PJM Manual 19:

Load Forecasting and Analysis

Revision: 38

Effective Date: December 17, 2025

Prepared By
Resource Adequacy Planning

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Approval

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Current Revision

Revision 38 (12/17/2025):

- Attachment B: Clarify responsibilities of PJM and EDC/LSEs in the large load adjustment process.
- Cover to Cover Periodic Review:
  - Section 3.1: Updated forecast horizon from 15 to 20 years.
  - Section 3.2: Added clarifying sentence under Dependent Variable – Unrestricted Load section "Additionally, hourly metered load data may also be supplemented with data through the Load Forecast Adjustment process (see Attachment B)."
  - Section 3.2: formula printing clean-up
  - Attachment C: formula printing clean-up

~~**Revision 37 (12/18/2024):**~~

- ~~Updates to Attachment A: Clarification on use of estimated load drops for load management in the Load Forecast.~~

Introduction

Welcome to the ***PJM Manual for Load Forecasting and Analysis***. In this Introduction you will find the following information:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*")
- How to use this manual (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM Office of the Interconnection for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for Load Forecasting and Analysis*** is one of a series of manuals within the Reserve group of manuals. This manual focuses on load-related topics. This manual describes the data input requirements, the processing performed on the data, computer programs involved in processing the data, and the reports that are produced. It then describes processes used to analyze load data and produce a long-term planning forecast.

The ***PJM Manual for Load Forecasting and Analysis*** consists of four sections. These sections are listed in the table of contents beginning on page 2.

Intended Audience

The intended audiences for the PJM Manual for Load Forecasting and Analysis are:

- *Electric Distribution Company (EDC) planners* — The EDC planners are responsible for supplying historical load data in the required format, for using coincident peaks to allocate normalized peaks, and for input data verification.
- *Load Serving Entity (LSE) planners* — LSEs use allocated peaks and the Load Management systems to determine their capacity obligations.
- *PJM staff* — PJM is responsible for the calculation of hourly PJM loads, normalizing PJM seasonal peaks, forecasting RTO and zonal peaks for system planning and capacity obligations, compiling the PJM Load Forecast Report, and administering Load Management. This information is used in calculating the capacity obligations.
- *Planning Committee members* — The Planning Committee is responsible for the stakeholder review of the peak forecasts and techniques for their determination.
- *Reliability Assurance Agreement Signatories* — The Markets & Reliability Committee is involved in the review of rules, methods and parameters associated with Load Forecasting and Analysis.

References

There are several references to other documents that provide background or additional detail. The ***PJM Manual for Load Forecasting and Analysis*** does not replace any information in these reference documents. The following documents are the primary source of specific requirements and implementation details:

- Power Meter documentation
- DR Hub documentation
- PJM Load Forecast Report
- PJM Manual for Emergency Operations (M-13)
- Reliability Assurance Agreement
- Behind-the-Meter Generation Business Rules (in Manual M-14D)

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.

- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of this PJM manual.

Section 1: Overview

Welcome to the *Overview* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the Load Forecasting and Analysis (see “Overview of Load Forecasting and Analysis”)

1.1 Overview of Load Forecasting and Analysis

Load Forecasting and Analysis utilizes PJM Power Meter load data, Load Management, PJM Load Forecast Model, and Weather Normalization and Peak Allocation.

PJM Hourly Load Data — After-the-fact hourly load data are entered by EDCs and used by PJM for deriving seasonal load profiles, weather normalized peak and energy, 1CP zonal load contributions for Network Service billing, RTO unrestricted seasonal peak loads for capacity obligation allocation (5CP), charts contained in the PJM Load Forecast Report, Operations reports, and NERC compliance reporting.

PJM Load Forecast Model — PJM staff produces an independent forecast of monthly and seasonal peak load and load management, for each PJM zone, region, the RTO, and selected combinations of zones. The PJM Load Forecast Report includes tables and charts presenting the results.

Weather Normalization and Peak Allocation — PJM uses approved techniques for weather-normalizing historical summer and winter zonal peaks.

Section 2: PJM Hourly Load Data

Welcome to the *PJM Hourly Load Data* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the historic hourly load data file (see “Load Data Overview”)
- Guidelines for reporting load data to PJM (see “Load Data Reporting Business Rules”)

2.1 Load Data Overview

Official historic hourly load data for each EDC with revenue-metered tie data reported to PJM are collected via the Power Meter application. For EDCs submitting all internal generation, Power Meter will calculate a revenue-quality load based on submitted tie and generation meter values. This ensures that all customer demand is counted once and only once, on an aggregated and dispersed basis. EDCs may accept these values as their reported hourly service territory load, with the option to input data directly through the application's user interface or via uploaded XML files. The entered data are available through Power Meter screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into Power Meter, refer to the information posted on the PJM Website (under "Tools Sign In", select "Power Meter.")]

Load Data Definitions

Actual Net Metered Interchange: The sum of allocated tie metered values to which the EDC is a party.

Total Internal Generation: The sum of all meter values for non-500kV generators electrically located in the EDC's zone. For PJM Western and Southern regions, 500kV generation will be counted as part of internal generation.

