Overview

This document provides the assumptions and timetable for the 2023 PJM Reserve Requirement Study (RRS). The study will examine the period beginning June 1, 2023 through May 31, 2034.

The 2023 RRS is consistent with the provisions of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. In accordance with Reliability Pricing Model (RPM) requirements, the results of this study will be used to determine the Forecast Pool Requirement (FPR) for the 2024/25, 2025/26, 2026/27 and 2027/28 Delivery Years.

The 2023 RRS will be conducted using two software tools: (i) the Probabilistic Reliability Index Study Model (PRISM), the tool that PJM has used historically to conduct the RRS and (ii) the hourly loss of load model used in ELCC studies. Given the different characteristics of the two software tools, two sets of assumptions (Assumptions Set #1 and Assumptions Set #2) will be used to perform the 2023 RRS. The decision to use two software tools to run the study this year is based on the fact that this is the first year PJM has an hourly loss of load model available to calculate the FPR. PJM recognizes the need to start conducting the RRS using an hourly loss of load model but instead of replacing PRISM with the hourly model this year, PJM is proposing to run the 2023 RRS with the two software tools as part of the transition to permanently use the hourly loss of load model.

Consistent with the above two sets of assumptions, two sets of results will be reported to stakeholders. Following review and discussion with stakeholders, PJM will then recommend for endorsement a single set of results.

Specific items to note for the 2023 RRS, common to the two sets of assumptions mentioned above, include:

1. All generators (except ELCC Resources) will be modeled as capacity units per the modeling assumptions in Attachment III.

2. All variable (wind, solar, hydro, landfill gas) and storage-type resources (pumped hydro, batteries, hybrids, and generic limited-duration resources) will be excluded from the model

3. For this study, the generator unit model data will be available for review, per Section 2 of Manual 20 and must be performed by PJM Member representatives that own generation. This effort is targeted for July of 2023.

4. The Capacity Benefit of Ties (CBOT) used to reduce the single-area FPR values calculated in the 2023 RRS will be determined by averaging seven individual historical CBOT values. The CBOT values to be averaged are those calculated in the RRS from the period 2017-2022 (2017 was the first RRS that excluded ISO-NE as part of the World) and the CBOT calculated this year in PRISM using Assumptions Set #1. The CBOT, produced by the average calculation described above, will then be converted to UCAP and subtracted from the single-area FPR calculated with PRISM and the single-area FPR calculated with the hourly loss of load model. This will determine the final FPR produced by each of the two models.

5. A summary timeline of the RRS process is shown in Attachment IV.

6. Flexibility to allow for additional case development and analysis is requested for this study.

In addition, PJM staff will perform 2023 RRS-related analysis at the request of the Critical Issue Fast Path – Resource Adequacy (CIFP-RA) stakeholder group. This additional analysis will not be subject to the approval process detailed in Attachment IV of this document. Furthermore, the set of reforms to the PJM resource adequacy construct that the CIFP-RA process may produce, may require the recalculation of the FPR values in the 2023 RRS.

Summary of Annual Study Procedure

The primary focus of the PJM Reserve Requirement Study (RRS) is to determine the installed reserves to satisfy the criterion specified in the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA). This Study, in conjunction with PJM's Load Deliverability Test, satisfies the requirements of ReliabilityFirst Standard BAL-502-ReliabilityFirst-03. The PJM Planning Committee (PC) has the primary responsibility to coordinate and complete activities to adhere to the requirements of the RAA. The Resource Adequacy Analysis Subcommittee (RAAS), established by the PC, has the responsibility to determine the proper assumptions used in this analysis and to review the final results.

The timetable shown in Attachment I list the sequence of activities in this process. To accomplish this task, subcommittees and working groups reporting to the PC have been assigned the responsibilities shown in Attachment I.

The member representatives that own generation calculate and maintain information on individual generating units and operating statistics. These individual unit statistics must be submitted via a secure PJM Internet application designed for this purpose.

