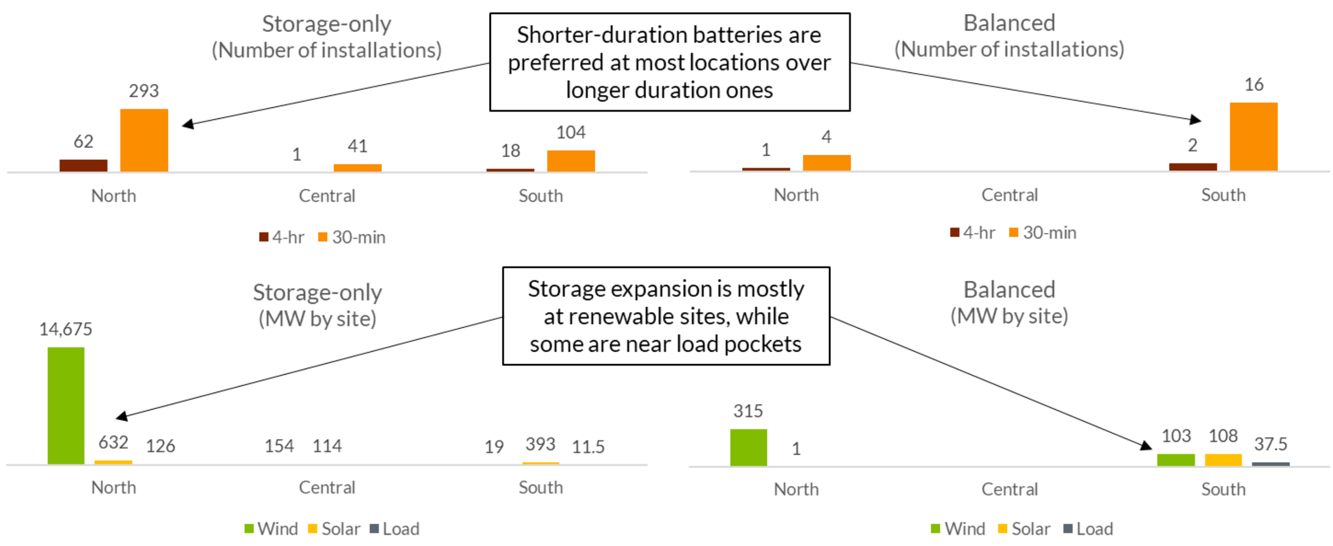
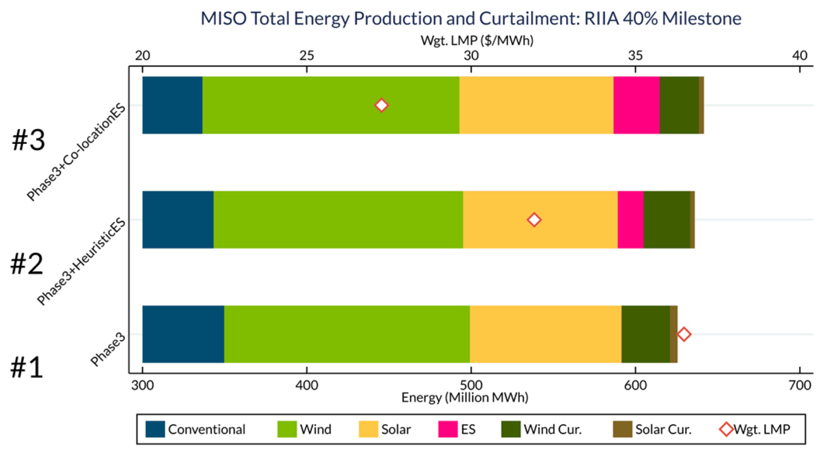


Figure EA-70: Battery storage duration compared for the MISO-developed optimization scenario of the energy storage sensitivity

Lastly, to reinforce our key findings that storage alone may not be sufficient for meeting penetration targets if without adequate transmission in the bulk electric system, RIIA performed three additional Phase3 sensitivities (Table EA-8) by combining multiple Phase 2 sensitivities while using the BaseT transmission model. Figure EA-71 shows the annual fuel mix and renewable curtailment were compared between the three Phase 3 sensitivities. First, for the #2 and #3 of Phase3 sensitivities, none of them reached penetration targets. These results re-validated our previous argument that without adequate transmission capacity in the system, energy storage alone is not enough to meet the renewable penetration. Second, #3 of Phase3 sensitivities provided a higher incremental improvement in terms of penetration target when compared with #2, which also supported our finding that storage paired with renewables is more effective in increasing renewable energy delivery.

Sensitivity	Sourced from Phase 2s Assumption	#1	#2	#3
Generator characteristics	• Generator characteristics from MISO proprietary data	V	V	V
Siting	• Wind/Solar ~50/50 at 50% milestone • Localized expansion/siting by LRZ load ratio	V	V	V
Energy Storage - Heuristic	• Storage capacity sourced from another MISO storage study		V	
Energy Storage - Co-location	• Assume batteries co-located with wind and solar resources Solar sites: batteries with fixed charging and discharging profiles Wind sites: batteries are price responsive			V

Table EA-8: Summary of simulation settings for the Phase3 energy storage sensitivity



Penetration (%)	Deviation (%)
37.83%	1.09%
37.19%	0.45%
36.74%	-

ES = Energy Storage; LMP = Locational Marginal Price

2

Figure EA-71: Fuel mix of the Phase 3 sensitivities, assuming BaseT transmission for the 40% milestone

Energy Adequacy — Market and Operation

Overview

In-depth analyses into the market and operational needs for identifying the challenges and opportunities of novel market products and operational processes was studied. This section describes the Energy Adequacy – Market and Operation Focus Area, also named the Portfolio Evolution Study (PES). This work was conducted in parallel with the core RIIA analysis. Many of the assumptions are the same, but some are different as seen in Methodology.

The scope of this work includes:

- The evaluation of system needs
  - Market system requirements (including ancillary services) and their expected evolution
  - Performance of market and operational constructs
- Exploration of Solutions
  - Platforms for analyses of potential market and operational adaptations to effectively accommodate new resources

Key Findings

The PES finds that:

- Flexibility needs at around the 40% renewable level are significant.
- Wind and solar increase hourly and multi-hour flexibility needs.
- Solar growth increases intra-hour needs due to its diurnal patterns and unique intra-hour profiles.

To illustrate the growing flexibility needs across and within hours due to increasing wind and solar production, Figure EAM-3 shows 15-minute net ramp, the average 30-minute headroom need, the average 1-hour net load ramp, and the maximum 4-hour persistent net load ramp-up for two different future portfolios and how it compares to current market. Under the 40% renewable scenario with 50% of that renewable comes from solar, ramping needs are considerably higher, highlighting potential operational issues.

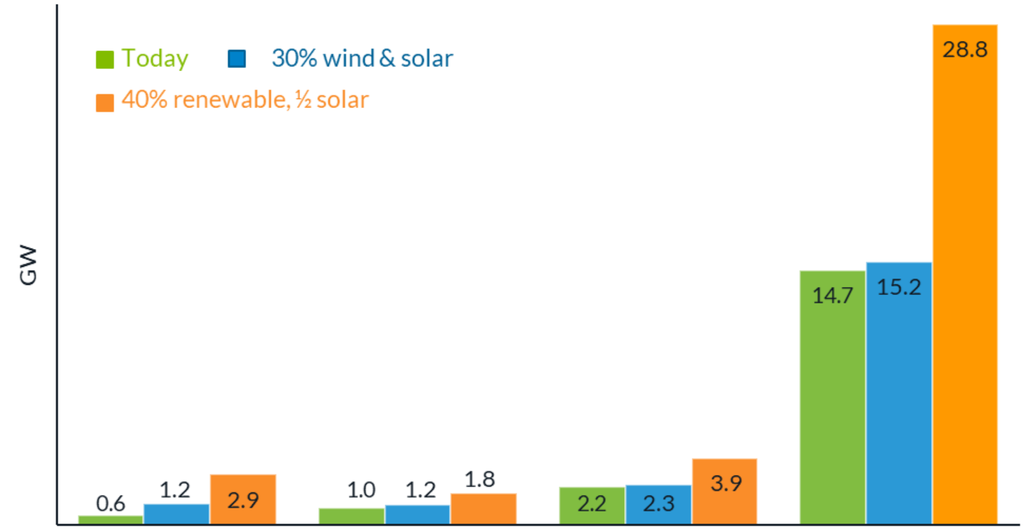


Figure EAM-1: Net ramp capability for different time horizons for different scenarios

Figure EAM-2 further shows that ramping capability may becoming tight or insufficient when net-load changes rapidly in real-time. The number of generation units that experience binding ramp rate constraints increases sharply in the simulated future scenarios.

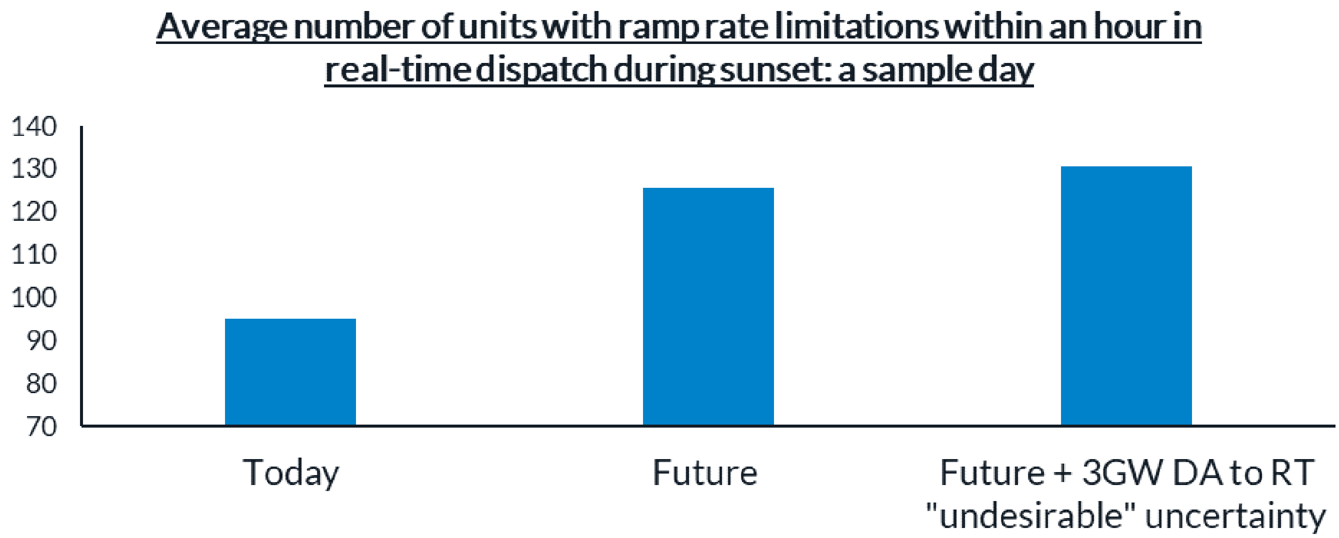


Figure EAM-2: Average number of units with binding real-time dispatch inter-hour ramp constraints during sunset for a sample day.

Additional observations from Figure EAM-1 and Figure EAM-2 include:

- The sunset time periods may be challenging to manage
- Fleet ramping capability is needed to manage discrepancies between solar reduction, wind pickup and load variation
- The operational challenges can be both inter-hour and sub-hourly
- Additional volatility within the hour at this timeframe could increase the need
- Real time actions influence the outcomes

In terms of deliverability, PES also finds such need will grow without transmission adaptation to the new resource mix. Within the analysis scope of PES, deliverability is indicated by the marginal congestion component (MCC) of locational marginal price. Figure EAM-3 illustrates the deliverability of 30-minute headroom within the 40% renewable penetration case, in which "good deliverability" from rampable MWs with lower marginal congestion component (MCC). On the other hand, ramp MWs that must come from resources with increasing congestion or higher MCCs are categorized as "bad deliverability." Figure EAM-3 shows that (1) deliverability issue will becomes even more crucial in the future along with increasing needs of flexibility; and (2) transmission builds, flexible transmission management, and market enhancements could improve deliverability outcomes.

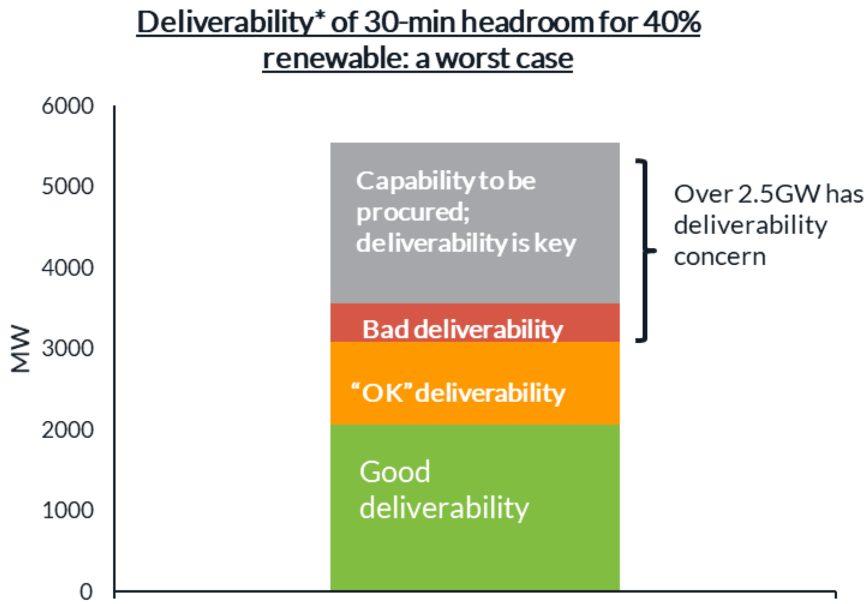


Figure EAM-3: Net ramp capability for different time horizons for different scenarios

Last, PES finds that without market or operations changes, greater variability and uncertainty could result in real-time resource scarcities. Figure EAM-4 shows, via real-time energy prices for a sample day, that higher prices and reduced capability are more likely to occur among future resource portfolios if without changes to current market practices. Findings suggests that in future market operator may run into Real-time capacity or reserve scarcities if variability and uncertainty are not well prepared for accommodating evolving future portfolio.

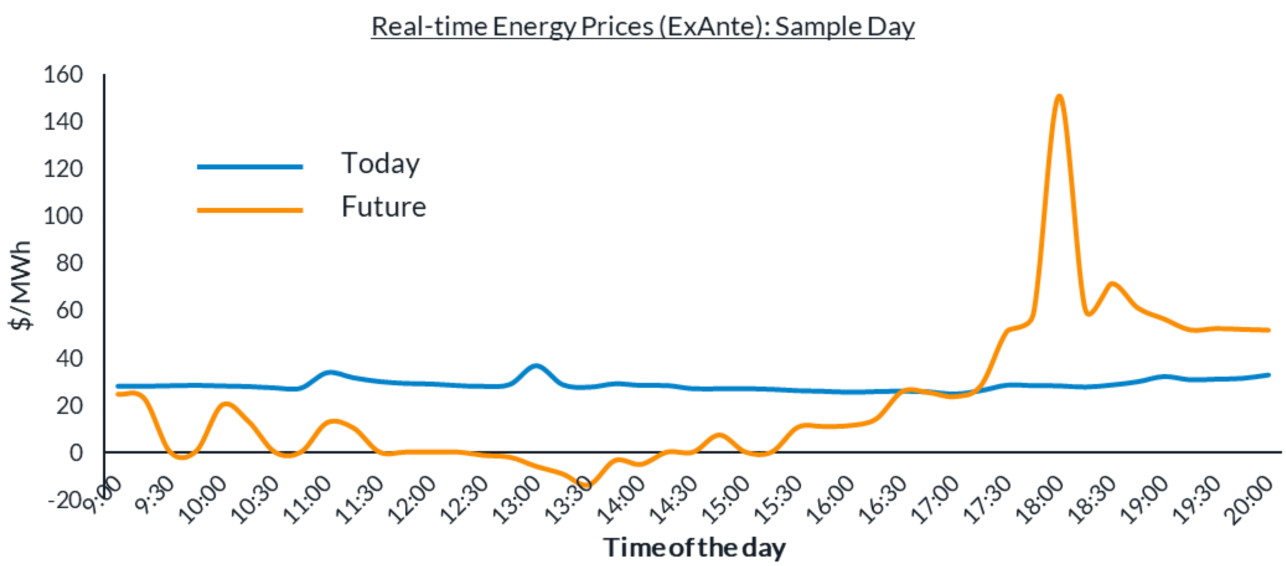


Figure EAM-4: Comparison of ex-ante real-time energy prices, today vs future (sample day)

Energy Adequacy — Uncertainty and Variability Trends

Overview

The goal of energy adequacy is to ensure that all system demand is reliably, and cost effectively met. Ensuring cost-effective and reliable energy delivery to meet the expected system demand requires a review of three key metrics: Flexibility, uncertainty and variability. The previous sections on Energy Adequacy — Planning and Markets and Operations, highlight the need for flexibility as a key metric. Understanding the uncertainty and variability associated with the supply and demand can help with planning and designing the energy market to improve its effectiveness or efficiency. Uncertainty is the deviation of the actual value of the supply or demand during the real-time in comparison to the forecasted value in the day-ahead timeframe while variability is the deviation of supply or demand over a certain time period. RIIA analyzed the forecasted uncertainties and variability associated with increased amounts of renewable generation penetration within the MISO region. The issues as well as the solutions associated with uncertainty and variability highlighted in the results below are currently under review in the MISO Forward Report[2] and the MISO's response to the reliability imperative[3]

Key Findings

Finding: Uncertainty and forecast error increases in the wind forecast varies across different months of the year.

Forecast error or uncertainty associated with wind and solar generation is the deviation in the respective generation output between the Day-Ahead and Real-Time markets. Uncertainty with the wind and solar generation if not handled appropriately, may have an impact on the efficiency of unit commitment and dispatch within the MISO market. It is therefore imperative for MISO to have a better understanding on the un-certainty from the renewable generation resources in order to provide an appropriate mechanism to handle it appropriately and improve market efficiency. Figure EAD-1 shows the forecast error associated with the wind generation across different milestones. In whisker charts like this, the lower whisker represents the first quartile (the lowest 25% of the values), the upper whisker represents the fourth quartile (highest 25% of the values), and any dots represent outliers. The thick middle portion is the second and third quartiles (middle 50% of the values) and the median is the horizontal line. From this figure, it is observed that the magnitude of the forecast error for wind generation would increase as renewable penetration increases in the MISO footprint.

[2] https://cdn.misoenergy.org/MISO%20FORWARD_2020433101.pdf

[3] https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf

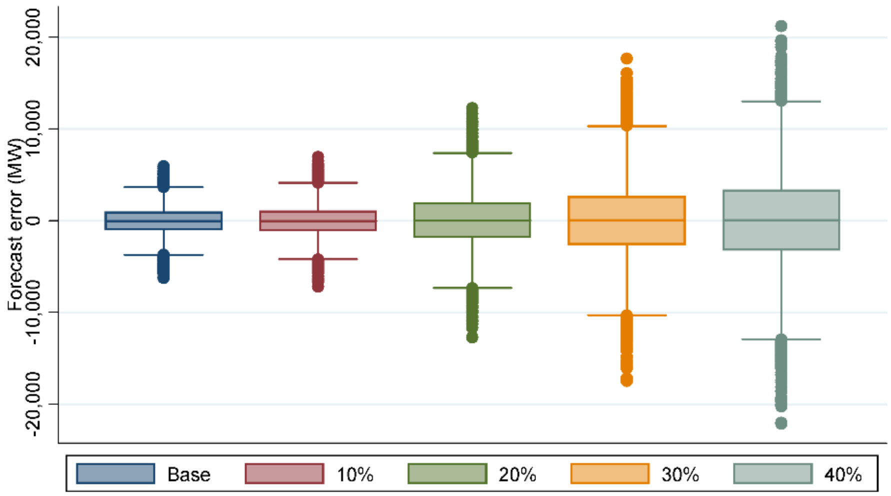


Figure EAD-1: Wind forecast error for various renewable milestones

Figure EAD-2 shows the forecast uncertainty broken down on a monthly basis for the base renewable penetration and the 40% renewable penetration. The forecast error is expected to be higher during the months with higher renewable output.

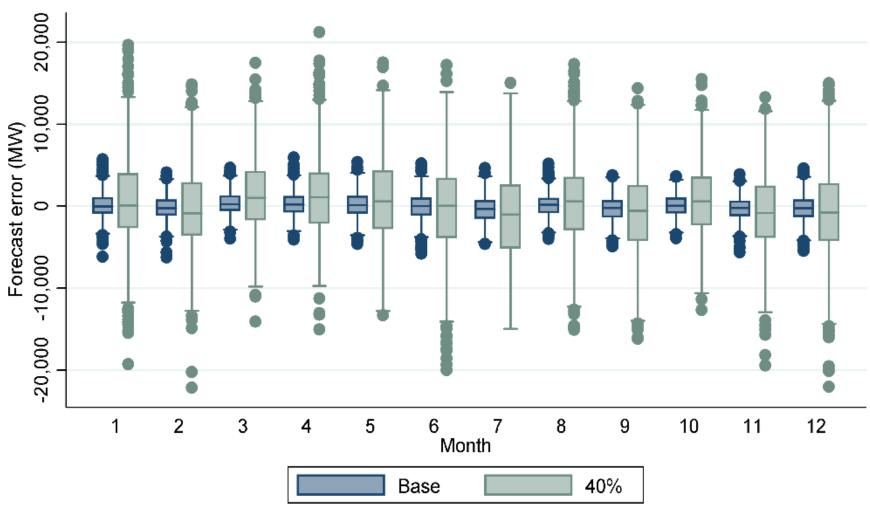


Figure EAD-2: Monthly breakdown of the wind forecast error for the base and 40% renewable milestones

Finding: Variability of the wind and solar generation decreases with geographic diversity

Variability is defined as the change in generation or demand over a pre-defined time interval. Figure EAD-3 shows the ramp rates associated with the wind and solar generation over an hourly interval. It is observed that variability in the aggregated generation reduces when the generation resources are geographically diverse. Any local variations in the renewable energy output can be easily compensated by the renewable generation within the same local resource zone (LRZ) or other parts of the footprint if adequate transmission capacity is built.

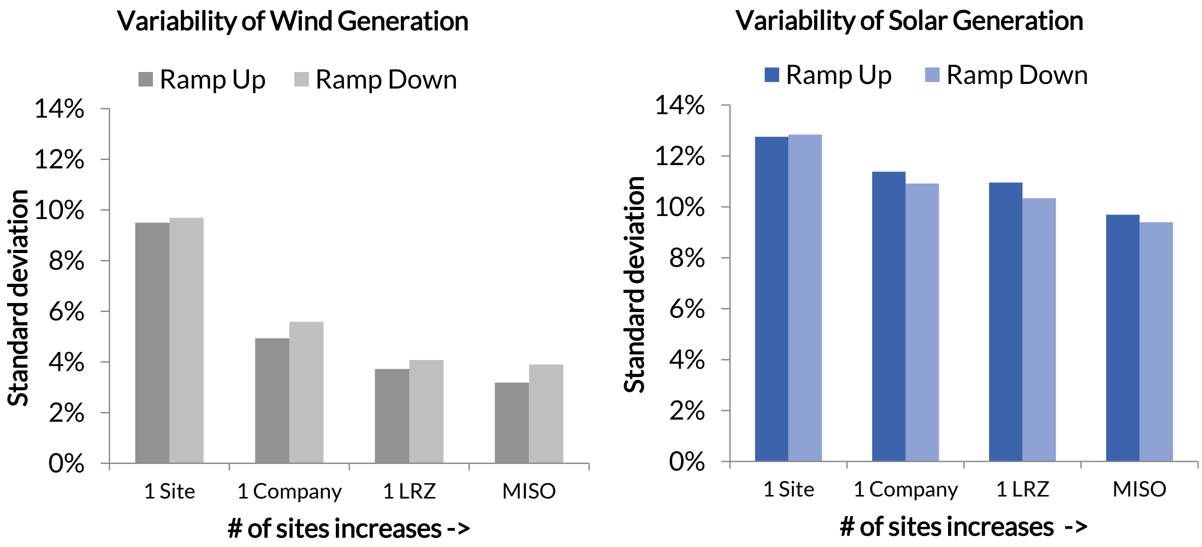


Figure EAD-3: Variability of wind and solar generation based on geographical aggregation

Finding: Increases in net load ramp is observed due to variability associated with the wind and solar generation

Figure EAD-4 and Figure EAD-5 shows that the variability or ramp from wind and solar generation increases in magnitude with increase in renewable penetration. The variability of wind and solar generation combined with the 1.4% variability associated with load leads to the net load ramp requirements increasing for the rest of the generation fleet (Figure EAD-6). The net load ramp is estimated by netting out the renewable generation amount from the hourly load. The variabilty of the wind and solar generation along with the increase in the net load ramp requirement calls for better coordination between the renewable generation resources and thermal generation in order to reliably serve load.

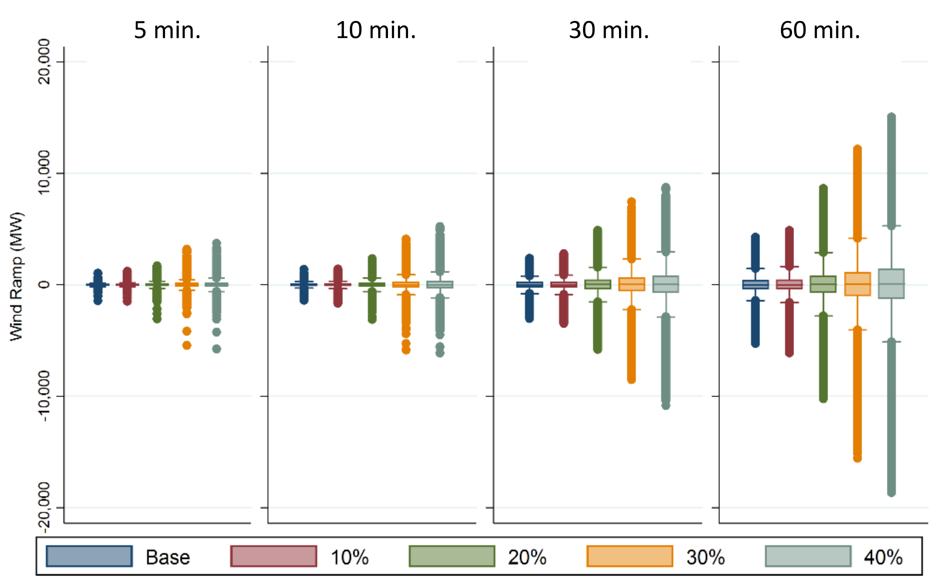


Figure EAD-4: Wind ramp for various renewable penetration milestones

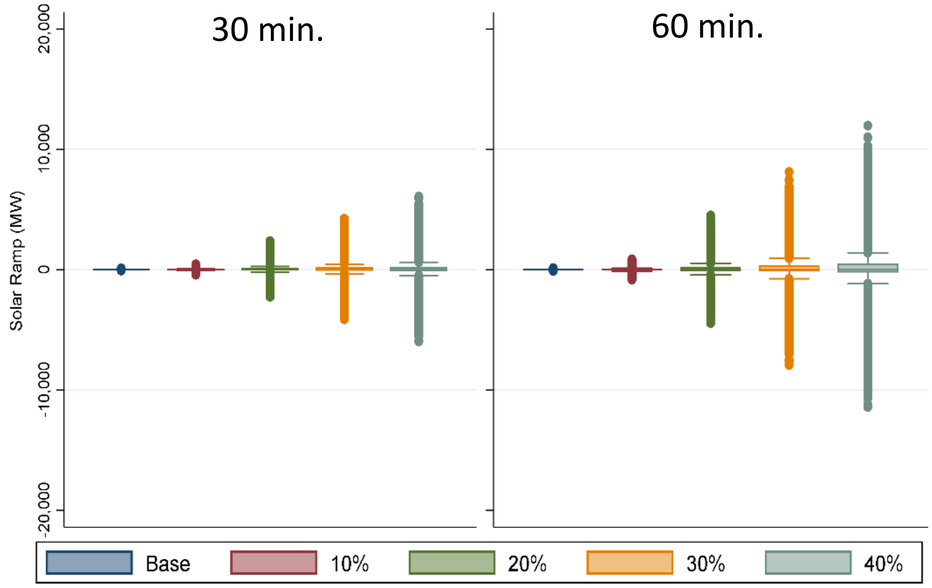


Figure EAD-5: Solar ramp for various renewable penetration milestones

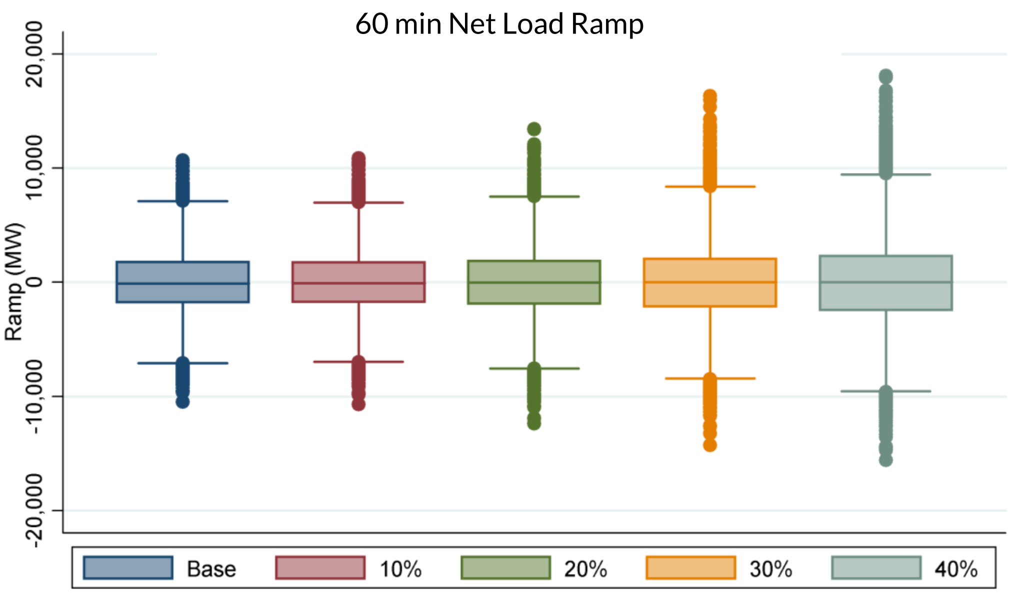


Figure EAD-6: Net load ramp for various renewable penetration milestones

Operating Reliability — Steady State

Overview

The purpose of steady-state reliability studies is to prevent the transmission system from exceeding its thermal and voltage ratings during normal and abnormal system operation, when deviations from normal operating conditions can occur without warning. Steady-state reliability studies are performed for a finite number of operating points. Traditionally, these points were chosen to align with periods of high system stress using engineering judgement, such as peak load. As renewable penetration increases, the times of transmission system stress also change. RIIA demonstrates that peak system stress is not necessarily coincident with the conditions traditionally studied -- peak system load or shoulder load -- in systems with high penetration of renewable generation. This is significant because traditional transmission planning presumes maximum system stress would be coincident (or nearly coincident) with peak system load.

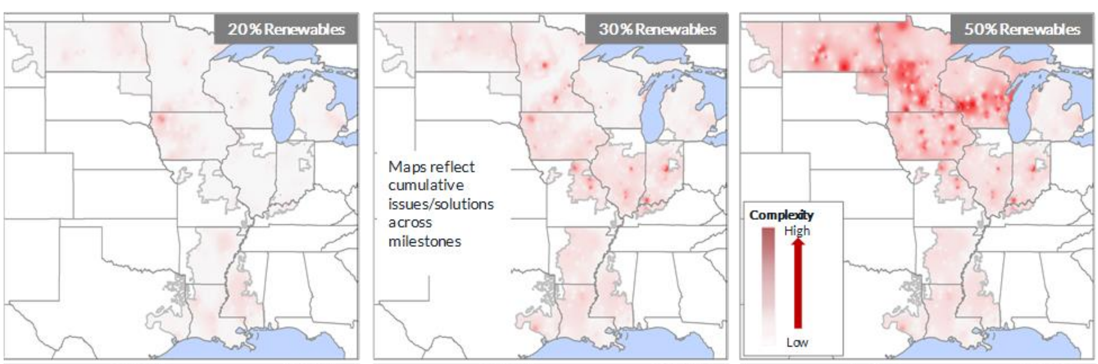
Within the RIIA OR-SS analysis, two primary concerns were examined:

- Will there be enough voltage-regulating equipment to support stable transmission system operation in high-stress conditions, since voltage-regulating controls, unlike regulating frequency, are a local resource, rather than a network-wide resource?
- Is there enough transmission capacity on long-distance transmission lines for the bulk electric system to operate reliably in case of unplanned outages?

In a world with high renewable penetration, RIIA suggests that there will be fewer thermal generators close to loads and more renewable generators remotely located from load centers, requiring longer transmission paths. Longer transmission paths increase the potential for thermal overloads as the older paths may not have been designed for the same level and direction of geographic power transfer. As a result, the complexity of the system increases with increasing renewable penetration (Figure OR-SS-1).

In summary, RIIA OR-SS analysis shows:

- As renewable penetration grows, system conditions and timing at which transmission stress occurs change
- The location of transmission stress changes significantly beyond 20% renewable penetration
- Steady-state complexity increases beyond 20% renewable penetration and is largely driven by mitigating thermal violations on transmission lines



	161 & below	230	345 & above		161 & below	230	345 & above		161 & below	230	345 & above
Ckt*miles	1500	300	400	Ckt*miles	1700	300	600	Ckt*miles	500	800	1700

Figure OR-SS-1: Steady-state results summary (thermal and voltage-support mitigations)

Key Findings

Finding: System conditions during and timing of transmission stress change as renewable penetration grows.

In the RIIA system models, the MISO load peaks in July at around 125 GW, while the lowest load levels of 55-60 GW are observed in the spring and fall seasons during night hours. At these very low load hours, a system with a higher share of wind energy in the renewable resource mix can experience very high instantaneous penetration (refer to "% Renewable at reference point" and bar chart on Figure OR-SS-2. Increase in solar installed capacity in the Siting sensitivity (discussed in Siting and Scenario Development), creates a new stressed operating point during the shoulder load periods, which may need further review in Operating Reliability).

Detailed steady-state and dynamic stability analysis was conducted on a total of 15 models (3 models for each of the 5 snapshots of 10% to 50% annual renewable energy) with instantaneous renewable penetration ranging from 5% to 89%. RIIA demonstrates total renewable output in the 50% milestone varies significantly throughout the year, with moments of high instantaneous renewable penetration reaching 89% in the MISO region, compared to 24% for the

10% milestone (Figure OR-SS-2). The shoulder periods studied in RIIA can differ greatly from the shoulder periods traditionally studied.

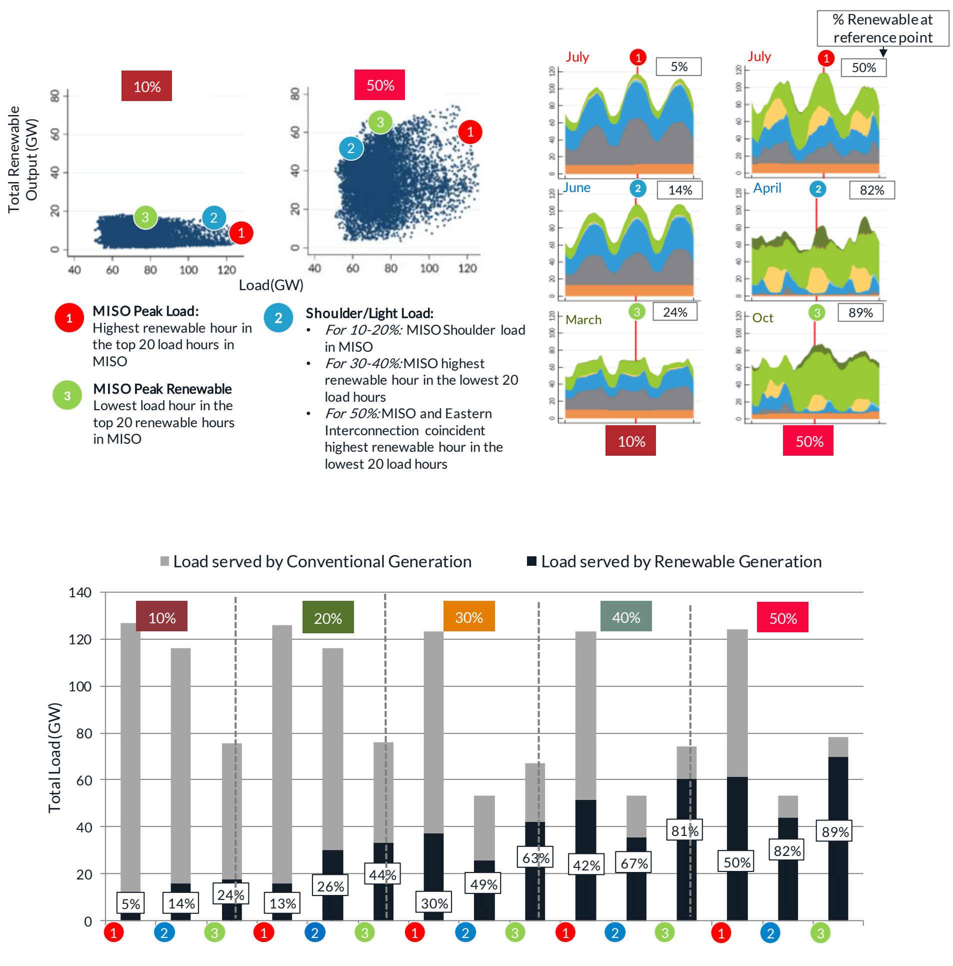


Figure OR-SS-2: Changing conditions during stress and changing timing of stress on the transmission system

During these periods of high instantaneous renewable penetration, conventional units are displaced by low-cost renewable energy. This displacement introduces new reliability risk periods, which are no longer aligned with the traditional risk-period (peak load) and represents new periods of stress on the transmission system (more detail on this is in sections below). An adaptive planning process is essential to evaluate new periods of risk as renewable penetration increases. Based on RIIA findings, MISO is actively engaging stakeholders to update dispatch assumptions used in the MTEP reliability process[4].

Finding: The location of transmission stress changes significantly beyond 20% renewable penetration

RIIA steady-state analysis indicates that in absence of any upgrades of existing transmission network or addition of new transmission equipment, the bulk electric system experiences significant post-contingent low voltages beyond the 20% renewable penetration level. As the renewable penetration increases, more power flows from the northwestern part of MISO to load centers in the central and southern parts of MISO. As a result of this changing flow pattern, several acute issues arise in different locations in MISO and progressively become worse as the renewable penetration increases (Figure OR-SS-3). Low-voltage issues can be mitigated by installing shunt reactive power devices (e.g. capacitors) or by adding transmission lines. Voltage issues becoming more severe and resulting in transient instability may require installing dynamic compensation devices, such as STATCOMs or VSC-HVDC devices (refer to the Operating Reliability — Dynamic Stability section). Because these voltage issues are exacerbated as the penetration level increases, cost-effectively mitigating voltage issues will require a forward-looking approach, tacking both steady-state and dynamic stability issues.

As a result of changing flow patterns, several acute issues arise in different locations in MISO and progressively become worse as the renewable penetration increases.

An adaptive planning process is essential to evaluate new periods of risk as renewable penetration increases.

A similar pattern is observed in thermal overloads; as renewable penetration increases, the number and severity of thermal overloads increases and expands into different geographic areas (Figure OR-SS-4). Initially, overloads are concentrated near the renewable expansion areas. With increasing renewable penetration, however, more overloads appear between renewable expansion areas and load centers. With the base-siting, this is driven by two major factors — (a) limited transmission capacity in the wind-rich northwestern part of MISO's footprint for delivering low-cost wind to other parts of MISO, and (b) conventional units, typically sited near large load centers, being displaced or retired due to economics as the renewable penetration increases.

[4] Refer to MISO PSC presentation "Wind / Solar Generation Dispatch Assumptions In The Reliability Planning, Models", Oct 2019, available online here.

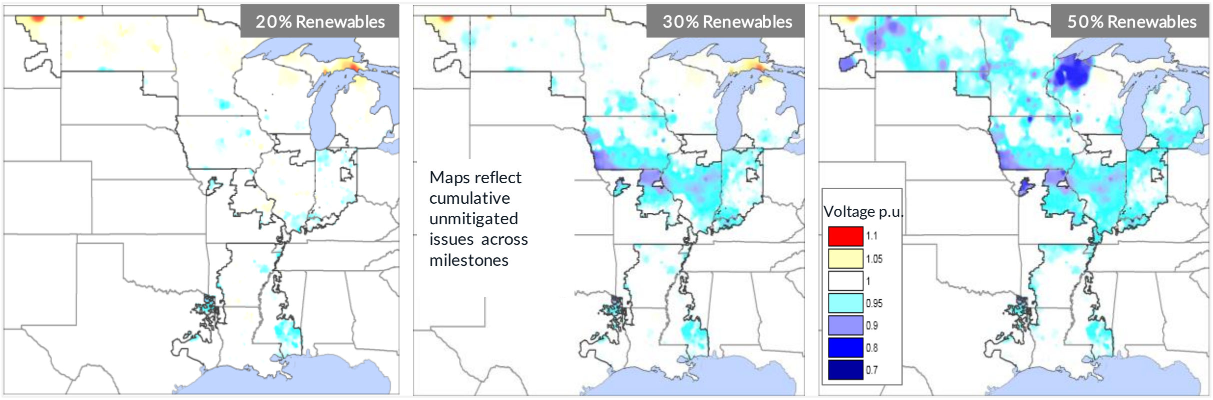


Figure OR-SS-3: Locations of low voltages in MISO

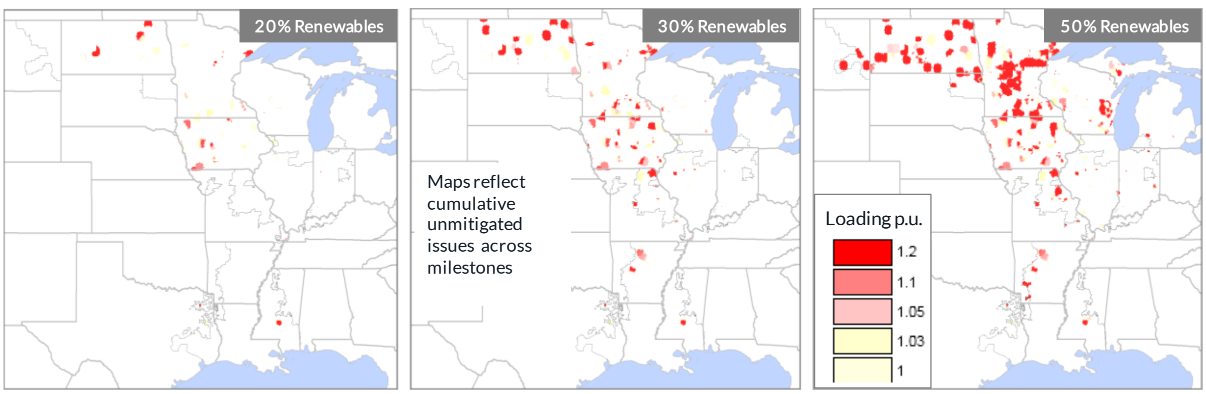


Figure OR-SS-4: Locations of thermal overloads in MISO

Finding: Steady-state complexity increases with renewable penetration levels after 20% and is largely driven by mitigating thermal violations on transmission lines

Transmission line upgrades to mitigate thermal limit violations comprise the largest driver of complexity for resolving steady-state issues. Upgrading transformers for thermal limit violations or installing shunt reactive devices for voltage issues make up a much smaller percentage of the complexity (Figure OR-SS-5). Although RIIA demonstrates that increasing renewable penetration will require considerable shunt reactive power devices to ensure acceptable voltage performance, the investment cost pales in comparison to the need for upgrading transmission lines.

Increasing renewable penetration will require considerable shunt reactive power devices, but the investment cost pales in comparison to the need for upgrading transmission lines.

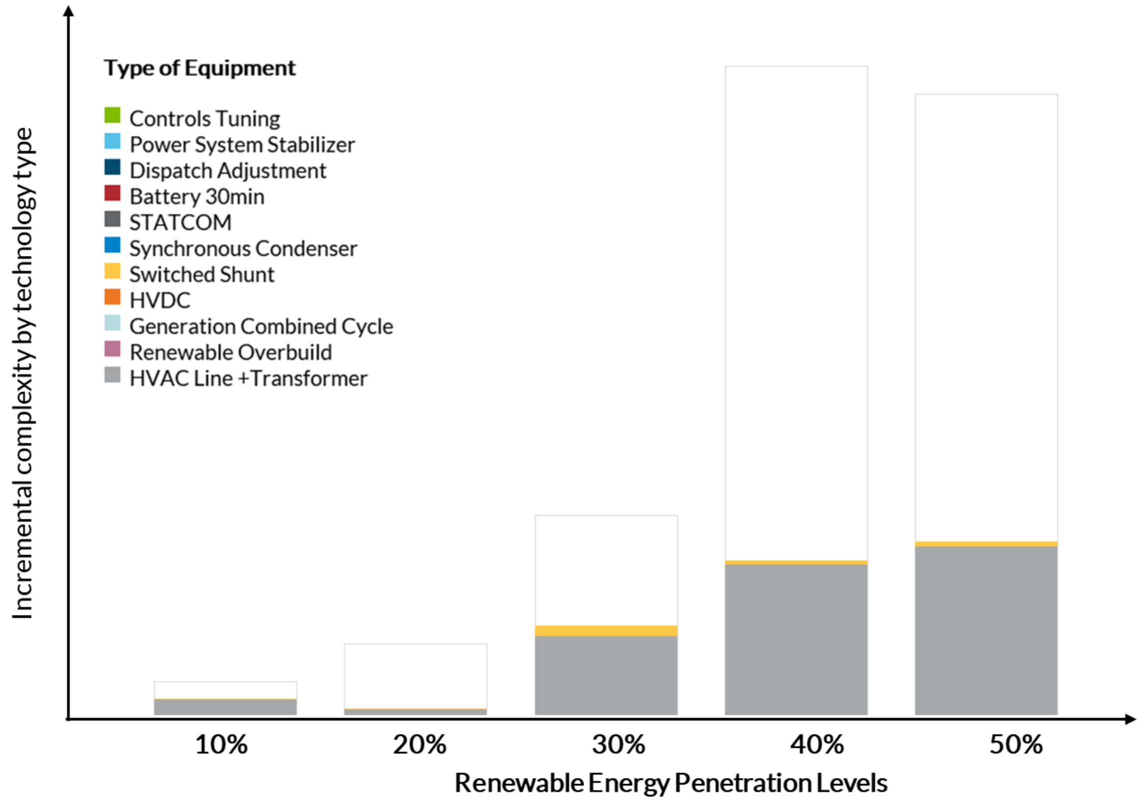


Figure OR-SS-5: Incremental complexity to resolve steady-state issues, by equipment type

Finding: As renewable penetration increases, more thermal mitigations on higher voltage lines are needed

Another interesting finding related to transmission grid stress can be distinguished by the fact that as the penetration increases more thermal overloads are seen on higher voltage lines. Typically, conventional generators are located near load centers, and have one point-of-interconnection (POI) to the electrical-grid and generate at or near their full capacity most of the time, whereas renewables resources are geographically dispersed, need more POIs and more nameplate capacity[5] is required to serve the same load (due to natural variations of irradiance and wind speeds).