Allocated Mid-Atlantic 500kV Losses: Participant's share of total PJM Mid-Atlantic 500kV losses

Calculated Load = Actual Net Metered Interchange + Total Internal Generation + Allocated 500kV Losses.

2.2 Load Data Reporting Business Rules

As established by the PJM Planning Committee, the following guidelines govern the reporting of load data into the PJM Power Meter application:

Data Reporting Responsibility

- It will be the responsibility of each PJM electric distribution company (EDC) with fully-metered tie flows to report hourly load data for its metered area(s), regardless of which entity is responsible for serving end-use customers.
- For all entities using network transmission service, it will be the responsibility of the signatory to the Network Integration Transmission Service Agreement to ensure that hourly load data are reported to PJM for its customers via PJM InSchedule.
- Curtailment Service Providers (CSPs) are responsible for providing information to estimate load management impacts as detailed in Attachment A.

Data Specifications

- Load data supplied to Power Meter will reflect each entity's total impact to the system, counting all customer demand once and only once, and will therefore need to properly account for system losses and flows. PJM will adjust loads for their assigned share of Extra High Voltage losses. LSEs providing load management impact estimates will adjust loads for system losses. Data are accepted in Power Meter in 0.001 MWh increments.

Reporting Schedule

- The data for each day should initially be entered within the following ten calendar days, except during peak periods, when the data must be entered daily. PJM contacts EDCs when daily reporting is needed.
- Edits to load data should be made by the tenth calendar day of the following month.
- PJM may adjust submitted load data, as necessary, to reflect additional load that is determined by PJM after-the-fact, resulting from third-party supply of generator station power requirements.
- EDC ability to submit loads via Power Meter is subject to a reporting window that includes the current month and three previous months. For example, in April, values for April, March, February, and January can be freely edited. For updates to months older than three full months prior, the participant must have PJM make the submission on their behalf. PJM may be contacted at mrkt_settlement_ops@pjm.com to arrange for assistance.
- Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 11 of the Reliability Assurance Agreement.

EDC/CSP Actions

- Enter Hourly Load Data — PJM EDCs submit aggregate hourly load values into Power Meter, as required. CSPs provide resource-specific settlements data to quantify Load Management impacts into the DR Hub application. (See Attachment A).
- Edit the Data as necessary — All hourly load value changes for a given month must be entered and edited by the 10th of the following month.

- Notify PJM of All Changes — Without this notification, PJM can only determine that changes have been made but cannot readily identify specific changes which were made.

PJM Actions

- Allocate Extra High Voltage Losses: — 500kV losses in the PJM Mid-Atlantic region are calculated as the total 500kV system energy injections minus withdrawals. Hourly 500kV losses are allocated to each PJM Mid-Atlantic EDC with revenue metered tie flows reported to Power Meter, in proportion to their real-time load ratio share.
- Post Zonal Data: — PJM will publish zonal load data in an electronic format on a monthly basis.
- Data Usage: — PJM uses the hourly load data for operational analysis, for calculating seasonal load factors, developing weather normalization curves, for allocating the PJM weather normalized seasonal peaks, for preparing various charts and tables in the PJM Load Forecast Report, and for reporting to regulatory and other authorities.

Section 3: PJM Load Forecast Model

Welcome to the *PJM Load Forecast Model* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the PJM Load Forecast Model (see "Forecast Model Overview").
- A description of the methodology used to produce the PJM forecast (see "Development of the Forecast").
- A description of the forecast review and approval process (see "Review and Approval the Forecast").

3.1 Forecast Model Overview

The PJM Load Forecast Model produces 2015-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, locational deliverability area (LDA) and the RTO. The model uses trends in equipment and appliance usage, anticipated economic growth, distributed solar generation and battery storage, plug-in electric vehicles, and historical weather patterns to estimate growth in peak load and energy use. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. Net energy forecasts are used in reporting requirements of FERC and NERC, and for market efficiency studies. The forecast is produced by PJM and released prior to each Planning Period, typically in January.

3.2 Development of the Forecast

The PJM Load Forecast employs multiple regression models to estimate hourly peak load for each PJM zone. Models for each PJM zone share the same general specification. Variables considered are:

Dependent Variable – Unrestricted Load

Hourly metered load data are supplemented with estimated load drops (as outlined in Attachment A), estimated load drops associated with peak shaving programs, estimated distributed solar generation, and battery storage to obtain unrestricted hourly loads. Additionally, hourly metered load data may also be supplemented with data through the Load Forecast Adjustment process (see Attachment B).

Calendar Effects

Days of the week, month of the year, holiday, and Daylight Saving Time impacts may be included in the model.

Weather Data

A full collection of the weather variables and transformations used for each PJM zone is provided in the corresponding year's Load Forecast Supplement. These variables include temperature, humidity, wind speed, and cloud cover. Additionally, the below weather equations are used for weather sensitive energy efficiency demand reduction. The Winter Weather Parameter is defined as:

$$\text{If WIND} > 10 \text{ mph},$$

$$WWP = DB - (0.5 * (WIND - 10))$$

$$\text{If WIND} \leq 10 \text{ mph},$$

$$WWP = DB$$

Where:

WIND	Wind velocity, in miles per hour
WWP	Wind speed adjusted dry bulb temperature
DB	Dry bulb temperature (^{o}F)

The Summer Weather Parameter, as reference in the Peak Shaving Adjustments section below,Temperature-Humidity Index (THI) is defined as:

$$\text{If DB} \geq 58,$$

$$THI = DB - 0.55 * (1 - HUM)* (DB - 58)$$

$$\text{If DB} < 58,$$

$$THI = DB$$

Where:

THI	Temperature-humidity index
DB	Dry bulb temperature (^{o}F)
HUM	Relative Humidity (where 100% = 1)

Additionally, measures of heating and cooling degree days are included, using the current and previous day's weather. Weather data for each PJM zone are calculated according to the mapping presented in the annual Load Forecast Supplement.

