Renewable Integration Impact Assessment (RIIA)

Assumptions Document

Version 1

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MISO

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1 Introduction

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[1] 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 and/or system operations need to be modified to reliably achieve the next tranche of renewable deployment. This study 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 examines 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 assumptions document discusses the details of data and processes used in the four Modules 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 study.

This is a living document and will be updated as the assessment progresses and feedback is received. Some areas of the document, such as assumptions for Module 1, contain more detail due to its place at the front of the study process. Information will be added as it is developed, and some information will change if it is deemed to be not applicable to this work.

2 Module Outlines

As discussed in the introduction, this assessment aims to remain “year agnostic.” However, for modeling reasons, it is necessary to choose a specific year to model. This study uses 2017 as a proxy year. The base model for Module 1 of RIIA is taken from MTEP17. The model includes a 15-year out transmission topology, including the remaining Multi-Value Projects (MVPs) and Appendix A transmission. This document is intended to provide 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[2].used for the four study Modules.

Table 1 describes the models used for the four study Modules.

Table 1 RIIA module tools & models

	Tool(s)	Vintage
Module 1	PLEXOS, Kermit	MTEP17 model; uses MTEP16 Powerflow model at 15-year out transmission
Module 2	PSSE	MTEP16 15-year model

[1] The RIIA concept paper includes a detailed list of relevant industry studies.
[2] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP17/MTEP17%20Full%20Report.pdf

Module 3	PSSE, TSAT	Same as Module 2
Module 4	PLEXOS	Same as Module 1

2.1 Module 1

Module 1 of RIIA is run 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. An overview of each phase is presented below, including the main assumptions adopted for the RIIA study. These phases can be run separately or together. PLEXOS also offers an interleave feature, which allows the user to simulate both a day-ahead and real-time market.

2.1.1 PASA (Projected Assessment of System Adequacy)

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.

Relevant outputs: Maintenance schedules for non-nuclear generators

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 provided by the Nuclear Regulatory Commission)

Model/Algorithm: Linear program (LP)/Simplex

2.1.2 MT Schedule (Medium-term Schedule)

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.

Relevant outputs: Generator-specific net revenue used in retirement decisions (see Section 4.3); dispatch of energy-limited resources (e.g. hydro)

Main assumptions: Regional transmission representation; non-chronological solve

Model/Algorithm: Linear program (LP)/Simplex

2.1.3 ST Schedule (Short-term Schedule)

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.

Relevant outputs: The majority of outputs in this study 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).

Main assumptions: Chronological dispatch

Model/Algorithm: Mixed-integer linear program (MIP)/Branch and bound

2.1.4 Interleaved Run Mode

Functions: The objective is to enable the passing of data between models such 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.

Relevant outputs: ST Schedule results for both day-ahead and real-time simulations

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)[3]; 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

Model/Algorithm:

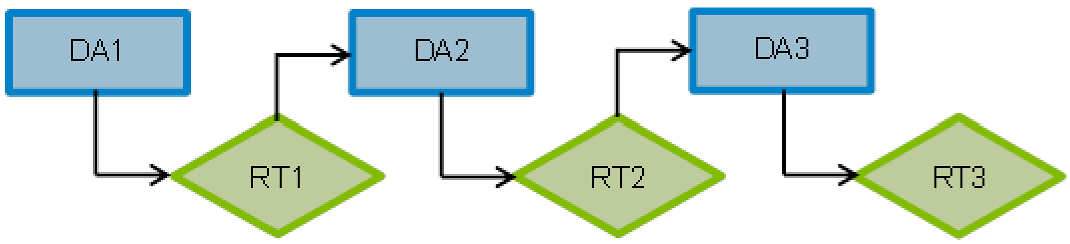

Figure 1 PLEXOS' interleave feature

2.2 Module 2

Module 2 of RIIA is performed using Siemens’ PSSE powerflow simulation software. PSSE’s AC contingency analysis allows for the identification of voltage and thermal reliability issues as a result of generation and transmission contingency events.