With subsequent increases in renewable penetration, the transmission bottlenecks shift to higher voltage lines, akin to freeways getting congested.

At lower RIIA milestones, the production-cost-model sourced generation dispatch and load levels in the power-flow models indicated the energy from these renewable resources tends to cause overloads on lower voltage lines -- akin to city streets getting congested. With subsequent increases in renewable penetration, the transmission bottlenecks shift to higher voltage lines, akin to freeways getting congested. This pattern provides an important insight into transmission infrastructure planning; while high-voltage transmission lines will be needed as backbones to enable more renewable delivery, lower voltage lines will also need upgrades to enable the last-mile delivery of renewable energy.

[5] Nameplate capacity is defined as MW injection at full output

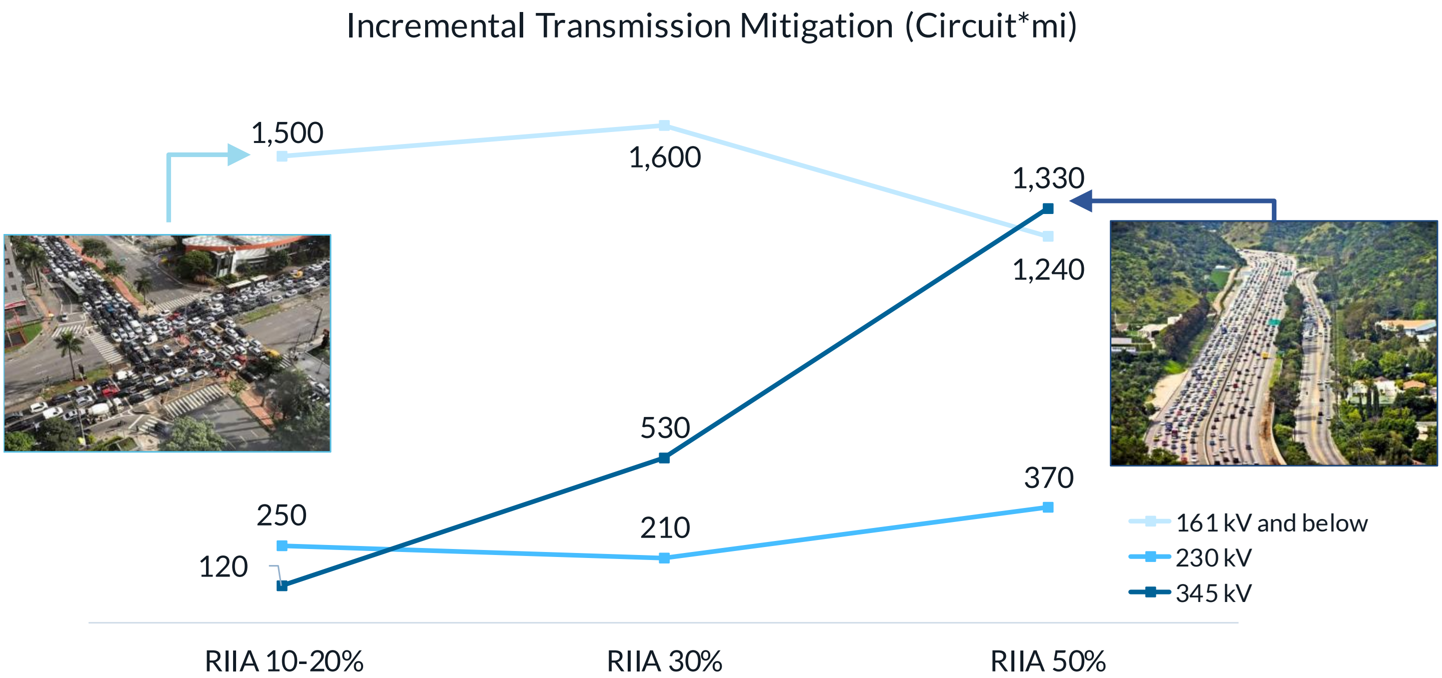


Figure OR-SS-6: As renewable penetration increases, the amount of higher voltage line upgrades increases

Operating Reliability — Dynamic Stability

Overview

Dynamic Stability is comprised of maintaining operating equilibrium post electric-grid disturbance in three distinct elements — (a) voltage stability, (b) adequate frequency response, and (c) rotor angle stability (Kundur[6], 2004). The equilibrium should be characterized by a well-damped, non-oscillatory behavior of electrical quantities (MW, Mvar, frequency). Dynamic stability looks at the timeframe within seconds of power system disturbances and involves laws of physics and fast-automatic-action of equipment responding to the event without any operator action. Similar to steady-state analysis, it is performed on a limited number of specific scenarios.

[6] P. Kundur, J. Paserba and S. Vitet, "Overview on definition and classification of power system stability," CIGRE/IEEE PES International Symposium Quality and Security of Electric Power Delivery Systems, 2003. CIGRE/PES 2003., Montreal, Quebec, Canada, 2003, pp. 1-4, doi: 10.1109/QSEPDS.2003.159786.

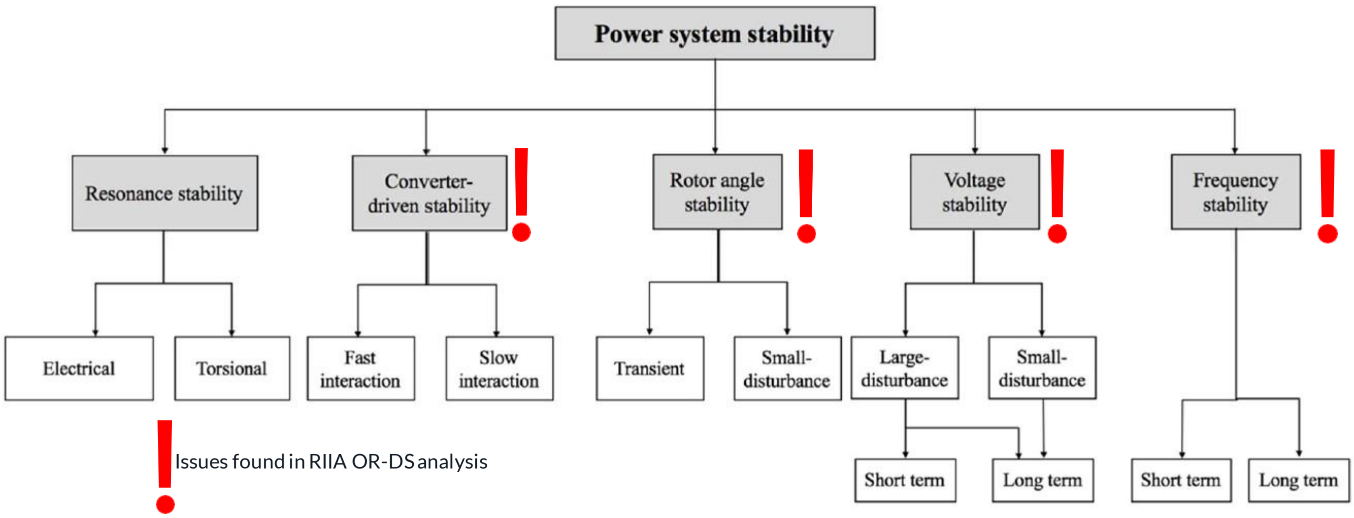


Figure OR-DS-1: Power system stability categories defined by IEEE and issues identified in RIIA

Within the RIIA operating reliability-dynamic stability (OR-DS) analysis, the following key concerns were examined within the context of three key elements of dynamic stability:

- What will the impact of high penetrations of renewable (inverter-based) resources be on frequency, transient and voltage stability, damping, and local grid strength (weak areas)?
- What actions will be required to maintain adequate performance? When will they be necessary?

RIIA identifies potential issues with all three elements of dynamic stability and an additional category of "converter-driven stability[7]" associated with inverter-based equipment defined in the new IEEE report (Figure OR-DS-1, IEEE PES- TR77[8], May 2020). With respect to voltage stability and inverter-driven stability, the RIIA assessment demonstrates that as inverter-based resources increase in penetration, there is a corresponding decrease in online conventional generation, which intensifies reliability issues. The same phenomenon is also responsible for frequency stability. As the increased penetration of inverter-based generation continues, the number of conventional units available to provide inertia and damping decreases. The result is the potential compromise of the system's ability to arrest a frequency excursion in the timeframe necessary to prevent involuntary load shedding, and, due to the displacement of conventional units with power system stabilizers, an Eastern Interconnection (EI) wide undamped oscillation (also known as "inter-area small-signal oscillations") appearing. The analysis was also conducted to gauge the rotor angle stability of the remaining online convention units by calculating critical clearing time (CCT[9]). The analysis indicates overall, CCT increases as renewable penetration increases denoting a positive impact of renewable penetration; however, RIIA finds that CCT may decrease at certain locations experiencing very high instantaneous penetration.

[7] Converter-driven stability is associated with resources (wind, solar or battery) or dynamic devices (STATCOM, HVDC) utilizing inverters to connect to AC grid.

8 Nikos Hatziargyriou, P. Pourbeik, *et al*, "Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies", May 2020

[9] CCT is defined as the maximum number of cycles a conventional unit can remain in synchronism during a faulted condition. 1 cycle = 1/60 second

The key findings of operating reliability-dynamics are summarized below, which are discussed in detail in the subsequent sections.

- Potential dynamic stability issues due to weak grid increase sharply beyond RIIA 20% milestone.
- Frequency response is stable up to 60% instantaneous renewable penetration, but may require additional planned headroom beyond.
- Small signal stability may become a severe issue beyond 30% RIIA milestone and can be addressed by specially tuned batteries or must-run units equipped with power system stabilizers.
- Overall, critical clearing time (CCT) becomes better as large units are displaced, but some locations may observe a decrease and may require installation of new protection techniques or transmission devices.
- Grid-technology-needs evolve as renewable penetration increases leading to an increased need for integrated planning and a blend of transmission solution types.

The dynamics stability concerns by the rank of severity are summarized in Table OR-DS-1, as follows: 1) transient voltage stability in weak areas, 2) small-signal and frequency response, and 3) rotor angle stability. The thumbs up and thumbs down on the rotor angle stability row indicates that some CCT values improve and others worsen, with the relative proportion indicated by the size of the symbol.

After analyzing a range of reliability issues pertaining to weak-areas, RIIA proposes several mitigation techniques (Figure OR-DS-2). Wherever applicable, low-cost solutions, such as tuning of controls of inverters and re-dispatch of generators can be applied. However, to address severe voltage and inverter-driven stability issues, adding synchronous condensers to the existing AC transmission system and utilizing advanced technologies, such as Flexible Alternating Current Transmission System (FACTS) devices and Voltage Source Converter (VSC) based HVDC transmission lines can be pursued. Frequency -related issues can be addressed by maintaining additional planned headroom on resources, including renewables and by storage. Although renewable resources have the capability (hardware) to provide frequency response and ramping, they cannot provide sustained response unless they maintain a certain amount of headroom (energy reserve) by operating below their maximum possible power output. Thus, wind and solar resources need economic incentives or regulations adopted to “spill” energy to maintain headroom.

Inter-area small-signal issues can be resolved by ensuring units with power system stabilizers (PSS) installed are committed or by installing specially tuned batteries at strategic locations. Additional research and pilots into advanced technology, such as grid-forming inverters, should be pursued to help counteract these risks or minimize cost. Inverter-based resources (IBR) can be equipped with Fast Frequency Response (FFR) to mitigate issues caused by reduced governor response and reduced inertia, due to retired or off-line thermal generating units. IBR and FACTS could also be equipped with stabilizing control loops.

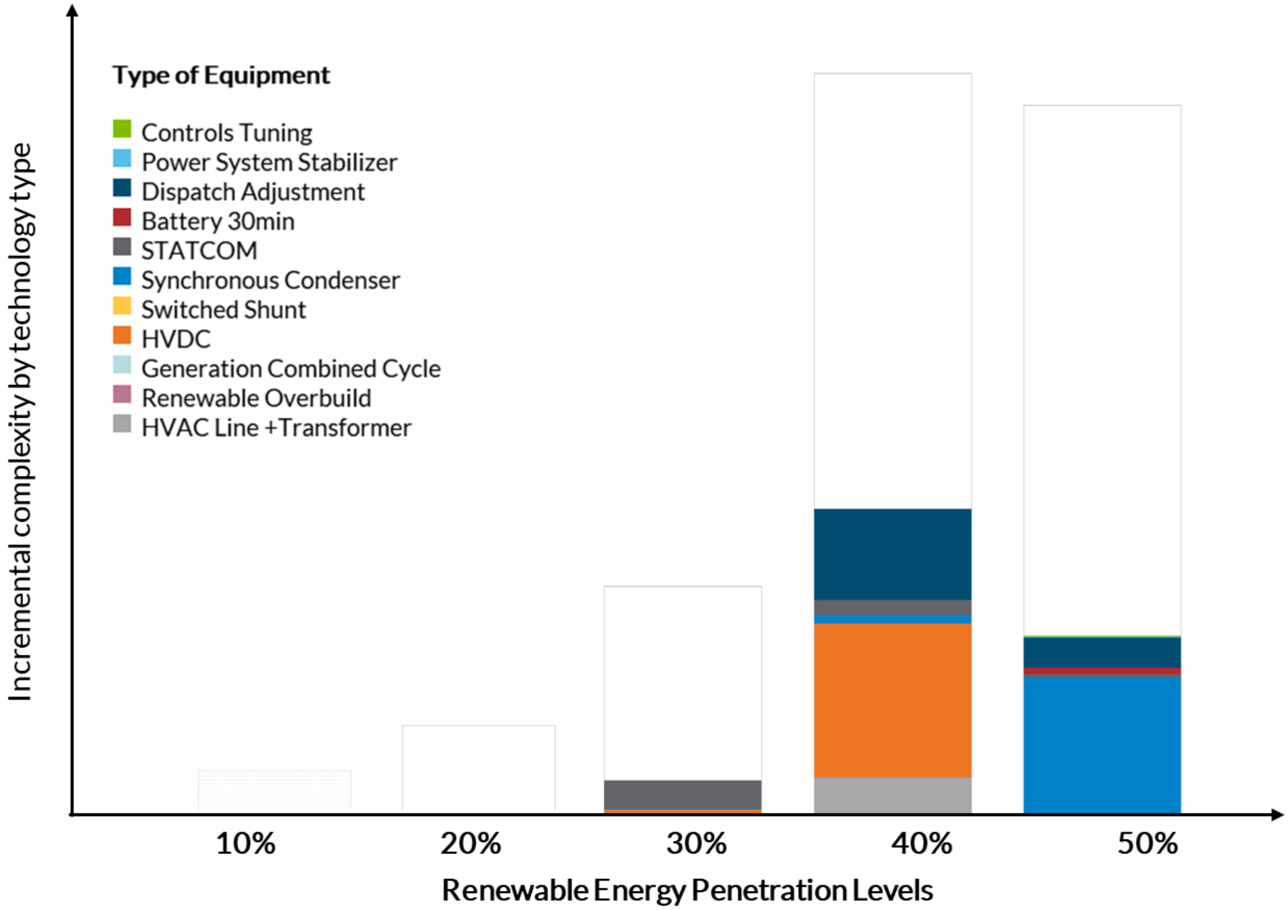


Figure OR-DS-2 :Different technology types used to solve operating reliability issues at each RIIA milestone

The analysis also indicates that to bring down the cost of grid-integration (particularly at high penetration levels) there is benefit to improving characteristics of inverter-based resources such as the following.

- Research and development should be pursued to develop better control-techniques (such as deploying "grid-forming" technique) to enable reliable operation in weak-grids. This can have the effect of reducing the need for synchronous condensers and transmission lines — both AC and DC.
- Interconnection-wide small signal oscillations in the range of 0.1-0.8 Hz can appear at high penetration of renewables. Currently, renewable resources are not known to have the capability to arrest inter-area oscillations, and it is uncommon to install power system stabilizers (PSS) on synchronous condensers (SC). Through detailed analysis, strategic locations can be identified where installing appropriately tuned and designed supplemental power oscillation damping (POD) controllers on renewable resources, batteries, SVC, STATCOM, or HVDC can help to improve small signal stability. Hence, RIIA makes a recommendation to the renewable resource owners (including electric storage) and dynamic device manufacturers to facilitate the addition of POD controllers to mitigate such issues in the future.
- Pilot-programs demonstrating the reliable operation of these new techniques should be pursued to educate and familiarize the electric grid operators and assets owners, and to facilitate mass adoption.

Area of stability	Ranked concern	Performance metric	Impacts	Possible mitigations	Concerned MISO group	Issue first seen	Impact of renewable penetration	Capital cost share to mitigate
Inverter-based stability and voltage stability	1. Transient voltage stability in weak areas	Short circuit ratio, undamped voltage and current oscillations, interactions between the controls of equipment	Local area, observed at many substations system-wide	• Control tuning • Synchronous condensers • STATCOM • HVDC	EP*, GI†	30%		
Frequency stability	2. Frequency response	Frequency nadir, rate of change of frequency (RoCoF), NERC BAL-003 obligations	Interconnection wide	• Additional planned online headroom • Batteries	Operations	50%		
	3. Small signal stability	Damping ratio of low frequency oscillations	Interconnection wide	• Must-run units with power system stabilizers • Specially tuned batteries	EP*, Operations	30%		
Rotor-angle stability	4. Transient rotor angle stability	TO's local planning criteria, NERC criteria	Local area	• Faster protection schemes • Transmission facilities	EP*, GI†	50%		-

*EP: Expansion Planning
†GI: Generator Interconnection

Table OR-DS-1: Summary of dynamic concerns by ranking, performance metrics, possible mitigations and impacted

Key Findings

Finding: Weak areas: Short circuit ratio (SCR) at several locations decrease with an increase in penetration due to a reduction in conventional generation and the increase in inverter-based generation.

Grid-following inverters face difficulties in operating reliably in areas known as "weak-area" or "weak-grid" and can be identified by calculating the short circuit ratio (SCR[10]). Low SCR defines weak areas. Typically, weak-area instability arises in long radial electric networks or local networks with high concentrations of inverter-based renewable resources with little or no conventional generation or synchronous condensers. Conventional generators, by design, improve SCR, thus making the grid stronger.

Existing inverter-based resources use a combination of phase locked loop (PLL) and extremely fast current-regulated controls to keep the current being injected into the grid by the inverters in synchronism with the grid frequency. Thus, in weak areas, following severe faults on the grid there is no strong grid frequency reference for the PLL to lock into, and present technology can have significant challenges with recovering and remaining connected to the grid post-fault. Advances in power electronic converter technologies, such as so-called "grid-forming" inverters, will be needed in the future as penetration increases. Some of these approaches are based on inverters that are able to create their own internal frequency reference and thus do not need a PLL for keeping synchronism with the grid and can thus avoid both the issue with PLL dynamics and not being able to lock into the grid post-fault, and moreover can provide inherent services such as virtual-inertia. Much of this still requires more research and development, but such technologies show promise for the future.

PLL in the grid-following inverter-based resource is one of the sources of reliability concern, and instabilities may also arise from a combination of challenges in weak grids such as

10 SCR is calculated as available fault MVA at a network node divided by MW injection by inverter-based resource. Other methods are also used to determine SCR. Refer NERC: Integrating Inverter Based Resources into Low Short Circuit Strength Systems Reliability Guideline, December 2017

- tracking of voltage and frequency using PLL,
- inverter-based resources behaving as current-controlled sources,
- sensitivity of power electronics to external disturbances (unlike conventional generation units able to survive under instantaneous high current or high voltage conditions),
- interactions between the high bandwidth controllers of inverters, and
- interactions between inverter controllers and other equipment (series compensation or long lines).

The focus may need to be to understand the conventional grid was planned and built for traditional synchronous generators serving machine loads. However, the trends in both loads and generation sources are moving towards increased penetration of power electronics-based resources introducing a different set of constraints needing further research and mitigations.

The heatmaps below show the geographical locations of the weak areas denoted by orange color (SCR[11]) in different RIIA milestones (Figure OR-DS-3). The intensity of color denotes severity of the weak-area issue; thus, darker areas are most likely to have a stability issue. A combination of renewable resources located in areas with limited grid strength (such as North Dakota, parts of Iowa, and southwest Minnesota) with displacement of conventional generation increases the number of locations with low SCR (Figure OR-DS-4) and exacerbates challenges faced by inverters. The potential reliability issues arising in the weak areas can manifest into different forms, ranging from undamped oscillatory behavior of electrical quantities to voltage and inverter-based stability issues. SCR is merely an indicator, much like a high temperature may indicate a person is ill, but it does not tell the exact ailment. To ascertain the nature of complications, 15 detailed EI-wide dynamic stability models (3 each for the 5 milestones of 10% to 50%) were developed, and findings are discussed below.

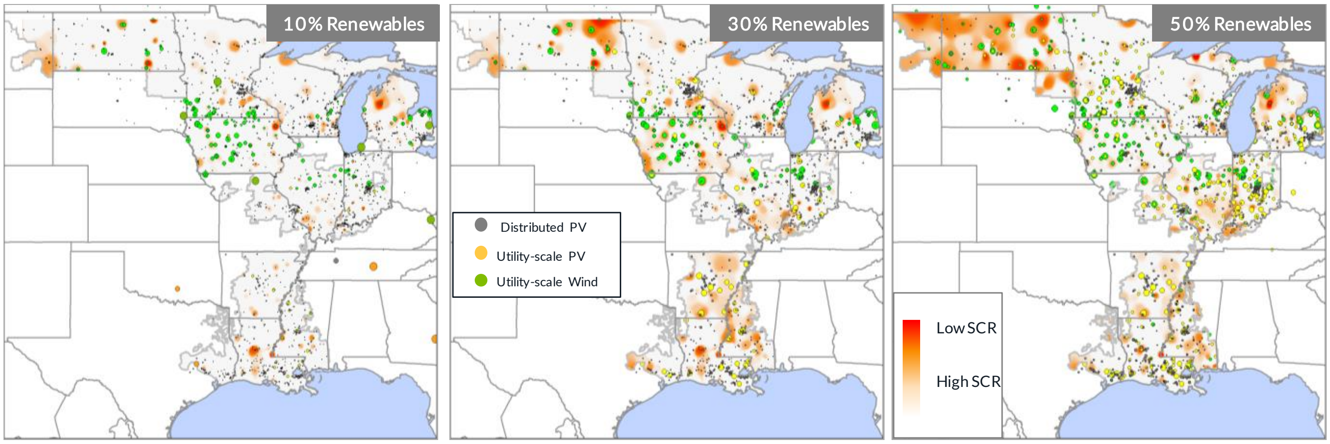


Figure OR-DS-3: Projected weak areas in MISO with growing penetration of renewables

[11] SCR was calculated using PSSE module

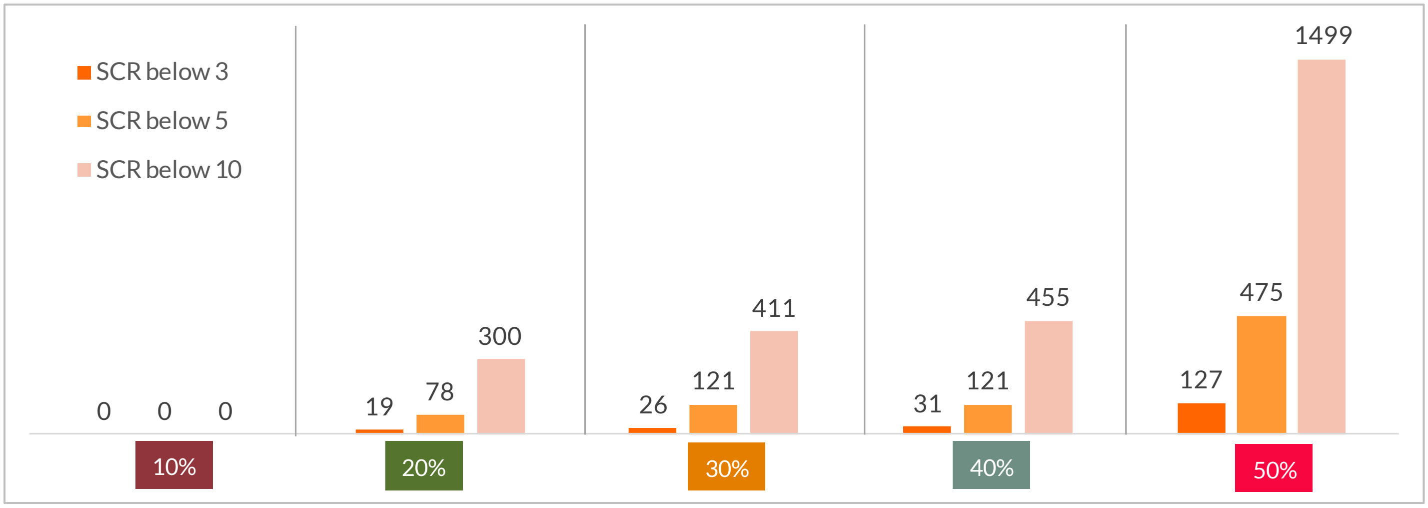


Figure OR-DS-4: Short Circuit Ratio (SCR) distribution in MISO (number of substations)

Finding: Weak areas: dynamic issues such as low -frequency undamped oscillations of electrical quantities are likely to appear during high renewable and low load conditions, which can be fixed by tuning wind and solar plant controls.

Dynamic issues, such as low-frequency undamped oscillations, are likely to appear during high renewable and low-load conditions.

The stability issue likely to appear first in the list of "reliability issues due to weak-area" is low frequency undamped oscillatory behavior of electrical quantities (MW and Mvar) at renewable resource's POI. Such issues can be fixed at relatively low cost by performing detailed modeling and analysis (positive sequence or electromagnetic transient (EMT) type simulations) of the renewable resource. Then tuning the control gains correctly resolves the instabilities. RIIA observes this issue for the first time in the 20% peak-renewable case at a non-MISO location. A solar farm of 600 MW capacity was modelled in the base case at that location, and the minimum SCR was found to be 4.3. At 20% RIIA milestone, a higher renewable capacity sited at that location, coupled with displacement of a nearby conventional generator lead minimum SCR to fall to 3.1 (Figure OR-DS-5). Interestingly, the minimum SCR coincides with the scenario of system-wide low load and high renewable penetration, because at higher system load more conventional units are committed to serve load and meet other requirements such as ramping. Lower SCR causes undamped oscillations at the terminal voltage and was fixed by tuning the gains of the inverter controls.

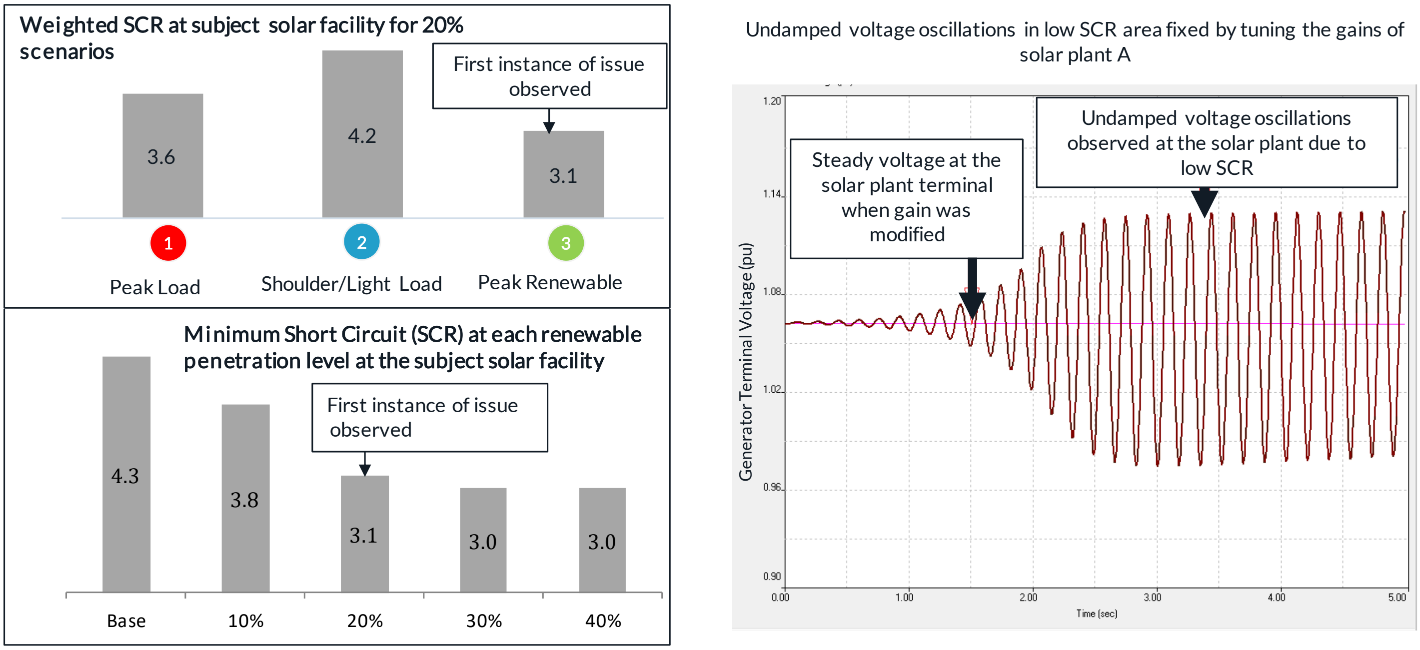


Figure OR-DS-5: Low-frequency undamped oscillations due to weak areas fixed by tuning of wind and solar plant controls

Finding: Weak areas: Wind and solar plants may require retuning of controls as system conditions change.

RIIA finds that as system conditions change over the years with increasing amounts of renewables and displacement or retirement of conventional generators, there could be a need to retune the gains of wind and solar plant controls. Analysis indicates that at 50% milestone the set of control parameters used to model future renewable resources had to be updated at several locations (Table OR-DS-2) to mitigate voltage oscillations in the range of 5-6 Hz (Figure OR-DS-6). The gains had to be reduced, and randomization[12] was introduced to prevent any unwanted unstable interactions between the renewable resources found by initially using the same parameters for all the new generation in the model. The finding even though surprising, can be well explained by the fact that at the 50% milestone several locations in MISO demonstrate low values of SCR, which is an indication of overall degradation of system strength (Figure OR-DS-3 and Figure OR-DS-4).

> *An RTO or Transmission Owner with renewable resources may need to conduct periodic studies to ensure the control parameters provide reliable operations, as the adjacent system changes.*

The finding also sheds light on an important emerging issue and deviation from the norm. Generally, after going through an interconnection study, inverter-based renewable resources rarely require retuning of the controls in the following years. However, there is significant possibility of an RTO or Transmission Owner with renewable resources conducting periodic studies to ensure that the control parameters ensure reliable operations as the adjacent system changes. Wind, solar, and hybrid plant owners will likely see a new normal of needing to retune their controls often, thus requiring a close coordination with transmission owners. It also provides another important insight; a renewable asset owner would need the control-hardware of the generation site to be easily accessible when necessary to modify it. In the

[12] The randomization simulated the natural differing control settings the developers of renewable generation sites will employ as they commission their generation sites

likelihood some of the control-gains reside within the equipment installed on the wind-turbine, an easy and secure access to the equipment ensures minimal delay and downtime to resolve the issues required by the Transmission Owner before resuming operation.

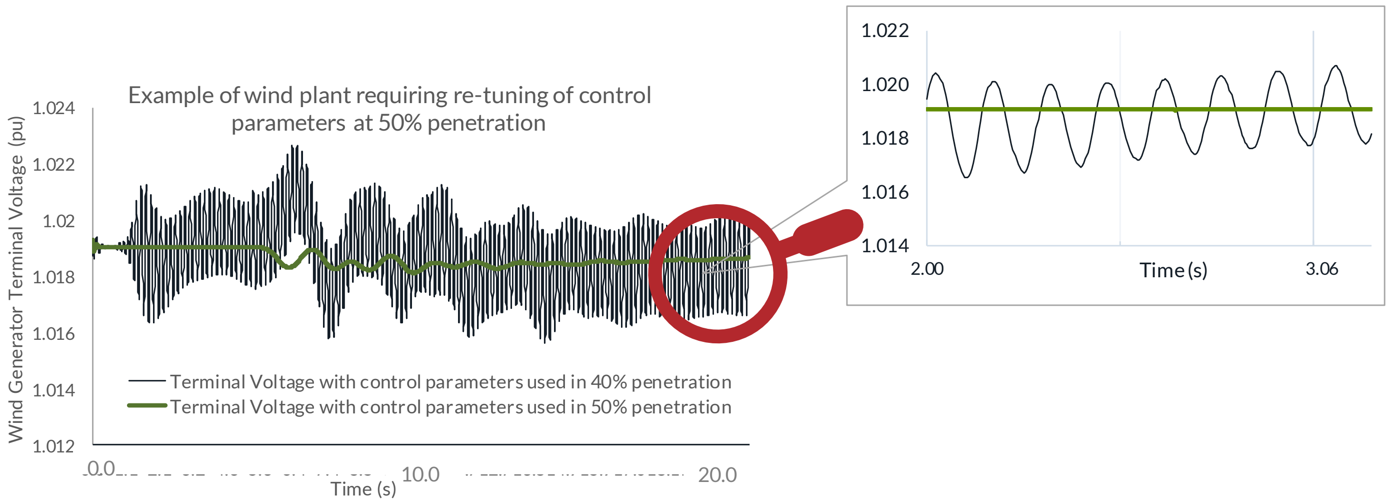


Figure OR-DS-6: Renewable resource retuning of controls as system conditions change

Control Parameters that were re-tuned	Value at 40%	Value at 50%*
Kp, Reactive power PI control proportional gain (pu)	4 or 10	1.60 - 2.40
Ki, Reactive power PI control integral gain (pu)	2 or 5	0.75 - 1.25
Kpg, Proportional gain for power control (pu)	0.25	0.2 - 0.28
Kig, Integral gain for power control (pu)	0.25	0.2 - 0.28
Kvi (pu), Voltage regulator integral gain	40	30-50

*Random values in the specified range chosen to minimize control interactions. Only RIIA sited wind and solar units were re-tuned.

Table OR-DS-2: Renewable controls tuning parameters

Finding: Weak grid: Power delivery from low short circuit areas may need transmission technologies equipped with dynamic support capabilities: A holistic approach is needed to develop solutions to solve the myriad of reliability issues

Energy adequacy analysis indicates that transmission solutions were needed to achieve 40% renewable energy penetration target (Figure EA-4). A least-cost solution proposed new AC transmission lines to be placed in the weak areas of ND and Iowa to reduce curtailment and increase wind power delivery. Per the study process these new AC transmission lines were then modeled in power-flow models, and steady-state contingency analysis was performed to identify additional thermal and voltage solutions, which were subsequently fed into initial 40% dynamics models. During the dynamics analysis, even after applying a combination of AC only solutions (new AC transmission lines only, AC lines and synchronous condensers only) the bulk electric system was unstable. For example, applying only new AC lines in absence of any synchronous condensers demonstrated severe voltage stability issues[13] at several nodes. New synchronous condensers were then modeled at these locations; they ensured the model initialized; however, the system was still unstable for several critical contingencies. Additionally, due to the large size of synchronous condensers located electrically very close to each other, low-frequency interactions were observed, and they created additional reliability issues[14].

For the purposes of RIIA analysis, the only workable solution found was addition of Voltage Source Converter (VSC) HVDC transmission lines (Figure OR-DS-7). Utilizing the older LCC HVDC technology in weak areas was found inadequate and indicated further system enhancements needed to keep the system stable (Figure OR-DS-8).

To port power from wind-rich zones located in weak-areas, building a VSC- HVDC line into those weak-areas may be more economical than incrementally installing a combination of AC transmission lines with many synchronous condensers.

The need for VSC HVDC technology to successfully solve a myriad of issues (reducing curtailment, ensuring power delivery, solving weak-area instability) demonstrates dynamic stability will become increasingly important for any large or small transmission expansion project in high renewable penetration scenarios, and the transmission design needs to be specifically vetted for dynamic performance. To port power from wind-rich zones located in weak-area, building a VSC-HVDC line into those weak-areas may be more economical than incrementally installing a combination of AC transmission lines with many synchronous condensers and mitigating the small signal stability issues created by installing the rotating masses of those synchronous condensers (Figure OR-DS-9). It also re-emphasizes the desire to develop new technology, such as grid-forming inverters and pilot projects, to demonstrate their effectiveness to bring down the cost of grid-integration of renewable resources.

Modern HVDC-VSC technology does not require filter banks. Modern HVDC systems can be tapped to form multi-terminal systems.

13 Severe voltage stability was denoted by solution infeasibility at certain nodes within acceptable iterations limits.

14 Similar results were reported by ERCOT in “Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT”, 2018 available online here.

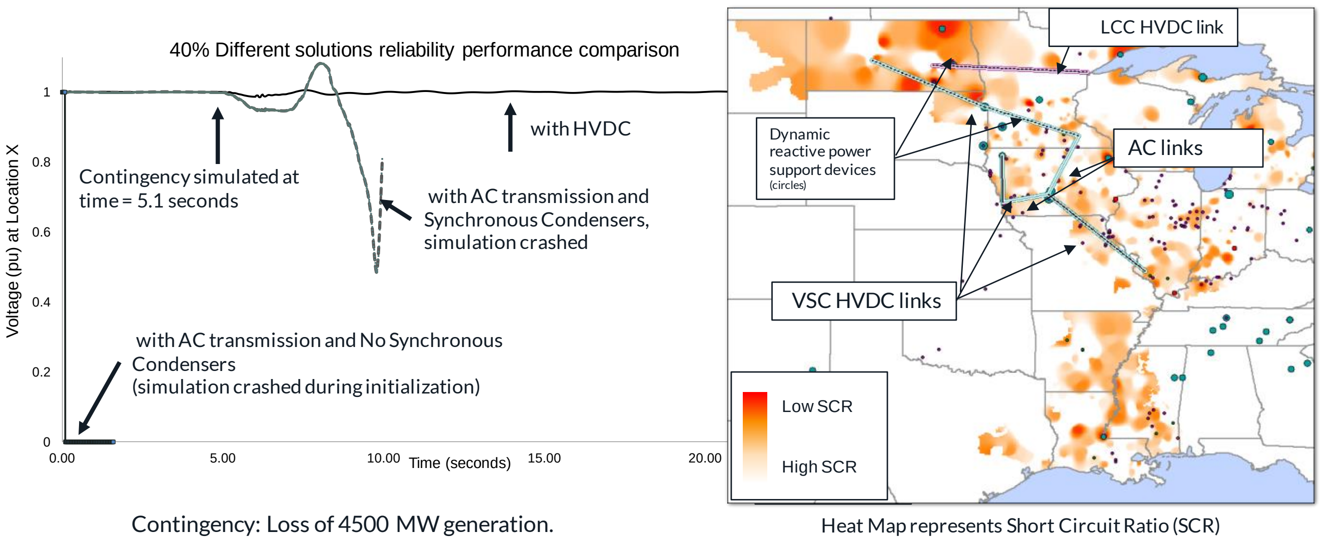


Figure OR-DS-7: Power delivery from low short circuit areas may need HVDC transmission technologies

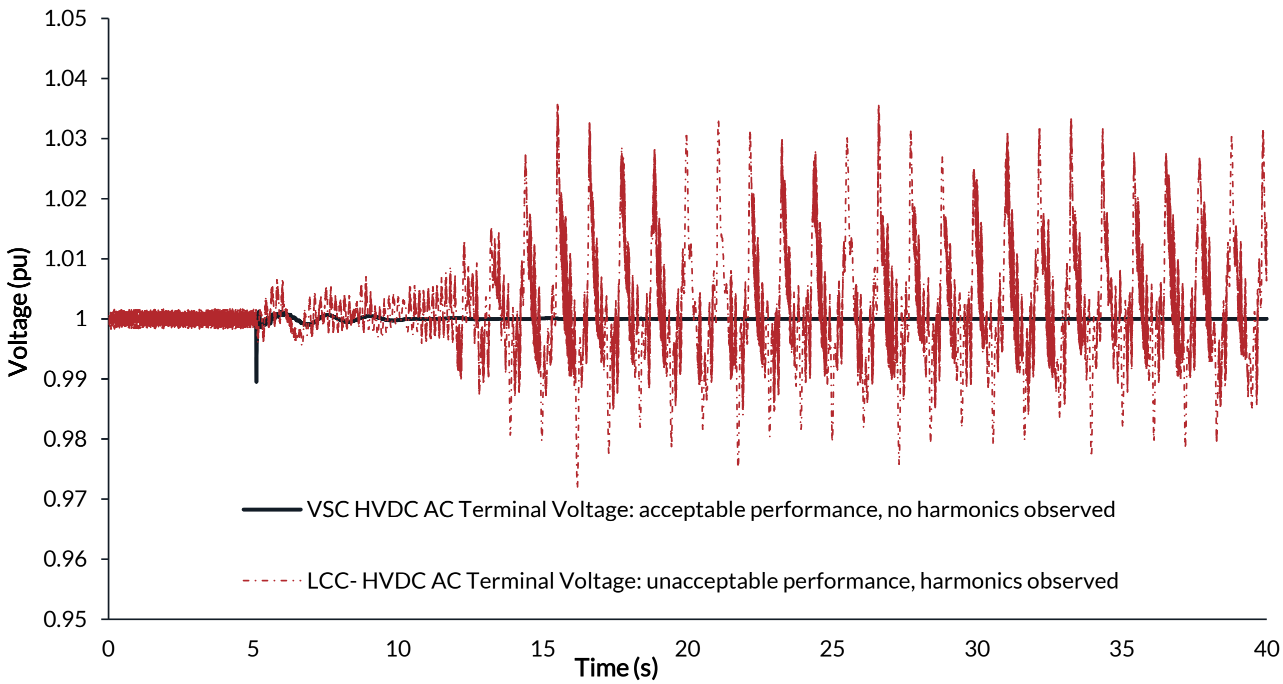
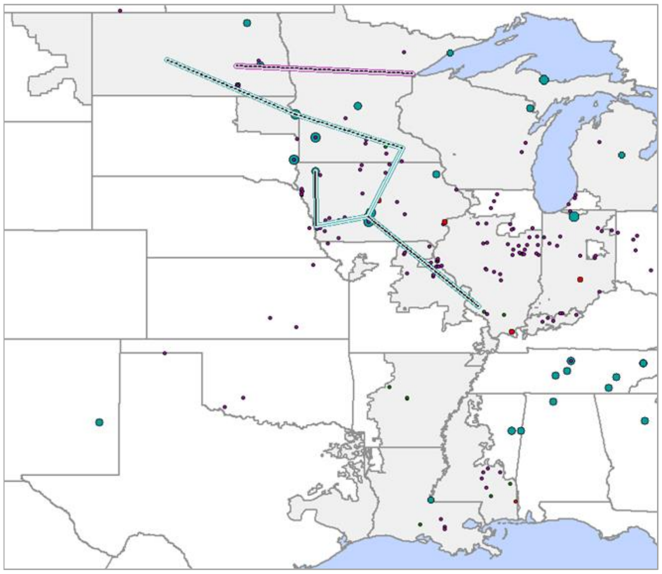
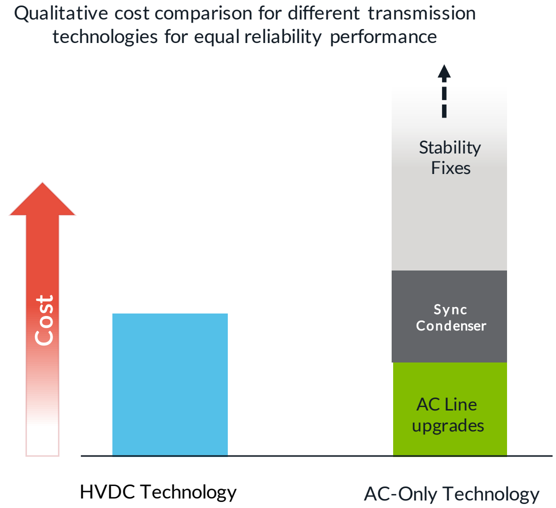


Figure OR-DS-8: LCC vs VSC terminal voltage comparison





To port power from wind-rich zones located in weak-area, building a VSC- HVDC line into those weak-areas may be more economical than incrementally installing a combination of AC transmission lines with many synchronous condensers and mitigating the small signal stability issues created by installing the rotating masses of those synchronous condensers

Figure OR-DS-9: A holistic approach is needed to develop solutions to solve the myriad of reliability issues

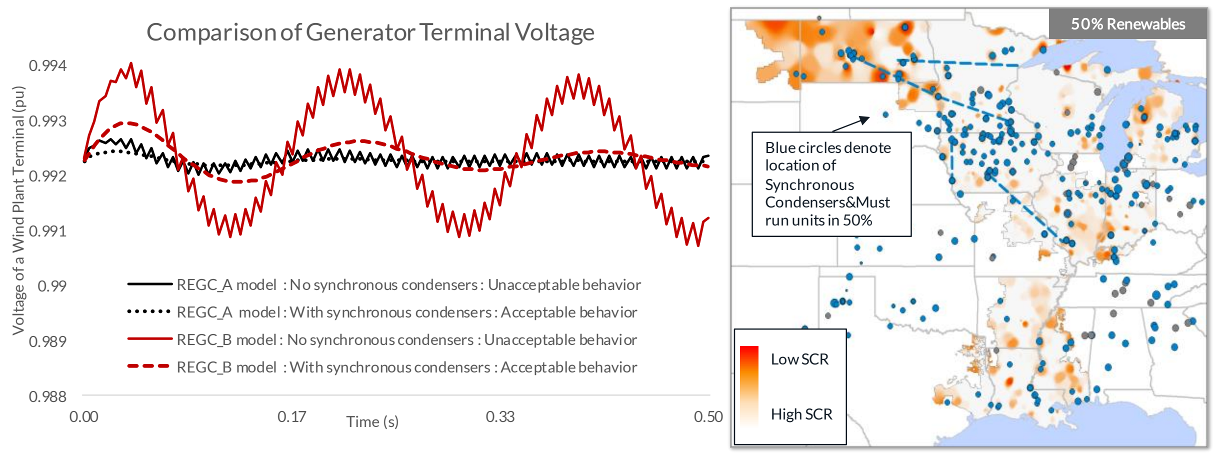
Finding: Weak-grid: Voltage stability remains the main driver of dynamic complexity at 50% and may require system-wide installation of synchronous condensers.

Installation of several synchronous condensers can provide a stabilizing impact on the voltage of the grid.