Economic Drivers

Measures of economic and demographic activity are included in the forecast models, representing total U.S., state, or metropolitan areas, depending upon their predictive value. Economic drivers for states and metropolitan areas are assigned to each PJM zone according to the mapping presented in the annual Load Forecast Supplement.

End-Use Trends

Measures of the stock and efficiency of various electrical equipment and appliances used in residential and commercial settings are included in the forecast models, grouped by heating, cooling, and other. End-use variables for each PJM zone are applied by Census Division. In some instances, PJM supplements this data with zone-supplied information.

PJM annually solicits information from stakeholders regarding electrification policies that pertain to end-uses.

Peak Shaving

In cases where a zone contains a peak shaving program with an approved Peak Shaving Adjustment Plan, the zone's forecast will be adjusted to reflect the program's impact.

Load Adjustments

In cases where a zone has experienced or is anticipated to experience a significant load change that may not be captured in the load forecast, PJM may elect to apply a load forecast adjustment by either adjusting model inputs or by an explicit adjustment to the modeled forecast.

In cases where the load change has not yet occurred, PJM will base any adjustment on information received from EDC load forecasters in response to PJM's annual request for details on large load changes that are known to the EDC. PJM will handle these requests on a case-by-case basis and perform (or have performed) whatever analysis is required to establish the degree of certainty and magnitude of the load change. Attachment B provides load forecast adjustment guidelines. PJM and the requesting EDC/LSE will produce documentation on and discuss load adjustments at the Load Analysis Subcommittee upon presentation of the annual load forecast.

Peak Shaving Adjustments

In cases where a zone has an approved Peak Shaving Adjustment Plan (as described in Attachment D), PJM will develop a load forecast adjustment to capture the impact of the

program. Initially, existing load history will be compared with modified load history that assumes the program's anticipated curtailment behavior occurred in all historical years used in the forecast model to determine the program's ability to reduce daily peaks. Programs will then be incorporated into the weather rotation simulation process to establish the program's initial forecast adjustment MW value.

Once incorporated into the PJM load forecast, the program's performance will be measured against its committed MW curtailment value (as dictated by the program specifications) and scored over a rolling three-year period[1]. Results of this measurement may result in a revision of the program's forecast adjustment MW value, as described in Attachment D.

Any program receiving a peak shaving adjustment will be required to peak shave on any day in which its "trigger" is met or exceeded. The trigger will be based on the actual maximum daily temperature–humidity index (THI) for the relevant PJM zone as determined in advance by the relevant entity. If triggered, the peak shaving must comply with its pre-established parameters regarding number of hours of interruption, dispatch sequence, etc. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a weather rotation simulation process. Using this approach, load forecasts are developed for each zone using the actual weather patterns that were observed in that zone over many years. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. From this distribution, the median values are used to shape the monthly profile within each season.

The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

RTO and Coincident Forecasts

To obtain the RTO/LDA peak forecasts, the solution for each of the zonal coincident peak (CP) models are summed by day, hour, and weather scenario to obtain the RTO/LDA peak for the day. By weather scenario, the maximum daily RTO/LDA value for the season is found. For the RTO/LDA, a distribution of the seasonal RTO/LDA peak vs. weather scenario is developed. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

[1] For programs with less than three years of history, a one- or two-year performance score will be used.

To determine the final zonal RTO/LDA-coincident peak (CP) forecasts, a methodology similar to the process for deriving zonal NCPs is applied. By weather scenario, the maximum daily CP load for a zone over the summer season is found. For each zone a distribution of zonal CP vs. weather scenario is developed. From this distribution the median value is selected. The median zonal CPs are summed and this sum is then used to apportion the forecasted RTO/LDA peak to produce the final zonal CP forecasts.

Net Energy for Load Forecasts

For each PJM zone, a distribution of forecasts is produced using a weather rotation simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by summing the hourly values per forecast year for each weather scenario.

Load Management, Price Responsive Demand and Behind-the-Meter Generation

PJM incorporates assumptions of load management, price responsive demand, behind-the-meter generation, and battery storage to supplement the base, unrestricted forecast.

For Demand Resources (DR) other than PRD, forecasted values for each zone are computed based on the PJM final summer season Committed DR amount, where the Committed DR means all DR other than PRD that has committed through RPM, Base Residual Auction and all Incremental Auctions, or a Fixed Resource Requirement plan.