2.2.1 Grid-Scale Generation Modeling

Siting of wind and grid-scale solar in the powerflow model will include generator step-up transformer topology. Renewable siting will be 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 & grid-scale solar) will be modeled as a Wind Machine, with Q limits based on a Power Factor of +/- 0.95 applied to the unit’s power output. The unit will be sited at a 0.69 kV bus, with a GSU transformer connecting it to a 34.5 kV bus. The GSU will be modeled per WECC recommendations, with 6% impedance and an X/R ratio of 8. A POI transformer will connect the 34.5 kV bus to the BES bus at which the generator is ultimately interconnected. The POI transformer will be modeled per WECC recommendations, with 8% impedance and an X/R ratio of 40. Figure 2 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 Section 4 of this document.

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

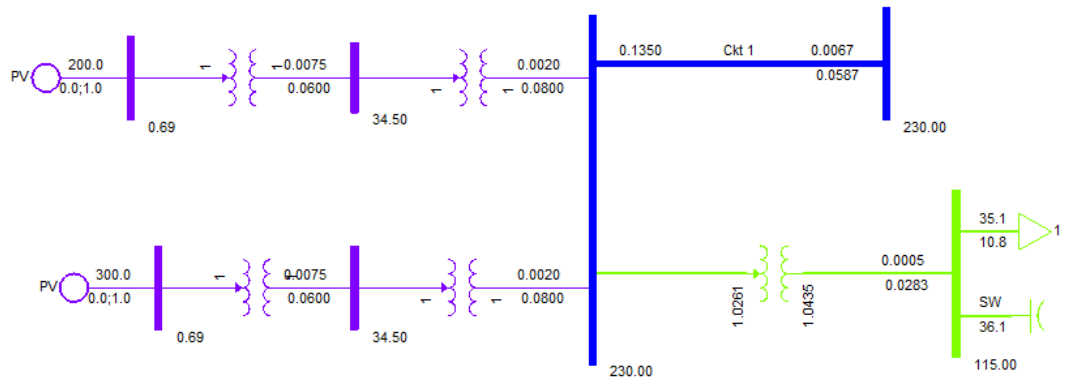

Figure 2 PSSE configuration for 500 MW of grid-scale solar

2.2.2 Distributed Generation Modeling

Distributed solar generation will be modeled as a Retail-Scale Distributed Energy Resource (R-DER). These are single-phase units and are used to offset customer loads. Therefore, the DG units will be sited directly on the BES bus containing the load, and will not model any step-up transformer topology. DG units will not provide any reactive power support, as no standard currently exists that requires it.

2.2.3 Powerflow Model Dispatch

The PSSE Powerflow models will be developed based on snapshots of "stressful" periods identified in Module 1. These "stressful" dispatch scenarios may include, but are not limited to:

- Periods of absolute peak system demand
- Periods with the maximum non-synchronous generation online
- Periods with the highest percentage of total energy from non-synchronous generation
- Periods of lowest system load
- Periods with maximum transfers across existing (or new) monitored transmission interfaces

The dispatch of wind and solar (distributed and grid-scale) from these snapshots in the PLEXOS model will be applied to the PSSE case using a PLEXOS-to-PSSE unit mapping. Similarly, area loads in PSSE will be scaled based on load levels in the PLEXOS model during each of these snapshots. Conventional generation in each powerflow area will be adjusted based on merit order to compensate for changes in load and renewable generation levels.

All transmission facilities 100 kV and above will be monitored for the Eastern Interconnection, and a contingency analysis consisting of P1 & P2 events will be applied for the Eastern Interconnection. Geographic scope and voltage level are subject to change.

2.3 Module 3

Module 3 will use PSSE and TSAT to look at the impact of high levels of renewable penetration on voltage stability, transient stability and MISO's frequency response obligations. This module will use models developed as part of the Module 2 powerflow analysis.