The Load Analysis Subcommittee (LAS) reviews the PJM Staff's efforts to calculate and maintain load forecasting values and associated probability of occurrence statistics. The PJM staff uses the information supplied from the Generation Owners, LAS, EIA-411 Report, NERC Electric Supply and Demand (ES&D) database, and the historical hourly peak loads to produce a probabilistic PJM system model. This model is used to determine the reserve requirement necessary to meet the ReliabilityFirst criterion for resource adequacy of a Loss of Load Expectation (LOLE) of one occurrence in ten years.

The initial task of the RAAS in this process is to develop the study and modeling assumptions and to seek endorsement of these assumptions from the PC.

Attachment I: Scheduled Target Dates for the 2023 PJM RRS

Corresponding Timeline Number	Activity	Target Date	Group Responsible
1	**Capacity Data Model Development**		
	a) Begin update of capacity model.	January 2023	PJM Staff
	b) Submit updated outage rate data to PJM Staff.	January 2023	Generator Owner Reps
1	**Load Data Model Development**		
	a) Submit PJM Staff forecast to PC	January 2023	PJM Staff
	b) Begin updating PJM load model.	January 2023	PJM Staff
7	**Capacity Models Finalized**		
	a) Submit final GORP outage rate data to PJM Staff.	May 2023	Generator Owner Reps
	b) Load & capacity models not changed after this date. Confirm that capacity and PJM reserves correspond to latest available information.	June 2023	PJM Staff
8	**FPR and IRM Analysis**		
	PJM RTO region	July 2023	PJM Staff
9	**Approval of Load Model Time Period**		
	RAAS Recommendation.	August 2023	PC
8	**Analysis of Winter Weekly Reserve Target for 2023-2024 Winter Period**		
	PJM RTO region.	September 2023	PJM Staff
13	**Report on Winter Weekly Reserve Target for 2023-2024 Winter Period**		
	This is based on the approved 2023 PJM RTO Region Reserve Study results.	September 2023	RAAS
	a) Forward letter to OC with recommended Winter Weekly Reserve Target.	Sept PC Mtg.	PC

13	**Distribute Final Report to PC**		
	Final Draft	Sept PC Mtg.	RAAS
	Final Report	Oct PC Mtg.	RAAS
14 A	**Endorsement/Recommendation of applicable Factors (IRM and FPR)**	Oct PC Mtg.	PC

Attachment II-A: Study Assumptions Set #1 for the 2023 PJM RRS

1. The 2023 RRS will be conducted as outlined in the "PJM Generation Adequacy Analysis: Technical Methods," and PJM Manual M20 revision 12, "PJM Resource Adequacy Analysis".

2. The PJM Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) will be determined using PJM's two-area model, the Probabilistic Reliability Index Study Model (PRISM). The analysis will focus on results for Area 1, the PJM RTO representation. The Area 2 model represents the electrically significant regions adjacent to the PJM RTO as described in Item 8. The modeling details of performing a two-area study are described in Attachment III. MARS will be used to supplement the PRISM study results, specifically concerning issues that require multi-area modeling techniques.

3. The PJM RTO footprint will be modeled as Area 1 in the study. Area 1 load will consist of the combined coincident loads of the following regions: PJM Mid-Atlantic, APS, AEP, ComEd, Dayton, DomVP, DLCO, ATSI, DEOK, EKPC, and OVEC.

4. All generators (except variable and storage-type resources) will be modeled as capacity units per the modeling assumptions in Attachment III.

5. All variable (wind, solar, hydro, landfill gas) and storage-type resources (pumped hydro, batteries, hybrids, and generic limited-duration resources) will be excluded from the model. These resources are excluded because PRISM cannot properly model the limitations of these resources namely, the intermittency in output of variable resources and the energy constraints of storage-type resources. Excluding these resources from the calculation of the FPR is appropriate given that the limitations and uncertainty associated with these resources' performance is reflected in the accreditation of the resources and therefore, they should not increase the procurement target in RPM (which is set by the FPR and is mainly driven by load uncertainty).