1. Compute the final amount of Committed DR (by DR product) for each of the most recent three Delivery Years. Express the Committed DR amount (by DR product) as a percentage of the zone's 50/50 forecast summer peak from the January Load Forecast Report immediately preceding the respective Delivery Year.
2. Compute the most recent three year average Committed DR percentage, by DR product, for each zone. For DR products with less than three years' worth of Committed DR data, compute the most recent one or two-year average Committed DR percentage.
3. The DR forecast, by DR product, for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the corresponding result from Step 2 minus the amount of the PRD forecast (described below) that in previous years committed as a different DR product.

For Price Responsive Demand (PRD), forecasted values for each zone on or after Delivery Year 2020/21 are computed based on the procedure below. The forecast is based on the amount of Cleared PRD in Base Residual Auctions on or after Delivery Year2020/21.

1. Compute the final amount of Cleared PRD for the most recent three Base Residual Auctions targeting Delivery Years 2020/21 or afterwards. Express the Cleared PRD amount as a percentage of the zone's 50/50 forecast summer peak for the corresponding Delivery Year from the most recent PJM Load Forecast Report.

2. Compute the most recent three year average Cleared PRD percentage for each zone. If there is less than three years' worth of Cleared PRD data, compute the most recent one or two-year average Cleared PRD percentage.
3. The PRD forecast for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the corresponding result from Step 2 for delivery years for which no Base Residual Auction has been held; for delivery years for which a Base Residual Auction has been held, the PRD forecast for each zone shall be equal to the amount of PRD cleared in the Base Residual Auction.

The total amount of behind-the-meter solar generation and battery storage will be forecasted separately from the load forecast model. The forecasted amounts will be used to adjust the unrestricted load of each zone.

Note:
More information on behind-the-meter generation can be found in the Behind-the-Meter Generation Business Rules in the PJM Manual for Generator Operational Requirements (M-14D) posted on PJM.com.

3.3 Non-Zone Peak Forecast

For use in the Reliability Pricing Model (RPM), PJM staff develops summer peak forecasts of the recognized non-zone loads. These forecasts are produced separately from the PJM Load Forecast Model, and utilize methods appropriate for each situation. Non-zone forecasted loads are added to the associated PJM zone for RPM purposes only.

3.4 Review of the Forecast

The PJM Load Forecast is reviewed by the Load Analysis Subcommittee and the Planning Committee. Upon presentation of the final forecast, PJM will supply a Load Forecast Supplement describing the methodology, the assumptions, and description of the data used in the forecast. Additionally, PJM will post data used in constructing the final forecast (except in those cases where not contractually permitted).

A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee.

Section 4: Weather Normalization and Coincident Peaks

Welcome to the *Weather Normalization and Coincident Peaks* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the weather normalization process (see “Weather Normalization Overview”).
- A description of the weather normalization procedure (see “Weather Normalization Procedure”).
- A description of the identification and calculation of PJM unrestricted coincident peaks (see “Peak Load Allocation (5CP)”).

4.1 Weather Normalization Overview

PJM performs load studies on summer and winter loads, for both coincident and non-coincident peaks, according to the procedures described below. The weather normalized (W/N) coincident peaks are used by EDCs to determine capacity peak load shares for wholesale and retail customers. W/N non-coincident peaks are provided by PJM for use by stakeholders in reviewing the PJM load forecast.

4.2 Weather Normalization Procedure

The PJM weather normalization procedure consists of utilizing the PJM Load Forecast Model as described in Section 3 above. After each season, each zonal/RTO NCP and CP model is re-estimated, adding the most recent historical data. Then, the weather simulation process is run, including historical weather through the just-completed season. From the resulting distribution of results, the median value is selected as the weather normalized seasonal peak.

EDC/ CSP Actions

- Enter hourly load data into Power Meter as described in Section 2 of this manual.
- Provide resource-specific settlements data to quantify Load Management impacts into the DR Hub application
- Submit voltage reduction and loss of Load Drop Estimates as described in Attachment A of this manual.

PJM Actions

- Obtain weather observations
- Produce voltage reduction load drop estimates, as described in Attachment A of this manual.
- Weather-normalize the zonal RTO-coincident winter and summer peak loads.

4.3 Peak Load Allocation (5CP)

Zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ the customer's shares of RTO actual peaks. The resulting Peak Load Contributions are then used in the determination of capacity obligations.

PJM establishes and publishes information, referred to as the 5CP, to aid EDCs in the calculation of Peak Load Contributions (also known as "tickets"). For each summer:

- Hourly metered load and load drop estimate data are gathered for the period June 1 through September 30
- RTO unrestricted loads are created by adding load drop estimates to metered load
- From the unrestricted values, the five highest non-holiday weekday RTO unrestricted daily peaks (5CP) are identified

5CP data are typically released in mid-October.

Attachment A: Load Drop Estimate Guidelines

General

Load Drop Estimates (also referred to as addbacks) are produced for three types of occurrences:

1. Curtailment of load for customers registered in the PJM emergency or pre-emergency program either as a Load Management resource (Demand Resource) or an Emergency – Energy Only resource, or customers registered to meet a Price Responsive Demand (PRD) commitment for either the Reliability Pricing Model (RPM) or the FRR Alternative.
2. Voltage Reductions implemented by PJM or an EDC
3. Significant losses of load.