The impact of renewable penetration on frequency response obligation of MISO will be studied through dynamic simulation of 120 seconds. To the extent possible, MISO will use models of the existing generating facilities validated against actual system disturbance to correctly capture the system response. A standard set of models for newly sited wind and solar generation will be compiled. Historically known stability issues and any new issues identified through other modules will be studied.

Local and regional planning criteria will be applied for all disturbances. 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 will be monitored for all generators with the exception of renewable energy plants or other generating plants which have detailed frequency/voltage capabilities already specified. Generic distance relays will be modeled for all lines 100 kV and above with the exception of lines which have detailed relays already specified.

At higher penetrations of renewable energy resources, the modeling of their frequency response will be further investigated and potentially modified in order to evaluate what, if any, changes need to be made to meet the appropriate frequency response.

2.4 Module 4

A key component of MISO's transmission planning process is the resource adequacy analysis, as required by the North Electric Reliability Council (NERC). Standard BAL-502-RFC-02 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 "one day in ten 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 is used to calculate the capacity contribution of wind generation[4].

This part of RIIA will focus on the implications of high wind and solar penetration levels on the system's resource adequacy. The LOLE will be used as the criteria to characterize the reliability of the system at different milestones. In order to quantify the capacity contribution of renewables during the system's coincident peak, this study will adopt the ELCC metric. In particular, at each milestone, this module will:

1. Compare the LOLE and identify conditions under which the system will perform below the "one day in ten years" LOLE target
2. Determine the ELCC for utility-scale wind, utility-scale solar PV, and distributed solar PV
3. Characterize the ELCC for utility-scale wind, utility-scale solar PV, and distributed solar PV

Model: This module will use the PLEXOS model built as part of Module 1. It will consider using SERVM as the study progresses.

Relevant outputs: LOLE, capacity credit, and ELCC for each milestone using 6 different meteorological years of synchronized wind, utility-scale solar and distributed solar profiles

[4] 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

3 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.

3.1 Study Areas

The Renewable Integration Impact Assessment (RIIA) model comprises the following six areas:

- 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)

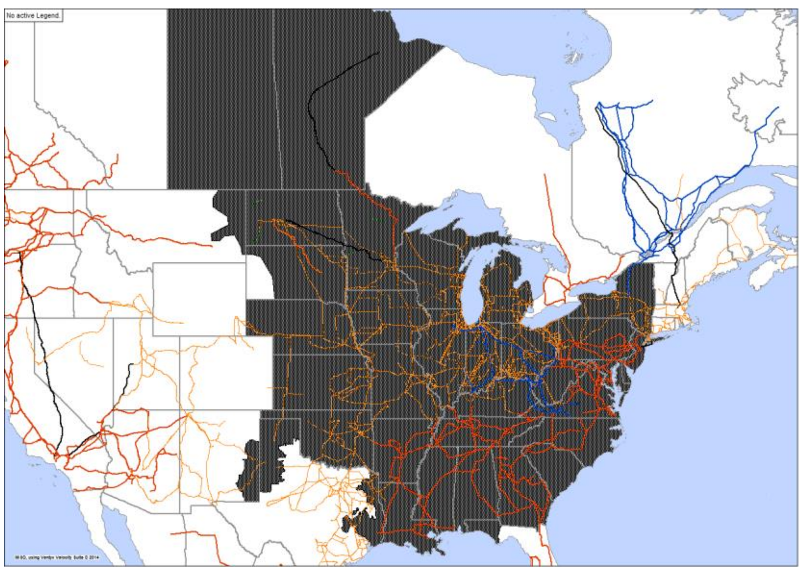

Figure 3 RIIA study footprint

3.2 Resource Mixes

Each planning region within the Eastern Interconnect 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.

Table 2 RIIA resource mix by region (in MW)

	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

3.3 Generator Characteristics

Table 3 contains the average values for the generator characteristics used in the model. These assumptions are taken directly from Ventyx/ABB unless otherwise noted.

Table 3 Generator characteristics by fuel type

	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

Forced outages occur randomly within the simulation and maintenance outages are scheduled using PASA and remain constant throughout the study (see Section 2.1.1).