6. Ambient derates of generating units will be represented via planned outages over the summer period. This is done to reflect operating experience related to a reduction of generating capability due to extreme ambient summer temperatures that would not be captured otherwise.

7. The Capacity Benefit of Ties (CBOT) will be determined by averaging the most recent seven historical CBOT values (including the value calculated using this set of assumptions for the 2023 RRS in PRISM).

8. World reserves will be modeled at the individual World sub-regions "one day in ten year" reserve levels. The World sub-regions shall be: New York Independent System Operator (NYISO), Tennessee Valley Authority (TVA), Virginia-Carolinas (VACAR) and Midwest Independent System Operator (MISO).

9. Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.

10. The Forecast Error Factor (FEF) will be held at one percent for all planning periods being evaluated. This practice is consistent with consensus gained through the PJM stakeholder process.

Attachment II-B: Study Assumptions Set #2 for the 2023 PJM RRS

1. The 2023 RRS will be conducted consistent with the methodology outlined in PJM Manual 20 revision 12 Section 5 PJM Effective Load Carrying Capability Analysis.

2. The PJM Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) will be determined using the hourly loss of load model used in ELCC studies. This model considers only the PJM region and not any external regions.

3. The PJM RTO footprint will be modeled as Area 1 in the study. Area 1 load will consist of the combined coincident loads of the following regions: PJM Mid-Atlantic, APS, AEP, ComEd, Dayton, DomVP, DLCO, ATSI, DEOK, EKPC, and OVEC.

4. All generators (except variable and storage-type resources) will be modeled as capacity units per the modeling assumptions in Attachment III.

5. All variable (wind, solar, hydro, landfill gas) and storage-type resources (pumped hydro, batteries, hybrids, and generic limited-duration resources) will be excluded from the model These resources are excluded from the study under assumptions Set #2 to be consistent with Assumptions Set #1, despite the fact that the hourly loss of load model can reflect the limitations and performance uncertainty of these resource types. Excluding these resources from the calculation of the FPR is appropriate given that the limitations and uncertainty associated with these resources' performance are reflected in the accreditation of the resources. Therefore, variable and limited-duration resources should not increase the procurement target in RPM (which is set by the FPR and is mainly driven by load uncertainty).

6. Ambient derates of generating units will be represented via planned outages over the summer period. This is done to reflect operating experience related to a reduction of generating capability due to extreme ambient summer temperatures that would not be captured otherwise.

7. The Capacity Benefit of Ties (CBOT) will be determined by averaging seven historical CBOT values (including the value calculated in the 2023 RRS using the assumptions in Set #1 in PRISM).

8. World reserves will not be modeled. The hourly load loss of load model only considers the PJM region.

9. Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.

10. The Forecast Error Factor (FEF) will not be modeled in this set of assumptions.

Attachment III-A: Modeling Assumptions Set #1 for the 2023 PJM RRS

1. Load Models

Both PJM and the World load models will be selected based on the methodology approved by the Planning Committee at their July 2023 meeting (see Attachment V).

2. PJM RTO Capacity Model

The generating units within the PJM RTO Study region will use statistics as detailed in the PJM Manual M22 revision 18, "Generator Resource Performance Indices," dated March 26, 2020. The statistics used are: Equivalent Demand Forced Outage Rate (EFORd), Effective EFORd (EEFORd), Capacity Variance, and Planned Outage Factor (POF).

The data for these statistics is primarily provided through PJM's electronic Generation Availability Data System (eGADS) web interface, per the online help function within eGADS. A five year time period (2018-2022) is used for the calculation of these statistics. These statistics are compared, for consistency, to those calculated and shown in the NERC Brochure for units reporting events (2018-2022). The Generation Owners of the various individual units are required to review and provide changes.

For each week of the year, except the winter peak week, the PRISM model uses the above statistics of each generating unit to develop a cumulative capacity outage probability table. For the winter peak week, to better account for the risk caused by the large volume of concurrent outages observed historically during this week, the cumulative capacity outage probability table is created using historical actual RTO-aggregate outage data. Winter peak week data from time period Delivery Year 2007/2008 to Delivery Year 2022/2023 (16 winter peak weeks) is used to calculate the cumulative capacity outage probability table for the winter peak week.