Energy adequacy simulations indicate that at the 50% milestone MISO could experience several hours of very high instantaneous renewable penetration where ~90% of load for that hour may be served by renewable generation, and very few conventional units will be online. Simulations indicate such conditions are precarious for the grid-following[15] technology, as it needs a strong grid (voltage source) to perform reliably. Installation of several synchronous condensers provides a stabilizing impact on the voltage of the grid, thus mitigating the chattering observed in the 50% milestone voltage waveform (saw-tooth type waveform observed in Figure OR-DS-10). However, to verify the need for several synchronous condensers across the footprint, a new model beta[16] model (regc_b) was also tested and gave the same results. The cost of renewable integration can be reduced if renewable manufacturers make inverter technology more grid friendly.

[15] RIIA utilized the industry-vetted WECC 2nd generation renewable model (regc_a), which is a current-source model representing commercially available inverters. However, as noted in the WECC documentation and papers, this model has its limitations, particularly the potential for numerical issues when used under very weak-grid conditions. Thus, some new models have been developed to address some of these issues, the so-called REGC_B model.

16 regc_b was under development by WECC when RIIA simulations were done.



Terminal voltage harmonics in absence of Synchronous Condensers indicates lack of system strength. To verify the need the for so many synchronous condensers a new model (REGC_B) was tested and gave the same results

Figure OR-DS-10: At 50% milestone system-wide installation of synchronous condensers may be required

Finding: Weak-grid stability: Summary of issues and solution

In summary, integration complexity to maintain reliability in weak areas rises sharply beyond the 20% milestone (Figure OR-DS-11), which creates a range of reliability issues. Short circuit ratio (SCR) decreases with an increase in inverter-based generation and reduction in fault current from conventional generation not being online. These dynamic instability issues can be solved by inverter-control-gain tuning, or by installing synchronous condensers, static var compensators (SVC), STATCOM, HVDC, or keeping more conventional generation online. Deployment of innovative new technologies such as properly tuned hybrid renewable resources, Type-5[17] wind, or grid-forming inverters can bring down the cost of additional transmission reinforcement required due to low SCR.

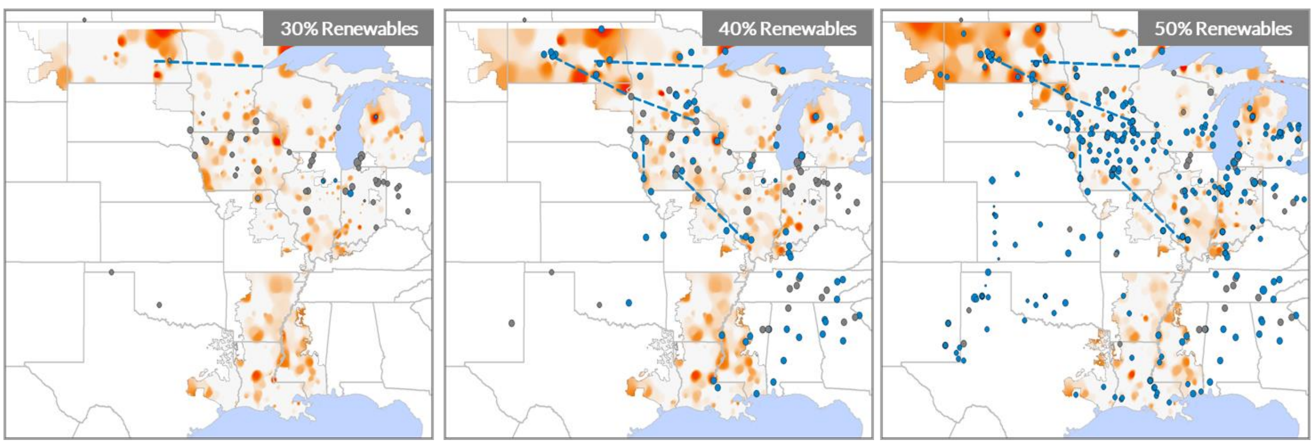


Figure OR-DS-11: Weak area instability is the main driver of dynamic complexity

[17] Type-5 wind technology concept has been around since as early as 2006, although it has not gained any significant commercial success. Other avenues are likely to be more successful (i.e. BESS, grid-forming inverter-based PV and Wind, and batteries etc.).

Finding: Frequency response is stable up to 40% renewable penetration*, but at 50%, planned headroom is required to remain above Under Frequency Load Shed (UFLS) threshold.

Inertial and primary frequency response remains one of the major concerns, as frequency response in the Eastern Interconnection has been relatively steady but just slightly above adequate levels for several years (IEEE, NERC 2017,2018), and performance of MISO's conventional resources during the primary frequency response period has been at adequate but not greatly above minimum compliant levels (refer to section -Operating Reliability — Dynamic Stability Focus Area). In addition, although renewable resources have the capability to provide frequency response and ramping, they cannot provide sustained response unless they maintain a certain amount of headroom by operating below their maximum possible power output. Thus, wind and solar resources need economic incentives or regulations adopted to "spill" energy to maintain headroom. Hence, the RIIA study assumes wind and solar will not preserve any headroom unless simulations identify the need.

Frequency response analysis was studied using dynamic models benchmarked with real-time measurements from MISO's phasor measurement units (PMU) (Figure TA-30), improved governor modeling[18] and considering non-responsive behavior of MISO's and EI's existing conventional units (Figure TA-31). Further details, such as types of contingencies, method to calculate primary frequency response, EI and MISO's BAL-003-1 obligations can be found in Technical Assumptions Summary — Operating Reliability — Dynamic Stability Focus Area.

...frequency response may be stable up to the 40% milestone; however, certain system conditions at the 50% milestone can be at risk of load disconnection.

RIIA finds that frequency response is stable up to 60% instantaneous renewable "system-wide" penetration but may require additional planned headroom beyond. As a rule of thumb, the highest instantaneous % of renewables in a given year can be near 2 times the annual renewable energy penetration level. The assessment indicates frequency response may be stable up to the 40% annual energy-wise renewable penetration milestone; however, certain hours at the 50% milestone can be at risk of load disconnection through automatic controlled action of Under Frequency Load Shedding (UFLS) protection schemes, which initiates if frequency dips below 59.5 Hz in the Eastern Interconnect. The rise in risk can be primarily attributed to the displacement of conventional resources (Figure OR-DS-13), which decreases the electric system's inertia and available online headroom. For example, at lower milestones (like 10%), the highest instantaneous penetration is around 24%; this increases to 89% at the 50% milestone[19]. The composition of the fuel mix of 50% snapshot-3 (Figure OR-DS-13) indicates the majority of the remaining 11% conventional units are comprised of nuclear units and a very small fraction of combined-cycle units. Nuclear units in the Eastern Interconnection are not assumed to provide primary frequency response, due to their normal operation being at maximum capacity, for efficiency. Gas-based units are also known for withdrawing their frequency response after a period of 30-35 seconds due to supplemental controls[20]. These conditions may lead to scenarios where the grid does not have sufficient primary frequency response to sustain tripping of a large generator or plant.

18 N.Mohan "Governor Modeling Improvement', MISO MUG meeting 2017, available online here.

[19] As a rule of thumb, the highest instantaneous % of renewables in a given year can be around 2 x annual renewable energy penetration level

[20] Several articles discuss the impact of "Outer-Loop Control" in Gas units. Refer to the following documents:

(1) NERC, "Primary Frequency Response – Natural Gas/Combined Cycle Webinar", November 13, 2018

(2) NERC, "Reliability Guideline Application Guide for Modeling Turbine Governor and Active Power-Frequency Controls in Interconnection-Wide Stability Studies", June 2019

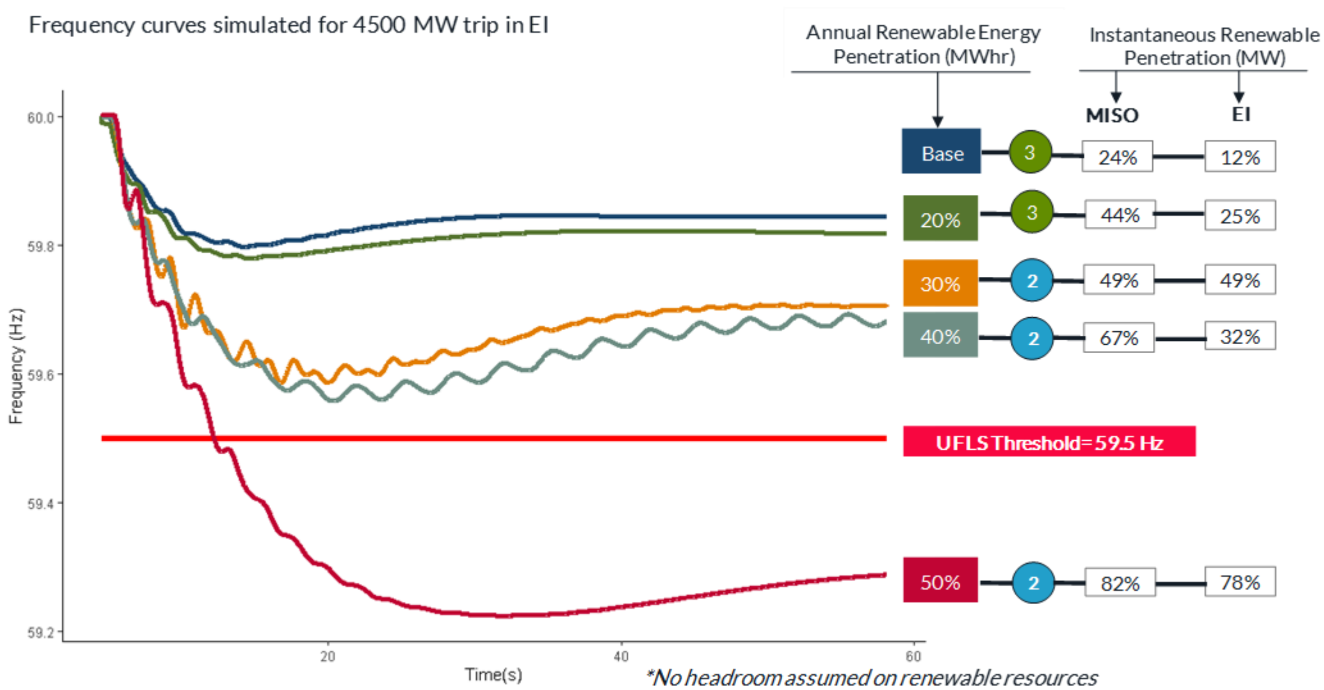


Figure OR-DS-12: Frequency response curves for all milestones in RIIA

Analysis indicates periods of low load with very high instantaneous penetration of renewables are most concerning, as described in the subsequent sections. To counteract frequency related risks, additional online headroom on resources (including wind and solar) can be procured in real-time grid processes to automatically respond without any operator intervention. Additionally, installation of fast response batteries can be also be done.

Finding: Periods of high renewable penetration during low load become important for frequency stability.

Frequency response analysis was conducted on various scenarios representing different system-wide load levels and instantaneous renewable penetration levels. These scenarios of high instantaneous renewable penetration can be divided into three main categories — (1) system wide near-peak load occurring in summer, (2) off-peak or low load conditions occurring in Spring, and (3) highest renewable output during low load hours occurring in the Fall months. The assessment shows the most concerning periods for frequency stability are scenarios 2 and 3, which can be explained by examining the composition of the types of generation (renewable versus conventional) at these scenarios and load levels (Figure OR-DS-13).

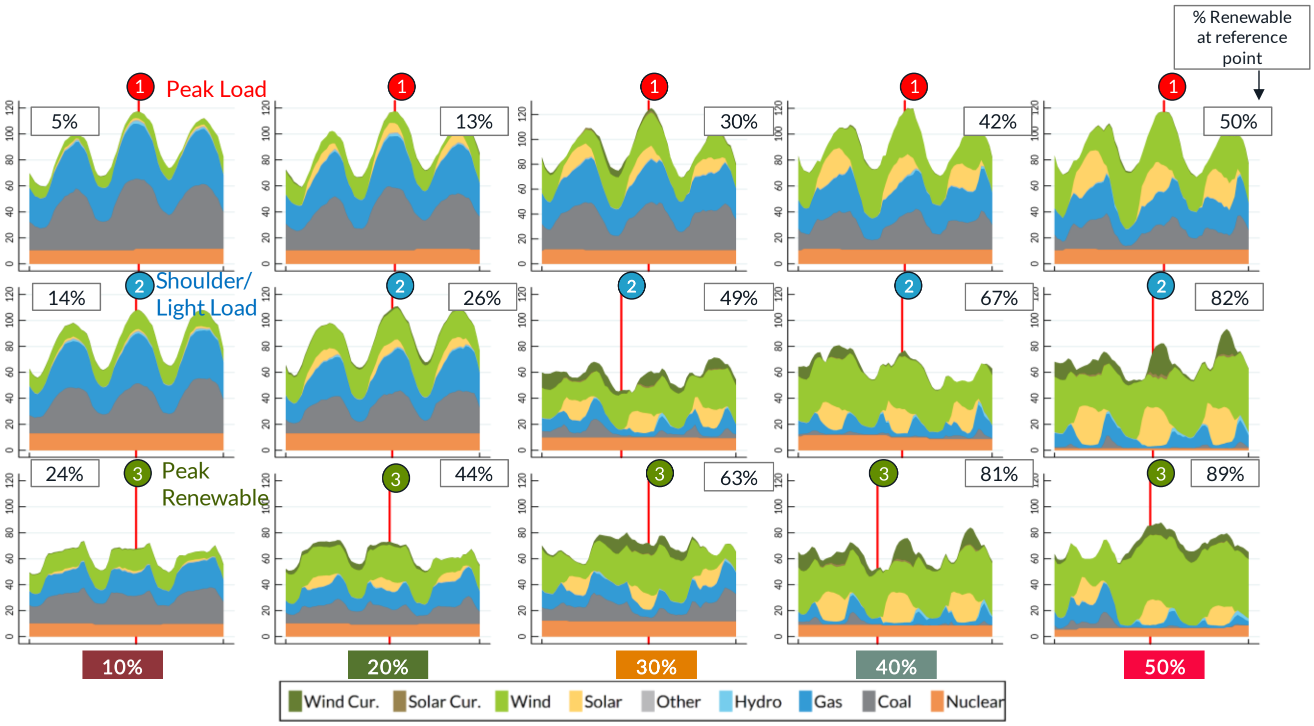


Figure OR-DS-13: Changing dispatch pattern and timing of stress on the transmission system

A combination of various factors such as: (a) very high instantaneous renewable penetration, (b) few conventional units, and (c) lower load result in frequency response diminishing rapidly.

Even at higher RIIA milestones, the summer scenarios are characterized by relatively low penetration of renewables (2%-36% in EI), and more conventional units being committed, and a substantially higher load (>~95% of peak load). These conditions help maintain sufficient inertia and online headroom on the grid. It is worth noting rotating loads also provide a stabilizing impact on frequency performance of the grid because those motor-loads (comprising a large share of the total electric grid) slow down after the sudden dip in the frequency post a generator trip, thus consuming reduced power and helping to support the grid. However, in scenarios 2 and 3, a combination of various factors such as (a) a very high amount of instantaneous renewable penetration, (b) low amount of conventional units and (c) lower amount of load result in conditions where frequency response diminishes rapidly, and load can be at the risk of automatic disconnection through the action of UFLS.

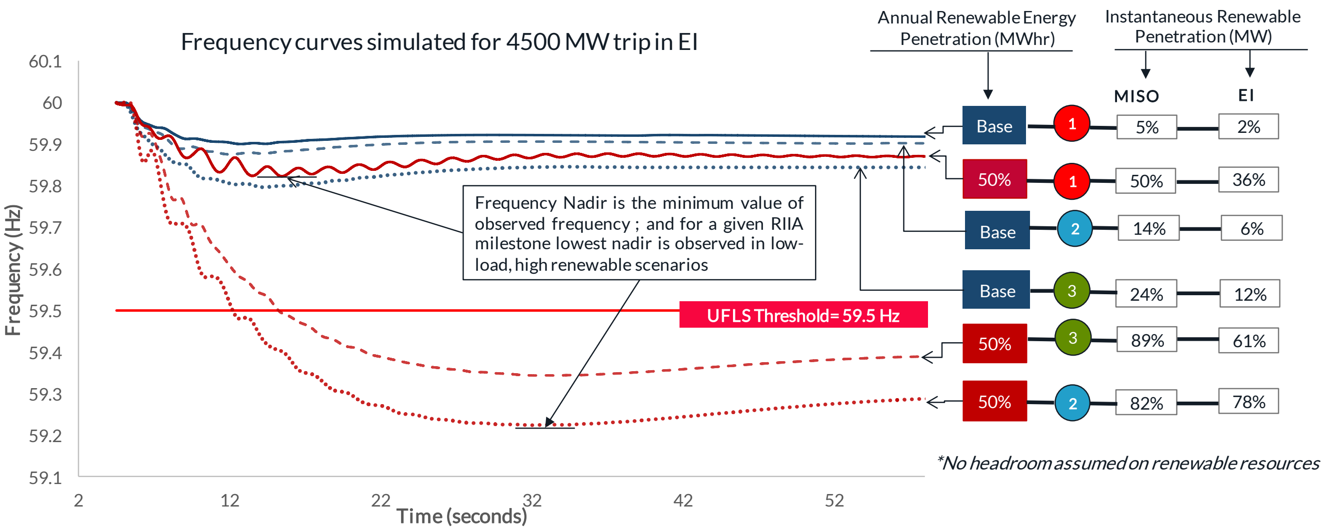


Figure OR-DS-14: Hours of high renewable penetration during low load become important for frequency stability

The trend of frequency nadir for all scenarios and simulated contingencies was plotted in Figure OR-DS-14. A significant finding revealed by assessment is the rapid reduction in system stability margin, particularly in the 50% milestone. For 50% scenario 2, it can be seen that following the loss of 2700 MW of generation (considerably lower than the largest simulated contingency of 4500 MW) frequency nadir is at the UFLS threshold of 59.5 Hz.

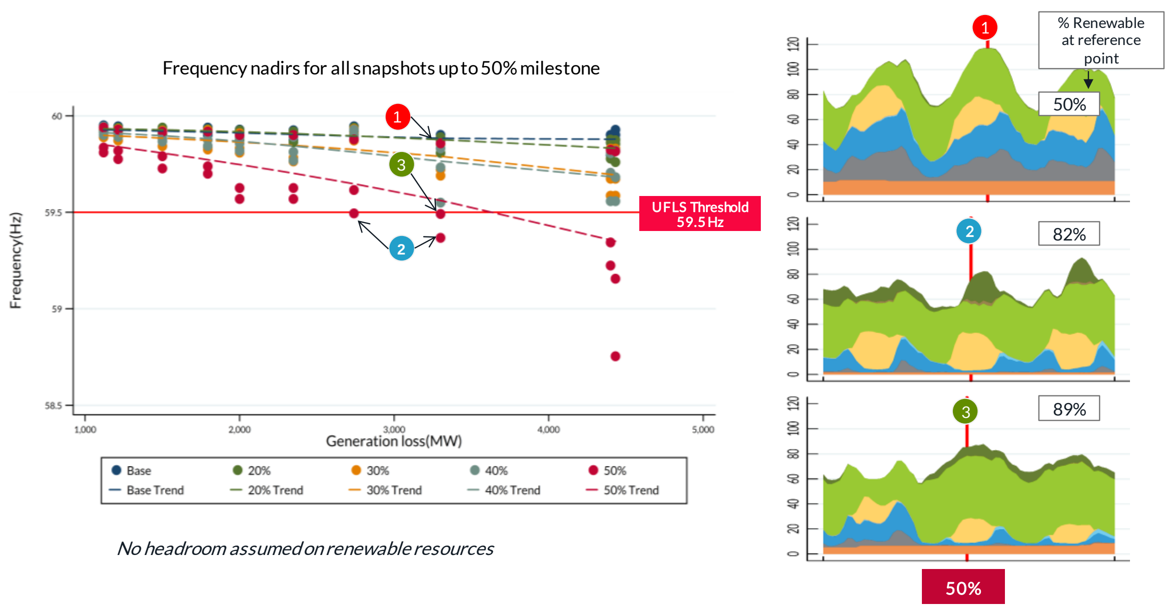


Figure OR-DS-15: Frequency nadir trend for all scenarios in RIIA

Finding: At higher renewable penetration, additional online headroom for primary frequency response may be needed to achieve NERC BAL-003 performance criteria.

NERC BAL-003-1 is the reliability standard requiring the grid operators to maintain primary frequency response, and it quantifies the performance of a synchronous interconnection (EI, WECC, Texas RE) by accounting for the amount of generation tripped and measuring average frequency deviation in the time period of 20-52 seconds following tripping of a large generator[21] (Figure TA-27, Figure TA-28). The standard also determines a minimum performance threshold for Eastern Interconnection and individual Balancing Authorities such as MISO, PJM etc. The assessment indicates the average performance of MISO is satisfactory up to the 30% milestone; however, starting at 40% there can be a few hours in a year where MISO's BAL-003-1 performance may be marginally above the threshold (Figure OR-DS-16) for a large generator trip, and, rather unsurprisingly, performance dips below the threshold several times at the 50% milestone. The root cause of the degradation of performance is similar to factors described above — displacement of conventional units, and reduction in inertia and online headroom.

Similar to the frequency nadir trend, the assessment indicates periods of low load with very high instantaneous penetration are most concerning. BAL-003-1 performance can be improved if additional planned online headroom is preserved on any resource, including renewables or storage.

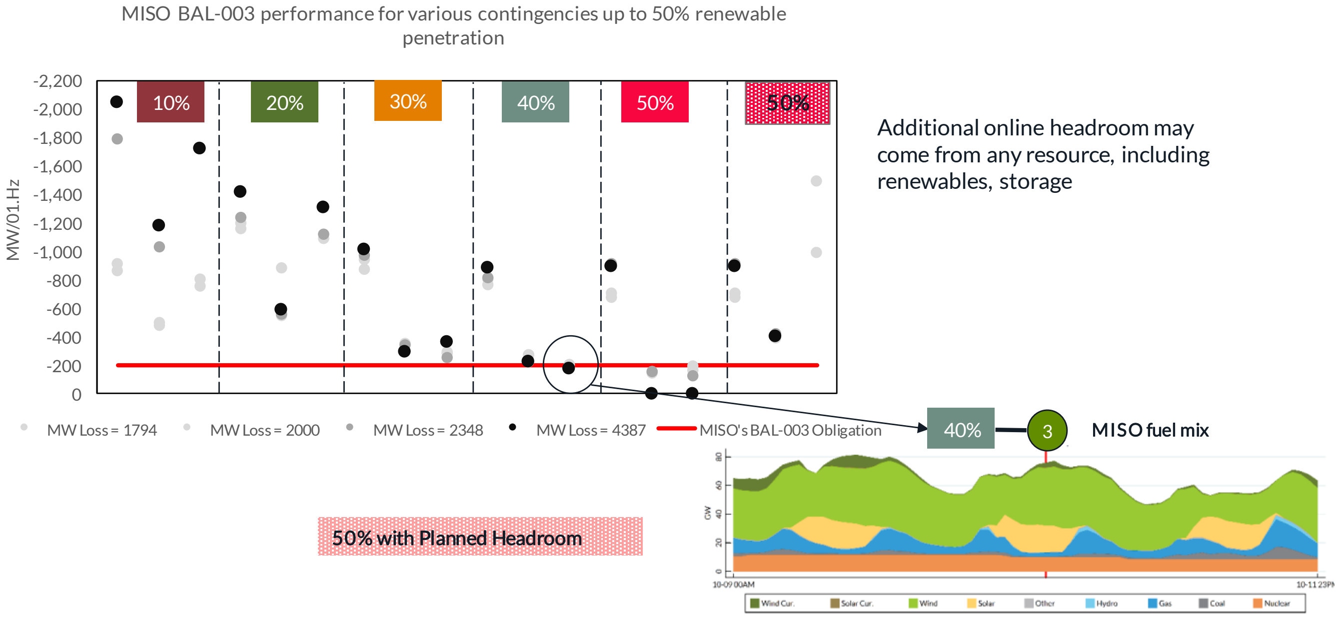


Figure OR-DS-16: MISO's projected trend per NERC BAL-003-1 requirement

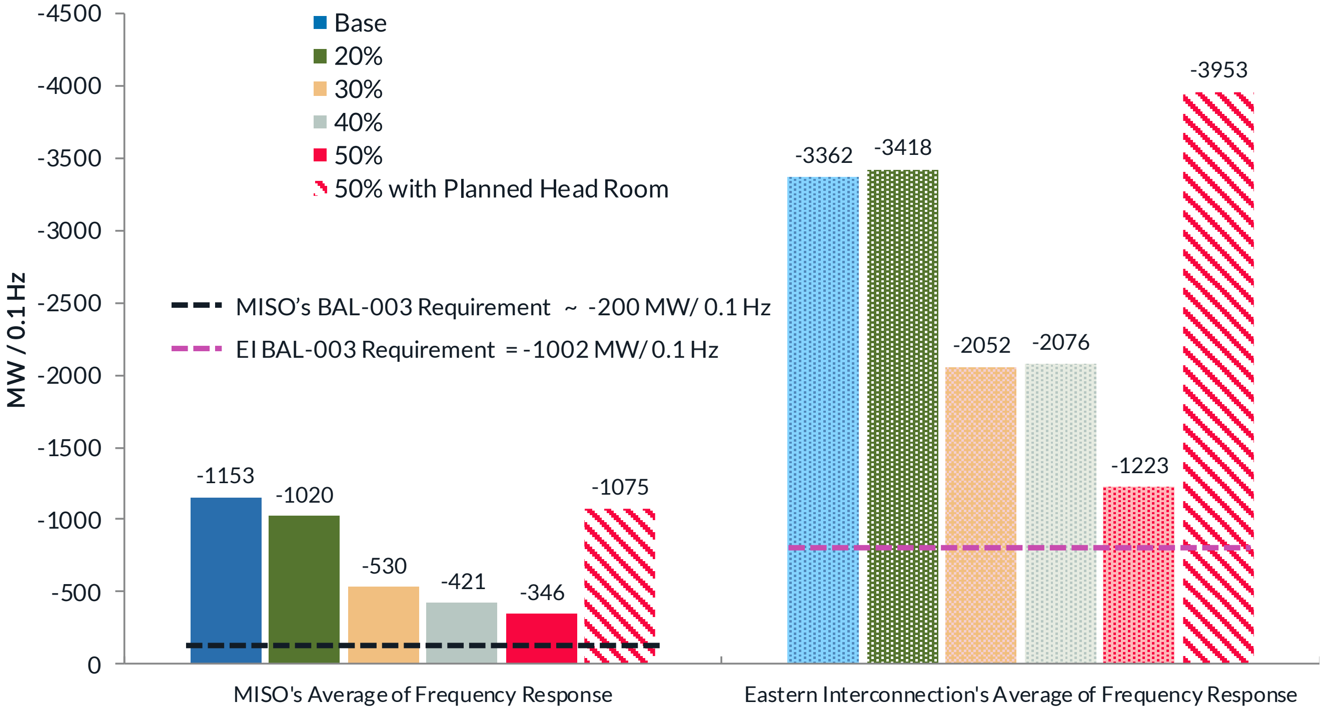
Finding: Average primary frequency response for MISO and the Eastern Interconnection remains satisfactory at 50%; however certain hours are at risk for UFLS.

It may not be prudent to continue with the present BAL-003 evaluation process; instead, the industry may need to transform it proactively as further degradation in frequency response is observed.

Currently, NERC evaluates the BAL-003-1 performance of the interconnection and Balancing Authorities by sampling data of several generator trip events from a year and averaging the calculated frequency response (FR) values for each event. The pass-fail criteria do not depend on any single event. The assessment indicates that the average performance of MISO and EI are satisfactory at all milestones studied in RIIA (Figure OR-DS-16); however, at the 50% milestone, there can be scenarios (as described on page 122) where load is at risk of automatic disconnection. While the current performance evaluation process may be suitable for the near future, the assessment points to a lacuna in the process stating averaging FR values may mask certain

[21] Refer to Technical Assumption section for details. The units of primary frequency performance metric are MW/0.1Hz (MW per 1/10 of a Hz)

hours where EI is at high risk of losing load. This is analogous to considering a student graduated even though the person failed the mid-term exam, but shined in the finals, versus a student who consistently performed well through all the tests and passes with flying colors. Being a reliable grid-operator is like being a student who needs to perform well in all the tests. This raises an important issue to the grid operators and auditors; it may not be prudent to continue with the present BAL-003 evaluation process; instead, the industry may need to transform it proactively if further degradation in frequency response is observed.



Negative sign in Primary Frequency Response value indicates under-frequency event. Average performance in absence of planned headroom remains high largely due to good performance in Peak Snapshot and smaller generator (MW) trip events.

Figure OR-DS-17: Eastern Interconnection and MISO's average BAL-003-1 performance

Finding: Analysis with conservative model parameters indicates a primary frequency response inflection point lies between 30% and 40% milestones.

While a considerable amount of effort was put into developing dynamic models to produce realistic frequency response behavior (Figure TA-30, Figure TA-31) the assessment acknowledges some optimism may still be present in the frequency response results, due to a modeling issue discovered mid-way during the course of the analysis (Figure TA-32). Last

Thus, the frequency response should be monitored, and future projections should be evaluated through improved modeling practices.

year NERC released a report[22] discussing some of these issues in detail. As part of RIIA, a study was conducted to evaluate the impact on the validity of the RIIA frequency response results, and it indicated the need for planned headroom may arise at earlier stages i.e. 30% annual penetration level to meet BAL-003-1 obligations. Thus, the frequency response should be monitored, and future projections should be evaluated through improved modeling practices. Figure OR-DS-18 presents the difference between the original model parameters and the results following the change in settings.

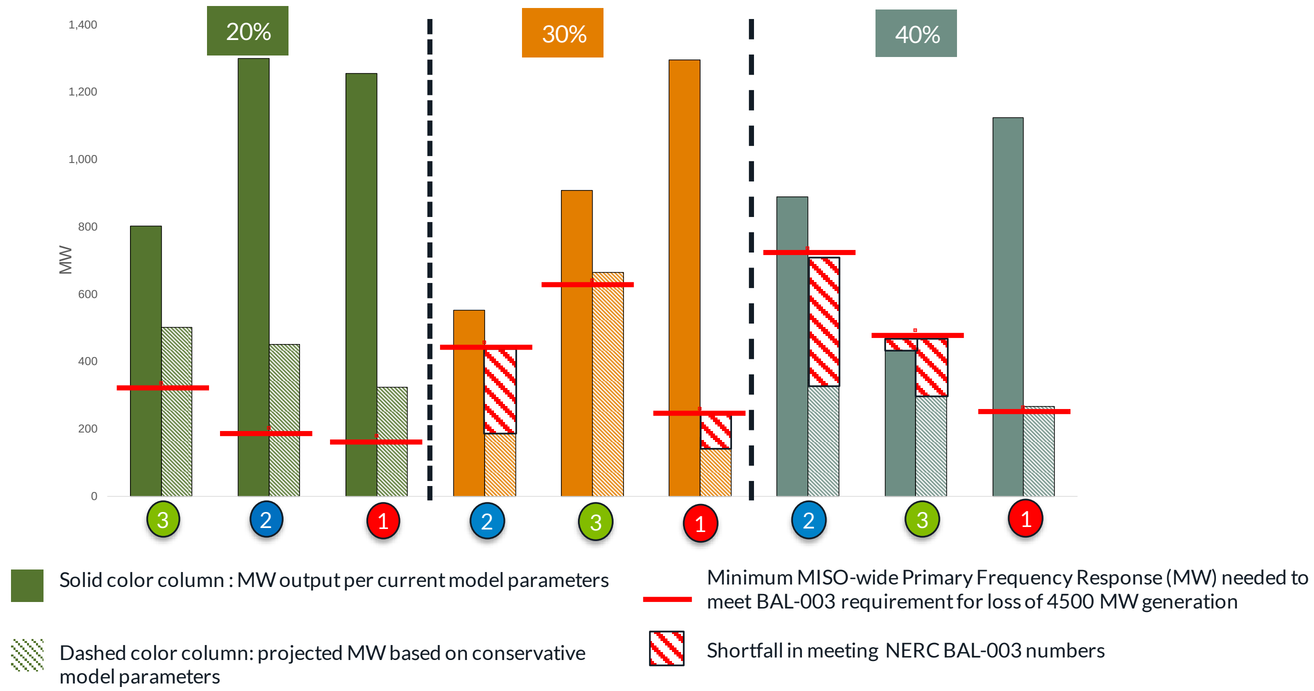


Figure OR-DS-18: Estimation of optimism in RIIA's BAL-003 analysis with conservative model parameters

Finding: Linear prediction models show system conditions will be in the caution zone 5% of the time for 30% penetration and increase to 73% in 50% penetration.

RIIA assesses the impact of renewable penetration on the frequency response of the grid by studying three snapshots at each milestone (total 15 scenarios). To gauge the impact on the frequency response throughout the year with changing fuel mix, a linear regression model was developed to predict the frequency nadir throughout the entire year. Inputs to this model were system load (MW), total conventional generation (MW), and total renewable generation (MW) obtained from production cost simulations for every hour of the year (8760). For the purposes of this analysis, the zone between the nominal frequency of 60 Hz to an empirical value of 59.7 Hz (denoted by the green line) is chosen as a low-risk zone, the zone between 59.7 Hz to the UFLS frequency threshold of 59.5 Hz is defined as the caution zone (zone between green and red color), and the zone below 59.5 Hz is automatic tiered load-shedding zone (denoted by red color, a zone of operation to avoid).

22 NERC Reliability Guideline: "Application Guide for Modeling Turbine-Governor and Active Power Frequency Controls in Stability Studies", June 2019

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline-Application_Guide_for_Turbine-Governor_Modeling.pdf

Analysis indicates that as the penetration increases, the number of hours of system conditions which are in the caution zone increase from 5% of the time in 30% milestone to 73% in the 50% milestone, and several hours are at the risk of automatic disconnection due to UFLS in 50% (Figure OR-DS-19).

Analysis indicates as the penetration increases, the number of hours of system conditions in the caution zone increase from 5% of the time in the 30% milestone to 73% in the 50% milestone, and several hours are at the risk of automatic disconnection due to UFLS in the 50% milestone.

A similar exercise was done for MISO's BAL-003-1 performance; however, results are less concerning partly due to the reasons discussed on page 126 (averaging the performance may be leading to underestimating the issue).

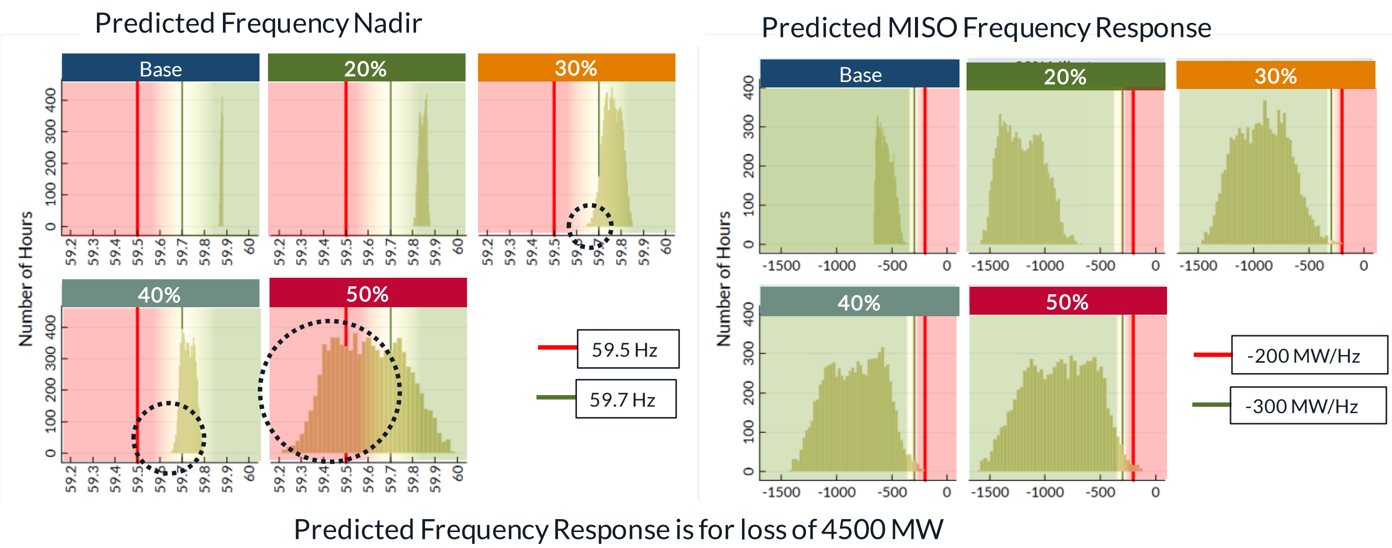


Figure OR-DS-19: Output of linear prediction model output to estimate frequency performance for 8760 hours of system conditions will be

Finding: Frequency response is stable up to 60% instantaneous renewable penetration but may require additional planned headroom beyond.

RIIA discusses the impact on the frequency response in terms of annual renewable energy penetration (10%, 20%, 50%, etc.). Rather, instantaneous renewable penetration is a superior metric to annual energy, as the frequency of the grid is maintained on a real-time basis for every second, every minute, and grid operators and planners are more concerned about real-time wind and solar output. Thus a few natural questions arise as follow.

(1) Since assessment denotes 50% annual renewable penetration is concerning, could there be periods in 40% or 30% milestone where frequency response may have been inadequate?
(2) Is there a way a better metric could be developed to track frequency nadir trend?

A study was conducted to draw a relationship between instantaneous renewable penetration and frequency response by utilizing the linear regression model described on page 128. The plot of frequency nadir against all possible ranges of instantaneous renewable penetration within each RIIA milestone is shown in Figure OR-DS-20.

For example, the instantaneous renewable penetration at the 30% milestone ranges from as low as ~10% to as high as 60% in MISO. The corresponding range of frequency nadir based on system conditions range from 59.8 Hz to 59.6 Hz, which is also the first time the predicted frequency nadir trend enters into the caution zone.

Thus, analysis provides long-term situational awareness to grid-operators and planners that starting at the 30% milestone they would need to:

- Prepare for the operations of the future
- Modify infrastructure
- Update processes to maintain stable frequency response

Frequency can be stable up to 60% instantaneous system-wide penetration and may need additional planned headroom beyond that 60% value.

Another important finding this analysis points to is the rate at which frequency nadir trend declines due to increasing renewable energy penetration; for a 30% energy penetration system, 60% instantaneous scenarios look quite different from the 60% instantaneous scenarios in a 50% energy-wise system. The former scenario (60% in 30% milestone) indicates minimum predicted frequency nadir dropping to 59.6Hz, thus entering in the "caution-zone". In the latter scenario (60% instantaneous in 50% milestone), the minimum predicted frequency nadir slides to "automatic-load-shedding-zone" and at a much higher speed, denoted by a higher slope of the line.

These results can be explained by examining the dispatch pattern at the two milestones. In the 30% renewable energy penetration system, at 60% instantaneous renewable penetration, the RIIA study indicates some coal, gas, and nuclear units are still committed (Figure OR-DS-13). However, in 50% energy system, during 60% instantaneous penetration, the majority of the thermal units have been displaced or retired, and only a few nuclear units and combined-cycle units are expected to be committed. Thus the overall system inertia-wise becomes "very light," which leads to faster degradation of frequency nadir performance.

Lastly, given all the analyses performed, parameters considered, and some remaining optimism in modeling, RIIA concludes instantaneous renewable penetration should be used to monitor frequency response, and further arrives at the conclusion that frequency can be stable up to 60% instantaneous system-wide penetration, but may need additional planned headroom beyond that 60% value. However, electric storage can change the conclusion about the "60%" number given that it was not considered in the simulations for the above results. The application of electric storage can significantly improve and preserve the frequency response trend (both primary and nadir) and is discussed in the following sections.

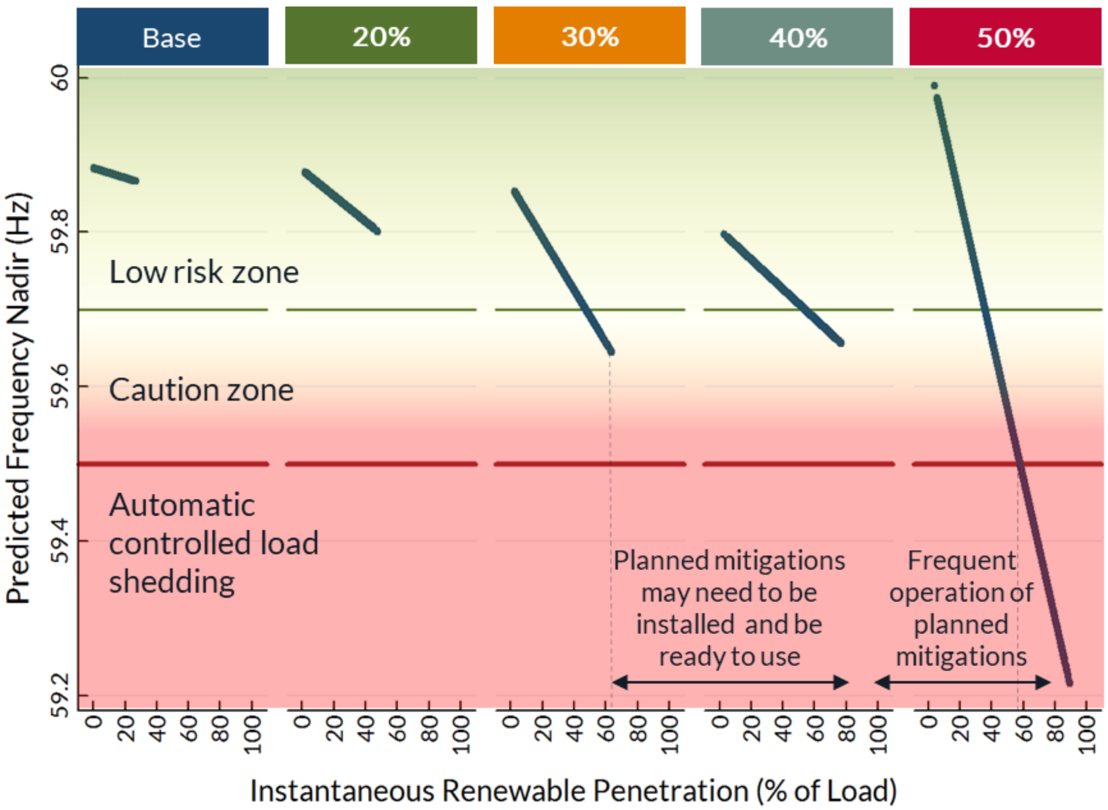


Figure OR-DS-20: Predicted frequency nadir across all RIIA milestone for 8760 hours of different system dispatch

Finding: Online available curtailment may be utilized to mitigate frequency response issues at certain hours but…

Battery storage may be needed to ensure sustained frequency response at very high instantaneous penetrations.

RIIA explores several techniques to resolve frequency response issues. Energy adequacy simulations indicate curtailment could be used for congestion management, particularly at higher milestones (Figure EA-1). Wind and solar resources can provide primary frequency response, even if they are curtailed due to congestion. Snapshot 2, Figure OR-DS-13, from the 50% milestone indicated approximately 80 GW of wind and solar may be curtailed (Figure OR-DS-21) in the Eastern Interconnect.

The production cost simulations indicated some of the wind farms can be curtailed down to zero MW output[23]. A wind farm owner informed the RIIA team that if a dispatch signal from an RTO or ISO is sent to the wind farm to operate near 0 MW, then roughly 15% of the turbines remain online and produce ~0 MW, and the remaining 85% of the turbines may be shut off. However, for primary frequency response, generation resources are needed on a "hot-stand-by", meaning they should be online and ready to inject power automatically. Considering all these factors, a conservative assumption was made that out of the 80 GW curtailment, only 30 GW of headroom could be utilized for frequency response.

[23] These results were validated against historical data which indicated that some wind farms in MISO were also curtailed down to near zero output to manage short periods of congestion, particularly during periods of very high system-wide wind output.

Results indicate frequency response is stable (Figure OR-DS-21) if renewables carry 30 GW of headroom for the 50% milestone; less may be needed for milestones less than 50%. To pragmatically implement curtailment as a solution to provide support during frequency response, RTOs and ISOs need to develop tools to obtain visibility on the amount of curtailed renewables (particularly wind) available online in the system.

However, the scenario-3 from the 50% milestone simulation indicates that banking on online curtailment only is insufficient to remedy frequency response issues at other hours. More on this follows.

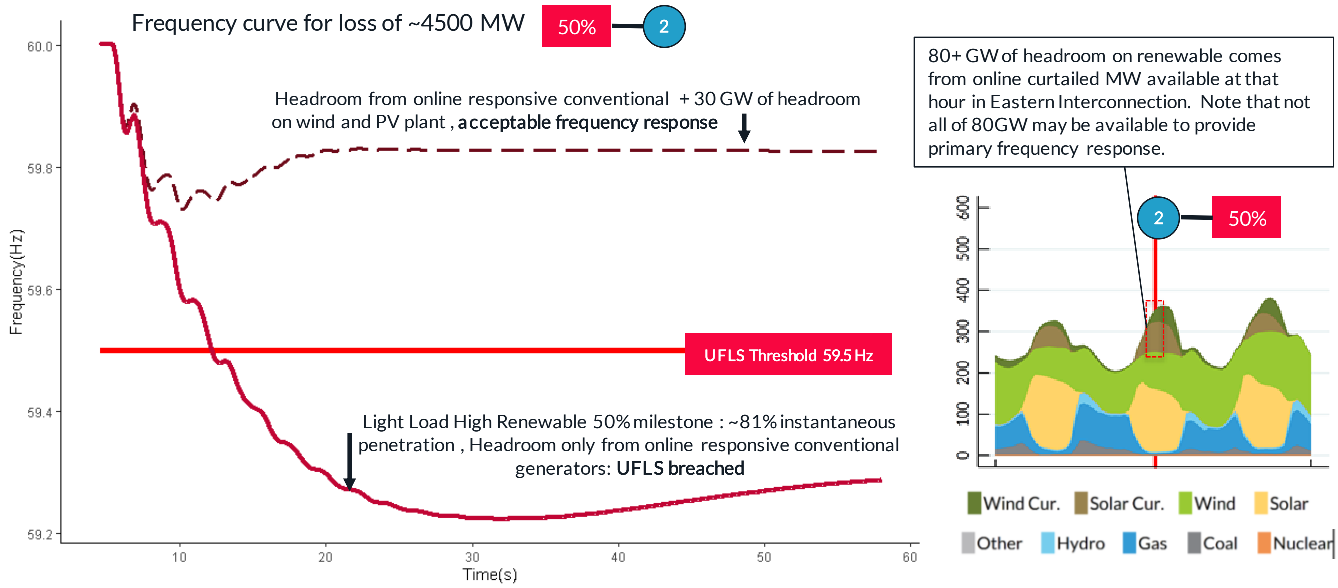


Figure OR-DS-21: Headroom from curtailed renewables can be used to provide frequency response

Finding: Battery storage may be needed to ensure sustained frequency response at very high instantaneous penetrations

The simulation of both scenarios 2 and 3 at the 50% milestone indicates potential frequency stability issues following the simultaneous tripping of 4500 MW generation. Similar to the approach described in the previous page, the curtailed renewable resources were assumed to be frequency responsive, with a difference that all of the 14 GW of headroom on renewable units is assumed to be available for frequency support (which is a very optimistic assumption). The simulations unearth some very interesting complications. Initially, the frequency response of the red dash-dot curve seems to be recovering after tripping the 4500 MW of generation; however, during the period of 30-35 seconds following the trip, frequency declines and slides back to settle near the UFLS level. This kind of performance is unacceptable, as it does not demonstrate a “sustained” frequency response in the defined 20-52 second window. Upon investigation, it was found the decay can be attributed to two major factors -- (a) the majority of conventional units are gas-fueled, and these units withdraw their response either due to hitting equipment limits, or due to outer-loop controls described on page 129, and (b) the real-power output of some renewable units in weak areas starts to decline as the voltage gradually decreases to a value lower than ~0.8 pu following the generation loss causing low voltages -- renewable units hit limits of their maximum current injection into the grid as they struggle to stabilize voltage and frequency simultaneously.