3.3.1 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)[5] 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.

3.3.1.1 Ramp Rates

Ramp rate is a unit's rate of change (MW/min) when the output is between the unit's minimum 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[6] 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 the RIIA study. Quick start ramp rate in the B&V study is used for the run rate in the RIIA study.

Table 4 Ramp and run rates by fuel type

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

Unit types not listed in Table 4 use ramp and run rates consistent with ABB's assumptions.

3.3.1.2 Start-Up Costs

The Power Plant Cycling Costs Report[7], 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.

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

[6] 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

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

Table 5 Start up costs by fuel type

	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

3.4 Fuel Prices

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

3.4.1 Natural Gas Prices

The Henry Hub natural gas price 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.

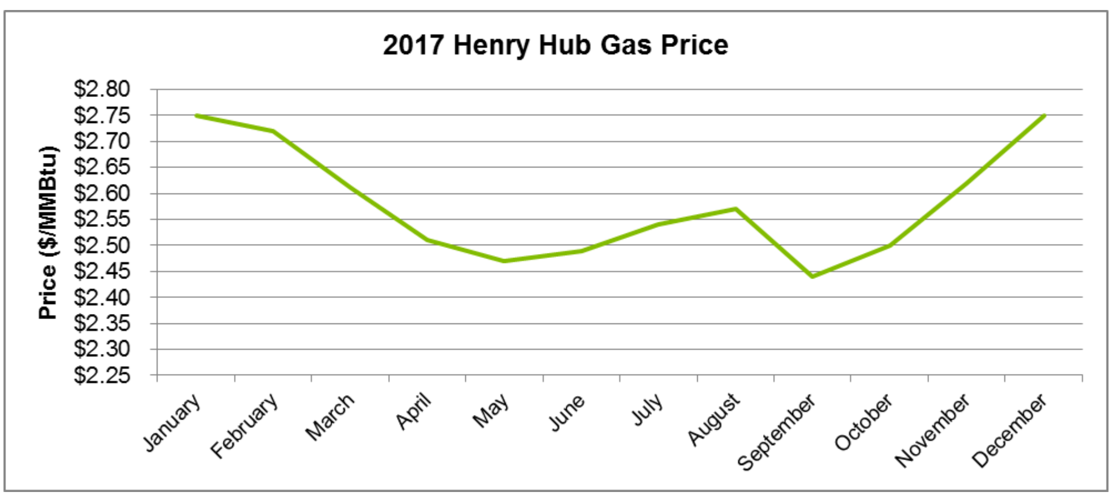

Figure 4 Monthly natural gas prices

3.4.2 Other Fuel Prices

The remaining fuel prices are listed in the Table 6. Several other fuel types also use location-specific prices. In those cases, the values in Table 6 are average values.

Table 6 Fuel prices

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

3.5 Load Profiles

MISO's local balancing authority (LBA)[8] 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/ABB), and then adjusted to create five-minute load profiles. This process is necessary due to the lack of publically available five-minute load data. It is described in detail in the following sections.

3.5.1 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 PROMOD 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/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 Appendix A – Creating non-MISO Load Shapes.

3.5.2 Data Processing

Within the 2012 five-minute load data, several LBAs have irregular dips and/or 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), as shown in Figure 5 (left). 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, as shown in Figure 5 (right). Dips/spikes below the 3-5% threshold are considered regular occurrences and assumed to represent expected levels of variation.

[8] 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.