PJM is responsible for producing Load Management/Emergency/Pre-Emergency load drop estimates, from CSP and EDC input into the appropriate PJM system. EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

PJM is responsible for producing PRD load drop estimates, from PRD Provider input into the appropriate PJM system. PRD Providers that registered price responsive demand to satisfy a PRD commitment for either RPM or FRR Alternative must provide PJM with meter data when PRD was required to be dispatched (LMP is greater than the offer price). Meter data is entered at the site level; load drop estimates will be calculated at the registration level.

Load drop estimates, as calculated in this manual or otherwise calculated by PJM to reflect the estimated hourly energy load reductions (with communication to the appropriate stakeholder group), are used to construct unrestricted loads used in the PJM Load Forecast Model, weather normalization of PJM seasonal peaks, and to calculate the unrestricted Peak Load Contributions used in formulating capacity obligations.

These rules also apply to Non-Retail Behind-the-Meter Generation as provided in Section G of Schedule 6 to the Reliability Assurance Agreement.

Load Drop Estimates for Load Management Customers

The table below summarizes the requirements for producing load drop estimates for customers registered as a Demand Resource, or in the Emergency– Energy Only option, or as Economic load response, depending upon the cause of the load curtailment. Following the table are descriptions of the methods used by PJM to calculate load drop estimates for each load management type (Firm Service Level, and Guaranteed Load Drop).

Requirements for Production of Load Drop Estimates

Reason for Load Drop		PJM-Initiated Emergency or Pre-Emergency Event or CSP-Initiated Test	Economic Event	EDC- or CSP-Initiated Event
Program Registration	Emergency/ Pre-Emergency Full (DR) or Emergency/ Pre-Emergency Capacity Only (DR)	Load Drop Estimates must be produced for any interruption that occurs during a product-type registration's required availability window set forth in PJM Manual 18 or any interruption outside the required availability window for which such registration received Bonus MWs in the Performance Assessment Hour.	Load Drop Estimates must be produced for any settled interruptions.	No Load Drop Estimates required.
	Emergency Energy Only	Load Drop Estimates must be produced for any interruptions during Emergency/Pre-Emergency hours.	No Load Drop Estimates required.	No Load Drop Estimates required.
	Economic	No Load Drop Estimates required.	No Load Drop Estimates required.	No Load Drop Estimates required.

Actual Emergency and Pre-Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Full or Emergency Capacity Only resources will be added back for the purpose of calculating peak load for capacity

for the following Delivery Year and consistent with the load response recognized for capacity compliance as set forth in the Manual.

Non-Interval Metered Customers

The estimated load drop for residential customers without interval metering is determined in accordance with Attachment C, Residential Non-Interval Metered Guidelines.

Contractually Interruptible

The estimated load drop which shall be used to determine capacity compliance and may be used as an addback to determine the unrestricted peak load for Firm Service Level and Guaranteed Load Drop customers is calculated as follows:

For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF")) is applicable in the summer period of June through October and May of the Delivery Year. For the non-summer period of November through April of the Delivery Year, the Winter Peak Load ("WPL") times the Zonal Winter Weather Adjustment Factor ("ZWWAF") times LF is used in the equation as opposed to the PLC. A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution (in summer period) or the current Delivery Year WPL times ZWWAF times LF (in non-summer period).

The calculation is represented by:

Summer : Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

Non-summer: Minimum of {(comparison load – Load) * LF, (WPL*ZWWAF*LF) – (Load * LF)}

For Firm Service Level end-use customers the current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF") is applicable in the summer period of June through October and May of the Delivery Year. For the non-summer period of November through April of the Delivery Year, the WPL times ZWWAF times LF is used in the equation as opposed to the PLC.

The calculation is represented by:

Summer : PLC – (Load * LF)

Non-summer : (WPL*ZWWAF*LF) – (Load * LF)

Note:
Winter Peak Load ("WPL") and Zonal Winter Weather Adjustment Factor ("ZWWAF") are defined in accordance with PJM Manual 18, PJM Capacity Market.

When Generation interval meter data is provided to determine test or event compliance, and interval metering on load is available, the interval metered load data should be provided to ensure load drop is below the PLC or (WPL*ZWWAF*LF). It is expected that interval load data will be available for all customers that have a PLC > 0.5 MW. If no interval meter load data exists, such Generation interval meter data multiplied by loss factor will be used as the estimated load drop.

Estimate of Comparison Load for Guaranteed Load Drop (GLD) Customers

For purposes of determining compliance with a PJM-initiated Load Management event or CSP-initiated test for Guaranteed Load Drop customers, several options are available to estimate comparison loads. The method used should result in the best possible estimate of what load level would have occurred in the absence of an emergency, pre-emergency or test event.

The CSP will be responsible for supplying all necessary load data to PJM in order to calculate the load reduction for each registered end use customer. PJM will calculate the load drop amount unless otherwise indicated below or approved by PJM. The amount of load data required will depend on the GLD method selected where the minimum amount shall be 24 hours for one full calendar day.

Comparable Day: The customer's actual hourly loads on one of the prior 10 calendar days before the test or emergency or pre-emergency event day selected by the CSP which best represents what the load level would have been absent the emergency or pre-emergency or test event. The CSP may request use of an alternative day for extenuating circumstances with supporting documentation that clarifies why the alternative day should be utilized. PJM must approve the use of any alternative day. CSP must provide usage data for all 10 days such that PJM may validate an appropriate day was selected.