To remedy these complications, 6 GW of batteries in EI (600 MW in MISO) were modeled, and subsequent frequency response was found to be stable (maroon dashed line on Figure OR-DS-22). The application of batteries drastically improves the frequency nadir, as batteries inject power at a very high rate into the grid with almost no delay, given they have control systems to support this.

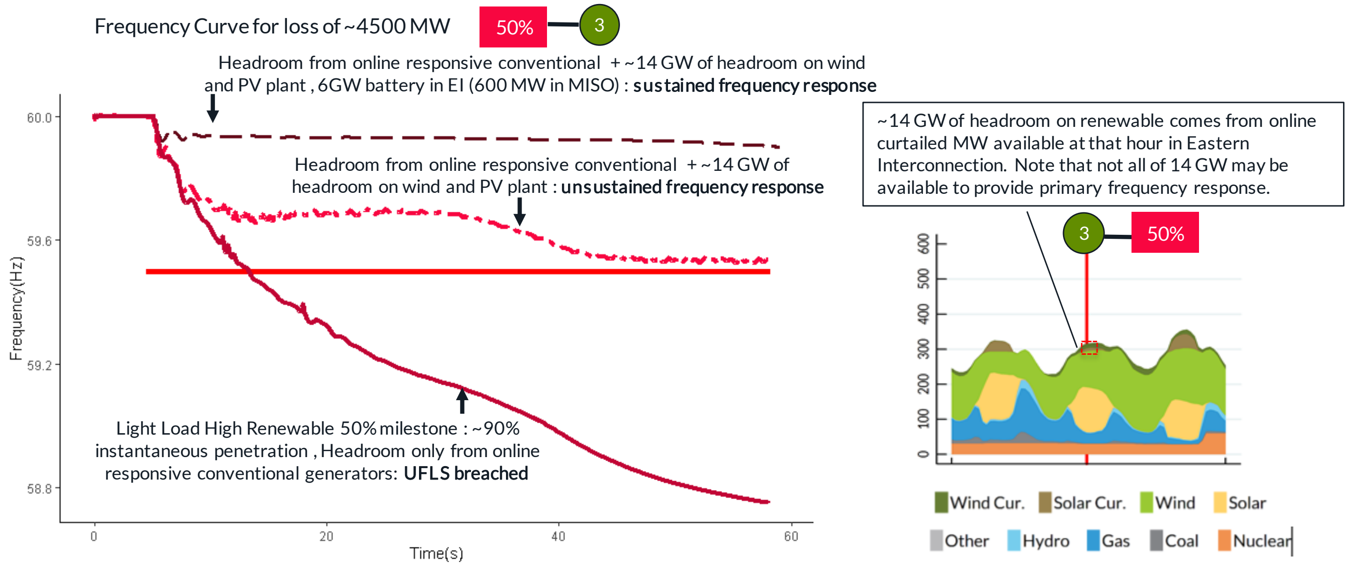


Figure OR-DS-22: Batteries storage can provide frequency response during system conditions of low curtailment

Finding: Large scale stability issues may occur due to displacement of units with power system stabilizers operating

Of all the challenging phenomena and issues discovered in RIIA, perhaps the most interesting and somewhat surprising finding was the observance of small-signal inter-area oscillations at 30% milestone, particularly for one contingency in one snapshot only (Figure OR-DS-23). Small-signal inter-area issues are low frequency (~0.1 Hz to 0.8 Hz) oscillatory behavior of several interconnected generating machines (dynamic devices). Any given frequency of oscillation is called a "mode". There can be several "modes" in an electric system. A well damped mode (damping ratio ≥ 5%) does not create any reliability issues. Historically, small-signal stability has been a major concern in the western part of the United States (WECC) and has been extensively studied. On the other side, EI is also known to have certain modes that can initiate large-scale issues impacting the whole interconnection due to small-signal instability; however, these modes are generally well-damped and are not problematic. When inter-area small-signal stability issues show up in real-time, they are difficult to mitigate, as wide-area coordination between different grid-operators is needed. The non-availability of any real-time tool to pinpoint to the root cause adds to the complexity. The NERC report[24] pointed out the challenges faced to mitigate inter-area stability in EI in 2019.

The report states: *"RCs [Reliability coordinators] were aware of the oscillation event relatively quickly by using both SCADA data and advanced applications and PMU measurements. RCs sought coordination activities, including use of the RC hotline; however, the RC hotline was inoperable due to technical issues. RCs were forced to call neighboring RCs individually that led to misinformation and mischaracterization of the event initially. Wide-area operator action did not contribute to mitigating the oscillation event, and most tools were ineffective at identifying a source location for the oscillation".*

[24] The most recent small-signal inter-area stability issue occurred in EI in Jan 2019 where a generator in Florida initiated a 0.25 Hz (mode) oscillation across the EI. Refer NERC, "Eastern Interconnection Oscillation Disturbance January 11, 2019 Forced Oscillation Event", released December 2019, available online here.

To remedy small-signal inter-area issues, numerous conventional units are equipped with a supplemental control system called power system stabilizer (PSS), that counteract the inter-area oscillations. The impact of inter-area small-signal stability issue is on a large-scale i.e. interconnection-wide. For example, the 30% milestone shows MISO may observe 700 MW peak-to peak oscillations on its tie-lines due to this phenomenon(Figure OR-DS-23). The assessment indicates the problem progressively worsens at the 40% milestone as three more "modes" enter the poorly-damped region and became severe at 50% to the point that dynamic stability models would exhibit undamped oscillations for a no-disturbance test (Figure OR-DS-24). The root cause of inter-area oscillations observed is the displacement of thermal units with PSS installed due to the dispatch of renewables. To verify this hypothesis, the RIIA study was performed on unmitigated models using SSAT[25] on all the 15 snapshots. The study indicated that, starting at the 30% milestone, certain modes may have damping less than 5%, which can lead to interconnection-wide issues. The study also indicated that renewables did not contribute to this issue; however, certain Synchronous Condensers, added as mitigation, participated in the oscillations, thus making matters worse.

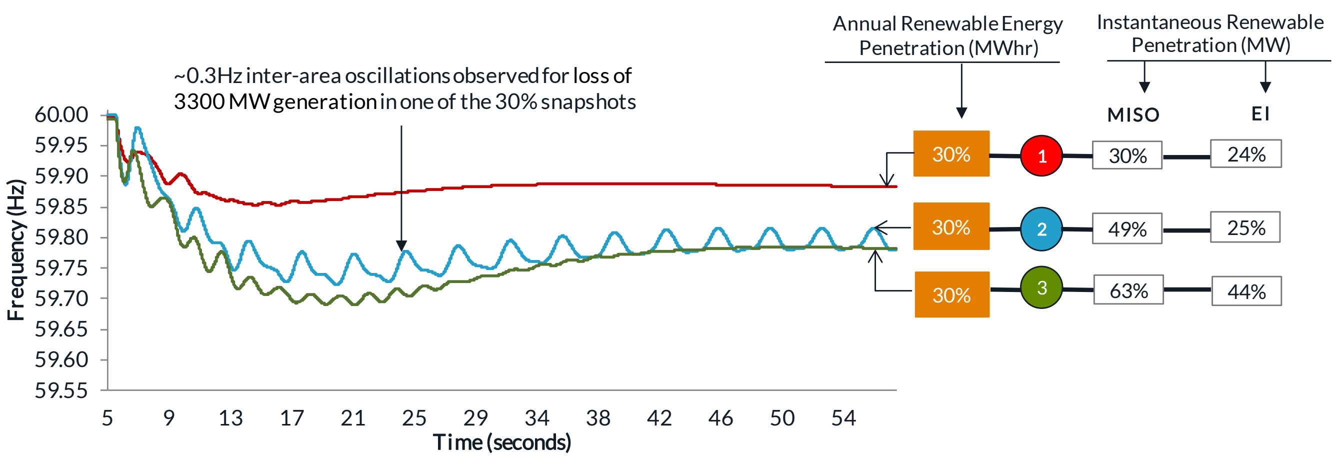


Figure OR-DS-23: Inter-area small signal stability issues observed in low-load high renewable in 30% milestone

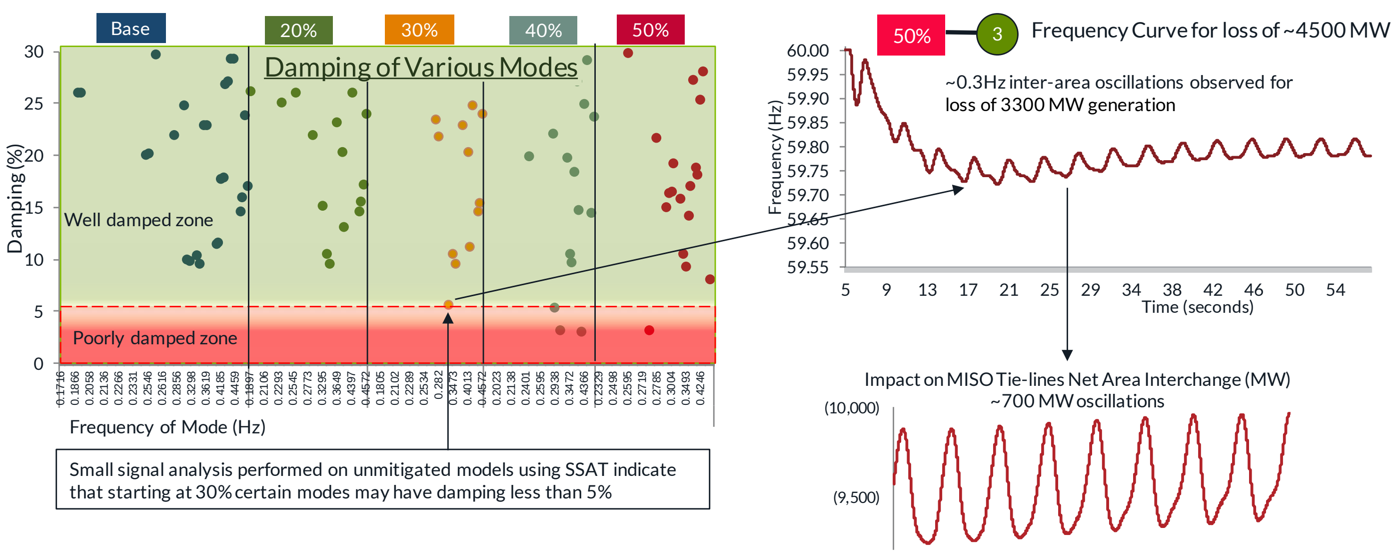


Figure OR-DS-24: Trend of damping of inter-area small-signal stability modes for all RIIA milestones

[25] SSAT is a tool produced by PowerTech Labs which helps determine the root cause of small-signal inter-area instability, modes, and units contributing to the issue.

Finding: Various techniques can be utilized to mitigate frequency and small-signal stability issues simultaneously

There are various methods to mitigate small-signal stability issues. The first method can be to study the network conditions and ensure the units with PSS installed are committed in real-time operations. For example, the analysis indicated to mitigate instability due to small-signal issues at the 50% milestone (maroon color line with 1600 PSS ON in Figure OR-DS-23), turning on at their minimum output 100 additional thermal units with PSS installed, combined with 14 GW of headroom on renewable was sufficient to completely address both frequency response and small-signal stability issues (light green color line in Figure OR-DS-23) . However, such a study and practice would involve a close coordination among all grid-operators in EI.

The assumption that grid-operators may be able to turn on the units with PSS has some practical limitations -- some of the units could be unavailable due to maintenance, or even could have retired. An alternative is to install specially tuned batteries across the entire EI. The study indicates that 7.2 GW of battery with small-deadband (±10 mHz compared to ±36 mHz traditionally used in EI) and high droop (126 compared to 20 traditionally used in EI) can provide a sustained frequency response (blue color line in Figure OR-DS-25) and damp-out small-signal oscillations. Such storage devices can operate automatically, thus minimizing the challenges stated above.

When small-signal inter-area stability issue appear in real-time, they are difficult to mitigate, as wide-area coordination between different grid-operators is needed. The non-availability of any real-time tool to pinpoint the root cause adds to the complexity. Per the NERC report pointing out the challenges faced to mitigate inter-area stability in EI in 2019 - "RCs [Reliability coordinators] were aware of the oscillation event relatively quickly by using both SCADA data and advanced applications and PMU measurements. RCs sought coordination activities, including use of the RC hotline; however, the RC hotline was inoperable due to technical issues. RCs were forced to call neighboring RCs individually leading to misinformation and mischaracterization of the event initially. Wide-area operator action did not contribute to mitigating the oscillation event, and most tools were ineffective at identifying a source location for the oscillation".

In summary, RIIA concludes the following regarding small-signal inter-area oscillations:

- Small signal stability issues may arise at higher renewable penetration levels
  - Renewable generation displaces conventional generators and creates different dispatch patterns.
  - Conventional units installed with Power System Stabilizers (PSS) may not be committed or could retire, which decreases the damping effect.
  - Must run operations of units with PSS may be needed or new PSS may be installed to increase damping.
- Currently, renewable resources are not known to have the capability to arrest inter-area oscillations in the range of 0.1-0.8 Hz, and it is uncommon to install PSS on Synchronous Condensers. Through detailed analysis, strategic locations can be identified where installing appropriately tuned and designed supplemental power oscillation damping (POD) controller on renewable resources, batteries, SVC, STATCOMs, or HVDC can help to improve small signal stability. Hence, RIIA makes a recommendation to

the renewable resource owners (including electric storage) and dynamic device manufacturers to facilitate addition of POD controller to mitigate such issues in the future.

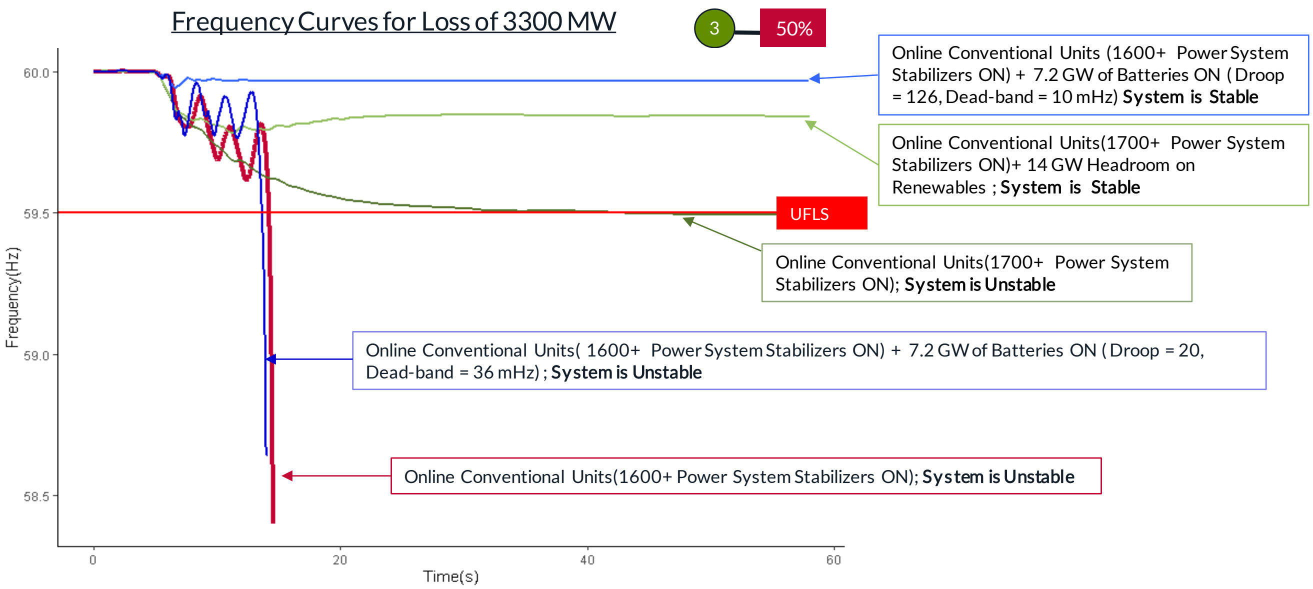


Figure OR-DS-25: Different techniques used to mitigate inter-area small signal stability issue

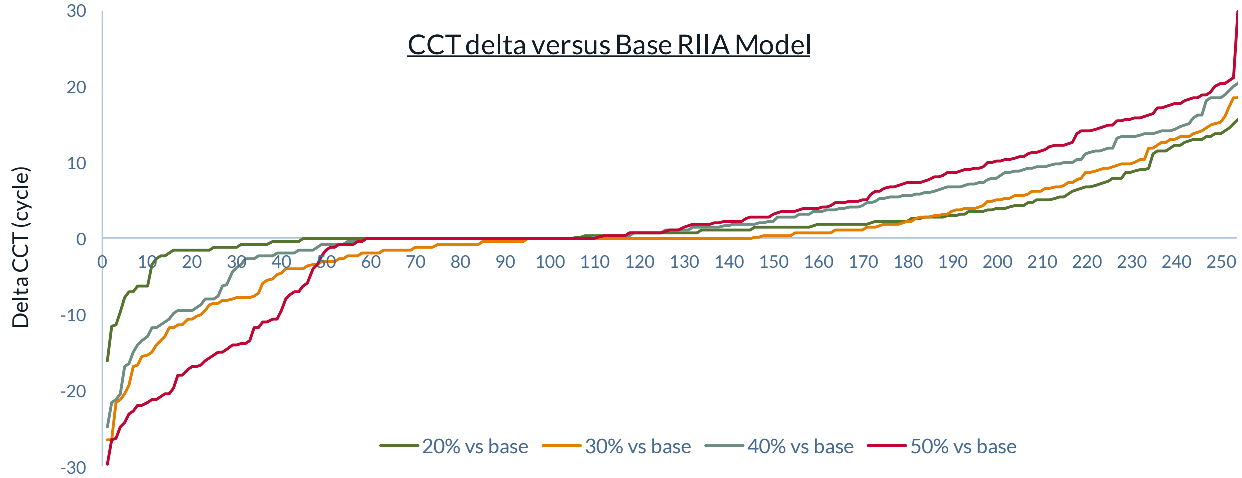
Finding: Overall, CCT increases as renewable penetration increases but may decrease at certain locations at very high instantaneous penetration

To evaluate the impact of renewable penetration on the rotor angle stability of conventional rotating machines (thermal and hydro) a study was performed to calculate the safety margins by calculating critical clearing time (CCT) at each milestone. The study utilizes the same snapshots, and tools used for frequency response analysis. The study utilizes the same snapshots and tools used for frequency response analysis. A sub-group of contingencies (270) utilized in MTEP[26] planning process was used to evaluate CCT. Thus, utilizing 3 snapshots at each milestone, minimum CCT for each of 270 contingencies valid in the RIIA models was calculated, and difference from the minimum base CCT was calculated. The trend (Figure OR-DS-26) indicates that overall, CCT increases as renewable penetration increases; however, certain geographical locations witness a decrease in CCT at the 50% milestone[27](Figure OR-DS-27). The following section discusses one of the reasons contributing to the increase in the CCT.

Significant decrease in CCT can cause problems in protecting circuits following disturbances, as the relaying and breaker-opening times may be greater than the CCT needed to keep the system from becoming unstable and causing widespread loss of load.

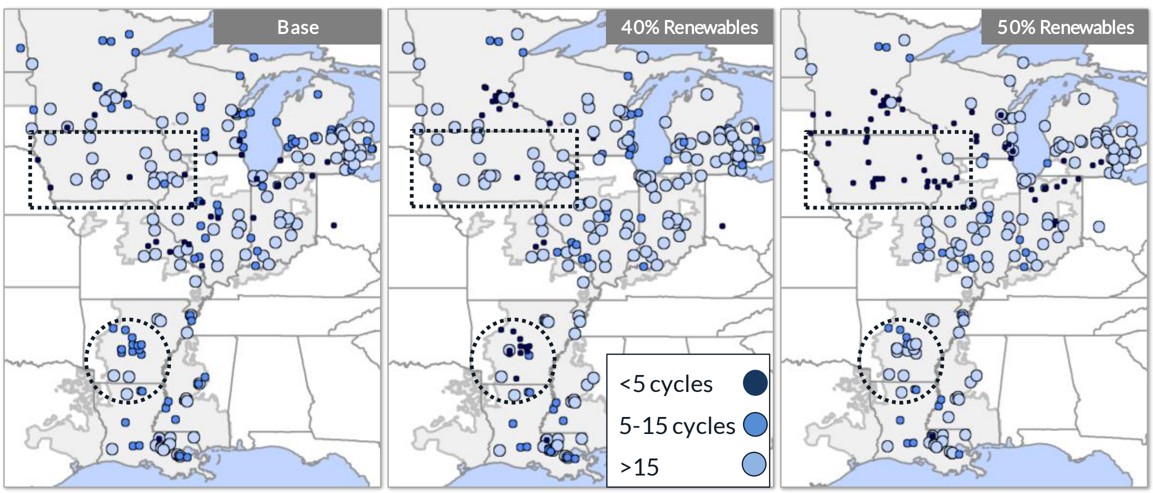
[26] Refer to MISO, "Determining Material Changes in Stability Between Planning Scenarios", available online here.

[27] A study performed by EirGrid and System Operator of North Ireland found a similar impact on CCT due to increase penetration of wind. Refer to "Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment", available online here.



- Graphs represent the delta in CCT between Base and 20%, 30%, 40% scenarios
- Total of 270 disturbances were simulated

Figure OR-DS-26: Trend of CCT for all RIIA milestone



CCT-specific mitigations not incorporated

Figure OR-DS-27: Geographical trend of CCT for RIIA milestone

Finding: CCT increases are due to displacement of large units

The generation output of Energy Adequacy results indicates as renewable penetration increases, conventional units will be generally dispatched down, and few thermal units will be committed. Based on this result a hypothesis is proposed that the increase in CCT can be attributed to the general trend that conventional units will be dispatched down or will be turned off. To test this hypothesis, a study was performed on 2 conventional units, one in the northern part of MISO, the other in southern footprint, and impact on CCT of nearby units utilizing contingencies in the local area near those units was calculated under two scenarios as listed in Table OR-DS 1. The results confirm the hypothesis that CCT of nearby units increases when the test unit is turned off, versus when the test unit was dispatched at maximum output (Figure OR-DS-28). Further, results confirm that due to local network topology, CCT of some nearby units may decrease as can be observed from the CCT trend in MISO south.

Test Unit Location	Scenario	Power output
North	1	Maximum Generation
	2	Turned Off
South	1	Maximum Generation
	2	Turned Off

Table OR-DS 1 Scenarios to study the impact on CCT of near-by units due to dispatch of a thermal generation

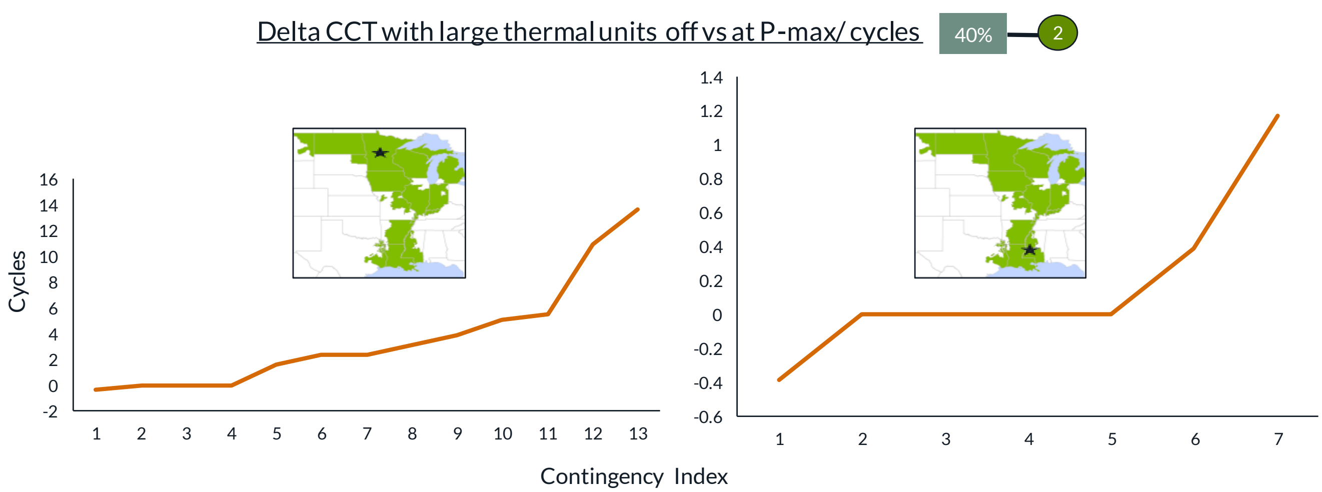


Figure OR-DS-29: Dispatch of thermal units impacts the CCT of nearby units

Technical Assumptions Summary

The technical assumptions summary serves as a detailed summary of the data, methods and process used for the Renewable Integration Impact Assessment (RIIA) analysis.

The primary purpose of the Renewable Integration Impact Assessment (RIIA) is to methodically find system integration inflection points driven by increasing levels of renewable generation. Industry studies[28] have shown that the complexity for renewable integration escalates non-linearly with increasing penetrations of renewables. Over certain ranges of renewable penetration, complexity is constant when spare capacity and flexibility exist, but at specific penetration levels when they are depleted, complexity rises dramatically. These are system inflection points, where the underlying infrastructure or system operations need to be modified to reliably achieve the next tranche of renewable deployment. This assessment aims to find those inflection points and examine potential solutions to mitigate them.

This assessment is designed to be "year agnostic" in that it does not intend to develop pathways for achieving high levels of renewable penetration, but instead intends to examine system conditions under renewable penetration levels assumed to have been reached in any year. The assessment does not attempt to develop an optimal resource mix, and the generation changes in the model are assumed to occur regardless of external drivers and timelines.

This assessment is designed to be "year agnostic" in that it does not intend to develop pathways for achieving high levels of renewable penetration, but instead intends to examine system conditions under renewable penetration levels assumed to have been reached in any year.

These technical assumptions section discusses the details of data and processes used in the three focus areas that comprise RIIA. The RIIA concept paper provides a detailed explanation of the assessment background, goals and structure. Together these two documents serve as the scope of work for the assessment.

Process

The RIIA process is made up of three focus areas: (1) Resource Adequacy, (2) Energy Adequacy and (3) Operating Reliability. Resource Adequacy is defined as the ability of available power resources to reliably serve electricity demands when needed across a range of reasonably foreseeable conditions. This focus area assesses changes in renewable resource capacity credit by calculating the Loss of Load Expectation (LOLE) and the Effective Load Carrying Capability (ELCC). Energy Adequacy looks at the ability of a system to be operated continuously. This involves analysis of ramping, over/under production, capacity factors, coordination, operating reserves and congestion. Operating Reliability studies the ability of the system to withstand sudden disturbances to system stability or unanticipated loss of system components. This focus area will look at voltage support, thermal overloads, dynamic stability issues such as voltage, inverter-driven, rotor angle and frequency stability.

These three focus areas flow together in a complex and robust process (Figure TA-1).

28 The RIIA concept paper includes a detailed list of relevant industry studies.

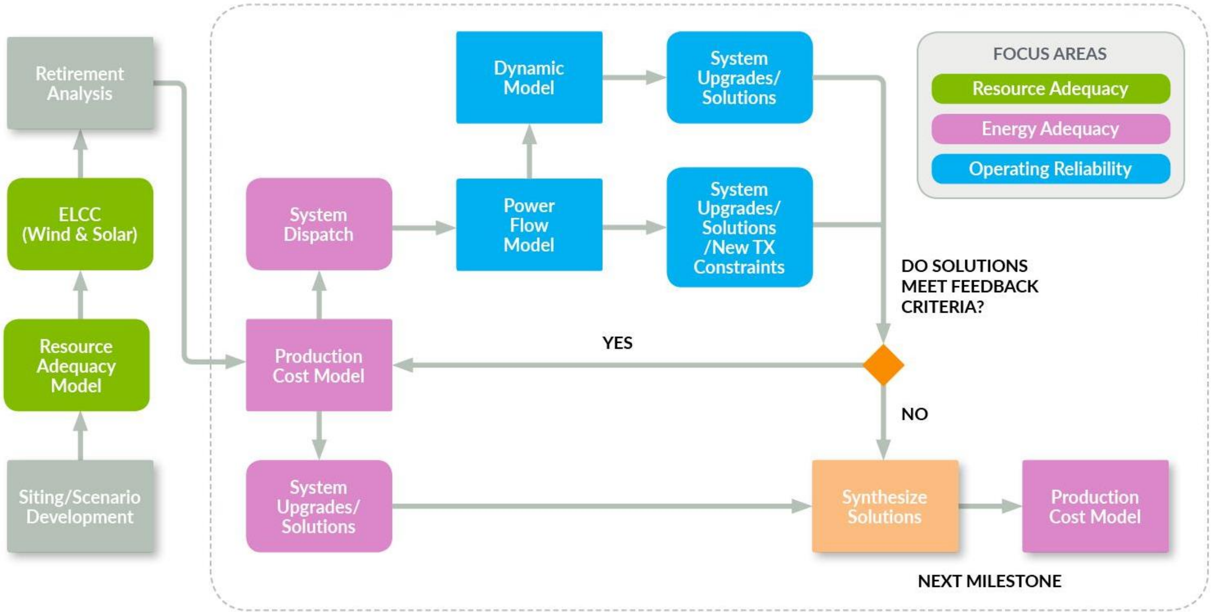
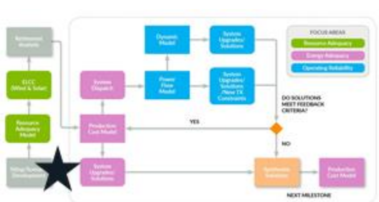


Figure TA-1: RIIA process map

First, scenarios are designed for use throughout the entire assessment. The scenarios represent different levels of renewable energy penetration that increment in 10% intervals, or milestones. Wind and solar resources are added and sited in each model region (MISO, PJM, NYISO, etc.) such that each region meets the desired milestones as seen in the next section.(Page 141). The first focus area, Resource Adequacy, then analyzes the system with the added resources to determine their ELCCs at each milestone. (Page 159). These values are used to determine the appropriate amount of retirements (page 164) to ensure the system is not over or under built. Once the expansion and retirements are determined, Energy Adequacy models are built and analyzed. Energy Adequacy (page 166) uses a production cost model for its analysis, which produces a full year of hourly dispatch based on the constraints present. Several hours of this dispatch are selected for study in the Operating Reliability focus area (pages starting 178 and 184) and the dispatch is passed from the production cost model to the power flow model and the dynamic model. These models assess the reliability of the system during the selected stressful hours. If any of the focus areas encounter problems preventing the reliable operation of the system that need to be addressed, solutions are developed and passed along to subsequent focus areas' models. The following sections discuss the process in greater detail.

Siting and Scenario Development



The base model for RIIA is derived from the MTEP17 model, as described in detail in the Process section. Generator additions and retirements assumed in the MTEP process are not utilized in this study. Instead, additions are calculated and sited using a process developed for this assessment, while retirements are determined based on initial screening results of the PLEXOS model. In this section, the expansion and siting processes are described, with the retirement process to follow in page 164.

Expansion

1. Determine the GWh of demand in each region from the load profiles developed for this assessment (Table TA-1)

Region	Energy (GWh)
MISO	677,466
SPP	264,805
TVA	222,637
SERC	469,283
PJM	829,073
NYISO	159,970

Table TA-1: Total demand by region

2. Assign the split of wind and solar energy to each region based on the ERGIS RTx30[29] scenario (Table TA-2)

Region	Wind	Solar
MISO	75%	25%
SPP	80%	20%
TVA	10%	90%
SERC	10%	90%
PJM	75%	25%
NYISO	75%	25%

Table TA-2: Split of wind and solar by region

For solar capacity, installed MW will be split into 70% utility-scale solar and 30% distributed solar, based on current industry trends.

3. Calculate the average capacity factors for new wind sites, existing wind sites, new solar sites and existing solar sites for each region from the 2012 NREL profiles used in the PLEXOS model, described in page 175. For new renewable sites, calculate capacity factors for each penetration level (Table TA-3 to TA-6).

[29] NREL Eastern Renewable Generation Integration Study: https://www.nrel.gov/docs/fy16osti/64472.pdf

Region	Existing Wind	Existing Solar
MISO	37%	19%
SPP	41%	20%
TVA	37%	19%
SERC	35%	19%
PJM	33%	18%
NYISO	35%	17%

Table TA-3: Capacity factors for existing wind and solar by region

<table>
<tr><th></th><th>10%</th><th>20%</th><th>30%</th><th>40%</th><th>50%</th><th>60%</th><th>70%</th><th>80%</th><th>90%</th><th>100%</th></tr>
<tr><th>MISO</th><td colspan="2">44%</td><td>45%</td><td colspan="2">44%</td><td colspan="2">43%</td><td>42%</td><td colspan="2">41%</td></tr>
<tr><th>SPP</th><td>N/A</td><td>N/A</td><td>48%</td><td colspan="7">46%</td></tr>
<tr><th>TVA</th><td>38%</td><td colspan="2">36%</td><td colspan="4">37%</td><td colspan="2">36%</td><td>35%</td></tr>
<tr><th>SERC</th><td>37%</td><td colspan="2">38%</td><td colspan="3">37%</td><td colspan="3">36%</td><td>35%</td></tr>
<tr><th>PJM</th><td>43%</td><td>40%</td><td>39%</td><td colspan="2">38%</td><td colspan="5">37%</td></tr>
<tr><th>NYISO</th><td>43%</td><td>41%</td><td>42%</td><td>41%</td><td colspan="6">42%</td></tr>
</table>

Table TA-4: Capacity factors for new wind by region

<table>
<tr><th></th><th>10%</th><th>20%</th><th>30%</th><th>40%</th><th>50%</th><th>60%</th><th>70%</th><th>80%</th><th>90%</th><th>100%</th></tr>
<tr><th>MISO</th><td colspan="3">19%</td><td>18%</td><td colspan="5">19%</td><td>18%</td></tr>
<tr><th>SPP</th><td>N/A</td><td>N/A</td><td>22%</td><td colspan="7">23%</td></tr>
<tr><th>TVA</th><td colspan="10">19%</td></tr>
<tr><th>SERC</th><td colspan="10">19%</td></tr>
<tr><th>PJM</th><td colspan="9">18%</td><td>17%</td></tr>
<tr><th>NYISO</th><td colspan="10">16%</td></tr>
</table>

Table TA-5: Capacity factors for new utility-scale solar by region

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	17%									
SPP	N/A	N/A	18%							
TVA	17%									
SERC	19%									
PJM	16%									
NYISO	15%									

Table TA-6: Capacity factors for new distributed solar by region

4. *Calculate the energy needed from new renewables by subtracting the energy produced by existing renewables from the demand.*
5. *Determine the amount of renewable capacity needed to produce the needed energy calculated in step 4.*

This process yields the following capacity expansion (Figures TA-7 to TA-9).

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1,993	15,511	28,303	41,521	55,168	69,031	84,427	98,097	114,297	129,647
SPP	0	0	4,200	9,900	15,000	20,250	25,675	30,700	36,225	41,750
TVA	675	1,450	2,175	2,800	3,600	4,400	5,200	5,800	6,300	7,300
SERC	1,350	2,800	4,300	5,750	7,250	8,750	10,250	12,000	13,500	15,250
PJM	11,300	29,600	48,750	68,900	87,600	107,700	128,200	147,025	164,900	185,600
NYISO	1,875	5,375	8,525	11,975	15,325	18,400	21,825	25,200	28,500	31,600

Table TA-7: Wind expansion (MW) by region and milestone

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1,050	8,500	15,575	23,125	30,550	37,700	44,900	52,500	59,325	67,975
SPP	0	0	1,600	3,400	5,200	7,100	9,000	10,600	12,600	14,700
TVA	8,200	16,675	25,250	34,625	42,150	50,675	59,300	67,750	76,275	85,275
SERC	16,300	36,550	52,600	70,800	90,625	110,825	126,125	145,100	161,475	180,825
PJM	6,200	15,600	24,800	34,600	45,050	55,250	63,375	72,850	84,600	93,100
NYISO	1,200	3,225	5,250	7,600	9,200	11,300	13,375	15,675	17,775	19,675

Table TA-8: Utility solar expansion (MW) by region and milestone

Region	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1,276	4,711	8,549	12,257	15,415	18,837	22,590	25,994	28,956	32,190
SPP	0	0	1,076	2,065	3,070	4,099	5,066	6,128	7,124	8,139
TVA	3,838	7,854	11,846	15,833	19,872	23,874	27,885	31,891	35,910	40,174
SERC	7,757	16,428	24,935	33,704	42,267	50,864	59,478	68,073	76,757	85,119
PJM	3,126	7,575	12,014	16,547	20,786	25,349	29,523	33,750	37,548	41,174
NYISO	595	1,499	2,363	3,283	4,138	5,064	5,921	6,805	7,667	8,483

Table TA-9: Distributed solar expansion (MW) by region and milestone

Siting

MISO's current siting process is robust and comprehensive for the circumstances under which it is used, such as MTEP studies. With this study, however, MISO is developing a variation on this process to deal with the large amount of renewables modeled.

1. Identify and map all buses 230 kV and above.
2. Exclude buses as viable siting candidates based on the following criteria.
    a. *Rural vs urban areas:* For wind, exclude any sites within 0.5 mile of an urban area (>500 people/square mile) or within 10 miles of a high-density urban area (>2000 people/square mile). For solar, exclude any sites within 0.5 mile of an urban area.
    b. *Airports:* For wind, exclude buses within a 5-mile radius of a regional airport (an airport with a control tower). For wind and solar, exclude areas within a 1-mile radius of any size airport.
    c. *Military facilities:* Exclude all locations within a 2-mile radius of the boundary of a military facility.
    d. *Federal lands:* Exclude all locations within a 2-mile radius of the boundary of federal land.

e. *State lands:* Exclude all locations within a 1-mile radius of the boundary of state land. This assumption may be adjusted at higher levels of renewable generation.

f. *Swamp and marsh lands:* Exclude all locations within a 2-mile radius of swamp/marsh lands greater 10 square miles.

g. *Retirements:* Buses with existing thermal generation larger than 300 MW may be used when the unit retires.

h. *Proximity to existing thermal unit:* If a candidate bus is in close proximity to a low kV bus with a thermal generator larger than 300 MW, exclude the candidate bus until the thermal unit retires.

3. Geographically group the buses and select a subset of buses per group.

    a. The average distance between existing wind farms greater than 100 MW and their 10 closest neighbors of equal or greater size within 200 miles is ~26 miles. A 15-mile grid is therefore appropriate to group buses.

    b. Select two buses as representative of each grid cell. High kV buses with significant outlets are given first priority. Representative buses must be at least 3 miles apart.

    c. For New York, SERC and TVA, grid cells include additional representative buses due to a small number of candidate buses relative to needed MW capacity.

4. Calculate the capacity factor of each site using the wind and solar profiles developed by NREL (see page 175). Create capacity factor bins.

5. Prioritize the list of viable buses in each pool based on the following criteria:

    a. Status in the various interconnection queues[30] (Table TA-10)

Status	Priority
Operating	1
Planned	2
Canceled	3
Retired	3
Cold Standby	3
Greenfield	4

Table TA-10: Siting priorities by unit status

    b. Capacity factor bins

    c. Rank within grid cell (determined in step 3)

[30] For MISO, use the tiers developed in previous MISO studies and currently used in the siting process. For external regions, sort the list of buses developed in steps 1-5 by queue status to develop proxies for tiers outside of MISO.

d. Proximity to queue locations

e. Outlet capability (measured by number of high kV lines connected to the bus)

6. Fill up and add capacity per bus to achieve desired renewable penetration level at each milestone. Buses are selected based on the priority sorted list.

   a. If a candidate bus is chosen for siting in a particular milestone, that bus must be used for all subsequent milestones. Each bus's sited MW monotonically increases across milestones.

   b. For SERC and TVA, allow co-location of wind and solar in any milestone. Allow co-location of wind and solar for all other regions only under the following conditions:

      i. 500 and 765 kV buses can be co-located at 10% penetration

      ii. 345 kV buses can be co-located at 20% penetration

      iii. 230 kV buses can be co-located at 30% penetration

Expansion Sensitivity

The sensitivity assumptions, based on the expansion of renewables based on subregional load ratio and resource mix in the generation queue, results in:

- A shift from a wind-heavy system to a more balanced wind-solar mix
- A shift in capacity from the North to the Central and South regions in MISO

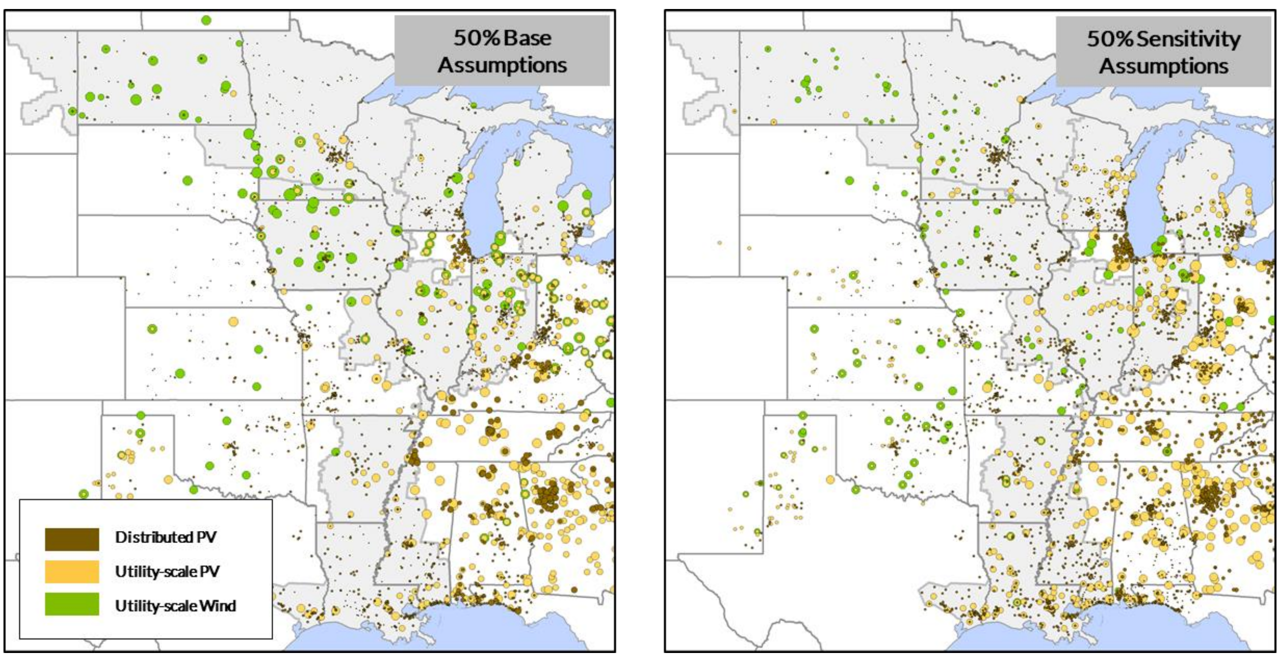


Figure TA-2: Geographic Distribution of Renewables Under Base and Sensitivity Assumptions

At the MISO level, the combined assumptions of a more regional distribution and recent queue trends for each subregion results in a shift from wind to solar compared to base assumptions (Figure TA-2 and Figure TA-3)

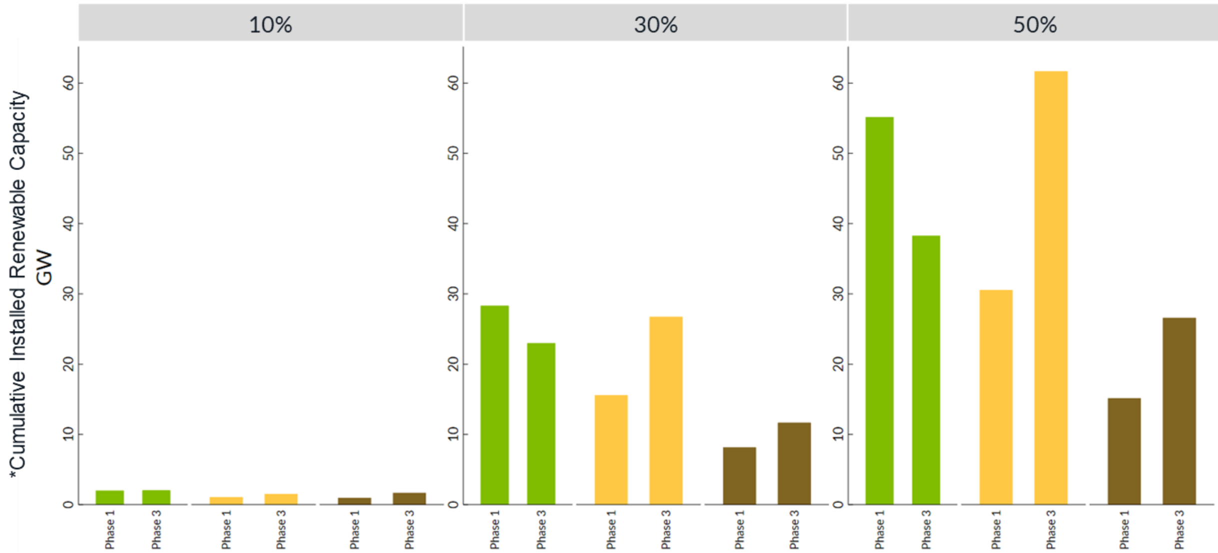


Figure TA-3: Installed Renewable Capacity Per Milestone Under Base and Sensitivity Assumptions

Furthermore, the expansion of renewable generation based on load ratio results in a shift of capacity from the North region to the Central and South regions (Figure TA-4).

Figure TA-4: Installed Renewable Capacity Per Subregion Per Milestone

Similar to the base assumptions, the capacity expansion used four steps, albeit with different approaches at each step.