3. World Capacity Model

The 2022 NERC Electricity Supply & Demand (ES&D) will be the basis for future World generating unit information. Future capacity plans for World areas will be obtained from neighboring NERC regions. All World unit EEFORd and maintenance cycles will be updated using the latest Class Average Outage Rates. These rates, obtained from the NERC's pc-based Generation Availability Report (pc-GAR) application or applicable PJM eGADS summaries, will be based on a five year period.

4. Planning and Operating Treatment of Generation

All generators (other than ELCC resources) that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:

1. Firm Transmission service to the PJM border
2. Firm ATC reservation into PJM
3. Letter of non-recallability from the native control zone

Assuming that these requirements are fully satisfied, the following comments apply:

- Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World.
- Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.
- Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area.
- Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.

5. Reserve levels in the World region

As stated above, the CBOT used to reduce the single-area FPR values calculated in the 2023 RRS will be determined by averaging seven individual historical CBOT values. The CBOT values to be averaged are those calculated in the RRS from the period 2017-2022 (2017 was the first RRS that excluded ISO-NE as part of the World) and the CBOT calculated this year in PRISM using Assumptions Set #1. To calculate the latter value, the reserve level in the World region will be determined as done in previous years' RRS (see for example page 18 in the 2022 RRS).

Attachment III-B: Modeling Assumptions Set #2 for the 2023 PJM RRS

1. Load Models

The PJM load model in the hourly loss of load model used in ELCC studies is composed of 3 elements:

Historical Weather Delivery Years (DY): In the 2023 RRS, the period DY 2012 – DY 2021 will be included.
Weight for each Historical Weather Year: In the 2023 RRS, the weights will be calculated based on the seasonal peak load values in period DY 2012 – DY 2021 and the seasonal peak loads from the weather scenarios considered in the 2023 PJM Load Forecast.
Hourly Load Scenarios: In the 2023 RRS, 1,000 scenarios for each Historical Weather Year are estimated based on monthly peak load values from the weather scenarios included in the 2023 PJM Load Forecast.

The above load model assumptions are consistent with the load model used in the 2022 ELCC Study.

2. PJM RTO Capacity Model

The generating units within the PJM RTO Study region will use statistics as detailed in the PJM Manual M22 revision 18, "Generator Resource Performance Indices," dated March 26, 2020. The statistics used are: Equivalent Demand Forced Outage Rate (EFORd), Effective EFORd (EEFORd), Capacity Variance, and Planned Outage Factor (POF).

The data for these statistics is primarily provided through PJM's electronic Generation Availability Data System (eGADS) web interface, per the online help function within eGADS. A five year time period (2018-2022) is used for the calculation of these statistics. These statistics are compared, for consistency, to those calculated and shown in the NERC Brochure for units reporting events (2018-2022). The Generation Owners of the various individual units are required to review and provide changes.

For each week of the year, except the winter peak week, the PRISM model uses the above statistics of each generating unit to develop a cumulative capacity outage probability table. For the winter peak week, to better account for the risk caused by the large volume of concurrent outages observed historically during this week, the cumulative capacity outage probability table is created using historical actual RTO-aggregate outage data. Winter peak week data from time period Delivery Year 2007/2008 to Delivery Year 2022/2023 (16 winter peak weeks) is used to calculate the cumulative capacity outage probability table for the winter peak week.

3. World Capacity Model

The World is not modeled under this set of assumptions. CBOT will be calculated according to #7 in Attachment II-B.