Same Day (Before/After Event): The customer's average hourly integrated consumption for two full hours prior to notification of an emergency or pre-emergency event or prior to one full hour before a test and for two full hours after skipping first full hour after the event or test. This option is appropriate for high load factor customers with no weather sensitivity.

Customer Baseline: The Customer's estimated baseline used to calculate load drops for PJM economic demand resources as defined on the applicable PJM economic registration.

Regression Analysis: The customer's estimated hourly loads from a regression analysis of the customer's actual loads versus weather. This option is appropriate for customers with significant

weather sensitivity. The CSP will perform the regression analysis and provide results including supporting information to PJM. The information should include all load and weather data and associated regression statistics used to estimate the load impact on the event or test day.

Generation: The hourly integrated output from a generator used to provide Guaranteed Load Drop. This method may only be utilized if the generation would not have otherwise been deployed on the emergency or pre-emergency event or test day and must comply with the provisions contained in the PJM Manuals.

Load Drop Estimates for PRD Customers

Load Drop Estimates are applicable to price responsive demand registrations that are used to satisfy a PRD commitment for either RPM or FRR Alternative. Load Drop Estimates are not applicable to Energy Only PRD registrations.

*Load Drop Estimate = Customer Expected Peak Load – (Metered Load * EDC Loss Factor)*

*Load Drop Estimate = Peak Load Contribution – (Metered Load * EDC Loss Factor)*

Missing Data

If an end use customer meter malfunctions during a Load Management test, retest or emergency or pre-emergency event and the end use customer performed the required load reduction activity and no interval meter data is available to use for purposes of measuring capacity compliance or to determine applicable energy settlements, then PJM may allow CSP one of the following two remedies, otherwise the end use customer will be considered to have taken no load reduction actions during such period:

1. CSP may provide supporting information to quantify the load reduction amount which includes an engineering analysis or meter data from a comparable site that reduced load based on the same actions during a comparable time, or;
2. CSP may perform a separate test for the end use customer(s) to quantify the load reduction that will be used for the test, retest or event time period compliance and, as appropriate, energy settlement(s). The test will need to be performed at comparable time and conditions to when the test, retest or emergency or pre-emergency event occurred.

Remedies will only be considered if the CSP and associated metering entity followed Good Utility Practice as outlined in the OATT, no interval load data is available from the EDC, and the CSP can provide supporting information, such as building automation system logs, to verify the load reduction action was taken during the test, or retest or emergency or pre-emergency event when the meter malfunctioned. CSP must also provide evidence that the meter did malfunction.

PJM must approve any remedy and CSP must meet appropriate load data submission deadline.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Load Forecast Adjustment Guidelines

The intention of these guidelines is to ensure that any adjustments made to PJM's load forecast model are properly identified, estimated, and reviewed prior to incorporation into the forecast.

Issue Identification

- PJM annually solicits information from its member Electric Distribution Companies (EDC) and/or Load Serving Entities (LSE; e.g. co-ops, munis) for large load shifts (either positive or negative and located in their territory) which are known to the EDC and/or LSE but may be unknown to PJM. PJM will send the request in mid-July with responses expected in time for any proposed adjustments to be reviewed with the Load Analysis Subcommittee in September/October. Industry groups and/or large end-use customers who anticipate large load adjustments should engage with their EDC and be transparent with as much information (historical and forecast) as possible.
- Requested load adjustments deemed appropriate by PJM will be used in the forecast that drives both market and reliability RTEP studies.

Issue Verification – verify that identified issue is real and significant, using the following methods:

- Determine if the load change has been publically acknowledged through the media, press release, regulatory process, etc.
- Verify that requesting EDC and/or LSE has or will adjusted its own financial/planning forecast. When appropriate the requesting EDC and/or LSE should provide PJM, on a confidential basis, with the certainty backed by a Letter of Agreement and/or Electric Service Agreement (LOA/ESA).
- Ascertain whether the load shift is related to a single site or a limited number of related sites (not a systemic cause)
- The EDC shall identify to PJM the Load Serving Entity (LSE) where the addition will occur.
- Identify if load would be captured in load forecast model to identify potential double counting. These steps may include: Discuss with economic forecast vendor(s) whether or not the load shift is reflected in its/their economic forecast(s). Also, determine if the requested load adjustment's load impact is consistent with its economic impact. Additionally, determine if the requested load adjustment is tied to any of the metro areas that PJM uses to define the economic variable of a zone.
- Verify that any behind-the-meter generation adjustment has complied with PJM's behind-the-meter process
- Determine adjustment's significance, either by sheer magnitude or percentage of a zone's load.
- For PJM's review, provide any available independent analysis of the impact of the load change.

Adjustment Estimation - for each identified and verified issue, PJM will estimate its impact on peak load using the following methods (which may be combined):

- Acquire load history for the load that has/will change and produce analysis to isolate the impact. Load history should be provided on an hourly granularity. In the event that no load history exists, EDC and/or LSE should provide PJM with expected hourly behavior of load.
- Acquire an extended forecast of the adjustment from the EDC and/or LSE for the length of the long-term load forecast.
- If available/appropriate, provide PJM with a high and low scenario for load adjustment request.