Step 1: Determine the energy demand (GWh) in each region

As opposed to the base assumptions, the energy required from renewables was determined for each subregion in the footprint; for MISO, Local Resource Zones were used (Table TA-11 and Table TA-12).

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	1.4	11.0	20.7	30.3	39.9	49.6	59.2	68.9	78.5	88.1
LRZ 10	0.3	2.7	5.2	7.6	10.0	12.4	14.8	17.2	19.6	22.0
LRZ 2	0.9	7.4	13.9	20.4	26.9	33.3	39.8	46.3	52.8	59.2
LRZ 3	0.7	5.6	10.5	15.4	20.3	25.2	30.1	35.0	40.0	44.9
LRZ 4	0.7	5.6	10.5	15.4	20.3	25.2	30.1	35.0	39.9	44.9
LRZ 5	0.5	4.3	8.0	11.8	15.5	19.2	23.0	26.7	30.5	34.2
LRZ 6	1.4	10.7	20.1	29.5	38.8	48.2	57.6	66.9	76.3	85.7
LRZ 7	1.4	11.3	21.2	31.1	40.9	50.8	60.7	70.6	80.5	90.3
LRZ 8	0.6	4.7	8.8	12.9	16.9	21.0	25.1	29.2	33.3	37.4
LRZ 9	1.8	13.8	25.8	37.9	49.9	62.0	74.0	86.1	98.1	110.2

Table TA-11: MISO Subregional Incremental Renewable Energy

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
SPP										
SPP - Central	0.0	0.0	10.6	23.7	36.8	49.9	63.1	76.2	89.3	102.4
SPP - NBDK	0.0	0.0	5.3	12.0	18.6	25.2	31.8	38.4	45.1	51.7
SPP - KSMO	0.0	0.0	6.0	13.5	20.9	28.4	35.8	43.3	50.7	58.2
TVA										
TVA	14.5	31.1	47.7	64.3	81.0	97.6	114.2	130.9	147.5	164.1
TVA-Other	5.0	10.7	16.5	22.2	27.9	33.7	39.4	45.1	50.9	56.6
SERC										
AL	7.9	16.6	25.3	34.0	42.6	51.3	60.0	68.7	77.3	86.0
GA	13.3	27.9	42.5	57.1	71.6	86.2	100.8	115.4	130.0	144.5
MS	1.3	2.7	4.1	5.5	6.9	8.3	9.7	11.1	12.5	13.9
NC	15.6	32.7	49.8	66.9	84.1	101.2	118.3	135.4	152.5	169.6
SC	5.3	11.0	16.8	22.6	28.3	34.1	39.9	45.7	51.4	57.2
PJM										
AEP-ATSI	14.1	35.1	56.1	77.1	98.1	119.2	140.2	161.2	182.2	203.2
PJM-W	8.4	21.0	33.5	46.0	58.6	71.1	83.7	96.2	108.8	121.3
COMED	7.0	17.4	27.7	38.1	48.5	58.9	69.3	79.7	90.1	100.4
MidAtl-E	6.8	17.0	27.1	37.3	47.4	57.6	67.7	77.9	88.0	98.2
MidAtl-PA	8.3	20.8	33.2	45.7	58.1	70.6	83.0	95.5	107.9	120.4
PJM-S	11.3	28.3	45.2	62.1	79.0	95.9	112.9	129.8	146.7	163.6
NY										
NY	10.4	26.7	43.0	59.3	75.6	91.8	108.1	124.4	140.7	156.9

Table TA-12: EI Subregional Incremental Renewable Energy

Step 2: Assign the wind and solar energy mix for each region

The Generation interconnection queues as of March 2019 for each region in the were used to determine the mix of wind and solar. Specifically, the subregional (LRZ) mix was used (Table TA-13 & 14). The current mix of installed renewables was used 10% penetration milestone. The furthest queue projections were used for the 50% penetration and above. The mix for milestones 20-40% were interpolated.

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	0.95	0.90	0.90	0.85	0.85	0.85	0.85	0.85	0.85	0.85
LRZ 10	0.00	0.10	0.15	0.20	0.25	0.25	0.25	0.25	0.25	0.25
LRZ 2	0.95	0.70	0.60	0.50	0.35	0.35	0.35	0.35	0.35	0.35
LRZ 3	0.95	0.95	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
LRZ 4	0.90	0.80	0.75	0.70	0.60	0.60	0.60	0.60	0.60	0.60
LRZ 5	0.95	0.85	0.80	0.75	0.70	0.70	0.70	0.70	0.70	0.70
LRZ 6	0.90	0.70	0.60	0.50	0.45	0.45	0.45	0.45	0.45	0.45
LRZ 7	0.95	0.85	0.75	0.70	0.65	0.65	0.65	0.65	0.65	0.65
LRZ 8	0.00	0.10	0.15	0.15	0.20	0.20	0.20	0.20	0.20	0.20
LRZ 9	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

Table TA-13: MISO Percentage of wind per subregion

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
SPP										
SPP - Central	0.95	0.90	0.85	0.85	0.80	0.75	0.75	0.75	0.75	0.75
SPP - NBDK	0.95	0.95	0.95	0.90	0.90	0.85	0.85	0.85	0.85	0.85
SPP - KSMO	0.95	0.95	0.90	0.85	0.80	0.80	0.80	0.80	0.80	0.80
TVA										
TVA	0.15	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TVA-Other	0.00	0.15	0.30	0.45	0.50	0.65	0.65	0.65	0.65	0.65
SERC										
AL	0.15	0.15	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05
GA	0.35	0.25	0.20	0.15	0.10	0.05	0.05	0.05	0.05	0.05
MS	0.15	0.15	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05
NC	0.00	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
SC	0.15	0.15	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05
PJM										
AEP-ATSI	0.95	0.85	0.75	0.60	0.50	0.45	0.45	0.45	0.45	0.45
PJM-W	0.95	0.80	0.65	0.50	0.35	0.20	0.20	0.20	0.20	0.20
COMED	0.95	0.95	0.90	0.85	0.80	0.75	0.75	0.75	0.75	0.75
MidAtl-E	0.10	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05	0.05
MidAtl-PA	0.95	0.80	0.60	0.50	0.30	0.15	0.15	0.15	0.15	0.15
PJM-S	0.70	0.55	0.50	0.35	0.20	0.05	0.05	0.05	0.05	0.05
NY										
NY	0.95	0.90	0.80	0.70	0.60	0.50	0.50	0.50	0.50	0.50

Table TA-14: EI Percentage of wind per subregion

Step 3: Determine avg. capacity factors for wind and solar resources at each penetration milestone

To convert the energy requirements into capacity, capacity factors for each technology in each subregion were used (Table TA – 15 -18).

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
LRZ 10	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
LRZ 2	46%	45%	45%	45%	45%	45%	45%	45%	45%	45%
LRZ 3	46%	45%	45%	45%	45%	45%	45%	45%	45%	45%
LRZ 4	43%	45%	44%	44%	44%	44%	44%	44%	44%	44%
LRZ 5	43%	43%	44%	44%	44%	44%	44%	44%	44%	44%
LRZ 6	43%	42%	42%	42%	42%	42%	42%	42%	42%	42%
LRZ 7	42%	43%	43%	43%	43%	43%	43%	43%	43%	43%
LRZ 8	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
LRZ 9	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%

Table TA-15: MISO Wind Capacity Factors by subregion

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
SPP										
SPP - Central	45%	45%	46%	45%	45%	45%	45%	45%	45%	45%
SPP - NBDK	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
SPP - KSMO	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%
TVA										
TVA	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
TVA-Other	45%	47%	44%	44%	45%	45%	45%	45%	45%	45%
SERC										
AL	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
GA	31%	32%	32%	32%	32%	32%	32%	31%	31%	31%
MS	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
NC	38%	38%	38%	37%	38%	38%	38%	38%	38%	38%
SC	38%	37%	37%	37%	38%	38%	38%	38%	38%	38%
PJM										
AEP-ATSI	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
PJM-W	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
COMED	43%	43%	43%	43%	43%	43%	43%	43%	43%	43%
MidAtl-E	38%	39%	39%	39%	39%	39%	39%	38%	38%	38%
MidAtl-PA	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%
PJM-S	37%	37%	37%	37%	37%	37%	37%	37%	37%	37%
NY										
NY	44%	43%	43%	43%	43%	43%	43%	43%	43%	43%

Table TA-16: EI Wind Capacity Factors by subregion

Subregion	UPV	DPV	Weighted
MISO			
LRZ 1	18%	15%	17%
LRZ 2	18%	15%	17%
LRZ 3	19%	15%	18%
LRZ 4	19%	16%	18%
LRZ 5	19%	16%	18%
LRZ 6	18%	16%	18%
LRZ 7	17%	15%	17%
LRZ 8	19%	17%	19%
LRZ 9	19%	16%	18%
LRZ 10	19%	16%	18%

Table TA-17: MISO Solar-PV Capacity Factors by subregion

Subregion	UPV	DPV	Weighted
SPP			
SPP - Central	23%	17%	21%
SPP - NBDK	21%	17%	20%
SPP - KSMO	20%	16%	19%
TVA			
TVA	19%	16%	18%
TVA-Other	19%	16%	18%
SERC			
AL	19%	16%	18%
GA	19%	16%	18%
MS	19%	16%	18%
NC	18%	16%	18%
SC	19%	16%	18%
PJM			
AEP-ATSI	18%	15%	17%
COMED	18%	16%	17%
MidAtl-E	17%	15%	17%
MidAtl-PA	17%	14%	16%
PJM-S	18%	16%	17%
PJM-W	18%	15%	17%
NY			
NY	16%	14%	15%

Table TA-18: EI Solar-PV Capacity Factors by subregion

Step 4: Determine the expansion capacity for new wind and solar* generation using the capacity factor and renewable energy targe (Table TA – 19 – 26). Similar to the base RIIA assumptions, the installed capacity for the solar PV generation is split into 70% utility scale (UPV) and 30%.

Region	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	2.7	16.5	27.2	31.5	37.2	46.4	53.4	59.2	68.8	73.8
NY	2.8	6.8	9.5	11.3	12.2	12.2	14.6	16.6	19.2	21.5
PJM	13.0	28.3	39.6	43.7	48.2	50.3	56.4	60.1	64.5	69.8
SERC	2.9	4.7	5.8	6.8	6.8	6.8	7.0	7.3	7.5	8.0
SPP	-	-	5.1	10.9	15.9	20.5	26.3	31.1	36.2	41.6
TVA	0.8	1.7	3.0	4.5	5.9	8.4	10.1	11.0	12.3	13.9

Table TA-19: Wind expansion by region

Region	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1.5	11.3	26.7	42.9	61.7	83.7	100.1	112.7	128.9	146.6
NY	0.4	1.7	4.9	9.5	16.1	24.4	28.2	31.9	36.1	40.2
PJM	6.3	20.5	42.2	73.2	114.0	156.7	184.5	213.2	237.6	267.3
SERC	16.8	35.2	55.4	77.9	99.4	120.9	138.3	156.6	174.0	194.1
SPP	-	-	1.2	2.8	5.2	9.3	11.5	23.0	23.0	23.0
TVA	8.2	17.7	23.4	32.3	39.8	47.0	53.5	61.7	68.3	77.4

Table TA-20: UPV expansion by region

Row Labels	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1.7	5.6	11.7	18.8	26.6	35.2	41.7	47.9	54.2	60.4
NY	0.2	0.7	2.0	4.1	6.9	10.4	12.1	13.5	14.8	16.1
PJM	2.4	8.4	17.3	30.1	46.8	66.1	75.3	82.6	88.5	94.3
SERC	7.6	16.1	24.5	33.0	42.4	51.5	58.2	62.5	66.9	71.6
SPP	-	-	0.7	1.3	2.5	3.9	4.8	5.7	6.7	7.6
TVA	2.8	5.6	8.4	11.6	14.7	17.2	20.4	23.4	25.1	26.7

Table TA-21: DPV expansion by region

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	1.8	5.6	8.4	8.4	8.9	11.4	12.0	12.6	13.8	14.4
LRZ 10	-	0.7	1.1	1.1	1.1	1.4	1.4	1.4	1.4	1.4
LRZ 2	0.2	1.8	2.7	2.7	3.2	3.6	4.1	4.5	5.4	5.9
LRZ 3	0.1	3.2	4.8	4.8	5.5	6.4	7.2	8.0	9.6	10.4
LRZ 4	0.1	1.6	3.3	3.3	3.9	4.4	5.0	5.5	6.6	7.2
LRZ 5	0.1	0.6	2.1	3.0	3.5	4.0	4.5	5.0	6.0	6.5
LRZ 6	0.2	1.1	1.7	4.5	5.2	6.0	6.7	7.3	8.6	9.3
LRZ 7	0.2	1.4	2.4	3.0	4.9	7.6	9.9	11.0	13.2	14.3
LRZ 8	-	0.3	0.4	0.4	0.8	0.8	1.8	2.0	2.2	2.4
LRZ 9	-	0.3	0.4	0.4	0.4	0.8	0.9	1.9	2.1	2.2

Table TA-22: MISO wind expansion by subregion

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
NY										
NY	2.8	6.8	9.5	11.3	12.2	12.2	14.6	16.6	19.2	21.5
PJM										
PJM-S	1.5	3.0	4.1	4.5	5.0	5.1	5.7	6.0	8.8	11.0
AEP-ATSI	5.3	11.6	16.8	18.7	20.9	21.8	24.3	25.2	25.2	26.9
COMED	1.3	2.8	4.0	4.3	4.5	4.8	5.5	5.8	5.8	6.3
MidAtl-PA	2.8	5.3	6.7	7.6	8.4	8.9	9.7	10.3	11.5	11.7
PJM-W	1.8	4.9	7.0	7.5	8.0	8.4	9.6	11.2	11.4	12.0
MidAtl-E	0.5	0.9	1.1	1.3	1.5	1.5	1.6	1.7	2.0	2.0
SERC										
NC	0.8	1.4	2.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6
AL	0.5	0.8	0.8	1.0	1.0	1.0	1.3	1.5	1.8	1.8
GA	0.9	1.5	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.2
SC	0.6	0.8	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
MS	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.5
SPP										
SPP - Central	-	-	2.4	4.7	7.0	9.4	12.0	14.3	17.1	19.4
SPP - KSMO	-	-	1.4	1.6	3.1	5.3	6.7	7.6	8.8	10.1
SPP - NBDK	-	-	1.4	4.6	5.8	5.8	7.6	9.2	10.3	11.4
TVA										
TVA	0.8	1.2	1.6	1.7	1.9	2.4	2.9	3.2	3.5	3.9
TVA-Other	-	0.5	1.4	2.8	4.0	6.0	7.2	7.8	8.9	10.1

Table TA-23: EI wind expansion by subregion

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	0.1	0.6	1.1	1.6	3.2	4.7	5.4	5.9	6.9	7.8
LRZ 10	0.1	0.7	2.1	3.1	4.1	4.9	6.0	6.7	7.3	8.1
LRZ 2	0.1	0.6	2.2	4.8	7.4	10.8	13.0	14.9	17.6	20.3
LRZ 3	0.1	0.5	0.8	1.3	1.8	2.7	3.0	3.3	3.9	4.5
LRZ 4	0.1	0.6	1.6	2.3	3.5	5.4	6.5	7.2	8.5	9.8
LRZ 5	0.1	0.5	0.8	1.5	2.1	3.2	3.5	3.9	4.6	5.3
LRZ 6	0.1	0.7	2.7	5.3	8.5	12.8	15.2	17.8	20.8	23.7
LRZ 7	0.1	0.8	2.4	3.8	6.7	9.5	11.5	13.2	15.6	18.0
LRZ 8	0.3	2.0	3.4	5.6	6.1	7.6	8.8	9.7	10.6	12.1
LRZ 9	0.7	4.5	9.7	13.9	18.5	22.3	27.4	30.3	33.4	37.2

Table TA-24: MISO UPV expansion by subregion

Subregion	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
NY										
NY	0.4	1.7	4.9	9.5	16.1	24.4	28.2	31.9	36.1	40.2
PJM										
AEP-ATSI	0.8	3.3	7.2	15.5	25.5	33.5	38.5	44.0	48.9	55.5
COMED	0.5	1.1	2.4	4.4	7.5	9.9	13.0	14.8	14.4	16.3
MidAtl-E	2.0	3.9	6.3	9.1	11.5	12.8	14.6	16.9	18.5	19.9
MidAtl-PA	0.5	2.9	7.4	12.7	21.0	30.8	36.9	42.8	48.2	54.2
PJM-S	2.0	6.5	12.6	20.0	30.0	42.5	49.7	57.2	65.3	73.4
PJM-W	0.5	2.8	6.4	11.6	18.6	27.3	32.0	37.6	42.5	48.2
SERC										
AL	3.0	6.5	10.6	14.7	18.9	22.5	26.3	29.8	34.0	37.7
GA	3.9	9.4	15.0	21.3	28.2	36.4	42.4	47.8	53.8	60.7
MS	0.8	1.5	2.3	3.2	4.0	4.8	5.3	6.0	6.5	7.2
NC	7.1	13.4	20.6	28.4	35.6	42.3	46.9	53.1	57.7	63.9
SC	2.1	4.4	6.9	10.4	12.7	15.0	17.5	20.0	22.1	24.7
SPP	-	-	1.2	2.8	5.2	9.3	11.5	23.0	23.0	23.0
SPP - Central	-	-	0.7	1.3	2.7	4.6	5.9	11.8	11.8	11.8
SPP - KSMO	-	-	0.3	0.9	1.7	3.0	3.4	6.8	6.8	6.8
SPP - NBDK	-	-	0.2	0.6	0.9	1.8	2.2	4.4	4.4	4.4
TVA										
TVA	5.6	12.0	15.8	22.0	24.8	29.3	33.3	38.5	41.5	47.8
TVA-Other	2.4	5.4	7.2	9.6	10.2	12.0	13.8	15.6	18.5	20.4

Table TA-25: EI UPV expansion by subregion

Row Labels	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO										
LRZ 1	0.3	0.8	1.7	2.6	3.8	5.1	5.9	6.8	7.7	8.6
LRZ 10	0.1	0.3	0.6	0.9	1.4	1.7	2.1	2.4	2.7	3.0
LRZ 2	0.3	0.6	1.2	1.9	2.7	3.6	4.2	4.8	5.5	6.2
LRZ 3	0.2	0.4	0.9	1.4	1.9	2.5	3.0	3.4	3.9	4.4
LRZ 4	0.1	0.3	0.7	1.1	1.6	2.1	2.5	2.9	3.3	3.6
LRZ 5	0.1	0.3	0.7	1.0	1.5	2.0	2.4	2.8	3.2	3.6
LRZ 6	0.2	0.7	1.4	2.2	3.2	4.1	5.0	5.8	6.5	7.3
LRZ 7	0.2	0.9	1.8	2.9	4.2	5.5	6.6	7.3	8.1	8.9
LRZ 8	0.1	0.3	0.7	1.1	1.6	2.1	2.5	2.9	3.3	3.5
LRZ 9	0.2	1.0	2.0	3.3	4.6	6.2	7.3	8.5	9.6	10.7

Table TA-26: MISO DPV expansion by subregion

Focus Area Outlines

This section describes the models, processes and assumptions used for RIIA's three focus areas.

Summary of Tools Used for Analysis

Table TA-27 gives a brief introduction to the models used, before in depth discussions in the subsequent sections.

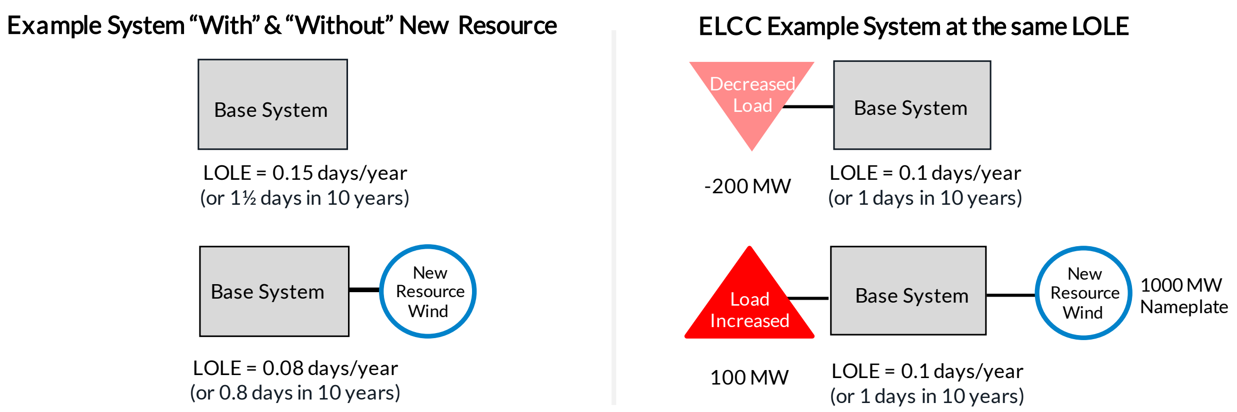
	Tools	Vintage	Criteria to meet
Resource Adequacy	PLEXOS	MTEP17 model; uses MTEP16 Powerflow model at 10-year out transmission	LOLE per BAL-502-RFC-02; ELCC
Energy Adequacy – Planning Focus area	PLEXOS	MTEP17 model; uses MTEP16 Powerflow model at 10-year out transmission	Renewable targets energy adequacy; ramping adequacy;
Energy Adequacy – Markets and Operation Focus Area	(a) MISO production engines for commitment, clearing, dispatch and pricing, (b) KERMIT (Regulating reserves simulation tool); and (c) other simplified commitment and clearing engine models	current MISO production data and models, as well as future renewable portfolios developed in RIIA,	Generation's ability to meet load; ramping adequacy; price volatility
Operating Reliability	PSSE, TARA, TSAT, VSAT	MTEP17 Series 5-year out models	BAL-003; TPL-001; small-signal stability; critical-clearing time (CCT); weak grid short-circuit ratio (SCR)

Table TA-27: RIIA focus area tools and models

Resource Adequacy Focus Area

A key component of MISO's transmission planning process is the resource adequacy analysis, as required by the North American Electric Reliability Council (NERC) Standard BAL-502-RFC-02. The standard requires Planning Coordinators to perform and document a resource adequacy study every year. The metric used to calculate the planning reserve margin (PRM) is the " 1-day in 10-years " metric, also known as the loss of load expectation (LOLE). The LOLE takes into account the forced and unforced outages and provides a probabilistic assessment of a given system.

The integration of higher levels of renewable resources into the MISO market has driven the need to quantify the effect of wind resources on the LOLE target. MISO has adopted the effective load carrying capability (ELCC), which uses an LOLE-type study to quantify the capacity value of wind during MISO's peak. A two-stage process (as shown in Figure TA-5) is used to calculate the capacity contribution of wind generation[31]. Using the ELCC technique, the load is adjusted to balance the LOLE to a common reliability level of 1-day in 10-years (or 0.1 d/yr.), both in the case before the renewable resource being studied is added and after the renewable resource is added. The simple difference in these load adjustments is the ELCC of the resource. Dividing this number by the installed capacity of the resource added yields the ELCC as a percentage. For this analysis, the ELCC was measured for: each 10% renewable penetration milestone; each renewable technology being studied: wind, utility-scale PV (UPV) and distributed solar PV (DPV); the isolated collective solar technologies and the combination of all renewable technologies; and each of six different profile years being studied (2007-2012). Including the reference case for each year with no renewables and the base case with current levels of existing wind and UPV solar (~8% penetration) leaves a grand total of 324 different ELCC cases being analyzed.



ELCC: the amount of incremental load a resource can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served

Figure TA-5: Example ELCC Calculation

Tool and Model Data Background

To calculate ELCC and measure the capacity contribution of renewables, a commonly used power system analysis tool was chosen: PLEXOS by Energy Exemplar. This program is used by many energy markets and system planning engineers throughout the industry. Most importantly, it has the functionality to compute LOLE using the convolution method and can be set up to perform sequential Monte Carlo simulations In order to capture the inter-annual variability of weather-related patterns, synchronized load, wind and solar hourly datasets were used for the study. A description of each dataset is included next.

Existing generation fleet

This model uses generation included in MISO's business-as-usual planning models with a signed Generator Interconnection Agreement (GIA) and an in-service date before 12/31/2017. Units scheduled to come on line and retirements scheduled to take place during the 2017 year are pushed to 1/1/2017 to produce a study year with no

31 MISO, "Planning Year 2017-2018 Wind Capacity Credit", Report, December 2016. Available online: https://www.misoenergy.org/Library/Repository/Report/2015%20Wind%20Capacity%20Report.pdf

generation changes. Forced outages occur randomly within the simulation and maintenance outages are scheduled during periods of high capacity reserves using the PLEXOS software.

Load profiles

Historical load profiles from 2007-2012 were gathered from MISO's market operations database. In order to keep the same peak load assumption, all hourly shapes are adjusted in magnitude to reflect the 2017 peak load of 126,465 MW. More details about load profile development can be found in page 173.

Wind and solar profiles

Hourly wind profiles were gathered from NREL's Wind Integration National Dataset (WIND) Toolkit. Solar data was sourced from NREL's Solar Integration National Dataset (SIND) Toolkit. Each wind and solar resource was assigned specific profiles based on their location, one profile for each of the six years (2007-2012) studied in the Resource Adequacy focus area. Sensitivity analysis for the Resource Adequacy focus area was conducted with additional data supplied by Vibrant Clean Energy for the years 2013-2018. More details about these data resources can be found in page 175.

Capacity Calculation Methods

Four methods were initially considered for the analysis. First deterministic methods were explored. Two options were studied, "Top n peak load hours", and second "top n peak net load hours". Second probabilistic methods were explored. Two options were studied, "sequential monte Carlo" and second "convolution".

The sequential Monte Carlo method for calculating LOLE was first considered for the ELCC analysis part of this research, as it is one of the most robust methods of determining LOLE. Accuracy can be easily controlled by selecting the number of random outage samples to simulate and by calculating the resulting statistical error. One downside to using the sequential Monte Carlo method is the run time associated with it due to computational intensity, especially for a system the size of MISO with more than a thousand generating units. With simulation times taking longer than a day for a sequential Monte Carlo run with 5,000 samples, and considering the number of runs it would take to adjust the LOLE to the targeted value as well as the number of cases and years that would need to be investigated for this research, it would have been extremely difficult to accomplish the goals of this study in a timely manner. Thus, a faster calculation method was sought after.

The second method tested for calculating LOLE was the convolution method as shown in Figure TA-6. This method proved to be much faster, taking only a few minutes. This technique, also known as the "Effective Load Approach", iterates through all units accumulating the unit outage patterns, calculating their respective probabilities and formulating a capacity outage probability table. The table is compared to a load duration curve and the installed capacity to calculate the Loss-of-Load Probability (LOLP) that, in turn ,is used to determine the daily LOLE. An LOLE benchmark was performed between the 5,000-sample sequential Monte Carlo approach and the convolution approach to approximate the amount of any additional inaccuracy in the ELCC value by using the faster convolution technique. Given the size of the system and number of study cases, it was concluded that the convolution method is acceptable for use in this assessment and the amount of error it introduces in the ELCC value is within the uncertainties of other modeling and data assumptions[32]

32 B. Heath and A. L. Figueroa-Acevedo, "Potential Capacity Contribution of Renewables at Higher Penetration Levels on MISO System," *2018 IEEE International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, Boise, ID, 2018, pp. 1-6.

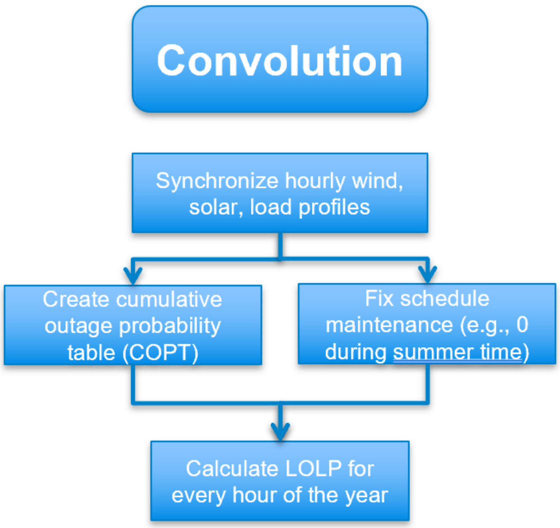
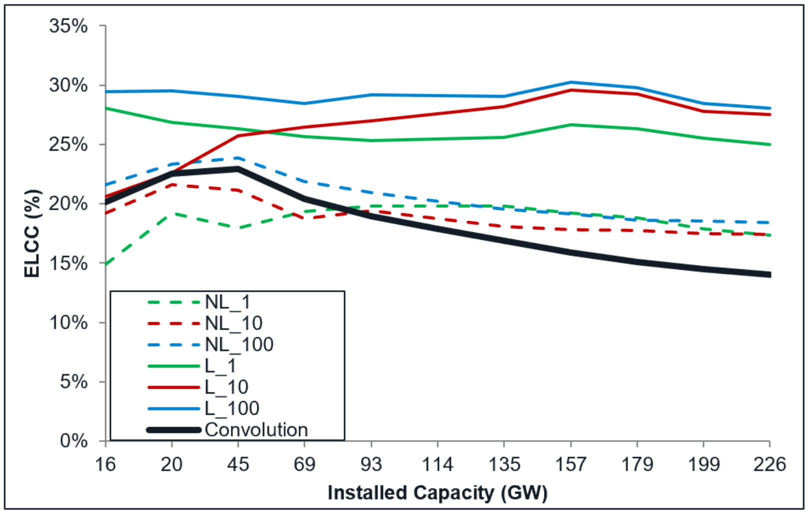


Figure TA-6: Process to conduct Convolution

Comparisons were conducted for each of the four methods to determine which one was the best fit for the scope of RIIA. As demonstrated by Figure TA-7, Figure TA-8 and Table TA-28 the convolution approach is within a reasonable error tolerance and is more computationally tractable. The majority of the Resource Adequacy analysis in RIIA was done using convolution for this reason.

	Modeling Features				
Approach	**Number of hours**	**Forced outage rates (FOR)**	**Scheduled maintenance**	**Renewables modeling**	**Simulation time**
Deterministic using gross load	1, 10, etc.	Not Included	Not Included	Availability at peak	None
Deterministic using net load	1, 10, etc.	Not Included	Not Included	Availability at net load peak	None
Probabilistic using Convolution	8760	Average	Optimized	Hourly generation	~5min/case
Probabilistic using Sequential Monte Carlo	8760	Random	Optimized	Hourly generation	~80hrs/case

Table TA-28: Comparison of Resource Adequacy modeling approaches



Deterministic Methods	Total number of samples averaged across all years
Peak Load (L_1)	Top 1 (peak load)
Peak Net Load (NL_1)	Top 1 (net peak load)
Peak Load (L_10)	Top 10 (peak load)
Peak Net Load (NL_10)	Top 10 (net peak load)
Peak Load (L_100)	Top 100 (peak load)
Peak Net Load (NL_100)	Top 100 (net peak load)

Figure TA-7: Deterministic and probabilistic approaches produce largely different results

- All Renewables ELCC at 100% penetration

Approach	ELCC
Top 100 Deterministic (Gross load)	28.00%
Top 100 Deterministic (Net load)	18.40%
Convolution	14.00%
Sequential MC	13.95%

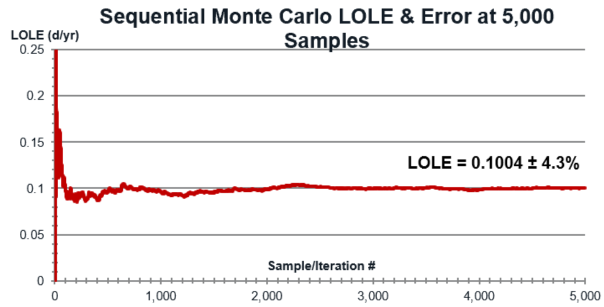
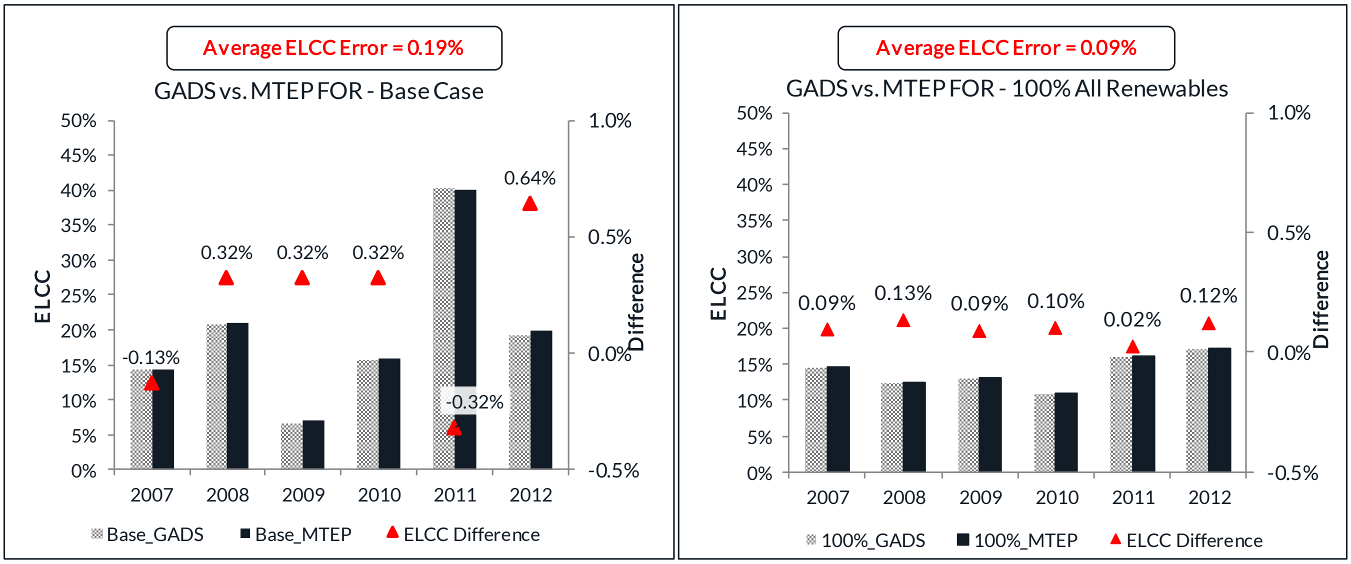


Figure TA-8: ELCC Comparison of Resource Adequacy approaches

A data comparison was conducted between two different datasets MISO uses. The first is the Generator Availability Data System (GADS), which contains actual generator level performance information, and the second is the MISO Transmission Expansion Plan (MTEP) dataset, which contains class average generator performance information. The different between these datasets on the ELCC of wind and solar is shown in Figure TA-9. For the purpose of system level studies, the error introduced by using class average data is negligible.



FOR – Forced outage rate

Figure TA-9: GADS vs. MTEP for current system and high renewable system

Another test was done to understand the impact of using a load adjustment verses a generation adjustment to calculate ELCC. The process is demonstrated in Figure TA-10.

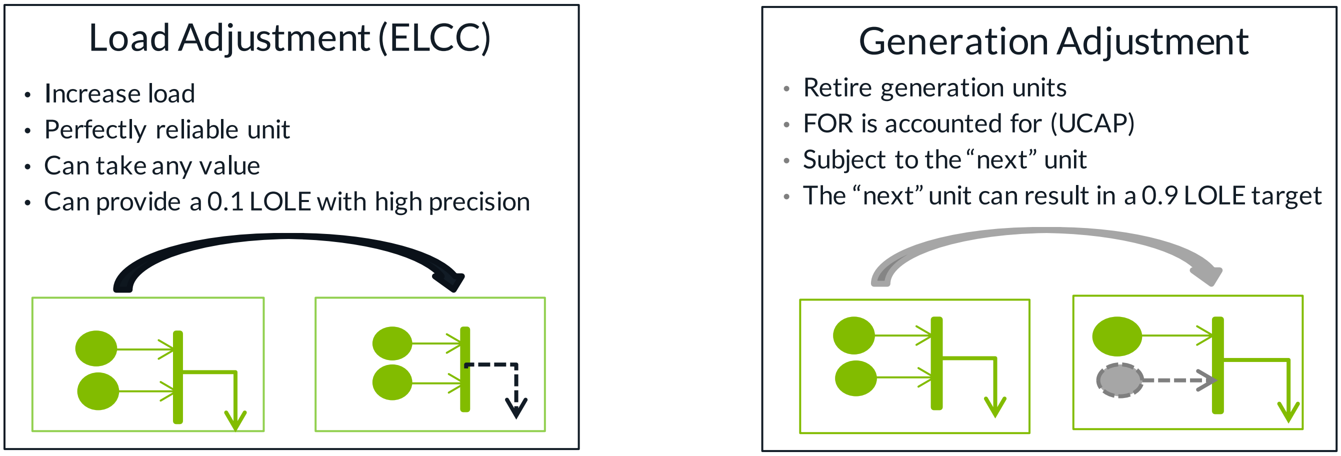


Figure TA-10: Load and generation adjust process

The results of the test show that either method produces very similar results. Table TA-29 shows a consistent negligible difference between these methods for the purpose of understanding trends in ELCC as the penetration of wind and solar changes in the footprint. It is worth noting that the load adjustment initially produces a higher ELCC value and then switches as the penetration of renewables increases.

Capacity Value (%) comparison				
Method	Base	10%	50%	100%
Generation Adjustment	19.66%	21.50%	19.88%	16.03%
Load Adjustment	20.12%	22.54%	17.87%	14.04%
Difference	-0.46%	-1.03%	2.01%	1.99%

Table TA-29: ELCC comparison by adjustment method

Capacity Contribution of Renewables

Other industry work has been conducted on the ELCC of wind and solar both inside and outside of MISO. Figure TA-11 and Figure TA-12 show the results of this work. The general conclusions shown here are directionally consistent with the findings in RIIA.

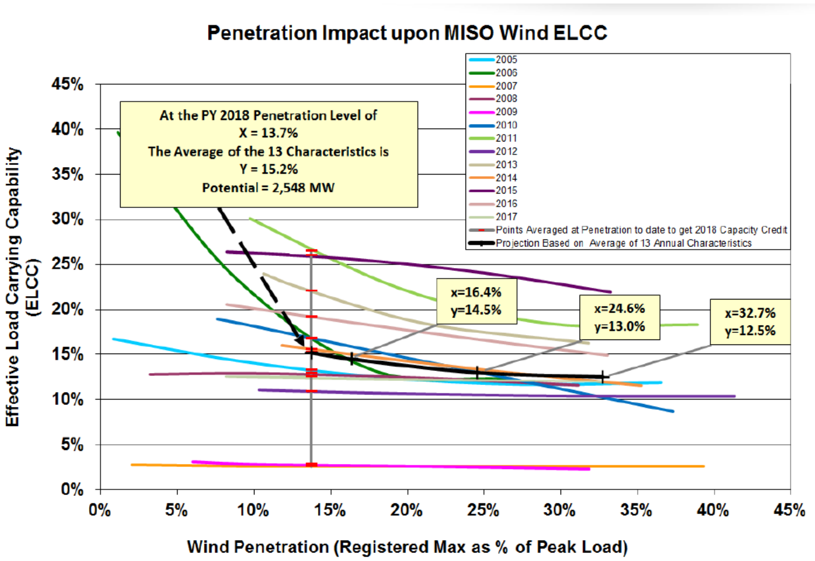
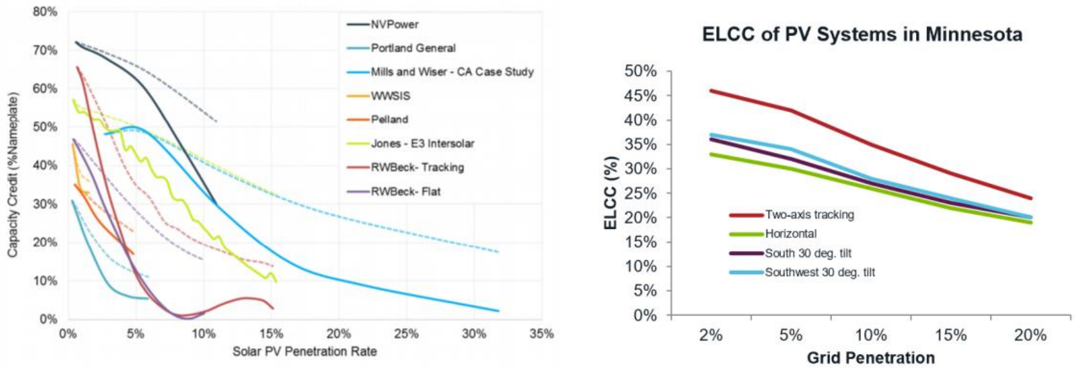


Figure TA-11: Previous MISO Studies have shown a decrease in wind ELCC as penetration increases



DOE, 2016, "Maintaining Reliability in the Modern Power System", Available Online: https://www.energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf

Assessing Minnesota's Solar Resource, Available Online: http://www.minneapolismn.gov/www/groups/public/@citycoordinator/documents/webcontent/wcms1p-084442.pdf

Figure TA-12: Previous industry work on ELCC of solar has shown a rapid decrease as penetration increases

An ELCC function was developed for each renewable technology to inform retirement decisions. The ELCC curve of each technology was characterized using the results from each milestone and a polynomial fitting (Figure TA-13).

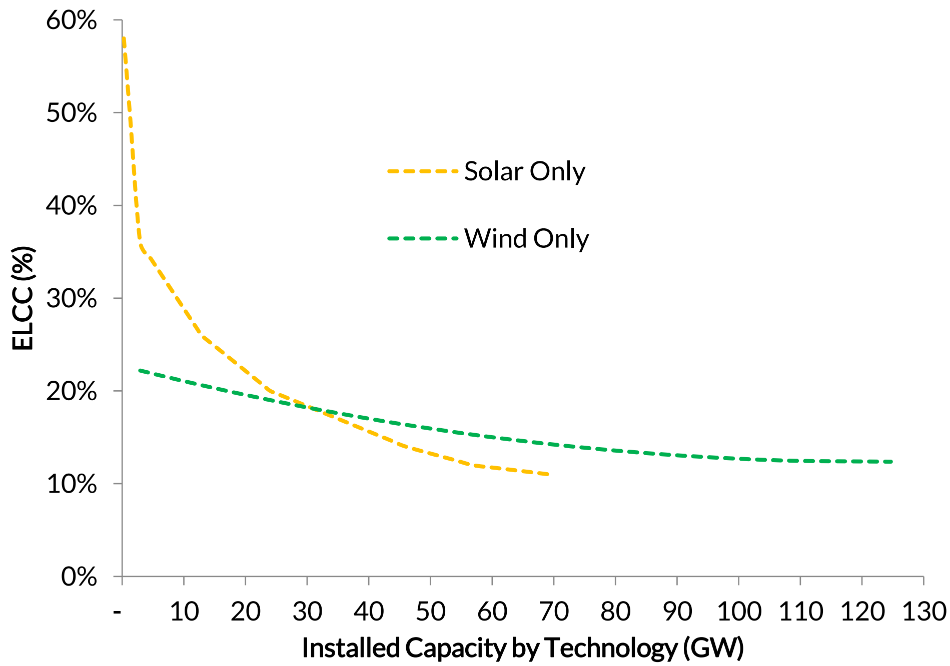


Figure TA-13: Wind and solar ELCC curves as a function of installed capacity

These graphs were approximated by the *siting- and fuel-mix specific* functions in Equation 1, where UCAP is unforced capacity and ICAP is installed capacity, in units of GW.

Equation 1: Approximate ELCC functions for wind and solar

$$\text{Wind } UCAP = 100 * (-0.03 \ln(ICAP) + 0.26), \text{ in percentage}$$

$$\text{Solar } UCAP = 100 * (-0.07 \ln(ICAP) + 0.42), \text{ in percentage}$$

These functions were evaluated for each milestone for each region to determine the appropriate amount of retirements to select.

Retirements

Retirements are incorporated into each milestone to accommodate the new generation. Candidates for retirements will ultimately include all non-renewable fuel types, although some are not initially considered. In the lower-end milestones, nuclear, hydro and combustion turbine (CT) and steam turbine (ST) and internal combustion (IC) renewable units are not considered candidates for retirements. The retirement process involves assessing a unit's viability using costs and revenues, and it is difficult to obtain decommission costs for nuclear units. MISO recognizes that not initially retiring nuclear units is counter to current trends, but it is necessary to work with the available data. MISO will continue to research nuclear retirements to ultimately work them in to later milestones. Hydro units are not initially retired due to lack of precedence. CT/ST and IC renewable units are not retired because they represent a small percentage of total system capacity. These assumptions are consistent with those in MTEP18 but may change as milestones progress.

1. *Determine the capacity contribution of all generators, both current and future.*

For retirement-eligible conventional generation, a unit's contribution to the reserve margin is equal to its maximum capacity multiplied by (1-Forced Outage Rate). For renewable units, the capacity credits developed in the Resource Adequacy focus area are evaluated for the given technology at the given penetration level.

2. *For each milestone, determine the net revenue of each generator using preliminary model results.*

One feature PLEXOS offers is its Medium-Term Scheduling, discussed in page 166. This feature solves the optimization problem by creating regional load duration curves (LDCs) for each user-defined interval then slicing those curves into blocks using a weighted least-squares fit methodology. This method enables accurate results in a shorter period of time. An output of this feature is the net revenue of each unit. Net revenue is calculated using the difference between a unit's revenue (the LMP multiplied by generation) and its variable and fixed O&M costs.

3. *For each milestone, determine the net present value (NPV) of each unit's revenue based on its simulated net revenue and remaining useful life. Rank units by these values.*

For each renewable milestone, a unit's "lifetime" revenue is calculated by assuming that the annual revenue determined at that milestone will persist for the remainder of the unit's useful life. A unit's remaining useful life is taken from Powerbase data (if the date is public) or fuel type specific useful life assumptions (if the date is not public). These assumptions are consistent with MTEP18.

Unit Type	Useful Life (years)
CC	55
CT Gas/IC Gas	50
CT Oil & Other	55
IC Oil/Other	50
IGCC	75
ST Coal	65
ST Gas & Oil	55
ST Other	60

Table TA-30: Generator useful life by fuel type

4. *For each region, retire units until the capacity contribution removed is equivalent to the capacity contribution added by renewables.*

Within the ranked list, retirements begin with units that were not economically selected to run within the preliminary simulation, thus have a 0% capacity factor. When those units have been exhausted, units are chosen based solely on their net revenue ranking. MISO will also consider candidates for retirements identified in MTEP and other MISO processes. The amount of retirements is based on the capacity contribution added by renewables as discussed in page 156.

5. *Add the chosen retirements into the model of the current milestone and the subsequent milestone.*

Retirements chosen in one milestone will section persist for the remaining milestones. Retirements are incorporated into the model for each focus area. Issues associated with retirement choices will be identified and remedied as necessary. This process is, by design, adaptive, and if retirements are causing irreparable issues, one solution may be to reevaluate retirement choices.

Table TA-31 details the retirements derived by this process for each region and milestone.