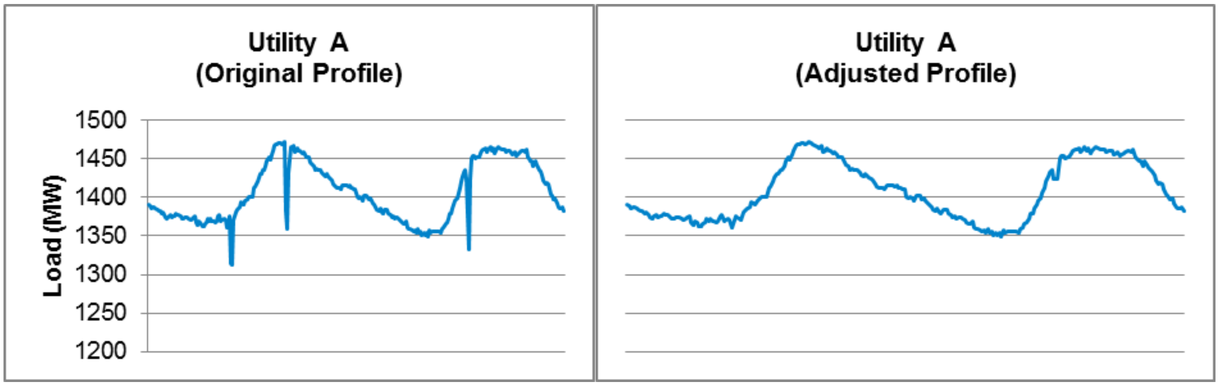

Figure 5 Utility A's load profile before & after data processing

3.5.3 Forecast Error

For this study, the PLEXOS interleave feature will 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.

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. Figure 6 shows the forecast error of MISO's footprint for a sample week.

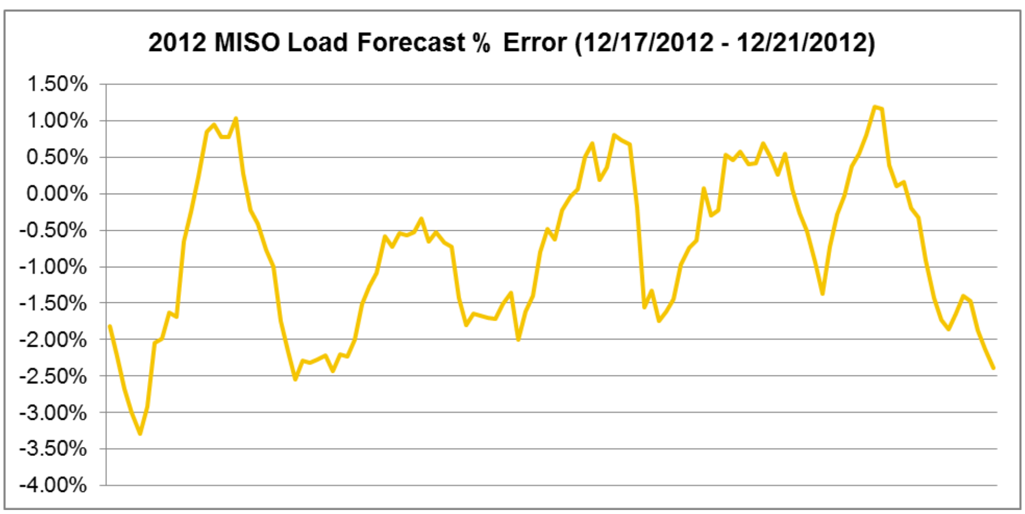

Figure 6 MISO's load forecast error

3.6 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.

3.6.1 Wind

Wind profiles source from NREL's Wind Integration National Dataset (WIND) Toolkit[9]. 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[10]. 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.

3.6.2 Solar

Solar profiles source from NREL's Solar Integration National Dataset (SIND) Toolkit[11]. 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 2007-2013. 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.

4 Milestone Generation Changes

The base model for the RIIA is derived from the MTEP17 model, as described in Section 3. 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 study, while retirements are determined based on initial screening results of the PLEXOS model. In this section, the expansion, siting and retirement processes are described.

4.1 Expansion

1. *Determine the GWh of demand in each region from the load profiles developed in Section 3.5.*

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

[10] 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.