Adjustment Review – each proposed load forecast adjustment will be reviewed with the Load Analysis Subcommittee prior to inclusion in the load forecast. Each requesting EDC and/or LSE will be expected to present on their adjustment request ~~including backup documentation~~ at a September/October LAS meeting and also provide backup documentation summarizing details of the EDC's and/or LSE's large load adjustment process and methodology. This public document will be posted by PJM with the final load report materials. The final decision on any load adjustment is made by PJM and will be reflected in the Load Forecast.

~~Any adjustment that is reflected in the Load Forecast will be summarized by the requesting EDC and/or LSE in a public document describing the method and forecasting approach followed. This public document will be posted by PJM with the load report materials.~~

Example 1: Single Large Load Change (positive or negative)

Issue Identification – EDC and/or LSE notifies PJM that a large industrial load is to increase/ decrease load

Issue Verification – PJM reviews request and specifically verifies:

- The industrial load change is widely reported in local media. A proof of requested load change validity is provided when a single load change is commercially sensitive;
- The EDC and/or LSE has or will adjust its own financial and planning forecasts to reflect the load change at the plant;
- The affected load is confined to one site/customer account.
- PJM consults with economic forecast supplier to determine if the load change is reflected in their economic forecast.

Adjustment Estimation – PJM requests historical hourly load data and/or hourly forecast load data for the end-use customer. If the large load is being removed, PJM may remove hourly loads from history. If the large load is being added adjustments to the hourly forecasted loads will be made. The final load adjustment will be included in the load forecast after review with LAS.

Example 2: Industry level load change

Issue Identification – EDC and/or LSE notifies PJM that it plans to integrate a large amount of load associated with one industry during the forecast horizon

Issue Verification – PJM meets with the EDC and/or LSE and through follow-up conference calls, e-mail exchanges and PJM independent investigation it is determined that:

- The load in question is confined to a single industry.
- The EDC has or will adjust its own financial and planning forecasts to reflect the change in load;
- The new load sites are not fully reflected in the economic variables included in the model.
- Updated expected near term growth (accounting for requested load changes) supported by contracts in place with the EDC and/or LSE, construction companies, and suppliers.

Adjustment Estimation – PJM requests historical hourly load data and/or hourly forecast load data for specific industry. PJM investigates its model inputs and makes modifications to history to reflect load impacts in order to avoid double counting. The accelerated load growth (or reduction) is layered on the forecast to reflect the expansion (contraction).

Attachment C: Residential Non-Interval Metered Guidelines

Statistical sampling for residential customers

Residential customers without interval metering may participate in the Synchronized Reserve, Capacity, and Energy markets using a statistical sample extrapolated to the population to determine compliance and energy settlements. The sample data must be from the same time interval as the event being settled.

Qualifications

A registration may participate using statistical sampling to determine compliance and energy settlements under the following conditions, and subject to PJM approval:

- The registration consists entirely of residential customers.
- Locations can be sampled to accurately reflect the population load data.
- Curtailment at each location uses Direct Load Control Technology.
- Synchronized Reserve: Locations otherwise qualify for participation in the Synchronized Reserve Market. Locations do not have meters that record load data at a period of 1 minute or shorter.
- Economic Energy: Locations otherwise qualify for participation in the Economic Energy Markets. Locations do not have meters that record load data at a period of 1 hour or shorter.
- Load Management: Locations otherwise qualify for Load Management. Locations do not have meters that record load data at a period of 1 hour or shorter.

Sample Design

Samples must be designed to achieve a maximum error of 10% at 90% confidence. The locations in the sample must be randomly selected from all the locations in the population group (a population group is a group of registrations that can share a sample based on the criteria listed below). The sample must be stratified by control device size (minimum of 2 strata) and geographic location, unless otherwise approved by PJM.

For Load Management registrations that participate in the capacity market, a sample is required for each combination of EDC, CSP, end-use device (such as air conditioner or water heater) or device grouping, curtailment algorithm and switch vintage if there is substantial variation among installed switch capability.

For economic registrations that participate in the Energy Markets, a sample is required for each combination of dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different. For economic registrations that participate in the Synchronized Reserve market, a sample is required for each

combination of SR subzone, dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different.

Sample Size Determination

A variance study is used to determine the initial sample size. Interval data must be collected from at least 75 randomly selected and stratified customers during the season the end use device is in use in order to determine the variance of the load data for the sample. Synchronized Reserves: At least 2 weeks of continuous meter data collected at a period of 1 minute or smaller.

Load Management and Economic Energy: At least 4 weeks of continuous meter data collected at a period of 1 hour or smaller.