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MISO	1,206	6,615	10,599	14,673	17,018					
SPP	-	-	1,885	3,829	5,241					
TVA	-	-	-	-	-					
SERC	6,174	10,664	12,846	14,882	16,326					
PJM	4,662	10,527	15,164	19,708	21,351					
NYISO	1,115	2,747	4,022	5,480	6,590					

Table TA-31: Cumulative retirements by region and milestone

Energy Adequacy — Planning Focus Area

The Energy Adequacy focus area is studied in Energy Exemplar's PLEXOS software. PLEXOS offers several interdependent phases for production cost simulations, three of which are used here: PASA, MT Schedule and ST Schedule, each described below.

PLEXOS Modeling Phases

- PASA (Projected Assessment of System Adequacy)
    - *Model or Algorithm:* Linear program (LP)/Simplex
    - *Functions*: The objective is to produce randomly generated maintenance events for all generation resources. PASA schedules maintenance based on availability of reserves. The maintenance schedules are then passed to the MT Schedule and ST Schedule phases for production cost simulations.
    - *Main assumptions*: Maintenance is not scheduled for the summer months of June, July and August (maintenance during periods of higher load is historically infrequent); maintenance is not scheduled for nuclear generators (nuclear maintenance schedules are part of the Powerbase dataset and provided by the Nuclear Regulatory Commission)
- *Relevant outputs*: Maintenance schedules for non-nuclear generators
  MT Schedule (Medium-term Schedule)
    - *Model or Algorithm:* Linear program (LP)/Simplex
    - *Functions*: The objective is to solve the optimization problem using a computationally tractable approach. The MT Schedule simulates typical operating conditions (e.g., load/net load duration curves) and solves a simplified production cost model. MT Schedule also decomposes system constraints that span time periods longer than those used in subsequent phases.
    - *Main assumptions*: Regional transmission representation; non-chronological solve
    - *Relevant outputs:* Generator-specific net revenue used in retirement decisions; dispatch of energy-limited resources (e.g. hydro)
- ST Schedule (Short-term Schedule)
    - *Model or Algorithm:* Mixed-integer linear program (MIP)/Branch and bound
    - *Functions:* The objective is to provide an optimal, chronological dispatch with user-defined time steps over a given period of time. This phase simulates conditions most similar to actual market operations.
    - *Main assumptions:* Chronological dispatch
    - *Relevant outputs:* The majority of outputs in this assessment come from the ST Schedule. The outputs include, but are not limited to, generator properties (output, capacity factor, ramping, and LMPs), load properties (unserved energy, LMPs) and transmission properties (congestion, congestion costs).

- Interleaved Run Mode
  - *Model or Algorithm:*

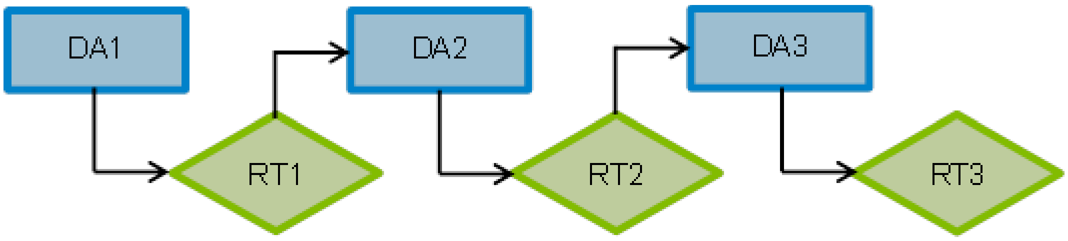


Figure TA-14: PLEXOS' interleave feature

  - *Functions:* The objective of the interleave mode as seen in Figure TA-14 is to enable the passing of data between models so that they are solved "in step". MISO is using this feature to model both a day-ahead and a real-time market. The day-ahead market uses an MT Schedule and an ST Schedule, while the real-time market uses only the ST Schedule. Operating conditions are passed by the model from day-ahead to real-time at the end of each day, and vice versa.
  - *Main assumptions:* Unit commitment decisions are passed from day-ahead to real-time, while economic dispatch can change in the real-time model (except for units with fixed generation profiles)[33]; random forced outages occur in the real-time model and are only passed to day-ahead if they occur over the span of multiple days
  - *Relevant outputs:* ST Schedule results for both day-ahead and real-time simulations

These phases can be run separately or together. PLEXOS production cost modeling is two-pronged: hourly modeling and sub-hourly modeling. For hourly Energy Adequacy modeling, MISO uses the MT and ST schedules. PLEXOS also offers an interleave feature, which allows the user to simulate both a day-ahead and real-time market. MISO will use this feature for 5-minute Energy Adequacy modeling.

Analysis and Solution Development

Put more broadly, the Energy Adequacy production cost model uses the inputs and outputs listed in Figure TA-15.

[33] Units with fixed generation profiles include qualifying facilities, some conventional hydro and other energy-limited resources.

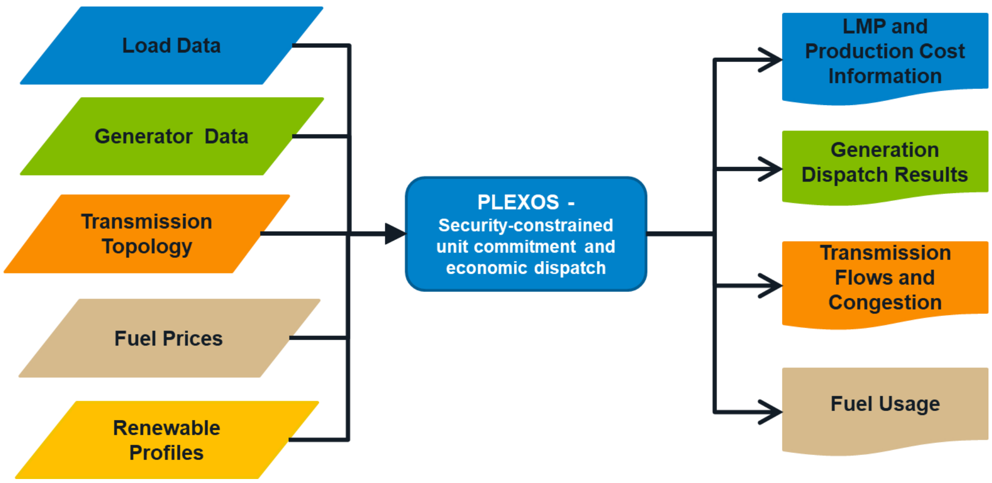


Figure TA-15: Inputs and outputs to the Energy Adequacy model

The input base model for the Energy Adequacy portion of RIIA is taken from MTEP17. Although this assessment aims to remain "year agnostic", for modeling reasons it is necessary to choose a specific year to simulate and this study uses 2017 as a proxy year. The model includes a 15-year out transmission topology, including the remaining Multi-Value Projects (MVPs) and Appendix A transmission. Each milestone's model includes the expansions and retirements discussed in Sections 0 and 0. As these expansions and retirements significantly change dispatch, analysis is performed to determine which flowgates are necessary for monitoring at each milestone. Other detailed assumptions are described in Appendix A of this document.

For a given milestone, the Energy Adequacy output analysis first looks at the percent of load served by renewable energy to determine whether the milestone target has been met. If this metric is within 5% of the target, the milestone is deemed met. If, due to curtailment or other factors, the milestone is not met, more analysis is necessary to develop solutions that enable the appropriate level of renewable energy penetration. Other metrics of note in output analysis are LMPs, capacity factors, reserve shortages, interchange, ramping behavior and transmission congestion. If any of these metrics indicate an inoperable/inadequate system, development of solutions is necessary.

Solution development in Energy Adequacy can take two forms: an optimized transmission build-out or a non-transmission solution. The transmission build-out uses a computer optimization program to identify system needs and design a conceptual transmission design to facilitate the delivery of renewable energy. The objective is to minimize total generation production cost and transmission build cost, subject to defined system constraints. With the input of a set of promising transmission candidates, the optimization program is able to select an economically effective combination of solutions to meet the objective and constraint, and to provide detailed information for engineers to design transmission. The non-transmission solutions could include re-siting renewable resources, changing retirement assumptions, increased reserves, energy storage or fast ramping generation.

Base Dataset

For this assessment, the MTEP17 model is used. This model includes all Appendix A transmission current as of MTEP16 to ensure the assessment will not develop solutions for problems that may be fixed by currently planned transmission infrastructure. This model also includes generation included in MTEP17 with a signed Generator Interconnection Agreement (GIA) with an in-service date before 12/31/2017. Units scheduled to come online and retirements scheduled to take place during the 2017 year are pushed to 1/1/2017 to produce a study year with no generation changes. This document provides assumptions used in this study that differ from those used in the MTEP process. Readers can access information about MTEP17 assumptions in the MTEP17 report.[34]

Study Areas

The Renewable Integration Impact Assessment (RIIA) model comprises the following six areas the combination of which is seen in Figure TA-16:

- Midcontinent Independent System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM Interconnection (PJM)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Tennessee Valley Authority (TVA)

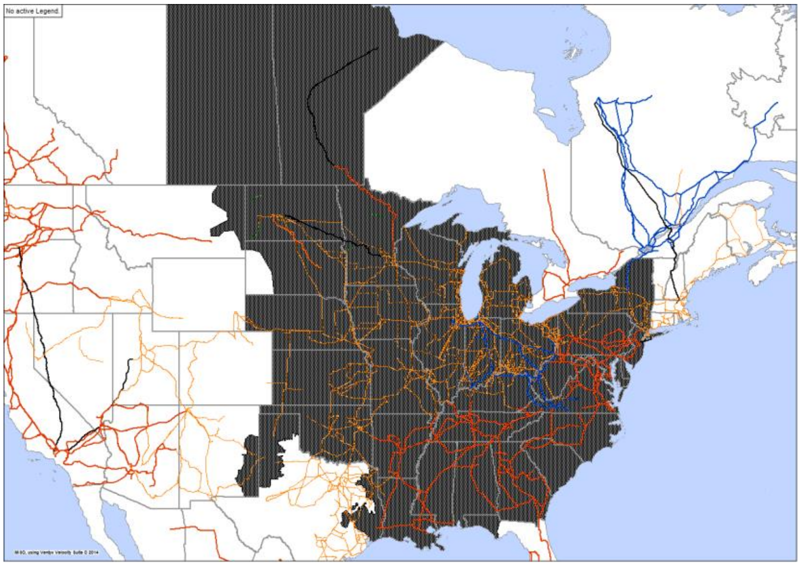


Figure TA-16: RIIA study footprint

Resource Mixes

Each planning region within the Eastern Interconnection is made up of a diverse mix of capacity resources. The base RIIA model's fuel mix is captured in the table below. Results of resource expansions and retirements performed as part of MTEP17 are not included in the RIIA model. Each region is assumed to meet its Planning Reserve Margin Requirement (PRMR) with these fuel mixes.

[34] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP17/MTEP17%20Full%20Report.pdf

	Coal	Gas	Nuclear	Wind	Solar	Hydro	Pumped Storage Hydro	Oil	Other
MISO	63,845	71,954	13,317	18,618	274	2,331	2,447	3,534	1,253
MHEB	97	274	0	258	0	4,476	0	0	0
NYISO	1,379	21,018	5,304	2,237	0	4,938	1,409	3,621	806
PJM	61,989	74,139	34,575	9,018	487	2,970	5,590	9,047	2,002
SERC	32,982	51,175	17,773	250	1,086	6,631	4,626	2,161	745
SPP	25,343	28,988	1,971	16,004	50	4,973	474	1,332	172
TVA	11,747	14,730	8,077	29	381	5,233	1,825	7	50
TVA - Other	8,088	6,599	0	308	0	147	31	69	0

Table TA-32: Base RIIA resource mix by region (MW)

Generator Characteristics

Table TA-33 contains the average values for the generator characteristics used in the model. These assumptions are taken directly from Ventyx (Hitachi ABB) unless otherwise noted.

	Coal	Gas	Nuclear	Hydro	Pump. Hydro	Oil	Other
Min Gen Level (% of Max Cap)	40.2	CC: 50.1 CT: 25.2 ST: 30.7	100	24.5		25.0	35.6
Min Up Time (hours)	15.8	CC: 5.7 CT: 1.8 ST: 22.2	122.8	1		1.8	4.5
Min Down Time (hours)	9.8	CC: 6.6 CT: 2.2 ST: 10.1	122.8	1.6		1.8	5.2
Variable O&M ($/MWh)	1.31	CC: 1.48 CT: 0.80 ST: 1.40	2.52	0	0	0.74	1.71
Forced Outage Rates (% of year)	10	CC: 5.8 CT: 5.8 ST: 9.1	4.8	5.2	NA	6.8	8.8
Maintenance Rates (% of year)	7	CC: 7.4 CT: 3.4 ST: 8.2	Sched. Maint.	6.1	7.7	3.5	3.6

Table TA-33: Generator characteristics by fuel type

Forced outages occur randomly within the simulation and maintenance outages are scheduled using PASA and remain constant throughout the study (see page 166).

Ramp Rates and Start-Up Costs

One major aspect of renewable integration is generation variability. This assessment incorporates a sub-hourly real-time simulation phase with five-minute step sizes, thus there is need for special consideration of unit start-up and ramping assumptions. Typically, MISO production cost models use one-hour simulation step sizes where ramping and unit start-up modeling data provided by ABB is sufficient. Here, the assumptions are reviewed against other industry studies and updated to capture a unit's physical ability to ramp in a five-minute simulation.

NREL's Eastern Renewable Generation Integration Study (ERGIS)[35] is a helpful reference source for review of these assumptions and thus is the basis for the updates to MISO's typically used ABB data.

Ramp Rates

Ramp rate is a unit's rate of change (MW/min) when the output is between the unit's minimum stable level and max capacity. *Run rate* is a unit's rate of change (MW/min) when the output is between zero and the minimum stable output level, or the start-up and shut-down rates. For this assessment, the source for the updates to ramp and run rates is the Black and Veatch[36] study performed for NREL, an analysis that yielded ramp rate data by various unit classes. Spin ramp rate and quick start ramp rate are listed as a percent of max capacity per minute. Spin ramp rate in the B&V study is used as the ramp rate in RIIA. Quick start ramp rate in the B&V study is used for the run rate in RIIA.

Category	Ramp Up & Down Rate (% Max Cap/Min)	Run Up & Down Rate (% Max Cap/Min)
CC	5	2.5
CT Gas/Oil	8.33	22.2
Nuclear	5	5
ST Coal	2	2
ST Gas & Oil	4	4

Table TA-34: Ramp and run rates by fuel type. Unit types not listed use ramp and run rates consistent with ABB's assumptions.

Start-Up Costs

The Power Plant Cycling Costs Report[37,] also prepared for NREL use in the ERGIS study, is a useful reference source for updating the unit start-up assumptions for different thermal unit classes. It includes the cost estimates ($/Max Cap) for hot, warm and cold start-ups, as well as the duration (in hours) of hot, warm or cold starts.

[35] NREL Eastern Renewable Generation Integration Study: https://www.nrel.gov/grid/ergis.html

[36] Black and Veatch. (2012). "Cost and Performance Data for Power Generation Technologies." Prepared for the National Renewable Energy Laboratory. http://bv.com/docs/reports-studies/nrel-cost-report.pdf

[37] Kumar et al. (2012). "Power Plant Cycling Costs." Prepared for the National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy12osti/55433.pdf

	Small Coal (<300 MW)	Large Coal (>=300 MW)	Combined Cycle	Large CT (>=40 MW)	Small CT (<40 MW)	ST Gas
Hot Start Time (h)	<4	<12	<5	<2	0	<4
Warm Start Time (h)	4 to 24	12 to 48	5 to 40	2 to 3	0 to 1	4 to 48
Cold Start Time (h)	>24	>48	>40	>3	>1	>48
Hot Start Cost ($/MW cap.)	94	59	35	32	19	36
Warm Start Cost ($/MW cap.)	157	65	55	126	24	58
Cold Start Cost ($/MW cap.)	147	105	79	103	32	75

Table TA-35: Start-up costs by fuel type

Fuel Prices

Fuel price assumptions are also taken from MTEP17 futures and are discussed in the following sections.

Natural Gas Prices

The Henry Hub natural gas price as shown in Figure TA-17 is the base price input to the model, with location-specific adders used to represent more granular prices. This natural gas price is the verbatim NYMEX forecast, as discussed in stakeholder forums during MTEP futures development.

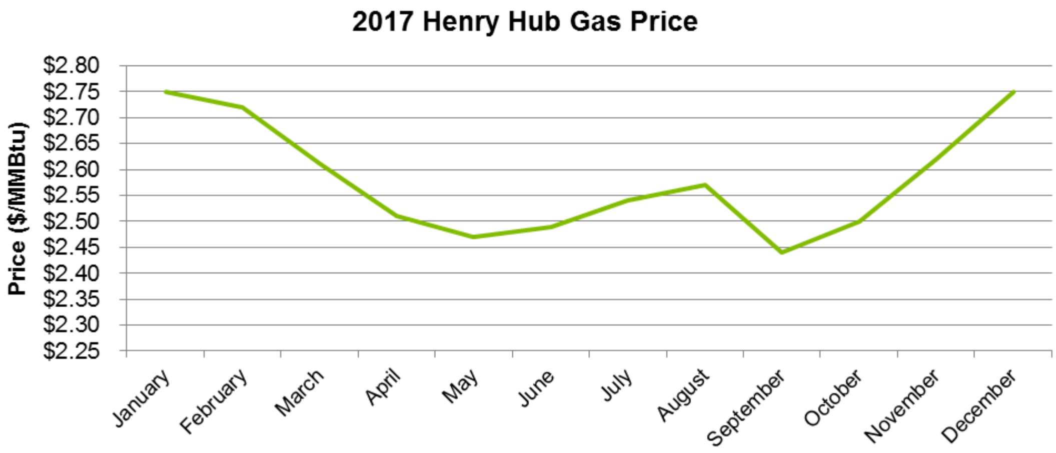


Figure TA-17: Monthly natural gas prices

Other Fuel Prices

The remaining fuel prices are listed in the Table TA- 36: Fuel prices. Several other fuel types also use location-specific prices. In those cases, the values are average values.

Fuel	Fuel Price ($/MBtu)
Coal	2.52
Kerosene	11.71
Oil-H	7.73
Oil-L	11.41
Uranium	1.11
Other	1.74

Table TA- 36: Fuel prices

Load Profiles

MISO's local balancing authority (LBA)[38] five-minute load profiles are obtained for 2012 from historical market data. Hourly load profiles are obtained for areas outside of MISO from PROMOD (Ventyx [Hitachi ABB]), and then adjusted to create five-minute load profiles. This process is necessary due to the lack of publicly available five-minute load data. It is described in detail in the following sections.

Hourly and Sub-Hourly Load Profiles

To create hourly load shapes for MISO LBAs, five-minute load values are averaged across each hour (e.g. 12:00-12:55). The load profile is scaled within the PLEXOS simulation from 2012 to 2017 using the ratio of each LBA's peak in MTEP17 and each LBA's 2012 hourly peak obtained by the averaging method.

Hourly profiles for areas outside of MISO for 2012 are obtained from Ventyx (Hitachi ABB). Using these 2012 profiles and data gleaned from MISO's five-minute load profiles, five-minute load shapes are developed for non-MISO areas. The process involves identifying patterns in five-minute load changes in MISO data and applying those patterns to the non-MISO hourly data. This creates load shapes that capture realistic variation that would not be present through simple interpolation, which is essential for the five-minute simulations used in this assessment. For a detailed explanation of this process, see Hourly and Sub-Hourly Load Profiles.

Data Processing

Within the 2012 five-minute load data, several LBAs have irregular dips and spikes in their load shapes. While a certain level of volatility is anticipated, extreme dips/spikes can often be attributed to metering errors. For this study, dips/spikes with a percent change from annual peak greater than 3-5% (depending on the size of the area) lasting 5-10 minutes are removed. As an example, Utility A had three such errors (dips) (left, Figure TA-18). By taking the load values from either side of the event and averaging their difference across the low (or high) period(s), these events are erased to obtain a smoother load shape (right, Figure TA-18). Dips/spikes below the 3-5% threshold is considered regular occurrences and assumed to represent expected levels of variation.

38 An operational entity or a Joint Registration Organization which is (i) responsible for compliance with the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the MISO Balancing Authority Area, (ii) a Party to Balancing Authority Agreement, excluding MISO, and (iii) shown in Appendix A to the Balancing Authority Agreement.

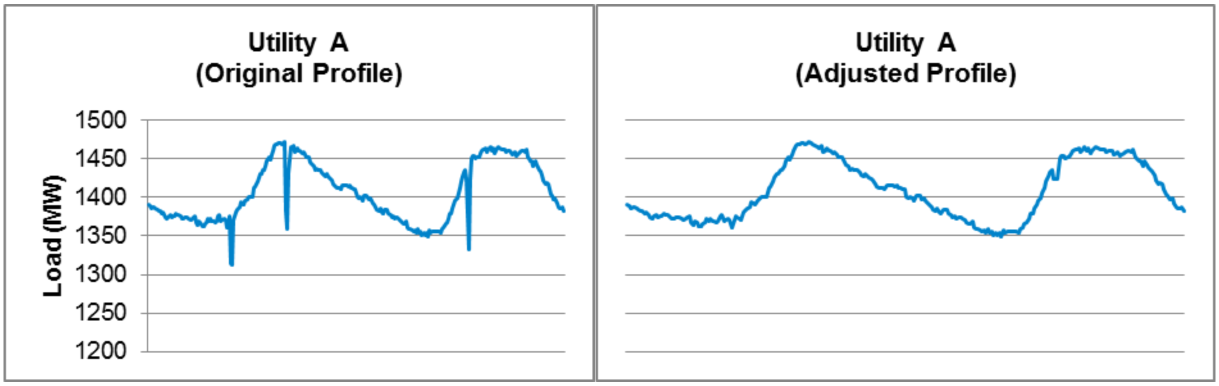


Figure TA-18: Utility A's load profile before and after data processing

Forecast Error

For this assessment, the PLEXOS interleave feature was planned to be used to simulate both the real-time and day-ahead markets. Because the hourly load shapes (for use in the day-ahead simulation) are calculated from the five-minute load shapes (for use in the real-time simulation), there is not a significant amount of error between the day-ahead forecast and real-time load. Some amount of error is expected to more accurately represent the relationship between day-ahead and real-time load. Due to complication in analysis, the interleave function was not used in the final analysis, but the data was used to understand the change in risk due to forecast error as seen in Energy Adequacy — Uncertainty and Variability Trends.

The historical market data used also provides hourly real-time load and hourly day-ahead load forecasts for MISO as a whole for 2009-2016. Loads are not forecasted at the LBA level. The error between the actual load and forecasted load is calculated for all years. The error from 2012 was applied to each of the MISO LBAs' day-ahead forecasts, and the errors from the remaining years are applied to external regions (e.g. apply 2007 error to PJM, 2008 error to SPP, etc.). Using different years for different regions provides error values that are in the range of historically accurate values and unique for each region in the model. The forecast error of MISO's footprint for a sample week shown in Figure TA-19.

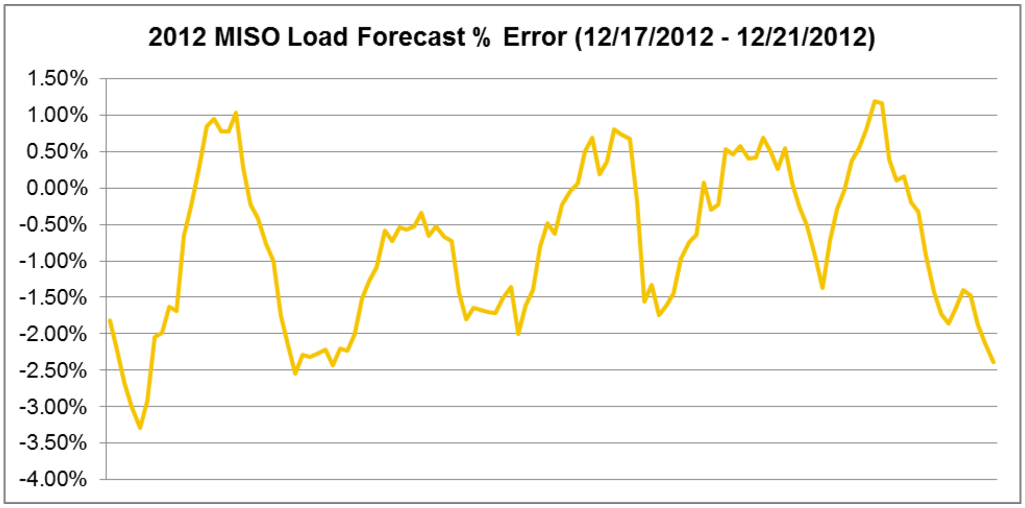


Figure TA-19: MISO's load forecast error

Renewable Profiles

The ongoing seams study performed by the National Renewable Energy Study (NREL) concluded that 2012 represents the year with the most typical meteorological conditions of wind, solar and hydro generation. MISO has historically used 2006 renewable and load profiles, but beginning with MTEP18, MISO will use a 2012 profile year. NREL's data is used to provide these 2012 profiles, the details of which are described below.

Wind Profile Source

Wind profiles source from NREL's Wind Integration National Dataset (WIND) Toolkit[39]. Meteorological conditions are captured at 5-minute intervals for 126,000 2-km x 2-km sites in the continental United States for years 2007-2013. Power output provided by NREL is estimated from the wind data by assuming a 100-m hub height. In addition, hourly forecast data is also available for every site at 1-hour, 4-hour, 6-hour, and 24-hour horizons.

Existing and expansion wind sites in the PLEXOS model are assigned a profile based on the closest NREL site to the modeled sites' latitude and longitude. Existing sites (with few exceptions) are assigned 80-m hub height profiles and expansion sites are assigned 100-m hub height profiles. The 80-m hub height profiles are obtained by scaling the 100-m profiles[40]. Both sub-hourly generation profiles for real-time modeling and hourly 24-hour forecast generation profiles for day-ahead modeling are used in the RIIA model.

Solar Profile Source

Solar profiles source from NREL's Solar Integration National Dataset (SIND) Toolkit[41]. In the latest toolkit available at time of study, meteorological conditions are captured at 30-minute intervals for more than 154,000 4-km x 4-km sites in the United States for years 2007-2012. Power output provided by NREL is estimated from the solar data and categorized based on solar technology type: single-axis tracking, fixed axis, or rooftop. Forecast data is not available at time of the study.

Existing and expansion solar sites in the PLEXOS model are assigned a profile based on the closest NREL site to the modeled sites' latitudes and longitudes. For the real-time model, the sub-hourly single-axis tracking generation profiles are interpolated via PLEXOS for utility scale solar while distributed generation is assigned interpolated sub-hourly rooftop profiles. Since solar forecast data is in development, MISO uses an hourly aggregation of the sub-hourly solar data as a proxy in the day-ahead model.

Wind and Solar Profile Source for Sensitivity Analysis

Additional data was sourced from Vibrant Clean Energy (VCE) for the purpose of robustness testing in the RIIA sensitivity analysis.

VCE provides a normalized power dataset for both wind and solar technologies for various weather years based on the National Oceanic and Atmospheric Administration's (NOAA) High Resolution Rapid Refresh (HRRR) weather forecast model. The power dataset is the best available estimate of what the synchronous wind and solar power profiles looked like across the contiguous United States (CONUS). These are provided on a calendar year basis, gridded spatially at 3km and temporally at five minutes. The calendar years originally provided to MISO were for

[39] https://www.nrel.gov/grid/wind-toolkit.html

[40] Factors used to scale 100-m profiles to 80-m profiles are calculated using MISO market historic output energy from specific units, compared to the output energy from the 100-m profiles. When unit-specific data is not available, the scaling factor is developed by comparing 80-m and 100-m NREL profiles from years where both heights are available.

[41] https://www.nrel.gov/grid/sind-toolkit.html

2014 through 2018. The input weather data is obtained from the NOAA HRRR weather forecast model, which is a specially configured version of Advanced Research WRF (ARW) model. The HRRR is a run hourly on a 3-km grid resolution and its domain covers the continental United States as well as portions of Canada and Mexico. Since its inception, the HRRR has undergone rapid and continuous improvement to its physical parameterization schemes, many of which have specifically targeted improved forecasts for the renewable energy sector. Through collaborative research efforts between Department of Energy (DOE) and NOAA, projects such as the Solar Forecast Improvement Project (James et al. 2015, Benjamin et al. 2016), the Wind Forecast Improvement Projects I and II (Wilczak et al. 2015, Shaw et al. 2019) were conducted to improve forecasts of meteorological quantities important for wind and solar energy forecasting.

Creating non-MISO Load Shapes

1. Create a matrix MI_h containing the change in MISO LBA load ML_h from the beginning of one hour, *h,* to the beginning of the next hour, *h+1*, over all hours for each MISO LBA. Create a matrix MR_h with the hourly percent change using these values.

$$MI_h = [(ML_{h+1} - ML_h) \quad \cdots \quad (ML_{h+8783} - ML_{h+8782})]$$

$$MR_h = \left[\frac{ML_{h+1} - ML_h}{ML_h} \quad \cdots \quad \frac{ML_{h+8783} - ML_{h+8782}}{ML_{h+8782}}\right]$$

2. If the absolute value of the percent change between two hours MR_h is greater than 0.25%, calculate the ratio of *the difference between each 5-minute interval i in an hour and the first interval of that hour* and *the MW difference between the two hours* MI_h.

$$MP_{h,i} = \left[\frac{ML_{h,i+1} - ML_{h,i}}{MI_h} \quad \cdots \quad \frac{ML_{h,11} - ML_{h,0}}{MI_h}\right]$$

If the value of a given of $MP_{h,i}$ is greater than 300% or if the percent change between two hours MR_h is less than 0.25%, consistent growth is assumed, thus $MP_{h,i} = i/12$.

The bounds of 0.25% and 300% were chosen using engineering judgment to prevent the passing of atypical data from MISO load data to non-MISO load data.

3. Calculate an average percent change per interval across all MISO LBAs for the entire year.

$$MA_{h,i} = \begin{bmatrix} avg(|MP_{h,i}|) & \cdots & avg(|MP_{h,i+11}|) \\ \vdots & \ddots & \vdots \\ avg(|MP_{h+8783,i}|) & \cdots & avg(|MP_{h+8783,i+11}|) \end{bmatrix}$$

4. Create a matrix NL_h containing the hourly load values for non-MISO LBAs. Create a matrix NI_h containing the change in non-MISO LBA load NL_h from the beginning of one hour, *h,* to the beginning of the next hour, *h+1*, over all hours for each non-MISO LBA.

$$NL_h = [NL_h \quad \cdots \quad NL_{h+8783}]$$

$$NI_h = [(NL_{h+1} - NL_h) \quad \cdots \quad (NL_{h+8783} - NL_{h+8782})]$$

5. Finally, calculate the load values for each 5-minute interval *i* in matrix $NL_{h,i}$ using values from NL_h, NI_h and $MA_{h,i}$.

$$NL_{h,i} = NL_h + NI_h * MA_{h,i}$$

Energy Adequacy — Market and Operation Focus Area

Methodology

The Energy Adequacy — Market and Operation Focus Area, also referred to as the Portfolio Evolution Study (PES) navigates different timescales to simulate detailed operational and market outcomes. The general methodology is shown in Figure TA-20. PES utilizes both current MISO production data and models, as well as future renewable portfolios developed in RIIA, as inputs to the models. The modeling tools then feed longer-term forward-looking solutions into the shorter-term finer granularity processes.

The tools used in study include (a) MISO production engines for commitment, clearing, dispatch and pricing, (b) KERMIT (Regulating reserves simulation tool); and (c) other simplified commitment and clearing engine models.

This method allows us to examine the evolution of portfolios and its associated uncertainty from the day-ahead market down to the real-time market. In particular, PES investigates the impact to the market due to the potential future changes in portfolio, including:

- Renewable penetrations of up to 40% of system-wide load level
- Load Modifying Resources up to additional 5 GW (on top of current portfolio)
- Battery storage up to 200 MW-capacity and 800 MWh energy storage capability (currently in Automatic Generation Control [AGC] study only)

The PES also includes the following modeling features in market and operation, including:

- Use as-is Net Scheduled Interchange (NSI) without modification.
- The virtual offers and bids are unchanged from the current Day Ahead market levels.
- "Must-run" units from the current Day Ahead market are preserved as in the original production data.
- To model the 40% renewable penetration level, a high level of solar production is assumed for exploring the impact on potential operational needs.
- A total of four weeks of data from 2017-2018 with each representative week selected from a different season. Note that three of the weeks had experienced Max-Gen events.
- Use as-is transmission system, i.e., no rebuild of transmission.
- The solar resources are spread out on the market footprint to avoid congestion focus.
- Wind and solar resource energy offers were offered at a flat 0 $/MWh.

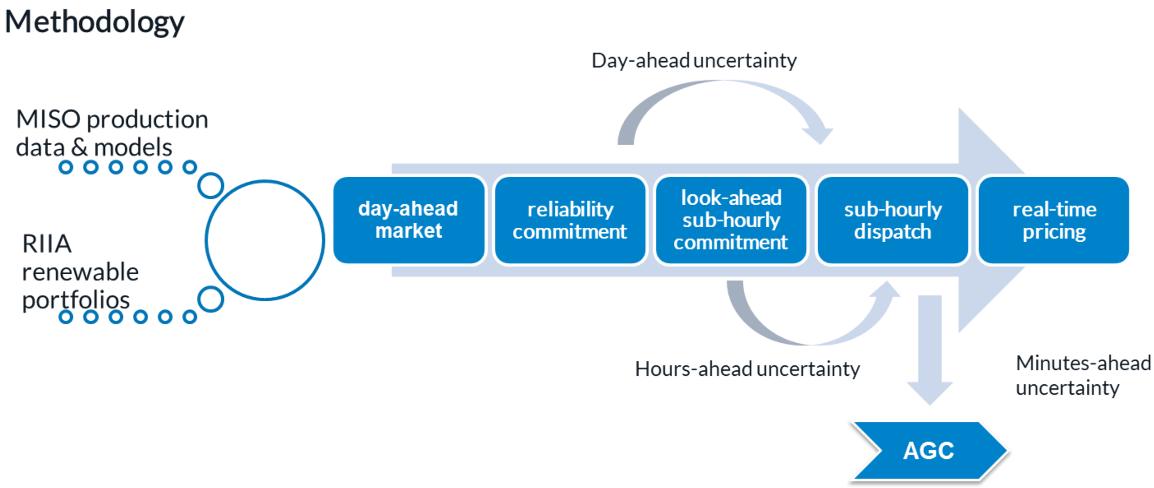


Figure TA-20: Day-Ahead and Real-Time Market Operations Analyses

Figure TA-21 is an itemization of the key metrics in the PES. In terms of Unit Commitment, the impact of additional time granularity on commitment is investigated as well as the timing. For dispatch and balancing, ramp rates and regulation are analyzed for the future portfolios. Deliverability is also being considered for studying whether and how ancillary service requirements could be met during times of congestion in the future scenarios, and how the requirements may have to be evolved. Finally, the impact to prices in terms of scarcity, as well as price volatility, are studied.

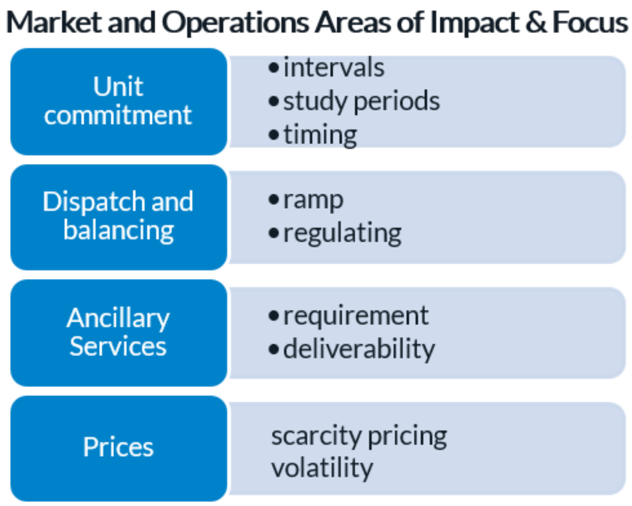


Figure TA-21: Market areas of impact and focus

Operating Reliability — Steady State Focus Area

The Operating Reliability focus area is divided into two categories: steady-state analysis and dynamics analysis. Per the process map (Figure TA-1), models are created first for steady-state analysis then passed and transformed for dynamics analysis.

Tool and Model Data Background

Steady-state analysis is performed using Siemens' PSSE powerflow simulation software and PowerGem's TARA. PSSE and TARA's AC contingency analysis allows for the identification of voltage and thermal reliability issues as a result of generation and transmission contingency events.

Steady-state models will be based on the MTEP17-5-year out models. This series was chosen for consistency between steady-state and dynamics models. The closest MTEP17 model to the given study scenario were chosen as a starting point (e.g. to build a low load-high renewables RIIA model the MTEP17 2022 Light Load case will be the starting point).

Three power-flow models are required for each renewable level (like 40% and 50%) — one for each snapshot of load and generation chosen. The topology of all three models were made consistent to represent consistent electrical topology. The primary benefit of this practice is all the mitigations identified in RIIA study are deemed due to RIIA, instead of being possibly due to a missing MTEP project or other facility.

Grid-Scale Generation Modeling

Modeling of wind and grid-scale solar in the powerflow model included a generator step-up transformer topology. Renewable siting was split into segments of no more than 300 MW, with each generator possessing its own

Generator Step-Up (GSU) and Point-of-Interconnection (POI) transformer. All generators (both wind and grid-scale solar) were modeled with a PSSE Reactive Power Control Mode of 2, which means that Q limits are based on a Power Factor of ± 0.95 applied to the unit's active power output. This represents a "triangular" reactive capability curve, as opposed to a "rectangular" curve in which the entirety of the ± Q range is available at all active power output levels42. Wind units were given an Mbase of 1.11* Pmax and an Xsource of 0.8. PV and Type-IV wind units were given an Mbase of 1.11*Pmax and an Xsource of 999.

The renewable units were sited at a 0.69 kV bus, with a GSU transformer connecting it to a 34.5 kV bus. The GSU was modeled per WECC recommendations, with 6% impedance and an X/R ratio of 8. A POI transformer was connected to the 34.5 kV bus to the BES bus at which the generator is ultimately interconnected. Collector system impedance was ignored as it is specific to any wind or solar site, and generic assumption could not be made for such a large number of diverse siting. The POI transformer was modeled per WECC recommendations, with 8% impedance and an X/R ratio of 40. For example, Figure TA-22 shows the siting for 500 MW of grid-scale solar interconnected at a 230 kV bus. The siting is split into two segments: 300 MW and 200 MW. For more details on siting amounts and locations, refer to 144 of this document.

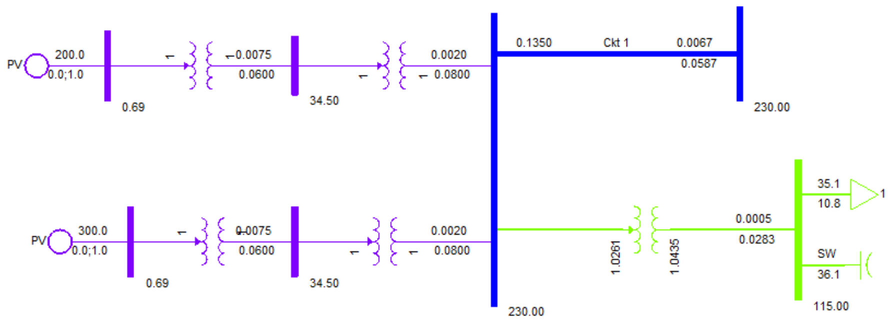


Figure TA-22: PSSE configuration for 500 MW of grid-scale solar

Distributed Generation Modeling in Steady-State

Distributed solar generation were modeled as a Retail-Scale Distributed Energy Resource (R-DER). These are single-phase units and are used to offset customer loads. For the sake of simplicity, DG units will be modeled in both Operating Reliability analyses as constant-current negative loads sited directly on the BES load bus. DG units were assumed to not provide any reactive power support.

It is worth noting that at the time of commencement of RIIA study, the latest DER models such as DER_A were still under development and could not be used in the study.

Powerflow Model Dispatch

The PSSE Powerflow models was developed based on snapshots of "stressful" periods by examining the hourly output of the Energy Adequacy focus area. Following criteria was used to select candidates of these "stressful" dispatch scenarios, but are not limited to:

- Periods of peak system demand with high instantaneous renewable penetration
- Periods with the maximum non-synchronous generation online
- Periods with the highest percentage of total energy from non-synchronous generation

42 Per FERC clarification on Order 827 (https://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf paragraph 49)

- Periods of lowest system load with high instantaneous renewable penetration
- Periods with maximum transfers across existing (or new) monitored transmission interfaces

Dispatch scenario selection varied under different renewable milestones. RIIA focused on peak and off-peak load and peak renewable system conditions, providing samples representative of year-round grid operating patterns to bound the majority of system issues likely to occur under “stressful” operating bookends. The selection criteria below could be adjusted to better suit the needs of future studies under higher system renewable penetration level where the operating states may drastically change from today.

1 Peak load: highest renewable percentage hour among the top 20 highest loading hours

2 Off peak load/Light load: highest renewable percentage hour among the 20 lowest loading hours

3 Peak renewable: lowest load hour among the top 20 highest renewable generation hours

Figure TA-23 illustrates an example of MISO-wide renewable generation versus MISO-wide load for 8760 snapshots during a year-long PLEXOS simulation. The selection of the three study scenarios in Figure TA-23 ensures that nearly all possible operating conditions are accounted for i.e. the “problem is bounded”. Generally, the system inertia decreases as instantaneous penetration of renewables increases, which was one of the key considerations for selecting

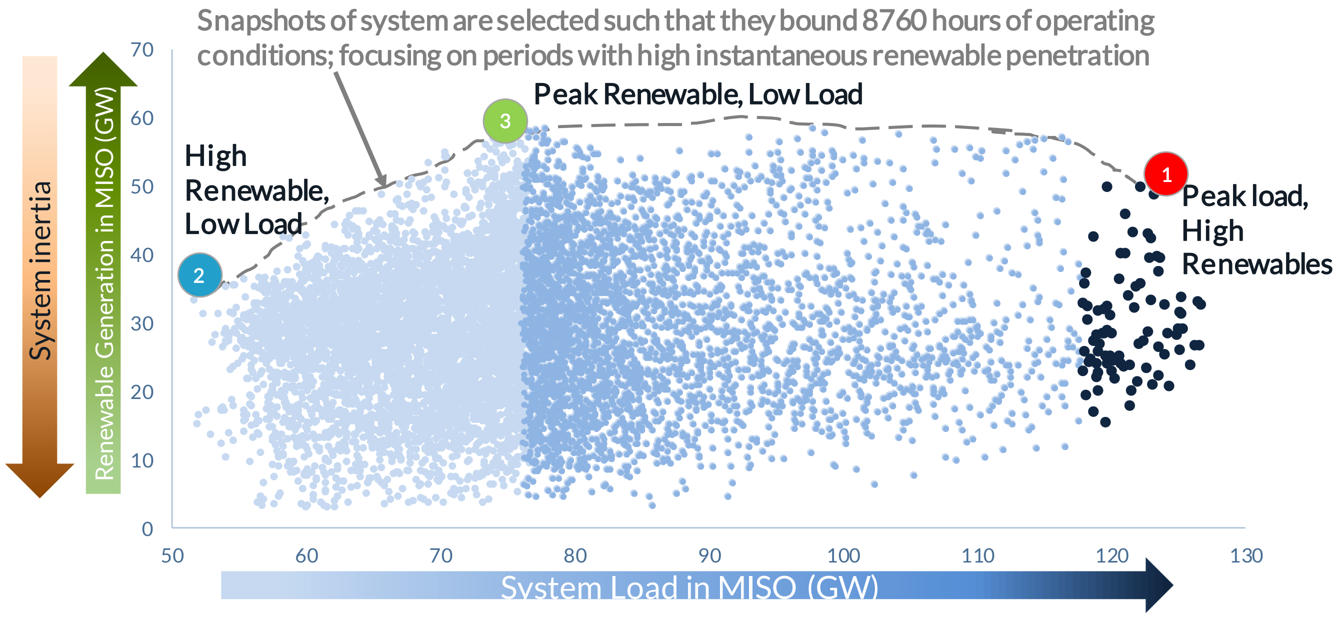


Figure TA-23: MISO renewable generation vs. load in the 40% milestone

The dispatch of wind and solar (distributed and grid-scale) and conventional generator from these snapshots in the PLEXOS model were applied to the PSSE model using a PLEXOS-to-PSSE unit mapping. Similarly, area loads in PSSE were scaled based on load levels in the PLEXOS model during each of these snapshots. For external areas, the dispatch of wind and solar was obtained from PLEXOS, however, conventional generation in each powerflow area were adjusted based on economic merit order to compensate for changes in load and renewable generation levels. A summary of models developed in Steady-state analysis is provided in Table TA-37.

RIIA Milestone	RIIA Snapshot Number	Total Renewable Output (GW)	Total Conventional Output (GW)	Renewable as % Output
Base	1	6.7	119.9	5%
	2	16.0	100.3	14%
	3	17.9	57.8	24%
20%	1	16.0	110.1	13%
	2	30.1	86.2	26%
	3	33.2	42.6	44%
30%	1	37.1	86.3	30%
	2	25.9	27.4	49%
	3	42.0	25.2	63%
40%	1	51.4	72.0	42%
	2	35.7	17.6	67%
	3	60.3	13.9	81%
50%	1	61.5	62.5	50%
	2	43.9	9.4	82%
	3	69.8	8.5	89%

Table TA-37: Summary of steady state models developed for analysis

Powerflow solution criteria and input model quality

The power-flow models were solved with all adjustments enabled, except for Area Interchange; the maximum mismatch tolerance was 3.0 MW and Mvar. Generator terminal voltages generally need to be within an acceptable range. Voltage of other buses were monitored and ensured that they are withing acceptable range (0.95<Voltage<1.05 pu). Following process was used for monitor and update the terminal voltage of new renewable units through the application of MISO developed script.

1) Input powerflow models were screened to ensure voltage profile of new units is in the range 0.95<V<1.05 pu
2) A script developed to perform checks, correct the voltages of future renewable generator sites in following order
   a) Update powerfactor value
   b) Update power factor and remote bus control
   c) Add switched shunt to POI if # a) and # b) is unsuccessful
   d) Manually fix if #c) is unsuccessful, manually add switched shunt if needed at the Point of Interconnection or collector system bus (34.5kV)

Ensuring input models for steady-state and dynamic analyses have good voltage profile has two significant advantages: 1) it ensures that simulation is not noisy and real issues are easily identified, and b) more importantly, it uncovers the need for mitigations. For example, the script developed to perform checks on powerflow models to tune generator terminal voltages indicated 72 locations needed switched shunts in 30% milestone and 19 of the locations were converted to STATCOM during dynamic stability analysis. The exercise also indicated the 30% final steady-state models (which are input to 30% dynamic models) post screening for terminal voltage of renewable units outside the bounds of 0.95 pu to 1.05pu, 30% snapshot 3 showed (Figure TA-24) 8.4 GVar difference in the net reactive power output after the improvement was implemented.