4. Planning and Operating Treatment of Generation

All generators (other than ELCC resources) that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:

4. Firm Transmission service to the PJM border
5. Firm ATC reservation into PJM
6. Letter of non-recallability from the native control zone

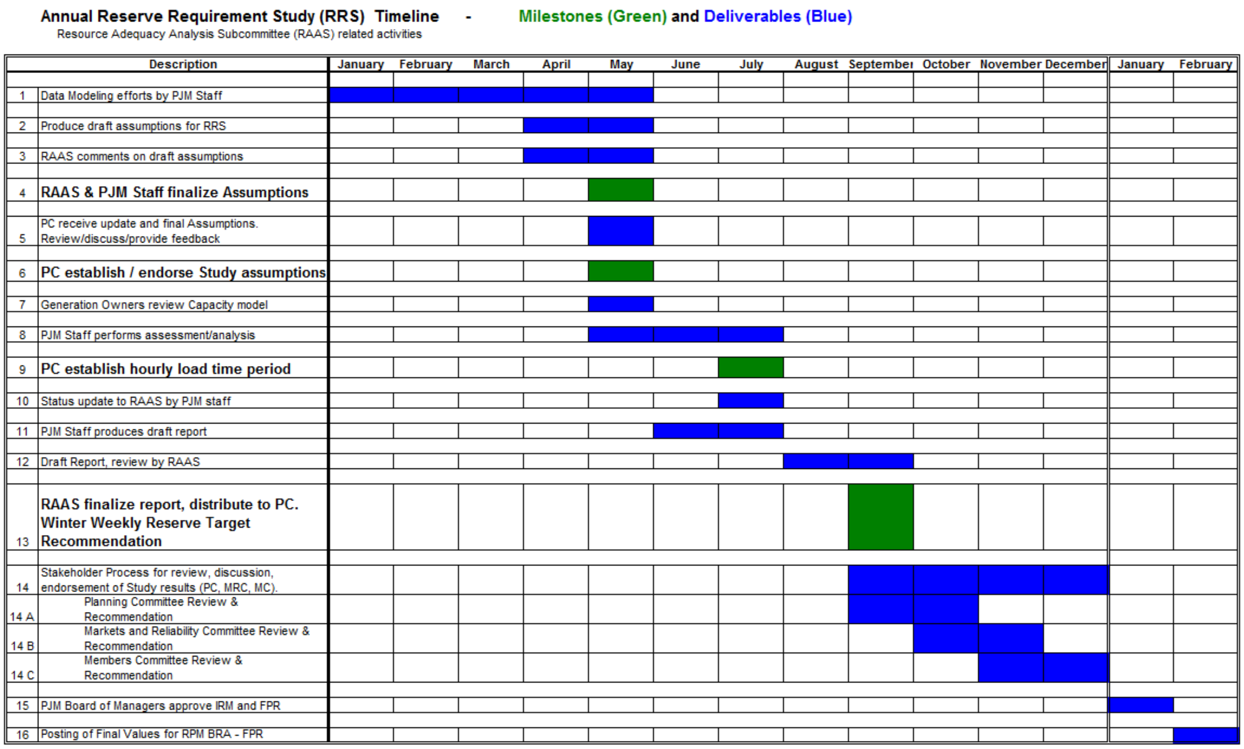
Assuming that these requirements are fully satisfied, the following comments apply:

- Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World.
- Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.
- Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area.
- Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.

5. Reserve levels in the World region

As stated above, the CBOT used to reduce the single-area FPR values calculated in the 2023 RRS will be determined by averaging seven individual historical CBOT values. The CBOT values to be averaged are those calculated in the RRS from the period 2017-2022 (2017 was the first RRS that excluded ISO-NE as part of the World) and the CBOT calculated this year in PRISM using Assumptions Set #1. To calculate the latter value, the reserve level in the World region will be determined as done in previous years' RRS (see for example page 18 in the 2022 RRS).

Attachment IV: Time Line for 2023 PJM RRS



The 2023 Study activities last for approximately 14 months. Some current Study activities, shown in items 1 and 2, overlap the previous Study timeframe. The posting of final values occurs on or about February 1st.