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

Table 7 Total demand by region

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

2. *Assign the split of wind and solar energy to each region based on the ERGIS RTx30[12] scenario.*

Table 8 Split of wind and solar by region

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

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. For new renewable sites, calculate capacity factors for each penetration level.*

Table 9 Capacity factors for existing wind and solar by region

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

Table 10 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><td>MISO</td><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><td>SPP</td><td>N/A</td><td>N/A</td><td>48%</td><td colspan="7">46%</td></tr>
<tr><td>TVA</td><td>38%</td><td colspan="2">36%</td><td colspan="4">37%</td><td colspan="2">36%</td><td>35%</td></tr>
<tr><td>SERC</td><td>37%</td><td colspan="2">38%</td><td colspan="3">37%</td><td colspan="3">36%</td><td>35%</td></tr>
<tr><td>PJM</td><td>43%</td><td>40%</td><td>39%</td><td colspan="2">38%</td><td colspan="5">37%</td></tr>
<tr><td>NYISO</td><td>43%</td><td>41%</td><td>42%</td><td>41%</td><td colspan="6">42%</td></tr>
</table>

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

Table 11 Capacity factors for new utility-scale 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><td>MISO</td><td colspan="3">19%</td><td>18%</td><td colspan="5">19%</td><td>18%</td></tr>
<tr><td>SPP</td><td>N/A</td><td>N/A</td><td>22%</td><td colspan="7">23%</td></tr>
<tr><td>TVA</td><td colspan="10">19%</td></tr>
<tr><td>SERC</td><td colspan="10">19%</td></tr>
<tr><td>PJM</td><td colspan="9">18%</td><td>17%</td></tr>
<tr><td>NYISO</td><td colspan="10">16%</td></tr>
</table>

Table 12 Capacity factors for new distributed 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><td>MISO</td><td colspan="10">17%</td></tr>
<tr><td>SPP</td><td>N/A</td><td>N/A</td><td colspan="8">18%</td></tr>
<tr><td>TVA</td><td colspan="10">17%</td></tr>
<tr><td>SERC</td><td colspan="10">19%</td></tr>
<tr><td>PJM</td><td colspan="10">16%</td></tr>
<tr><td>NYISO</td><td colspan="10">15%</td></tr>
</table>

4. *Identify the capacity credits for wind and solar in each region.*

In discussion with MISO's Loss of Load Expectation (LOLE) team, it is determined that for all regions wind has a 15% capacity credit and solar has a 50% capacity credit. For purposes of this expansion process, these capacity credits are generic values used for all milestones (i.e. renewable penetration levels). However, one goal of this assessment is to determine how capacity credits may change as renewable energy increases. The exploration of this change is discussed in Section 2.4. The expansion process will be repeated based on the results of that exploration.

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

This process yields the following capacity expansion.

Table 13 Wind expansion by region and milestone

	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 14 Utility solar expansion 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 15 Distributed solar expansion by region and milestone

	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

4.2 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 that will be 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/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 Section 3.6). 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[13]

Table 16 Siting priorities by unit status

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

    b. Capacity factor bins
    c. Rank within grid cell (determined in step 3)
    d. Proximity to queue locations
    e. Outlet capability (measured by number of high kV lines connected to the bus)
6. Fill up/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

4.3 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 CT/ST/IC renewable units are not considered candidates for retirements. This 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

[13] 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.

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/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 wind units, a capacity credit of15.6% is assumed[14]. For both utility-scale and rooftop solar units, a capacity credit of 40% is assumed (consistent with MTEP17 assumptions). MISO's current capacity credit construct is based on wind penetration levels consistent with those seen today.

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

One feature PLEXOS offers is its Medium Term Scheduling. 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.

Table 17 Generator useful life by fuel type

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

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

[14] See MISO's Planning Year 2017-2018 Wind Capacity Credit Report https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20Wind%20Capacity%20Report.pdf

chosen based solely on their net revenue ranking. MISO will also consider candidates for retirements identified in MTEP and other MISO processes.

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

Retirements chosen in one milestone will persist for the remaining milestones. Retirements are incorporated into the model for each module. 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.

5 Appendix A – 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 $MA_{h,i}$.

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