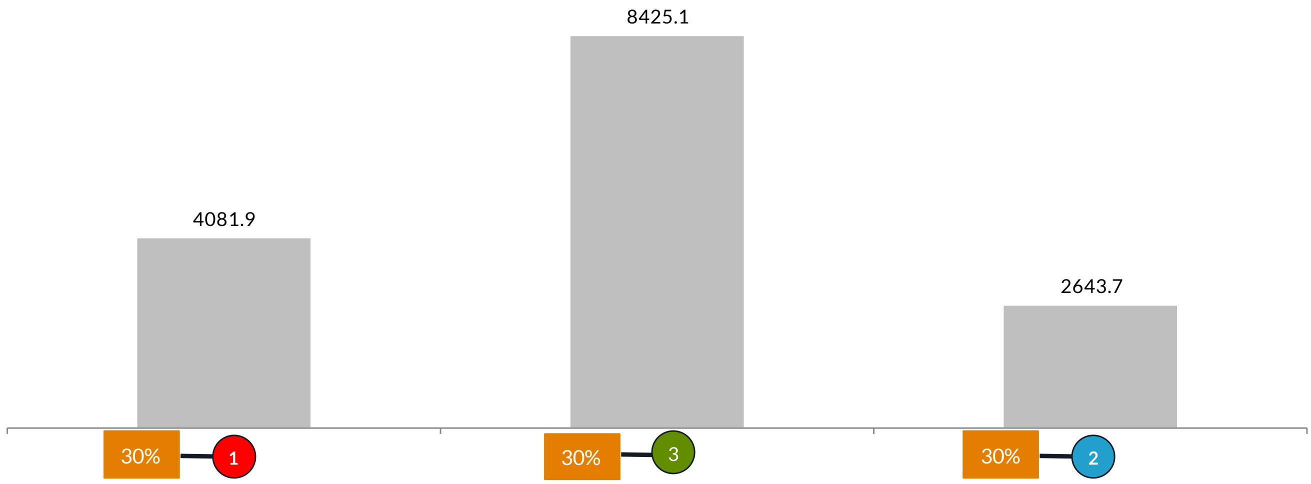


Figure TA-24: Difference between total reactive power (Mvar) output in the input 30% steady state model and starting dynamic input powerflow model

Scope of Equipment to be Mitigated Under Steady-State Study

All transmission facilities 100 kV and above will be monitored for MISO and its first-tier neighbors, and a contingency analysis consisting of P1 events and 230 kV and above P2 events[43] were applied for MISO and its first-tier neighbors using MTEP 17 series base contingency files.

The analyses used the following Bulk-Electric System definition per NERC to determine facilities to be mitigated:

1) Transmission lines > 100 kV
2) Transformers with at least two windings > 100 kV
3) Generator step-up transformers for plants > 75 MVA and units > 20 MVA.

Issue Fix Development in Steady-State

For identified system thermal overload and voltage violations, a screening process was performed to focus on the high-likelihood events that tend to cause severe reliability violations on MISO system (Table TA-38).

[43] https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf pg. 1956

Violation Criteria	
Thermal Overload	**Voltage Violation**
Criteria for Thermal Overload • A line or branch was considered overloaded if it overloaded more than 103% of its emergency rating and more than 5 MVA above its applicable rating — normal rating or emergency rating. The 3% and 5 MVA adder was included to focus on more sever issues, and to isolate some of the issues arising from basecase models. • Thermal violation that did not show up in base case or show up in base case but increased by at least 5MVA and 3% of circuit emergency MVA rating in current milestone. • Erroneous contingencies were screened out or other non-actual issues (like overloads covered by op-guides). • If a contingency did not solve in the basecase, the practice was to not attempt to solve it in the study Case (with added RIIA generation).	Criteria for Voltage Violation • Voltage criteria per Local Planning criteria of MISO transmission operators was utilized to define voltage violations. • Voltage violations that did not show up in base case or significantly more severe from the most severe scenario in base case (more than 5%). • If a contingency did not solve in the basecase, the practice was to not attempt to solve it in the study Case (with added RIIA generation).
Mitigation Criteria	
Thermal Overload	**Voltage Violation**
• Fix thermal overloads on BES (100kV above monitored) elements in MISO footprint • Fix severe thermal overload issues in external system.	• Mitigations were focused on low voltages issues, occurring in all three scenarios. If voltage violations are ±5% across all the milestone, the equipment was upgraded. If a voltage violation was not observed in all 3 scenarios, 10% threshold was used
Mitigation Technique A step-by-step approach is being developed to reflect the band-aid system issue mitigation practice widely implemented in industry, instead of trying to find the optimal minimum cost solutions. The mitigations are shown in order of preference below.	
Thermal Overload	**Voltage Violation**
• Re-build the line to a higher rating (per modified MIO's Competitive Transmission Administration's minimum design requirements) • Re-build existing facility to a higher voltage class • Build a new transmission project • Other types of transmission or non-transmission fixes	• Reactive support device (switched cap bank, switched inductor) • Other types of transmission or non-transmission fixes

Table TA-38: Steady-state violation, mitigation criteria and mitigation technique

Operating Reliability — Dynamic Stability Focus Area

Tool and Model Data Background

Operating Reliability's dynamics analysis uses TSAT to look at the impact of high levels of renewable penetration on voltage stability, transient stability and MISO's frequency response obligations. This focus area uses the models developed as part of the steady-state powerflow analysis (Table TA-37) and MTEP17 dynamic data as base-models, and mapping of TSAT models[44] (Table TA-39).

Milestone	RIIA Snapshot Number	TSAT Name
Base	1	RIIA_Base_Snapshot1_July_18_4 pm
	2	RIIA_Base_Snapshot3_March8_2am
	3	RIIA_Base_Snapshot2_June20_8pm
20%	1	RIIA_20p_Snapshot1_July_24_4pm
	2	RIIA_20p_Snapshot2_June20_3pm
	3	RIIA_20p_Snapshot3_March8_28_2pm
30%	1	RIIA_30p_Snapshot1_July26_3pm
	2	RIIA_30p_Snapshot2_April9_5am
	3	RIIA_30p_Snapshot3_Feb26_3pm
40%	1	RIIA_40p_Snapshot1_July26_3pm_VSC
	2	RIIA_40p_Snapshot2_April9_5am_VSC
	3	RIIA_40p_Snapshot3_Oct_2pm_VSC
50%	1	RIIA_50p_Snapshot1_July26_4pm_wSCs_PSS
	2	RIIA_50p_Snapshot2_April9_12pm_wSCs_PSS
	3	RIIA_50p_Snapshot3_Oct18_11am_wSCs_PSS
	2'	RIIA_50p_Snapshot2_April9_12pm_wSCs_PSS_wFreq_Batteries
	3'	RIIA_50p_Snapshot3_Oct18_11am_wSCs_PSS_wFrq_Batteries

Table TA-39: Dynamic model names corresponding to Steady state models

Grid-Scale Renewable Generation Dynamic Parameters Modeling

Consistent with modeling practice of wind and grid-scale solar in the powerflow models, RIIA uses WECC 2nd generation models for dynamic representation. A standard set of dynamic models for newly sited wind and solar generation was compiled, with the assumptions that these resources do not observe momentary cessation phenomenon[45] (Table TA-43, Table TA-44, Table TA-45, Table TA-46, Table TA-47, and Table TA-48). Wind resources were equally represented by Type-3 and Type-4 technologies. Solar resources are considered large scale utility type

[44] MISO has posted RIIA TSAT models on its secured file transfer site per the name indicated in Table TA-39

[45] NERC report on Southern California 8/16/2016 Event involving momentary cessession, available online : https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf

resources. Future renewable resources will be assumed to operate in modes shown in Table TA-40 and small test system was used to evaluate the dynamic response of a wind farm Figure TA-25.

Control Modes	Type 3 Wind Turbine	Type 4 Wind Turbine	Grid scale Solar plant	Grid Scale Battery
Reactive power Control Mode: Voltage Control at Point of Interconnection	Yes	Yes	Yes	Yes
Active power control (Primary frequency control)	Capability modelled, but headroom was assumed to be zero.			Capability modelled; assumed non-zero state of charge.
Certain control parameters were tuned and updated during the course of study				

Table TA-40: Control modes for renewable plants

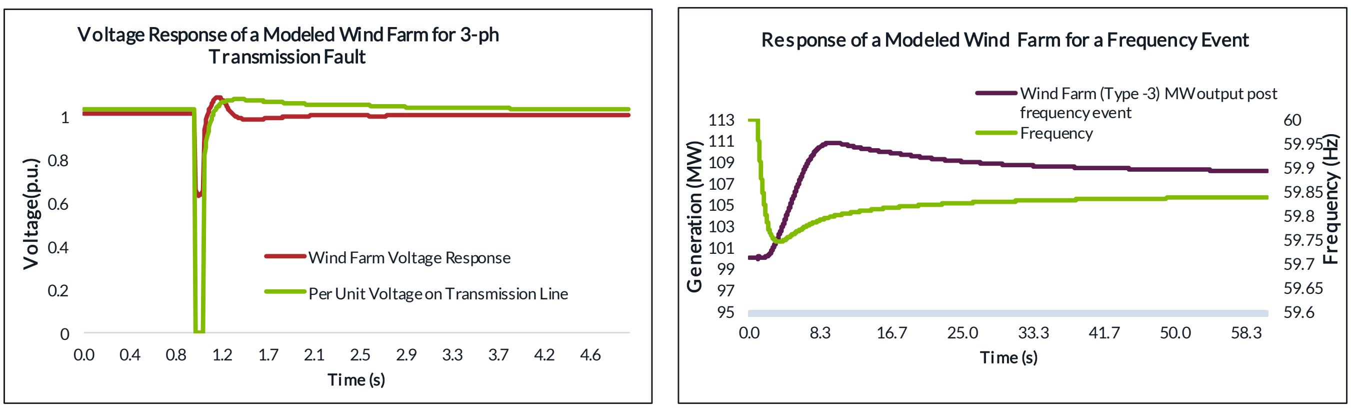


Figure TA-25: Reasonable dynamic base model behavior was obtained for renewable resources

Generic Dynamic Parameters for Synchronous Condensers

PSSE library model GENROU representing Round Rotor Generator Model with Quadratic Saturation and IEEE Type ST4B exciter (PSSE model name ESST4B) were used to represent synchronous condensers. The inertia range for the synchronous condensers added for the 50%-renewable analyses is 2.5<H<4; the gain range assumed is 2.0<gain<10.0, with both integral and proportional gains of each exciter for each machine held equal to each other. Gains and inertia are varied for added machines to avoid common modes of operation.

Weak-area Study Process: Metrics and Modelling and Potential Solutions for Breached Threshold

Weak areas were identified by calculating SCR at each of the POI. A script was developed utilizing PSSE fault calculation (ASCC) module. Input to this script were steady-state models at each milestone for each snapshot, and MW injection at each milestone at selected bus (existing and new generating sites). The short circuit ratio (SCR) at the selected buses was obtained three phase fault values using ASCC module in PSSE. Weighted SCR[46] was used if more than two renewable resources at one point of interconnection.

Performance Criteria	Threshold	Potential Solutions (if threshold is breached)
1. Undamped oscillations seen in transient stability study (Voltage, MW) near new or existing generating resources due to low SCR 2. Voltage collapse during model initialization or contingency	TO's Planning or NERC Criteria	1. If oscillations originate from the new plant, then tune control parameters of wind/solar farm. 2. If tuning does not mitigate the issue, turn on nearby synchronous generation. 3. Install new synchronous condensers or STATCOM if #1 and #2 do not work. 4. Install HVDC network if severe issues are observed

Table TA-41: Weak - area study process metrics and modelling and potential solutions

Frequency Response Fundamentals

In the U.S. RTOs, ISO and utilities maintain frequency close to 60 Hz by constantly balancing instantaneous generation and load. A large generator trip may cause instantaneous frequency to drop, for example, currently approximately 1,000 MW trip causes approximately 40mHz drop in Eastern Interconnection (EI). Post generator trip, many layers of action are required to restore frequency (Figure TA-26). Automatic action of governors on conventional generating resources provides most of the primary frequency response. For inverter-based resources, governing action is performed by electronic controls.

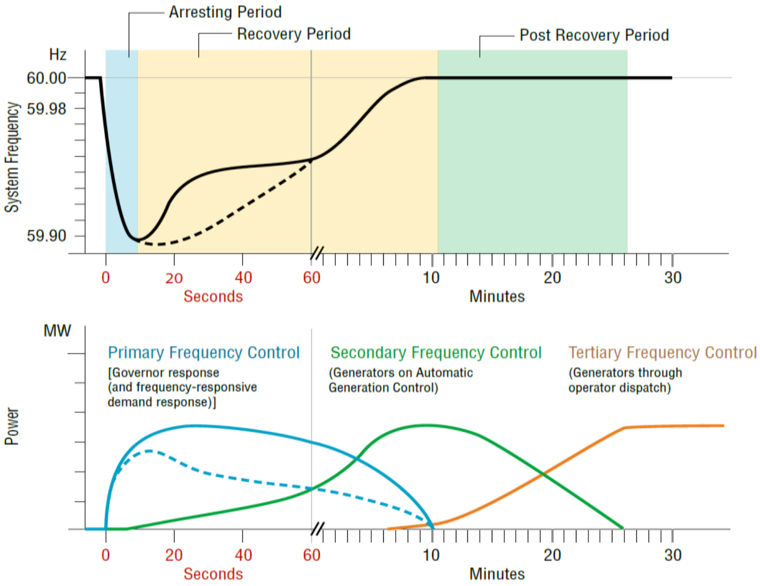


Figure TA-26: Frequency Response Fundamentals [Image source LBNL]

[46] Refer NERC: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems Reliability Guideline, December 2017

Frequency Response Study process: metrics and modelling and potential solutions if threshold is breached

The impact of renewable penetration on the inertial and primary frequency response[47,] (Figure TA-26, Figure TA-27), BAL-003 obligations of MISO (Figure TA-28, Figure TA-29) were studied through dynamic simulation of 60 seconds length, and key Frequency Response metrics studied in RIIA are listed in Table TA-42. Historical large generation loss events informed the assessment of frequency response (Figure TA-29). Renewable resources were initially assumed to have no headroom thus were non-responsive to the under-frequency events. At higher penetrations of renewable energy resources, modeling of their frequency response was investigated and modified in order to evaluate what, if any, changes need to be made to meet the appropriate frequency obligations. Changes included maintaining head-room in renewable resources to provide frequency response for under-frequency type events (refer to page 131).

#	Performance Criteria	Threshold	Significance	Potential Solutions (if threshold is breached)
I-I	Eastern Interconnection Frequency Response Obligation	-1002 MW/0.1Hz	NERC BAL-003 Standard[48]	Install fast response resources, such as flywheels, capable renewable resources, batteries or demand response. Reserve headroom of traditional and renewable generation.
I-II	MISO's Frequency Response Obligation	~ -200 MW/0.1Hz		
I-III	Frequency nadir	59.5 Hz	Under Frequency Load Shedding (UFLS), NERC PRC-006	
I-IV	Rate of Change of Frequency (RoCoF)	-	Single largest contingency to initiate UFLS	

Table TA-42: Key Frequency Response Metrics Studied in RIIA

[47] NERC, "Essential Reliability Services Task Force Measures Framework Report", page -20, available online: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf,

[48] NERC BAL-003-1 Standard, page 13, available online: https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/BAL-003-1_clean.pdf

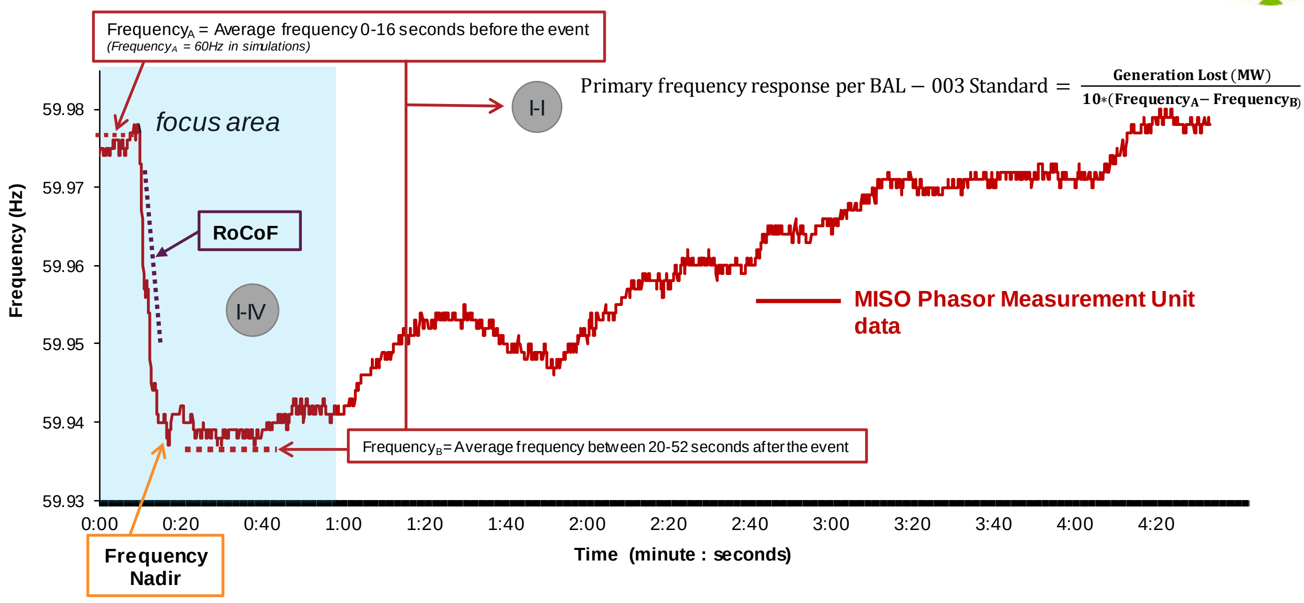


Figure TA-27: Key Frequency Response Metrics: Frequency Nadir, Rate of Change of Frequency (RoCoF), NERC BAL-003 Obligations

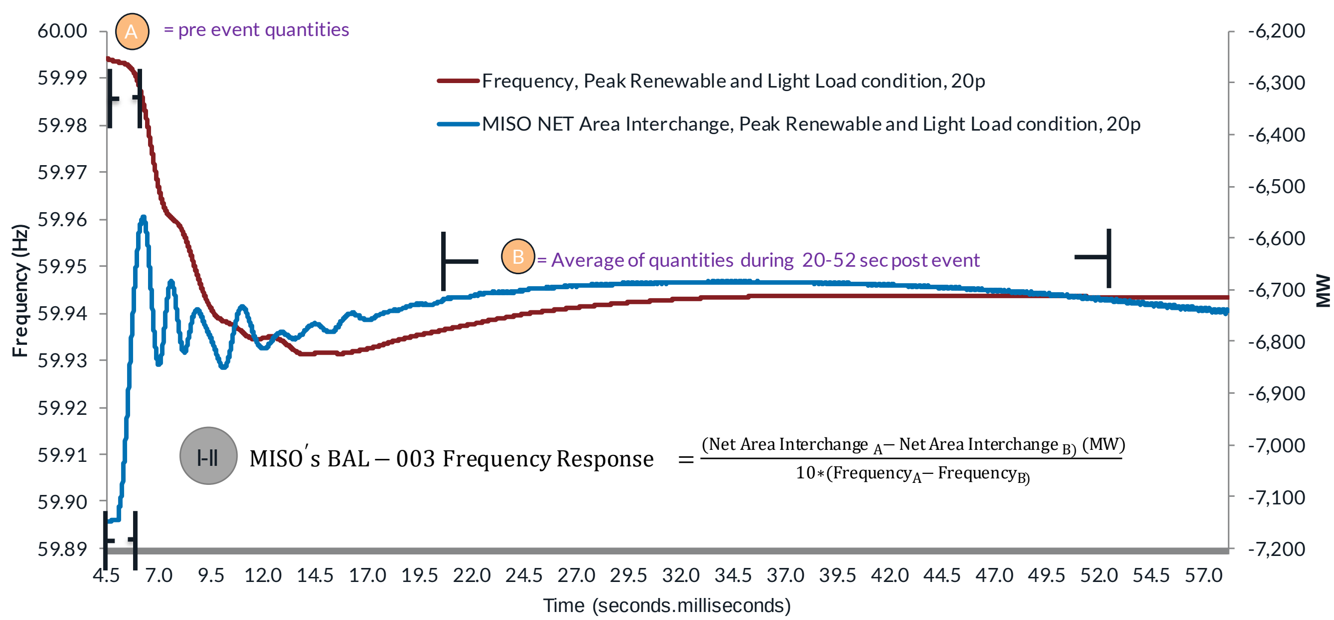


Figure TA-28: MISO's BAL-003-1 obligations are calculated based on Net Area Interchange and Frequency profile

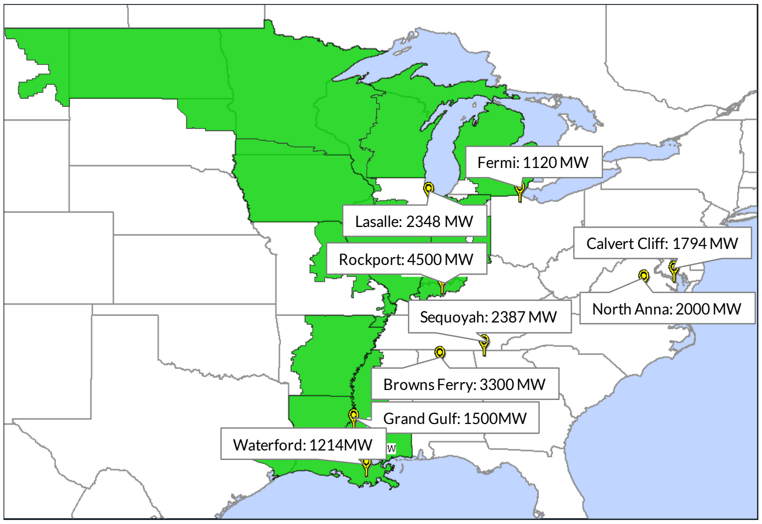


Figure TA-29: Historical large generation loss events are to evaluate frequency response

Benchmarking of models for frequency response study

Through previous model validation efforts, MISO has observed that Eastern Interconnection (EI) wide dynamic models are highly optimistic[49] and do not capture system response realistically, hence MISO incorporated model updates such as modeling asymmetrical dead-bands in existing governor models with generic values (Figure TA-30), removal of governor models for any unit that remain non-response to frequency events (Figure TA-31), and model withdrawal of frequency support by certain units (especially gas unit by utilizing LCFB1[50] model). The base dynamic models were validated against actual system disturbances by utilizing Phasor Measurement Data (PMU) to benchmark against actual system response (Figure TA-30).

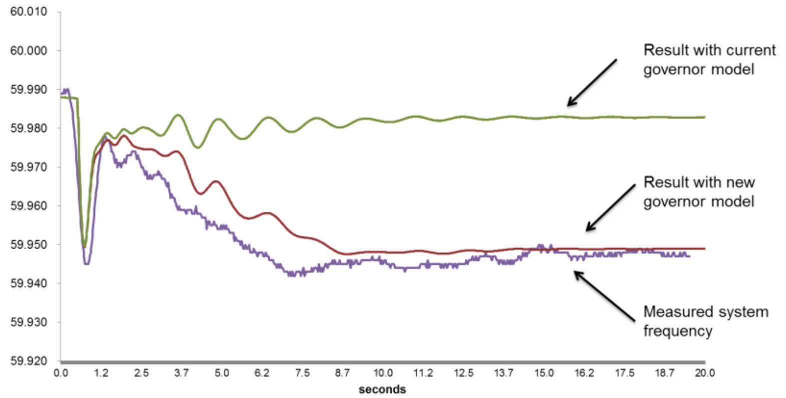
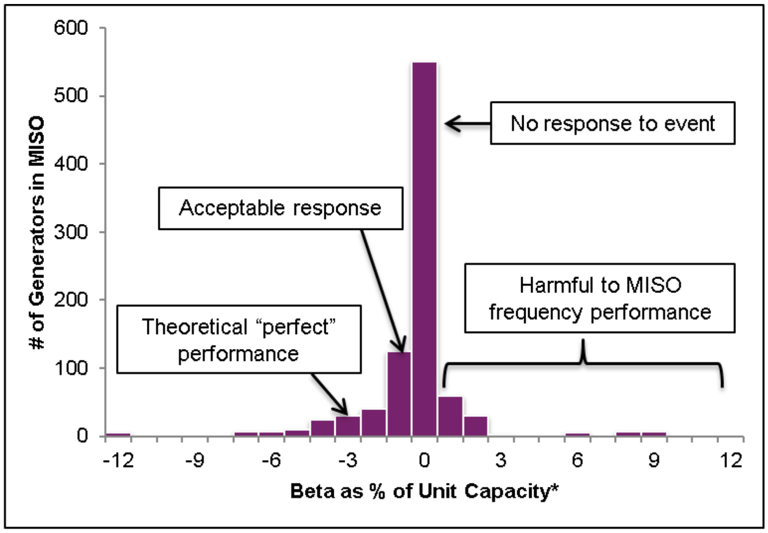


Figure TA-30: Validation results after implementing governor dead-band modeling improvements in dynamics models

[49] N. Mohan, "Governor Modeling improvement", MISO MUGforum, 2017, https://cdn.misoenergy.org/20171003%20MUG%20Item%2003f%20MISO%20Frequency%20Response%20Recommendation199031.pdf

[50] WECC Thermal governor Modeling, https://www.wecc.org/Reliability/WECC%20MVWG%20Thermal%20Governor%20Model%20Revision%202012-06-20.pdf



**Based on real-time MISO data.*

Figure TA-31: Non-responsive units were identified through Real-Time Operations and accordingly modelled

Issue identified during the frequency response analysis per NERC 2019 report

The *NERC Reliability Guideline Report*[51] released on June 2019 indicated that some optimism, due to inaccurate individual unit parameters, is observed in units' response (Figure TA-32). Impact of optimism was studied and discussed in the127.

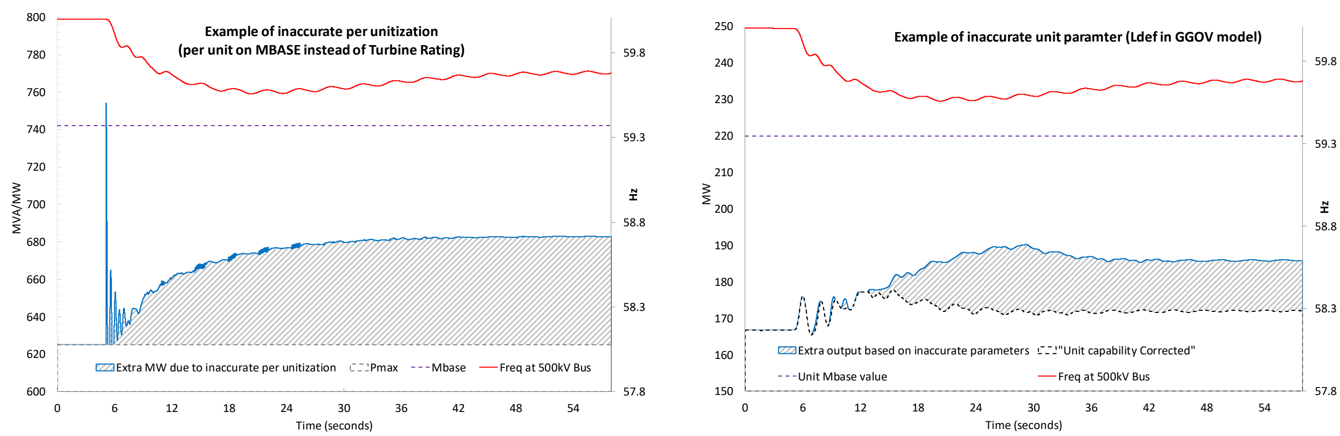


Figure TA-32: Additional optimism in frequency response model due to inaccurate per-unitization and inaccurate unit parameters

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[51] NERC Reliability Guideline : "Application Guide for Modeling Turbine-Governor and Active Power Frequency Controls in Stability Studies", June 2019 available online here

Rotor Angle Stability: Critical Clearing Time Analysis

Historically known stability issues and any new issues identified through other focus areas were studied in this analysis. Local and regional planning criteria were applied for all disturbances simulated. These criteria monitor first swing transient stability, angular oscillation, damping characteristics, line relays, and voltage recovery. The generic PRC-024 frequency and voltage ride-through capability was monitored for all generators with the exception of renewable energy plants or other generating plants that had detailed frequency and voltage capabilities already specified. Generic distance relays were modeled on all lines 100 kV and above with the exception of lines that have detailed relays already specified.

Model REGCAU1; regc_a : RE Converter Model A	PSSE Translation	Parameter Name	Type 3 WTG	Type 4 WTG	Grid Scale PV	Grid Scale Battery
Lvplsw (Low Voltage Power Logic) switch (0: LVPL not present, 1: LVPL present)	M	1	1	1	1	1
Tg, Converter time constant (s)	J	Tg	0.02	0.02	0.02	0.02
Rrpwr, Low Voltage Power Logic (LVPL) ramp rate limit (pu)	J+1	Rrpwr	10	10	10	10
Brkpt, LVPL characteristic voltage 2 (pu)	J+2	Brkpt	0.9	0.9	0.9	0.1
Zerox, LVPL characteristic voltage 1 (pu)	J+3	Zerox	0.5	0.5	0.5	0.05
Lvpl1, LVPL gain (pu)	J+4	Lvpl1	1.22	1.22	1.22	1.22
Volim, Voltage limit (pu) for high voltage reactive current management	J+5	Vtmax	1.2	1.2	1.2	1.2
Lvpnt1, High voltage point for low voltage active current management (pu)	J+6	Lvpnt1	0.8	0.8	0.8	0.2
Lvpnt0, Low voltage point for low voltage active current management (pu)	J+7	Lvpnt0	0.4	0.4	0.4	0.05
Iolim, Current limit (pu) for high voltage reactive current management (specified as a negative value)	J+8	qmin	-1.3	-1.3	-1.3	-1.3
Tfltr, Voltage filter time constant for low voltage active current management (s)	J+9	Tfltr	0.02	0.02	0.02	0.02
Khv, Overvoltage compensation gain used in the high voltage reactive current management	J+10	accel	0.7	0.7	0.7	0.7
Iqrmax, Upper limit on rate of change for reactive current (pu)	J+11	iqrmax	999	999	999	99
Iqrmin, Lower limit on rate of change for reactive current (pu)	J+12	iqrmin	-999	-999	-999	-99
Accel, acceleration factor (0 < Accel $\leq$ 1)	J+13		0.7	0.7	0.7	0.7

Table TA-43: regc_a Model parameters

WTPTAU1, wtgp_a : Wind Turbine Pitch Controller	PSSE Translation	wtgp_a	Type 3 WTG	Type 4 WTG	Grid Scale PV	Grid Scale Battery
Kiw, Pitch-control Integral Gain (pu)	J	Kiw	25	Do not use this model		
Kpw, Pitch-control proportional gain (pu)	J+1	Kpw	150			
Kic, Pitch-compensation integral gain (pu)	J+2	Kic	30			
Kpc, Pitch-compensation proportional gain (pu)	J+3	Kpc	3			
Kcc, Gain (pu)	J+4	Kcc	0			
Tp, Blade response time constant (s)	J+5	Tpi	0.3			
TetaMax, Maximum pitch angle (degrees)	J+6	Pimax	30			
TetaMin, Minimum pitch angle (degrees)	J+7	Pimin	-5			
RTetaMax, Maximum pitch angle rate (degrees/s)	J+8	Piratmx	10			
RTetaMin, Minimum pitch angle rate (degrees/s) (< 0)	J+9	Piratmn	-10			

Table TA-44: wtgp_a model parameter

WTDTAU1, wtgt_a: Generic Drive Train Model for Type 3 wind machine	PSSE Translation	wtgt_a	Type 3 WTG	Type 4 WTG	Grid Scale PV	Grid Scale Battery
H, Total inertia constant constant (s) (>0)	J	Ht+Hg	5	Do not use this model		
DAMP, Machine damping factor (pu)	J+1	0	0			
Htfrac, Turbine inertia fraction (Ht/H)	J+2	Ht/Hg	0.86			
Freq1, First Shaft Torsional resonant frequency (Hz)	J+3	K	1.7162 +- 0.5 Hz			
Dshaft, Shaft damping factor (pu)	J+4	Dshaft	1.5			
WTARAU1, wtga_a : Generic Aerodynamic Model for Type 3 wind machine	**PSSE Translation**	**wtga_a**	**Type 3 WTG**			
Ka, Aerodynamic gain factor (pu/degrees)	J	Ka	0.007			
Theta 0 Initial pitch angle (degrees)	J+1	Theta0	10			

Table TA-45: Generic drive train wtgt_a and Generic Aerodynamic wtga_a models used for Type-3 wind machines

REECAU1, reec_a : Generic Renewable Electrical Control Model	PSSE Translation	reec_a	Type 3 WTG	Type 3 WTG	Type 4 WTG	Grid Scale PV	Grid Scale Battery
Bus number for voltage control; local control if 0	M	PSSE Remote BUS	<RB>	<RB>	<RB>	<RB>	Do not use this model, used reec_c
PFFLAG (Power factor control flag): 1 if power factor control 0 if Q control (which can be controlled by an external signal)	M+1	pfflag	0	0	0	0	
VFLAG: 1 if Q control 0 if voltage control	M+2	vflag	0	0	0	0	
QFLAG: 1 if voltage or Q control 0 if constant pf or Q control	M+3	qflag	0	0	1	0	
PFLAG: 1 if active current command has speed dependency 0 for no dependency	M+4	pflag	0	0	0	0	
PQFLAG, P/Q priority flag for current limit: 0 for Q priority 1 for P priority	M+5	pqflag	0	0	0	0	
Vdip (pu), low voltage threshold to activate reactive current injection logic	J	vdip	-1	-1	-1	-1	
Vup (pu), Voltage above which reactive current injection logic is activated	J+1	vup	2	2	2	2	
Trv (s), Voltage filter time constant	J+2	Trv	0.02	0.02	0.02	0.02	
dbd1 (pu), Voltage error dead band lower threshold (<=0)	J+3	dbd1	-1	-1	-1	-1	
dbd2 (pu), Voltage error dead band upper threshold (>=0)	J+4	dbd2	1	1	1	1	
Kqv (pu), Reactive current injection gain during over and undervoltage conditions	J+5	kqv	0	0	0	0	
Iqhl (pu), Upper limit on reactive current injection Iqinj	J+6	iqh1	0.001	0.001	0.001	0.001	
Iqll (pu), Lower limit on reactive current injection Iqinj	J+7	iql1	-0.001	-0.001	-0.001	-0.001	
Vref0 (pu), User defined reference (if 0, model initializes it to initial terminal voltage)	J+8	vref0	1	1	1	1	
Iqfrz (pu), Value at which Iqinj is held for Thld seconds following a voltage dip if Thld > 0	J+9	iqfrz	0	0	0	0	
Thld (s), Time for which Iqinj is held at Iqfrz after voltage dip returns to zero	J+10	thld	0	0	0	0	
Thld2 (s) (>=0), Time for which the active current limit (IPMAX) is held at the faulted value after voltage dip returns to zero	J+11	thld2	0	0	0	0	
Tp (s), Filter time constant for electrical power	J+12	Tp_	0.05	0.05	0.05	0.05	
QMax (pu), limit for reactive power regulator	J+13	Qmax_	0.33	0.33	0.33	0.33	
QMin (pu) limit for reactive power regulator	J+14	Qmin_	-0.33	-0.33	-0.33	-0.33	
VMAX (pu), Max. limit for voltage control	J+15	Vmax	1.1	1.1	1.1	1.1	

REECAU1, reec_a : Generic Renewable Electrical Control Model	PSSE Translation	reec_a	Type 3 WTG	Type 3 WTG	Type 4 WTG	Grid Scale PV	Grid Scale Battery
VMIN (pu), Min. limit for voltage control	J+16	Vmin	0.9	0.9	0.9	0.9	
Kqp (pu), Reactive power regulator proportional gain	J+17	kqp	0	0	0	0	
Kqi (pu), Reactive power regulator integral gain	J+18	kqi	0.2	0.2	0.2	0.2	
Kvp (pu), Voltage regulator proportional gain	J+19	kvp	0	0	0	0	
Kvi (pu), Voltage regulator integral gain	J+20	kvi	5 +-2	40 +-10	5 +-2	5 +-2	
Vbias (pu), User-defined bias (normally 0)	J+21	vref1	0	0	0	0	
Tiq (s), Time constant on delay s4	J+22	tiq	0.02	0.02	0.02	0.02	
dPmax (pu/s) (>0) Power reference max. ramp rate	J+23	dpmax	1	1	1	1	
dPmin (pu/s) (<0) Power reference min. ramp rate	J+24	dpmin	-1	-1	-1	-1	
PMAX (pu), Max. power limit	J+25	Pmax_	1.05	1.05	1.05	1.05	
PMIN (pu), Min. power limit	J+26	Pmin_	0.05	0.05	0.05	0.05	
Imax (pu), Maximum limit on total converter current	J+27	imax	1.8	1.8	1.5	1.5	
Tpord (s), Power filter time constant	J+28	Tpord	0.05	0.05	0.05	0.05	
Vq1 (pu), Reactive Power V-I pair, voltage	J+29	vq1	0	0	0	0	
Iq1 (pu), Reactive Power V-I pair, current	J+30	iq1	1.4	1.4	1.4	1.4	
Vq2 (pu) (Vq2>Vq1), Reactive Power V-I pair, voltage	J+31	vq2	0.1	0.1	0.1	0.1	
Iq2 (pu) (Iq2>Iq1), Reactive Power V-I pair, current	J+32	iq2	1.4	1.4	1.4	1.4	
Vq3 (pu) (Vq3>Vq2), Reactive Power V-I pair, voltage	J+33	vq3	0.5	0.5	0.5	0.5	
Iq3 (pu) (Iq3>Iq2), Reactive Power V-I pair, current	J+34	iq3	1.4	1.4	1.4	1.4	
Vq4 (pu) (Vq4>Vq3), Reactive Power V-I pair, voltage	J+35	vq4	1	1	1	1	
Iq4 (pu) (Iq4>Iq3), Reactive Power V-I pair, current	J+36	iq4	1.4	1.4	1.4	1.4	
Vp1 (pu), Real Power V-I pair, voltage	J+37	vp1	0	0	0	0	
Ip1 (pu), Real Power V-I pair, current	J+38	ip1	1.1	1.1	1.1	1.1	
Vp2 (pu) (Vp2>Vp1), Real Power V-I pair, voltage	J+39	vp2	0.1	0.1	0.1	0.1	
Ip2 (pu) (Ip2>Ip1), Real Power V-I pair, current	J+40	ip2	1.1	1.1	1.1	1.1	
Vp3 (pu) (Vp3>Vp2), Real Power V-I pair, voltage	J+41	vp3	0.5	0.5	0.5	0.5	
Ip3 (pu) (Ip3>Ip2), Real Power V-I pair, current	J+42	ip3	1.1	1.1	1.1	1.1	
Vp4 (pu) (Vp4>Vp3), Real Power V-I pair, voltage	J+43	vp4	1	1	1	1	
Ip4 (pu) (Ip4>Ip3), Real Power V-I pair, current	J+44	ip4	1.1	1.1	1.1	1.1	

Table TA-46: Generic Renewable Electrical Control Model for wind and solar models

REECCU1, reec_c : Battery Renewable Electrical Control Model	*PSSE Translation*	*reec_c*	*Grid Scale Battery*
Bus number for voltage control; local control if 0	M	PSSE Remote BUS	<RB>
PFFLAG (Power factor control flag): 1 if power factor control 0 if Q control (which can be controlled by an external signal)	M+1	pfflag	0
VFLAG: 1 if Q control 0 if voltage control	M+2	vflag	1
QFLAG: 1 if voltage or Q control 0 if constant pf or Q control	M+3	qflag	0
PQFLAG, P/Q priority flag for current limit: 0 for Q priority 1 for P priority	M+4	pqflag	0
Vdip (pu), low voltage threshold to activate reactive current injection logic	J	vdip	-99
Vup (pu), Voltage above which reactive current injection logic is activated	J+1	vup	99
Trv (s), Voltage filter time constant	J+2	Trv	0.01
dbd1 (pu), Voltage error dead band lower threshold (<=0)	J+3	dbd1	-0.05
dbd2 (pu), Voltage error dead band upper threshold (>=0)	J+4	dbd2	0.05
Kqv (pu), Reactive current injection gain during over and undervoltage conditions	J+5	kqv	15
Iqhl (pu), Upper limit on reactive current injection Iqinj	J+6	iqh1	0.75
Iqll (pu), Lower limit on reactive current injection Iqinj	J+7	iql1	-0.75
Vref0 (pu), User defined reference (if 0, model initializes it to initial terminal voltage)	J+8	vref0	1
Tp (s), Filter time constant for electrical power	J+9	Tp	0.05
QMax (pu), limit for reactive power regulator	J+10	Qmax	0.75
QMin (pu) limit for reactive power regulator	J+11	Qmin	-0.75
VMAX (pu), Max. limit for voltage control	J+12	Vmax	1.1
VMIN (pu), Min. limit for voltage control	J+13	Vmin	0.9
Kqp (pu), Reactive power regulator proportional gain	J+14	kqp	0
Kqi (pu), Reactive power regulator integral gain	J+15	kqi	1
Kvp (pu), Voltage regulator proportional gain	J+16	kvp	0
Kvi (pu), Voltage regulator integral gain	J+17	kvi	1
Tiq (s), Time constant on delay s4	J+18	tiq	0.017
dPmax (pu/s) (>0) Power reference max. ramp rate	J+19	dpmax	99
dPmin (pu/s) (<0) Power reference min. ramp rate	J+20	dpmin	-99
PMAX (pu), Max. power limit	J+21	Pmax_	1
PMIN (pu), Min. power limit	J+22	Pmin_	-0.667
Imax (pu), Maximum limit on total converter current	J+23	imax	1.11

REECCU1, reec_c : Battery Renewable Electrical Control Model	*PSSE Translation*	*reec_c*	*Grid Scale Battery*
Tpord (s), Power filter time constant	J+24	Tpord	0.017
Vq1 (pu), Reactive Power V-I pair, voltage	J+25	vq1	0
Iq1 (pu), Reactive Power V-I pair, current	J+26	iq1	0.75
Vq2 (pu) (Vq2>Vq1), Reactive Power V-I pair, voltage	J+27	vq2	0.2
Iq2 (pu) (Iq2>Iq1), Reactive Power V-I pair, current	J+28	iq2	0.75
Vq3 (pu) (Vq3>Vq2), Reactive Power V-I pair, voltage	J+29	vq3	0.2
Iq3 (pu) (Iq3>Iq2), Reactive Power V-I pair, current	J+30	iq3	0.75
Vq4 (pu) (Vq4>Vq3), Reactive Power V-I pair, voltage	J+31	vq4	1
Iq4 (pu) (Iq4>Iq3), Reactive Power V-I pair, current	J+32	iq4	0.75
Vp1 (pu), Real Power V-I pair, voltage	J+33	vp1	0.2
Ip1 (pu), Real Power V-I pair, current	J+34	ip1	1.11
Vp2 (pu) (Vp2>Vp1), Real Power V-I pair, voltage	J+35	vp2	0.5
Ip2 (pu) (Ip2>Ip1), Real Power V-I pair, current	J+36	ip2	1.11
Vp3 (pu) (Vp3>Vp2), Real Power V-I pair, voltage	J+37	vp3	0.75
Ip3 (pu) (Ip3>Ip2), Real Power V-I pair, current	J+38	ip3	1.11
Vp4 (pu) (Vp4>Vp3), Real Power V-I pair, voltage	J+39	vp4	1
Ip4 (pu) (Ip4>Ip3), Real Power V-I pair, current	J+40	ip4	1.11
T, battery discharge time (s) (>0)	J+41	T	999
SOCini (pu), Initial state of charge	J+42	SOCini	0.5
SOCmax (pu), Maximum allowable state of charge	J+43	SOCmax	0.8
SOCmin (pu), Minimum allowable state of charge	J+44	SOCmin	0.2

Table TA-47: Generic Renewable Electrical Control Model for grid scale battery

REPCAU1, repc_a : Generic Renewable Plant Control Model: All plant modelled with Voltage Control at POI + Primary Frequency Response	PSSE Translation	repc_a	Type 3 WTG (1st type) 5% droop 36mHz dead-band	Type 3 WTG : (2nd Type) 5% droop 36mHz dead-band	Type 4 WTG 5% droop 36mHz dead-band	Grid Scale PV 5% droop 36mHz dead-band	Grid Scale Battery with High Droop, 5mHz dead-band
Difference in PSSE dyr format			IBUS, 'USRMDL', ID, 'REPCTAU1', 107, 0, 7, 27, 7, 9,	IBUS, 'USRMDL', ID, 'REPCTAU1', 107, 0, 7, 27, 7, 9,	IBUS, 'USRMDL', ID, 'REPCAU1', 107, 0, 7, 27, 7, 9,	IBUS, 'USRMDL', ID, 'REPCAU1', 107, 0, 7, 27, 7, 9,	IBUS, 'USRMDL', ID, 'REPCAU1', 107, 0, 7, 27, 7, 9,
Bus number for voltage control; local control if 0	M	<Remote bus (RB)>	<RB>	<RB>	<RB>	<RB>	<RB>
Monitored branch FROM bus number for line drop compensation (if 0 generator power will be used)	M+1	<Low side of Interconnecting Transformer to BES BUS>	<Low side of Interconnecting Transformer to BES BUS>	<Low side of Interconnecting Transformer to BES BUS>	<Low side of Interconnecting Transformer to BES BUS>	<Low side of Interconnecting Transformer to BES BUS>	<Low side of Interconnecting Transformer to BES BUS>
Monitored branch TO bus number for line drop compensation (if 0 generator power will be used)	M+2	<High side of Interconnecting Transformer to BES BUS>	<High side of Interconnecting Transformer to BES BUS>	<High side of Interconnecting Transformer to BES BUS>	<High side of Interconnecting Transformer to BES BUS>	<High side of Interconnecting Transformer to BES BUS>	<High side of Interconnecting Transformer to BES BUS>
Branch circuit id for line drop compensation (enter in single quotes) (if 0 generator power will be used)	M+3	<Interconnecting Transformer ckt ID>	<Interconnecting Transformer ckt ID>	<Interconnecting Transformer ckt ID>	<Interconnecting Transformer ckt ID>	<Interconnecting Transformer ckt ID>	<Interconnecting Transformer ckt ID>
VCFlag (droop flag): 0: with droop if power factor control 1: with line drop compensation	M+4	vcmpflg	0	0	0	0	1
RefFlag (flag for V or Q control): 0: Q control 1: voltage control	M+5	refflg	1	1	1	1	1
Fflag (flag to disable frequency control): 1: Enable control 0: disable	M+6	frqflg	1	1	1	1	1
Tfltr, Voltage or reactive power measurement filter time constant (s)	J	Tfltr_	0.02	0.02	0.02	0.02	0.02
Kp, Reactive power PI control proportional gain (pu)	J+1	Kp	10 +- 10%	4 +- 10%	10 +- 10%	10 +- 10%	0
Ki, Reactive power PI control integral gain (pu)	J+2	Ki	5 +- 10%	2 +- 10%	5 +- 10%	5 +- 10%	0.0001
Tft, Lead time constant (s)	J+3	Tft	0	0	0	0	0
Tfv, Lag time constant (s)	J+4	Tfv	0.05	0.05	0.05	0.05	0.05
Vfrz, Voltage below which State s2 is frozen (pu)	J+5	vfrz	0.7	0.7	0.7	0.7	0
Rc, Line drop compensation resistance (pu)	J+6	rc	0	0	0	0	0
Xc, Line drop compensation reactance (pu)	J+7	xc	0	0	0	0	0
Kc, Reactive current compensation gain (pu)	J+8	Kc	0.02 (in the range 0.02 - 0.04)	0.02 (in the range 0.02 - 0.04)	0.02 (in the range 0.02 - 0.04)	0.02 (in the range 0.02 - 0.04)	0

REPCAU1, repc_a : Generic Renewable Plant Control Model: All plant modelled with Voltage Control at POI + Primary Frequency Response	PSSE Translation	repc_a	Type 3 WTG (1st type) 5% droop 36mHz dead-band	Type 3 WTG : (2nd Type) 5% droop 36mHz dead-band	Type 4 WTG 5% droop 36mHz dead-band	Grid Scale PV 5% droop 36mHz dead-band	Grid Scale Battery with High Droop, 5mHz dead-band
emax, upper limit on deadband output (pu)	J+9	emax	0.1	0.1	0.1	0.1	0.1
emin, lower limit on deadband output (pu)	J+10	emin	-0.1	-0.1	-0.1	-0.1	-0.1
dbd1, lower threshold for reactive power control deadband (<=0)	J+11	dbd	0	0	0	0	0
dbd2, upper threshold for reactive power control deadband (>=0)	J+12	dbd	0	0	0	0	0
Qmax, Upper limit on output of V/Q control (pu)	J+13	Qmax	0.33	0.33	0.33	0.33	0.75
Qmin, Lower limit on output of V/Q control (pu)	J+14	Qmin__	-0.33	-0.33	-0.33	-0.33	-0.75
Kpg, Proportional gain for power control (pu)	J+15	kpg	0.2-.27	0.2-.27	0.2-.27	0.2-.27	1
Kig, Proportional gain for power control (pu)	J+16	kig	0.2-.27	0.2-.27	0.2-.27	0.2-.27	0
Tp, Real power measurement filter time constant (s)	J+17	Tp	0.05	0.05	0.05	0.05	0.25
fdbd1, Deadband for frequency control, lower threshold (<=0)	J+18	fdbd1	-0.0006	-0.0006	-0.0006	-0.0006	-0.0000833
Fdbd2, Deadband for frequency control, upper threshold (>=0)	J+19	fdbd2	0.0006	0.0006	0.0006	0.0006	0.0000833
femax, frequency error upper limit (pu)	J+20	femax	0.05	0.05	0.05	0.05	99
femin, frequency error lower limit (pu)	J+21	femin	-0.05	-0.05	-0.05	-0.05	-99
Pmax, upper limit on power reference (pu)	J+22	pmax	1.05	1.05	1.05	1.05	1
Pmin, lower limit on power reference (pu)	J+23	pmin	0.05	0.05	0.05	0.05	-0.667
Tg, Power Controller lag time constant (s)	J+24	tlag	0.1	0.1	0.1	0.1	0.1
Ddn, reciprocal of droop for over-frequency conditions (pu)	J+25	ddn	20	20	20	20	126
Dup, reciprocal droop for under-frequency conditions (pu)	J+26	dup	20	20	20	20	126

Table TA-48: Generic Renewable Plant Control Model

Background and Outside Studies

The scope for RIIA was developed based on the lessons learned and conclusions from past studies both performed by MISO and other industry groups. RIIA seeks to overcome limitations seen in previous studies and provide a more complete understanding of integration issues for the MISO region as well as create a more complete and comprehensive study process. Even with this view, limitations exist in RIIA that require additional considerations that were only lightly touched or were outside the scope entirely as discussed below in Gaps in Analysis.