Attachment V: Load Model Selection Procedure for RRS for Assumptions Set #1

Introduction

The RRS uses PRISM to calculate the IRM/FPR. Load uncertainty in PRISM is modeled via 52 normal distributions, one for each week. The normal distributions (mean and standard deviation) can be estimated by using historical load data. The length of the time period used to estimate the normal distributions has to be 7 years or longer to ensure statistically significant estimates of the mean and the standard deviation. PJM has load data for its entire footprint and for its neighbors' from 1998 up until 3 years prior to the RRS year. Using this data, there are multiple time-periods (7 years or longer) that can be considered to estimate the mean and standard deviation. The comparative assessment of these time-period candidates (from here on in referred to as Load Model candidates) is based on two premises: 1) consistency with the RTO's CP1 distribution for 4 years in the future from the most recent PJM Load Forecast and 2) reasonable representation of historical PJM-World load diversity.

Definitions

To understand the premise of the comparative assessment at the core of the Load Model Selection Procedure, the following concepts are defined.

- CP1 Distribution (or Coincident Peak 1 Distribution): PJM develops a peak load forecast for each of the next 15 years at the RTO and zonal levels. The forecast accounts for weather uncertainty by considering historical weather scenarios. Each of these weather scenarios has the same probability of occurrence and produces a different peak load forecast. This collection of equally likely peak load forecast values corresponds to the CP1 Distribution. The value published in the PJM Load Forecast Report is the median (or 50/50 value) of the CP1 distribution.

- PJM-World Load Diversity: difference in the timing of annual peaks between PJM and the World. It is usually expressed as the World's load (in per-unitized terms) at the time of the PJM peak and vice-versa.

Procedure

- Assess the consistency of each of the Load Model (LM) Candidates with the RTO's CP1 distribution for 4 years in the future from the most recent PJM Load Forecast. This is accomplished by using two approaches:
    - Approach 1
        - For each LM Candidate,
            - Make the necessary adjustments to the 52 means and standard deviations so that the monthly peak relationship from the most recent PJM Load Forecast is captured by the LM.
            - Perform 5 random draws (one for each weekday daily peak) from the normal distribution that contains the expected annual peak
            - Calculate the highest of the 5 numbers previously drawn (this number represents the sampled annual peak)
            - Repeat the two step above N times, with N being the number of weather scenarios in the most recent PJM Load Forecast

            - Develop a Cumulative Distribution Function (CDF) by sorting the N sampled annual peaks (each of the N peaks is equally likely and therefore all have the same probability 1/N)
            - Calculate the point-to-point absolute MW error between the sampled CDF and the CDF produced with the CP1 distribution.
            - Add up the N absolute MW errors; this is the total MW error for a LM Candidate.
        - Select 3-5 LM Candidates with the smallest total MW error in the 70th percentile and above (where LOLE risk is concentrated).
    - Approach 2
        - For each LM Candidate,
            - Make the necessary adjustments to the 52 means and standard deviations so that the monthly peak relationship from the most recent PJM Load Forecast is captured by the LM.
            - Using the mean and standard deviation of the week that contains the expected annual peak, calculate the probability of the annual peak being less than or equal to each of the N peaks in the CP1 distribution (this results in N probability values)
            - Calculate the point-to-point absolute probability error between the above N probability values and the probability values of the CDF produced with the CP1 distribution.
            - Add up the N absolute probability errors; this is the total probability error for a LM Candidate.
        - Select 3-5 LM Candidates with the smallest total probability error in the 70th percentile and above (where LOLE risk is concentrated).

- Develop World Load Models using the time-periods of the PJM Load Models shortlisted in Approaches 1 and 2 (it is likely that both approaches produce the same set of PJM Load Models)
- Make the necessary adjustments to the 52 means and standard deviations of each World Load Model so that the relationship between the World's forecasted monthly peaks is captured by the LM.
- Compare the annual peaks of PJM and the World for each of the LM candidates and corresponding World LMs to ensure consistency with historical load diversity patterns. Also, consider the Capacity Benefit of Ties resulting from multi-year GE-MARS simulations.

Additional Notes

In the case of ties between LMs, take into consideration the following:

- A more recent LM is preferred
- A LM built with more data (longer time-period) is preferred
- Results from Approach 2 are favored over Approach 1 since Approach 2 does not rely on random sampling.