Background Studies

Minnesota Renewable Energy Integration and Transmission Study (MRITS)

https://mn.gov/commerce/industries/energy/distributed-energy/mrits.jsp

Relevant Findings:

- 40-50% Renewable in Minnesota
- 20% MISO wide

Regional Generation Outlet Study (RGOS)

A multi-year study on how to integrate state-mandated wind into MISO

https://www.misoenergy.org/Planning/Pages/RegionalGenerationOutletStudy.aspx

Relevant Finding:

- ~20% Renewable MISO Midwest

Eastern Wind Integration and Transmission Study (EWITS)

https://www.nrel.gov/docs/fy11osti/47078.pdf

Relevant Finding:

- 20% Renewable Eastern Interconnect

Eastern Renewable Generation Integration Study (ERGIS)

https://www.nrel.gov/grid/ergis.html

Relevant Finding:

- 30% Renewable Eastern Interconnect

Western Wind and Solar Integration Study (WWSIS)

https://www.nrel.gov/grid/wwsis.html

Relevant Finding:

- 35% Renewable Western Interconnect

PJM Renewable Integration Study (PRIS)

http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx

Relevant Finding:

- 30% Renewable PJM

2016 SPP Wind Integration Study

https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf

Relevant Finding:

- Looked at 60% peak renewable rather than % of energy.

Minnesota Solar Pathways

http://mnsolarpathways.org/

Relevant Finding:

- Studied 10% Solar by 2030 in Minnesota and 70% Renewables by 2050 in Minnesota

External Resources

Other resources were reviewed to inform the design of this assessment.

NERC Essential Reliability Services Sufficiency Guideline Report

http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf

NERC Essential Reliability Services Task Force Measures Framework Report

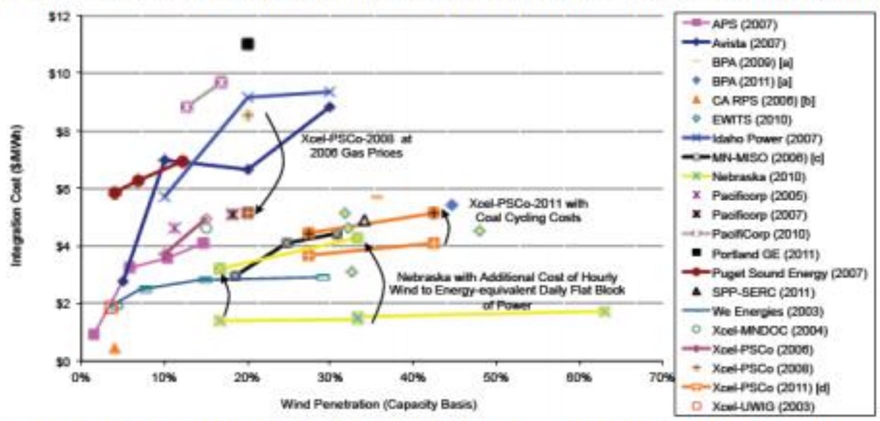
http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

2011 Wind Technologies Market Report

https://emp.lbl.gov/sites/all/files/lbnl-5559e.pdf

Relevant Finding: Figure AC-1.

Exhibit 3 Integraton Costs at Various Levels of Wind Power Capacity Penetration



Source: R. Wiser and M. Bolinger, 2011 Wind Technologies Market Report, Lawrence Berkeley National Laboratory
Note: Because methods vary and a consistent set of operational impacts has not been included in each study, results from the different analyses of integration costs are not fully comparable

Figure AC-1: Inflection Point Example from the 2011 *Wind Technologies Market Report* (Page 64))

Gaps In Analysis

To fully understand the impacts of the increasing amounts of wind and solar generation in a specific electrical area, a broad suite of models and views must be examined. For RIIA, the same models and assumptions were used across the entire geographic and time scales. However, assumptions and compromises were made to keep consistency and to conduct the work in a reasonable time frame.

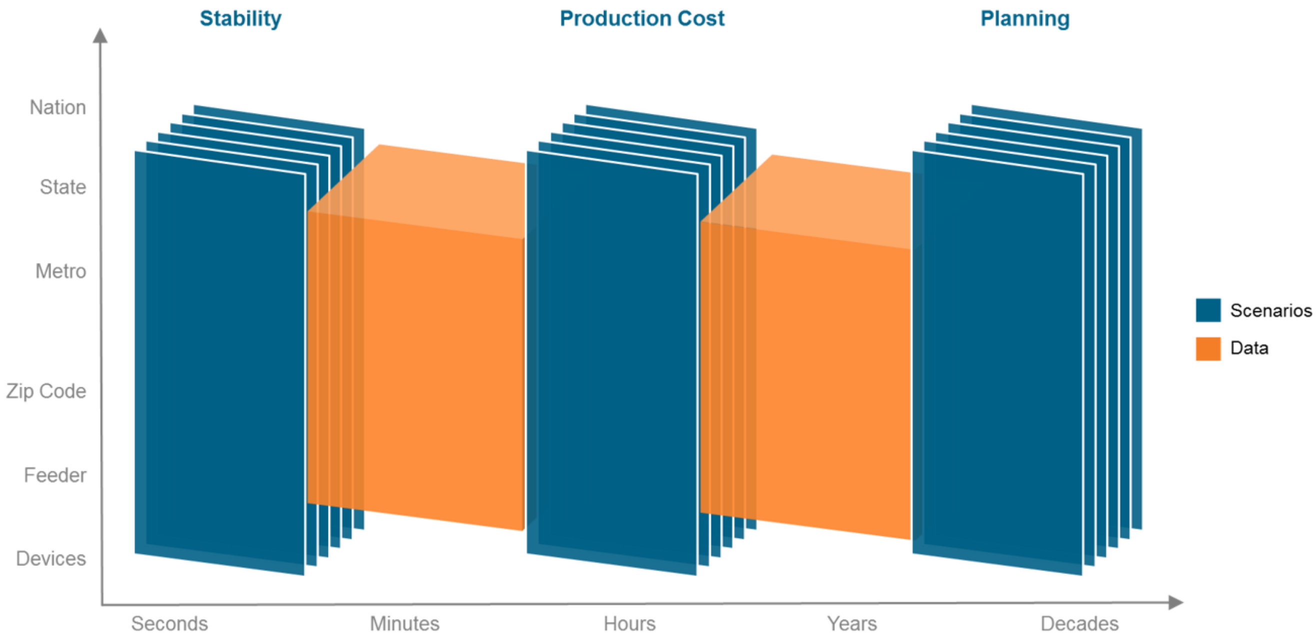


Figure AC-2: Variety models for different geographic and temporal resolutions (Source: *NREL)*

The majority of the analysis was conducted on a single planning scenario to keep consistency between the detailed geographic and time scale modeling and the more general modeling. This limitation was addressed by examining the impacts of technology, at different penetration levels, on specific geographic areas (Figure AC-2). In addition, analyses were done to understand the effects key assumptions had on the results. Sensitivity analysis was also conducted in the energy market modeling and resource adequacy areas to look at other scenario combinations.

The majority of the analysis was based on a single weather year (2012). Other analyses found this to be the most recent representative weather year when the RIIA began in 2017; however, this limited the ability to see weather outliers and their effect on the results. This shortcoming was partially addressed by using a series of weather years from 2007-2017 for the Resource Adequacy analysis. Data analytics was also used to understand ramping and other behavior across the years.

Limited analysis was conducted for the timeframe between 1 and 60 minutes. This was primarily due to the lack of good data, models and the difficulties of performing the analysis. This was partially addressed through data analytics of 5-minute time series data and studying select 5-minute periods. Additional work is needed to look at 5-minute energy market performance over an entire year and generator performance when responding to Ancillary Service calls.

Work outside of MISO has addressed some of these limitations, looking at different power systems and wind and solar penetration scenarios. Lessons can be learned to inform future work by comparing RIIA findings and other industry work products.

Frequently Asked Questions (FAQ)

General

(Q1) **How is RIIA different than other renewable studies in North America?**

- RIIA employed highly detailed siting of renewable generation in a way to mimic the way actual renewable generation may be sited in the future. Other studies have sited renewable generation in a more clustered way. For instance, some studies examined only clustered renewable generation around retired coal and other thermal plants.
- RIIA studied actual dispatch & load levels generated from a production cost model. A process was used to identify the expected most stressful 3 hours (snapshots) from the 8760 hours simulated; then those snapshots were studied in the Operating Reliability realm to identify facility upgrades needed for a secure system with the high level of renewable generation added, up to the 50% milestone; in those snapshots, the renewable penetration rose as high as 89% of load being served by renewable power.
- In the Operating Reliability realm, studies examined reliability for thermal, voltage, frequency, rotor angle stability, and small-signal inter-area issues. Facilities were added to the models to mitigate any reliability standards not met.

(Q2) **What do the percentage penetrations mean?**

The calculated penetrations in this study are done on a regional basis for MISO or the EI, as specified in this report. The percentage values mean two things.

- The milestone values, like 40%, represent the proportion of MISO load energy served annually by renewable energy resources. Any percentage paired with “milestone” can be interpreted in this way.
- In some parts of the work, analyses examine the so-called “instantaneous” penetration, which represents the portion of MISO load demand (MW) 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 specified in this report.

(Q3) **Will MISO post transmission constraints and solicit for transmission solutions to ensure cost-effective solutions are identified?**

The purpose of RIIA isn’t to identify individual constraints or lines. Rather it is to show the general types, locations and risks seen in order to help frame future work. For this reason, MISO will not publish detailed solution data and costs.

(Q4) **Which states belong to each subregion?**

MISO North comprises North and South Dakota, Minnesota, Wisconsin, and Iowa. MISO Central includes Illinois, Indiana, Michigan, Missouri, and Kentucky. MISO South consists of Arkansas, Louisiana, Mississippi, and Texas. Several states, including Texas, have utilities that are not a part of MISO.
Is the complexity metric basically equal to the cost of integrating renewables into the MISO system? Is it quantitative or qualitative? Has the complexity been scaled at all?
Understanding Renewable Complexity describes the quantitative complexity in creating the chart. MISO attempted to quantify the cost of solutions for each focus area. Given that there is subjectivity in the quantitative exercise of developing costs, it makes more sense to focus on the relative scale rather than the specific numbers. Using the relative scale also allows for consideration of other issues. For example,

unexpected difficulties in siting, routing, procuring materials and construction crew availability could also be considered. The complexity has not been scaled.

(Q5) **Why hasn't MISO released the underlying data for the complexity chart?**

MISO has chosen not to release the specific data, as MISO believes it distracts from the purpose of the work. The purpose is not to develop specific plans or give specific costs, although they were necessary to create the conclusions and graphics. The purpose is to understand the implications of increasing renewable penetration in the MISO region and to highlight the specific causes and timing of challenges; inform ongoing focus; and plans needed to address them. MISO decided to not disclose the detailed solutions, because RIIA is not a transmission planning study. It is a proof-of-concept study to show how the MISO system could operate reliably up to 50% renewable energy with existing technology. The section *Solutions* includes the general cost assumptions and types of technologies considered when analyzing options.

(Q6) **Does the system break at 30% and cause the need for rolling blackouts? Where is the "Houston, we have a problem" point?**

RIIA found the challenges to integrate renewables increase as the penetration increases, with a stark escalation occurring between the 30-40% penetration levels. However, even at the 50% milestone, the system can still operate reliably once solutions utilizing existing technology are deployed. MISO did not find any milestones of the system being inoperable, up to the 50% milestone studied.

(Q7) **Is the inflection point near 30% caused by issues distributed throughout the MISO footprint, or are the issues localized to a particular region?**

The challenges at 30% penetration are spread across an extensive area. Although there are local pockets with higher penetrations of renewables (some at 60% of the local load energy), the risk is associated with a wide area.

(Q8) **What is the specific starting point for each milestone's models?**

The starting point for each milestone model (for instance, the 40% milestone models), unless otherwise noted, is the prior milestone models (for instance, the 30% milestone models) including all transmission solutions needed to securely meet the 30% energy penetration.

(Q9) **What is the difference between Phase 1, Phase 2, Phase 2s, and Phase 3?**

Phases 1 through 3 reflect the progress of RIIA, in which:

- Phase 1 includes the completion of Resource Adequacy from 10% to 100% milestone, and completion of Energy Adequacy and Operation Reliability from 10% to 30% milestone
- Phase 2 includes completion of Energy Adequacy and Operational Reliability from 40% to the 50% milestone
- Phase 2s examines Sensitivities of the Phase 2 models by altering key model assumptions
- Phase 3 combines multiple Sensitivities and creates the final Energy Adequacy and Resource Adequacy models, again from 10% to 50% milestone.

For the purpose of this report the Phase terminology was not used as it was meant to mark progress during the analysis rather than mark distant parts of the work.

(Q10) **Does MISO believe the insights gained from the RIIA may be impacted by the difference between the siting of MISO RIIA analysis and where project developers will ultimately choose to site their projects?**

In RIIA, the siting sought a balance between good resource areas, proximity to load, available transmission capacity and actions taken by developers (i.e. interconnection activity). MISO views the RIIA siting as a reasonable representation of future developer activity but recognizes that renewable siting is very difficult to predict. MISO does not believe that the differences between its siting assumptions and actual renewable development will impact the insights described.

(Q11) **How has the RIIA work already been integrated into other MISO studies?**

MISO is referencing RIIA simulation results of hourly wind and solar generation to evaluate key assumptions in the Reliability Planning Models. Model assumptions and findings in RIIA Resource Adequacy and Energy Adequacy focus areas also serve as valuable references for MISO to explore future challenges to Resource Availability and Need (RAN) in market operation, given continued shifts in resource mix.

(Q12) **Has MISO thought of doing localized transmission solutions?**

Local and regional transmission solutions were employed as deemed necessary to meet reliability standards.

Next Steps

(Q13) **Where will the results of this study be used?**

RIIA assessed the broad implications of increasing amounts of wind and solar in the MISO footprint. The work looks at broad areas such as resource availability and variability, transmission, and stability. RIIA is actively other areas and studies as applicable. MISO expects several future studies will build on the insights from RIIA. Some of the processes developed in RIIA are currently being utilized in MISO planning processes as part of the Long-Range Transmission Plan (LRTP); for example, RIIA aided in determining ways wind and solar units should be dispatched in MTEP reliability models. Areas of future focus are discussed in the Executive Summary.

(Q14) **Given that the demand forecast and baseline generation assumptions used in RIIA, based on MTEP19, are very different than those used in MTEP21, will MISO re-perform the RIIA study with updated assumptions from MTEP?**

RIIA was designed to understand the risks of increasing wind and solar levels in the MISO footprint and to help shape the scope of future work related to those risks. Analyses included several sensitivities to test input assumptions. Thus, MISO believes the results and recommendations are robust for that purpose. MISO has no plans to redo the RIIA work to align with different input assumptions from other MISO studies.

(Q15) **The optimization process used by MISO in RIIA considered approximately 11,000 transmission project candidates between major high voltage substations across the MISO footprint. Some projects must have demonstrated superior adjusted production cost (APC) benefits to others. There are also significant differences in load forecasts between MTEP19 and MTEP21. Does MISO intend to introduce these projects into the MTEP21 process? If yes, as what type of project?**

RIIA is not a transmission planning study. Transmission solutions have been shared to inform other MISO planning processes, such as the Long-Range Transmission Plan (LRTP), but each will have to perform according to the requirements of the individual study and its use in RIIA will not play a role.

(Q16) **Are the issues only regional or interregional? Can MISO post information about interregional issues to supplement LRTP discussions?**

Some issues are regional, and some are interregional. For example, some reliability issues (thermal and voltage) are regional, while some of issues (frequency and small-signal inter-area oscillation) are interregional. The regional and interregional violations and mitigations have been covered in this report and in the RIIA workshops and presentations.

(Q17) **Will MISO develop the transmission projects identified by RIIA?**

The purpose of RIIA is not to identify actionable solutions. Instead, MISO determined the timing and nature of transmission or storage needs in a future system with a high penetration of renewables. MISO expects that the actual development of generation and transmission will differ from the assumptions and solutions of RIIA, but thinks the study is representative of the needs of a high renewable future.

Siting and System Assumptions

(Q18) **Why does MISO examine renewable integration over the entire Eastern Interconnection?**

It is important to model the renewable expansion expected in the entire Eastern Interconnection, because this study specifically examines the addition of renewables to find out when the existing system is stressed. If renewables were only added within the MISO footprint, the study might understate the potential complexity because MISO would be able to easily export low-cost energy to areas outside of MISO and take advantage of the ramping capabilities of the thermal units of MISO's less-stressed neighbors in simulations of system behavior.

(Q19) **How diverse is wind output across MISO?**

Wind diversity is quite large. Some areas of the MISO footprint have wind capacity factors nearing 50%, while others have capacity factors less than 10%.

(Q20) **Did RIIA use existing grid topology and conditions, and were studies done considering batteries as solutions, as opposed to transmission?**

RIIA starts with the system as it was in late 2017 (with a 5-year-out transmission model representing the 2022 expected transmission topology) and builds forward from that starting point. Generation and topology were changed as needed to achieve the analysis targets. The energy storage sensitivity analysis examined the ability of batteries to aid in enabling renewable energy to serve load.

(Q21) **Were other resources added beyond renewables?**

Some units were "un-retired" for stability purposes. No other resources were added.

(Q22) **Does MISO plan to examine the potential for adding more gas and thermal capacity, and how to rely on those units in the transition to a system with a high penetration of renewable energy?**

The focus of the RIIA study is to look at renewable generation development within MISO. Siting new gas and thermal generation was not considered, though the analysis does look at how thermal units support the transition through flexibility.

(Q23) **Why initially use the 75:25 wind to solar ratio? And would the results change significantly from a different ratio of wind to solar?**

When the RIIA study was initiated, the 3:1 capacity ratio between wind and solar aligned with historic and near-term MISO generation interconnection queue. In the subsequent years, solar technology has rapidly decreased in cost, leading to a higher proportion of solar in the MISO interconnection queue. The sensitivity analysis examined the relative mix of wind and solar capacity by modifying the siting assumptions, such that the wind and solar capacity mix reached an even split by the 50% milestone. That work did not demonstrate significantly different performance than the original work with 3:1 capacity ratio. Additional work has shown the general conclusions hold.

(Q24) **What study year and season was used for the study? Are the wind profiles and solar profiles for a specific year?**

For the Resource Adequacy work, the years were 2007 through 2012 and all seasons, based on the best data availability. In addition, some sensitivities used 2014 through 2018. For the Energy Adequacy work, 2012 was selected as the most representative weather year, so the wind, solar, and load profile shapes from 2012 were used.

(Q25) **Did MISO study multi-day, low-wind periods?**

MISO studied both high and low wind periods, based on historical weather.

(Q26) **Do the wind farms in MISO North generally peak at the same time because they see weather systems at the same time?**

No, due to the large geographic area of the region. As weather fronts move through the MISO footprint, there is a wide variety of wind output.

(Q27) **Does MISO assume uniform penetrations across the footprint?**

The penetration and impact are different at certain locations — wind-rich or solar-rich. The solar irradiance values and wind speed values come from industry hourly data at a granular level by geography across the study area.

(Q28) **What were the renewable energy targets and to where was the energy delivered?**

The purpose of RIIA is to understand higher renewable penetrations in MISO and to determine the system risk. As such, analysis target milestones were set in 10% increments of annual renewable energy serving MISO-wide load, rather than examining targets set by states or utilities. Renewable generation within MISO was targeted to serve load within MISO, but some interchange with MISO's neighbors was permitted. The study stopped at the 50% milestone due to stakeholder feedback and indicated that MISO would need to make significantly different assumptions beyond that point.

(Q29) **Is there more exploration of non-traditional solutions?**

Phase 3 of the RIIA studies explored battery storage.

(Q30) **Will RIIA consider more demand-side resources?**

RIIA's scope did not include considering demand-side resources other than limited DER and demand-side storage.

(Q31) **Were hybrid plants studied?**

Hybrid plants were studied in Phase 3 of RIIA.

(Q32) **Has MISO thought about replacing renewables with nuclear units, since they are comparable from a decarbonization perspective?**

RIIA was not a decarbonization study.

Resource Adequacy

(Q33) **When considering ELCC for solar, solar does a good job of addressing gross peak of solar, but not so much at net peak. How can that be communicated?**

Similar to other studies, RIIA indicates that as renewable penetration increases, the risk of losing load shifts to later in the day i.e. from noon to later in the evening. It should be noted that these periods of risk are not necessarily the period of highest gross load but are periods of highest net-load (gross load minus total renewable output).This shift in risk is therefore primarily driven by adding more solar to the system which moves the net-load peak to later hours of the day. ELCC as measure of capacity contribution looks at the availability of a resource to meet load during the period of highest risks, which as more solar is added becomes less coincident with peak solar output. This phenomenon drives the ELCC of solar to decline. Thus, the current process leads to a situation where solar gets lower ELCC numbers, even though it is available during the period of the gross load.

(Q34) **Is there an optimal mix of wind and solar?**

The goal of RIIA was not to identify the optimal mix of wind and solar. The optimal mix is highly dependent on cost assumptions and future system configuration.

(Q35) **Does the dispatch of storage get applied to the same 6-hour window, or does it adjust accordingly as the net load peak shifts?**

Referring to the LOLP curves, it can be observed that the software does apply dispatch outside the net-load peak; a flattening of the curve is seen, indicating that it applies it outside the peak.

Energy Adequacy — Market and Operation

(Q36) **How does the “must-run” assumption work in RIIA simulations?**

If a unit is must-run in the current market, then it’s assumed it will still be must-run in the future. A sensitivity analysis has been done by assuming none of the units will be must-run.

(Q37) **Why are there negative prices even with solar and wind at 0 $/MWh?**

The negative prices are due to excessive energy. When online capacity is greater than load, there will be excessive energy due to the inability of some resources to ramp down in a sufficient amount of time; this will result in scarcity of downward regulation and possible negative prices.

(Q38) **How did MISO achieve 40% renewable penetration when there is 80% self-scheduled thermal?**

Must-run is a commitment concept, MISO market separates the market operation processes into commitment and energy dispatch, the 80% of must-run thermal is just commitment. When a unit is must-run, the energy MW is still being optimized instead of defaulting to maximal capacity. Energy from all thermal must-run is way lower than 80%.

(Q39) **Solar drop at sunset is very well known. If a 36-hour commitment time frame is used, why are capacity shortages seen in real time?**

Solar drops at sunset is well known but there is still uncertainty around pace and quantity. In practice, MISO often defers out-of-market commitment to the last feasible point and any unforeseen uncertainty will add flexibility pressure on that period which already consumes a lot of ramping capabilities from the fleet.

Energy Adequacy — Planning

(Q40) **How does MISO determine the sufficient amount of curtailment?**

The production cost model solves unit commitment and dispatch by fulfilling load while minimizing total production cost and honoring transmission constraints; hence renewable curtailment is the modeling result highly dependent on assumptions of renewable profile and transmission constraints. For the purpose of this study a threshold was determined to deem a maximum amount of curtailment that would be allowed. This was done since the purpose of RIIA was to measure the complexity of delivering specific percentages of renewable power.

(Q41) **Is the transmission expansion solely driven by thermal violations?**

Transmission expansion is mostly driven by the need to deliver renewable energy from remote load centers. Expansion drivers include congestion, thermal and voltage violations and stability violations.

(Q42) **Are the energy adequacy solutions transmission solutions?**

Energy adequacy solutions are primarily transmission solutions.

(Q43) **Were non-transmission solutions considered?**

The study considers non-transmission solutions, including energy storage, re-siting of renewable generation plants, un-retiring units, increased reserve requirements, or additional fast-ramping generation at various stages of the process.

(Q44) **Did MISO consider dynamic thermal ratings?**

Utilization of dynamic thermal ratings is generally considered as a tool used in operations to alleviate congestion, as it requires knowledge of ambient temperature variation to accurately calculate line ratings. Sufficient data was not available to accurately model dynamic thermal ratings.

(Q45) **Did MISO consider transmission maintenance?**

Transmission maintenance in the form of removing facilities from the models were not included. MISO also did not add increased transmission maintenance to the costs for the complexity values.

(Q46) **Can MISO quantify the cost of ramping and cycling for different fuel groups?**

RIIA study does not assume specific cost of ramping and cycling for different fuel groups. The RIIA study quantified the ramp behavior, but accurate cost data was insufficient to use.

(Q47) **Why does MISO continue to be an energy importer in all scenarios?**

RIIA assumes MISO *and* the entire Eastern Interconnection meets the renewable penetration target for each milestone, without making unrealistic thermal unit retirement assumptions. Hence excess renewable energy in the rest of the Eastern Interconnection will flow into MISO and vice versa as the objective of the simulations is to minimize total production cost of the entire Eastern Interconnect. In reality, MISO has also become a net energy importer in the Eastern Interconnection in the past few years.

(Q48) **Is MISO importing solar from SERC and TVA?**

RIIA simulation results show SERC and TVA energy also flow into MISO.

Operating Reliability — Steady State

(Q49) **Are the high-voltage areas of concern?**

Prior to mitigations being applied, simulations showed high- and low-voltage criteria violations. Both types of violations are of concern, due to the potential for equipment damage. Both types of violations are not of concern after solutions were developed to mitigate any violations.

(Q50) **What is the difference between the issues in this analysis and the issues identified in the energy adequacy analysis?**

The issues explored in the OR analysis include evaluation of voltage and thermal violations from power-flow simulations, considering the non-linear nature of electrical phenomena (AC solutions) and active and reactive power. The mitigations identified through the energy adequacy analyses are needed to be able to serve each milestone's target renewable energy levels, and involve a DC-based solution algorithm unable to capture reactive power impact on the electric grid.

(Q51) **How does the model incorporate reactive power support from inverters?**

The renewable energy generation and inverters were modeled as providing reactive power support, consistent with industry requirements and FERC directives for generator interconnection. Refer to section 3 "Technical Assumption: Operating Reliability — Steady State Focus Area" for details

(Q52) **Did MISO identify any voltage stability issues driven by line overloads?**

MISO did not perform any P-V or voltage stability study driven by the high transfer of power across the transmission lines. In RIIA, many of the overloads were mitigated by upgrading the voltage class (kV) of the line (such as 230 kV to 345 kV), so the voltage stability issues would generally have been mitigated. The required addition of many dynamic reactive power devices — STATCOMs and synchronous condensers — would also mitigate voltage stability issues.

(Q53) **Did RIIA consider additional renewable resources for voltage support?**

The renewable siting was done before the models were built and run, so adding additional renewable generation was not done to help voltage support.

(Q54) **Why doesn't the MISO Generation Interconnection process address the issues seen in this analysis?**

The MISO Generation Interconnection process does address these types of issues. The renewable generation levels modeled in RIIA are far beyond any queue cycles yet studied in the MISO Generation Interconnection process.

Operating Reliability — Dynamic Stability

(Q55) **When it comes to dynamics, how is the cost quantified?**

The costs are for the facilities needed to resolve criteria violations observed and meet reliability standards, such as NERC TPL-001.

(Q56) **As far as criteria violations from added renewable generation are dealt with in the MISO Generation Interconnection process, is there any benefit to addressing the issues in a more holistic way?**

There may be several benefits to addressing issues in a holistic process, such as building long-term, most-economic, least regret transmission solutions to address several areas, such as generator interconnection and congestion alleviation.

(Q57) **Is it possible to convert retired units into synchronous condensers to be more cost effective?**

It is possible to convert retired units into synchronous condensers. Doing so may or may not be less expensive than adding a new synchronous condenser.

(Q58) **How does one relate low Short Circuit Ratio (SCR) to power flow?**

SCR is calculated in power flow models. Low SCR causes issues in the dynamics realm. Refer to the Operating Reliability — Dynamic Stability Focus Area section under the heading: "Weak - area study process: metrics and modelling and potential solutions if threshold is breached" for detailed explanation.

(Q59) **When moving from 30% to 40% penetration, did MISO apply any corrective action for frequency response?**

No frequency-related corrective actions were identified when moving from the 30% to 40% milestone.

(Q60) **Are there specific requirements for the headroom? Can wind curtailment be used as headroom?**

There are requirements for headroom implied by NERC reliability standards (BAL-001, 003 etc.). Wind curtailment can be used for headroom, if the curtailment is attained by operating wind turbines below their maximum output levels and online. For example, wind turbine blades can be pitched to operate sub-optimally and to make turbines be able to respond quickly by re-pitching to inject power into the grid.

Storage Sensitivity Assumptions

(Q61) **Is there a block size of the energy storage? For example, in the 30 GW case, does the entire 30 GW get applied to the same block of hours, or can it be spread out?**

There is no one block size of energy storage. Different scenarios have different capacities of storage located at different sites. For example, in the co-location scenario, the 12 GW capacity is split between 41 sites. For the high capacity cases of 100 GW, the sites are scaled from the nominal value used in the 12 GW case. Other scenarios assume different block sizes and storage duration.

(Q62) **Is the heuristic approach just siting storage alone, no hybrid, and no consideration of renewables siting? Is it focused on siting near load?**

All methods are meant to address the method of siting storage only. Each deploys a unique strategy for the type and location of the storage resource.

(Q63) **Where generation is located closer to load, does the location of the battery (closer to load or generation) matter from the perspective of deliverability?**

MISO finds the wind and solar generation delivery is best aided when storage is located near generation, as storage effectively reduces curtailment of the renewable generation and mitigates some transmission constraints encountered in the other case of needing to move the renewable generation to storage sited near load.

(Q64) **Storage seems to reduce wind curtailment more than solar curtailment, but developers seem to be focused on solar-storage hybrids. Is the storage sited near more wind than solar resources?**

Solar-storage hybrids are attractive due to the economics of sizing optimization for the inverter panels and battery, energy arbitrage, or ancillary services provision, rather than installing storage as an alternative to transmission. While the RIIA work finds synergy between storage and transmission, storage is only able to reduce the amount of transmission needed on a limited basis. Storage was sited both near wind and solar resources.

(Q65) **What is the difference between "storage paired with load" and "storage paired with renewables?" Is the latter utility scale and the former distribution and retail scale?**

For the RIIA work, this distinction deals with the physical location of the storage. The installation locations were biased either near wind and solar sites or near load locations. In either case, the storage is modeled as stand-alone utility-scale batteries.

(Q66) **Should storage always be installed near generation and none at load?**

The results of RIIA are sensitive to the siting of wind and solar and are sensitive to the primary objective for adding storage. For example, the storage sensitivity addressing reducing renewable curtailment contained 60 GW of wind, mostly in MISO North and far from load centers. Storage near renewable resources serves as a reservoir to store excess renewable energy when not needed to serve load, and the stored energy can be used later at times the renewable resource has lower production. If storage is sited near load without solving transmission issues encountered in delivering renewable generation to load areas, there may still be curtailment. Application of storage to resolve other reliability issues, such as small-signal inter-area oscillation, requires detailed analysis using dynamic-analysis tools. Locations of storage may be at strategic locations neither near generators nor load centers.

(Q67) **Was the storage modeled at higher voltage buses?**

The co-location storage sites were located at higher voltage class buses. For co-optimization, buses of various voltage levels were considered as candidate locations for storage.

(Q68) **Does this work show that all storage will be used for ancillary services?**

The purpose of the RIIA storage work was limited to the ability of storage to help mitigate risks presented by increasing wind and solar. The analysis does not suggest that storage would only provide ancillary services. The RIIA work did not examine the optimal value stream of storage.

(Q69) **When MISO talks about pairing storage with renewables, is it referring to being physically located at the same site or simply interconnecting to the transmission system at the same point?**

MISO means the same interconnection point.

Resource Adequacy with Storage

(Q70) **What is the difference between Portfolio and Storage (with Wind + Storage)?**

"Portfolio" means the combined ELCC of a portfolio (mix) of resources which combines wind, solar, and storage, whereas "Storage (with wind+ solar)" denotes the marginal ELCC of storage alone in a system with renewables. With the base siting assumptions, there is more wind in the North, while solar is spread throughout the footprint, but with a higher concentration in the South.

(Q71) **As storage and renewables are added to the system, how does the allocation vary, and how are transmission constraints considered in the analysis?**

Allocation varies per the siting methodology and the resource mix (75:25) and differs subregionally in MISO. In Resource Adequacy, analysis on a zonal level, and per current industry standards, some of the details such as economic data and transmission topology are not included.

(Q72) **Does the location of storage vary as ICAP increases? Ditto for renewables? Or, is the sensitivity done on a zonal basis (copperplate)? What role does transmission capacity play in the storage sensitivity?**

For Resource Adequacy, the analysis is zonal (copper plate), but the location also varies, with the implication being that the availability and capacity factor of the sources change. In Resource Adequacy, PLEXOS is used with no transmission (copper plate). In Energy Adequacy, the transmission is modeled, and flow constraints are enforced.

Energy Adequacy with Storage

(Q73) **The optimal amount of storage found in RIIA is small given the large amount of storage currently proposed in the MISO interconnection queue. A significant share of that queued storage capacity appears not to be co-located with renewable generation, but instead sited to participate in energy arbitrage and ancillary services markets, subject to market conditions. Does MISO believe that incorporating a reasonable percent of the storage presently in the interconnection queue in the RIIA modeling would have significantly changed the RIIA projected transmission?**

The RIIA storage sensitivity was narrowly scoped to look at the ability of storage to help mitigate risks presented by increasing wind and solar. It is MISO's understanding that the storage and hybrids being proposed in the interconnection queue are not intended for that purpose. In the storage sensitivity modeling, large amounts of storage were added to the MISO system, but the result was a limited change to the transmission needs of the system.

(Q74) **Was the entire 100 GW of storage applied for the same six-hour period?**

Storage was modeled as smaller individual units, so each could perform differently and was free to dispatch during periods of risk.

(Q75) **It is surprising that MISO would only need 500 MW of storage. Is that an indictment of energy-arbitrage storage?**

The co-optimization expansion started with the 30% milestone transmission solutions included. The 500 MW of storage added to get to the 40% penetration level was therefore in addition to a significant amount of transmission already added to the model. The analysis suggests that although transmission would play a larger role, based on the current assumptions, there is an opportunity for storage and transmission to work well together.

Papers, Presentations and Contributors

Papers/Conference papers:

B. Heath and A.L Figueroa-Acevedo, "Potential Capacity Contribution of Renewables at Higher Penetration Levels on MISO System," in Proc. of the 2018 IEEE International Conference on Probabilistic Methods Applied to Power Systems (PMAPS) Boise, ID, 2019.

J. Bakke, M. Boese, A.L Figueroa-Acevedo, B. Heath, Y. Li, N. Mohan, J. Okullo, A. J. Prabhakar, and C.H Tsai, "Renewable Integration Impact Assessment: The MISO Experience," *IAEE Energy Forum*, First Quarter 2019, pp. 47 – 51

A.L Figueroa-Acevedo, C.H Tsai, K. Gruchalla, Z. Claes, S. Foley, J. Bakke, J. Okullo, and A. J. Prabhakar, "Visualizing the Impacts of Renewable Energy Growth in the US Midcontinent," in *IEEE Open Access Journal of Power and Energy*, vol. 7, pp. 91-99, 2020, doi: 10.1109/OAJPE.2020.2967292.

A. Figueroa-Acevedo. MISO Kaleidoscope Package. Accessed: July 12, 2019. [Online]. Available: https://github.com/al_gueroa21/MISOKaleidoscope

C.H Tsai, A.L Figueroa-Acevedo, M. Boese, Y. Li, N. Mohan, J. Okullo, B. Heath, J. Bakke, "Challenges of planning for high renewable futures: Experience in the US midcontinent electricity market, *"Renewable and Sustainable Energy Reviews,* Volume 131, 2020, https://doi.org/10.1016/j.rser.2020.109992.

Workshops:

"Renewable Integration Impact Assessment (RIIA) - Storage Sensitivity," MISO, October 27, 2020. Available: https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia---october-27-2020/

"Renewable Integration Impact Assessment (RIIA) – Energy Adequacy Sensitivity," MISO, July 24, 2020. Available: https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia---july-24-2020/

"Renewable Integration Impact Assessment (RIIA) Expansion/Siting and Resource Adequacy Sensitivity," MISO, June 16, 2020. Available:
https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia---june-26-2020/
"Renewable Integration Impact Assessment (RIIA) Phase 2 Conclusion Workshop," MISO, November 14 - 15, 2019. Available:
https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia-phase-2-conclusion-workshop---november-14---15-2019/

"RIIA 40% Penetration: Dynamics Studies Results Workshop," MISO, July 17, 2019. Available: https://www.misoenergy.org/events/riia-40-penetration-dynamics-studies-results-workshop---july-17-2019/

"Renewable Integration Impact Assessment Workshop," MISO, November 28, 2018. Available: https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia-workshop---november-28-2018/

"Renewable Integration Impact Assessment Workshop - methods, assumptions, and preliminary results" MISO, June 5, 2018. Available:
https://www.misoenergy.org/events/renewable-integration-impact-assessment-riia-workshop---june-5-2018/

MISO Stakeholder Presentations:

August 16, 2017: MISO PAC - Introduce need for assessment

September 27, 2017: MISO PAC - Introduce concept behind the assessment

April 18, 2018: MISO PAC - Discuss Resource Adequacy results

June 6, 2018: Workshop - Discuss details behind work to date

October 4, 2018: MISO RSC - Discuss frequency response results 20%

November 14, 2018: MISO PAC - Discuss results 10-40%

November 28, 2018: Workshop - Discuss details behind results 10-40%

March 14, 2019: Workshop - Discuss phase III feedback and work-plan

July 17, 2019: Workshop - Discuss dynamics impacts to conclude 40%

November 13, 2019: MISO PAC - Discuss phase II conclusion

November 14 - 15, 2019: Workshop – Discuss details of phase II conclusion

June 16, 2020: Webinar – Discuss expansion/siting and resource adequacy sensitivities

July 24, 2020: Webinar – Discuss energy adequacy sensitivities

October 27, 2020: Webinar – Discuss storage sensitivities

Conferences and External Public Meetings:

October 11, 2017: UVIG - Introduction to RIIA

November 7, 2017: Iowa Utilities Board - RIIA Overview

April 27, 2018: PLEXOS User Group Meeting - RIIA overview and use of PLEXOS

March 8, 2018: Transmission Summit East (Infocast) - Discuss lessons learned to date

April 26, 2018: ND PSC Meeting - Results to date

May 21/22, 2018: GO15 Governing Board meeting - Future grid needs

June 12, 2018: Iowa Utilities Board - RIIA Results to date

June 20/21, 2018: 2018 NERC Power System Modeling Conference

June 24-29, 2018: PMAPS International

August 9, 2018: IEEE PES GM panel session

August 9, 2018: IEEE LOLE Working Group at the IEEE PES

September 11, 2018: ISU Seminar (RIIA overview)

September 13, 2018: NCEP Webinar

October 9/10, 2018: GO15 Steering Board meeting - Future grid needs

October 12, 2017: ND PSC - RIIA Overview

October 23, 2018: MRO Fall Reliability Conference - RIIA Update

November 7, 2018: INFORMS Panel on sustainable systems - RIIA overview

January 9, 2019: MN Society of Professional Engineers - RIIA overview and lessons learned

February 26, 2019: MN Senate Energy Committee - RIIA overview and lessons learned

March 20, 2019: Energy Systems Integration Group (ESIG) - RIIA overview and lessons learned

April 9, 2019: EIPC Spring Technical Workshop - RIIA implications for transmission planning

April 24-25, 2019: NERC SAMS Meeting: Renewables Impact on Frequency Response

June 26, 2019: FERC Software Conference: Discuss software needs in the context of RIIA

August 4, 2019: IEEE PES GM - Panel session on "Transmission for renewables."

August 6, 2019: IEEE PES GM - International Practices in Power System Planning

January 10, 2020: MN commission MISO 101 – RIIA

January 21, 2020: MN Center for Environmental Advocacy

January 28, 2020: NERC SAMS- Update on RIIA 50% Frequency Response

January 29, 2020: Midwest Governors Association

February 18, 2020: ND PSC RIIA

May 21, 2020: ESIG 2020 Spring Technical Workshop/System Planning Working Group

April 1, 2020: Minnesota Municipal Utilities Association

June 4, 2020: RF Board of Directors meeting

July 21-22, 2020: SERC Summer Regional Meetings

Contributors

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Maire Boese
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BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

REQUEST NO. 2-21: ***Explain whether the Company receives any financial incentives to keep the Wilson plant operating.***

RESPONSE: Big Rivers does not receive any tax or grant incentives to keep the Wilson plant operating.

Witness: Nathanial A. Berry

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

REQUEST NO. 2-22: ***Explain whether BREC's planning for a future NGCC unit is focusing on a J or H class unit. If so, provide a discussion regarding the load-following capabilities of such a unit, and what that capability would do for BREC. Include in your discussion whether such a unit could perform ancillary services such as ramping, and whether such services could be marketed to MISO.***

RESPONSE: Yes, Big Rivers' plan for a future NGCC unit focuses on an advanced class combined cycle such as the J or H class machines. These units provide increased efficiency and typically have less than a 7,000 btu/kw heat rate (HHV – higher heating value). They also provide improved operating flexibility with faster start times, increased ramp rates, and lower turn down capabilities while maintaining high levels of reliability and availability. Machines of the J or H class would be capable of providing the following Ancillary Services: RampUp, RampDown, Regulation, Spinning Reserves, Online Supplemental, and Online Short-Term Reserves. Machines of the J or H class would not be capable of providing Offline Supplemental or Offline Short-Term Reserves.

Witness: Nathanial A. Berry

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORÅTION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

I, Nathanial A. Berry, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Nathanial A. Berry
Nathanial A. Berry
Chief Operating Officer
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Nathanial A. Berry on this the 15 day of February, 2024.

My commission expires: 1-14-2026

Ralph Lynn Jones
Notary Public

Notary ID: KYNP43026

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

I, Terry Wright, Jr., verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Terry Wright, Jr.
VP of Energy Services
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Terry Wright, Jr. on this the 15 day of February, 2024.

My commission expires: 1-14-2026

Notary Public

Notary ID: KYNP 43026

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

I, Talina R. Mathews, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Talina R. Mathews

Talina R. Mathews
Chief Financial Officer
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Talina R. Mathews on this the 15th day of February, 2024.

My commission expires: October 31, 2024

Kathleen Rolz
Notary Public

Notary ID: KYNP16841

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO THE
OFFICE OF THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUESTS FOR
INFORMATION

I, John Christensen, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John Christensen
Senior Project Manager
Burns & McDonnell Engineering Co., Inc.

STATE OF	Minnesota	)
		) ss:
COUNTY OF	St. Louis	)

SUBSCRIBED AND SWORN TO before me by John Christensen on this the 9th day of February, 2024.

My commission expires: January 31st, 2027

ERIN KAYE JOHNSON
Notary Public-Minnesota
My Commission Expires Jan 31, 2027

Erin K. Johnson
Notary Public

Notary ID: 13076791 00037