The number of locations in the sample is then calculated as follows, unless otherwise approved by PJM:

n = number of sampled customers in variance study, ≥ 75

$X_{i,\,t}$ = meter reading for customer i during interval t

Calculate the mean and variance of the meter data across all customers for each interval:

$$\text{Mean}(X_t) = \overline{X_t} = \frac{1}{n}\sum_{i=1}^{n} X_{i,\,t}$$

$$\text{Var}(X_t) = s^2_{X_t} = \frac{1}{n}\sum_{i=1}^{n}\left(X_{i,\,t} - \overline{X_t}\right)^2$$

Calculate the sample size necessary to get 10% error at 90% confidence for each interval:

$$M_t = \left(\frac{Z_{\alpha/2}}{e}\right)^2 \frac{s_t^2}{\overline{X_t}^2}$$

Where

$$Z_{\frac{\alpha}{2}} = 1.645 = \text{critical value at 90\% confidence } \left(\alpha = 0.1\right)$$

$e = 0.1$ = error

Take the average sample size across all intervals to determine *M,* the sample size:

$$M = \frac{1}{T}\sum_{t=1}^{T} M_t$$

Where T is the total number of intervals. T should be at least 20,160 for SR (2 weeks of 1 minute intervals) and 672 for economic energy and Load management (4 weeks of hourly intervals).

Alternate calculations may be used subject to PJM approval.

Sample Recalibration

The sample must be recalibrated annually as follows:

1. The sample size must be recalculated using the same method listed above using data from all locations in the sample.
2. If the population was expanded in a non-random manner, the sample must be expanded appropriately, so that the sample is representative of the population.
3. The number of locations in each stratum in the sample must be adjusted so that the number of locations in each stratum is proportional to the population in that stratum within +/- 1 location.

Data Validation and Estimation

Data must be validated and estimated in accordance with the NAESB Validating, Editing, and Estimating (VEE) Protocol. This protocol should be used for validation and estimation of 1-minute data for the SR market as well as hourly data for capacity and energy markets. Note: All rules for hourly data shall apply to 1 minute data where the only difference is the use of 1 minute interval instead of 1 hour interval.

If 5 minutes or more are missing or faulty from 1 minute meter data for a single event, or 2 hours or more are missing or faulty from hourly meter data for a single event, data from that meter may not be used for that event. If there is 1 way switch communication, the data for that meter must be reported as the PLC value for every reported interval on the event day. If there is 2 way switch communication and a sufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then an estimate for the missing meter data should not be reported for this event. If there is 2 way switch communication and an insufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then the PLC value should be reported for every reported interval for the event day for each location with missing meter data such that there are enough locations to meet the sample requirements unless otherwise approved by PJM.

Example with one-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from the 7 faulty meters as the PLC value for each of the 7 EDC accounts for every reportable hour that day.

Example with two-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from 2 randomly selected faulty meters as the PLC value for those 2 EDC accounts for every reportable hour that day.

Switch Operability

Two-way switch communication: Two-way switch communication is when the CSP receives verification from the switch that it successfully cycled base on CSP instruction. When there is two way switch communication in place, the CSP will calculate the performance factor, *F,* as the total number of switches in the population that were sent the instruction to cycle for that event divided by number of switches in the population that successfully cycled for that event. The meter data will be multiplied by this value before submission to PJM to scale the sample average load data to the represent the population that performed the load reductions.

One-way switch communication: One-way switch communication is when the CSP cannot accurately determine if each switch in the population successfully cycled based on CSP instruction. In this case the operability value is implicit in the sample. The CSP must report all data from all meters in the sample, even if a switch in the sample is faulty. The CSP may not repair any faulty devices in the sample that could also be faulty in the population (for example an air conditioner cycling switch cannot be repaired/replaced but a 1-minute meter could be repaired/replaced) unless the CSP repairs/replaces those same devices that are faulty in the population. Switch failure in the sample must be reported to PJM within 2 business days.

Converting sample data to meter data

Note:
Note that the sample data must be from the same time interval being settled.

$X_{i,t}$	is the meter reading for customer ***i***during interval ***t*** after VEE protocol is applied per this manual
B	is the set of EDC accounts in sample that are to be included in estimation (after subject to rules in this manual
M_S	is the sample size (number of EDC accounts in B)
M_C	is the population of Cycled customers
F	is the operability factor, calculated subject to this manual (1 for one way switch communication)

The meter data value to be submitted to PJM for interval *t* is Y_t:

$$Y_t = F\frac{M_c}{M_s}\sum_{i \in B} X_{i,t}$$

Measurement and Verification Plan

The CSP must submit a Measurement and Verification (M&V) plan to PJM before the registration is submitted. The M&V plan must be approved by PJM before the registration is submitted. CSP is to resubmit an updated M&V plan annually to continue participation in the PJM markets.

The M&V plan must include details on: how the variance study was conducted and sample size was determined; sample selection and stratification; meter qualification and quality assurance; data validation and error correction protocol; and how sample meter data will be converted to population meter data. A template of the M&V plan is to be published on pjm.com.

Churn and Customer Documentation

Note:
Parts of this section apply to interval metered residential customers, as indicated below.

Applicable to all residential customer registrations (interval metered and non-interval metered):

- CSP to submit initial list of customers to PJM at time of registration, including all EDC account numbers PLCs and zip codes. Where legal or regulatory conditions prohibit provision of EDC account number as personally identifiable customer information the EDC may use unique identifying numbers for EDC account numbers, through 5/31/16 or as otherwise approved by PJM. EDC is responsible to maintain list of EDC account numbers and associated unique identifying numbers when used. EDC may need to check for duplicate as approved by PJM.
- Replacement allowed for customer who moves from their premises or customer terminates contract with CSP.
- CSP must maintain list of all replacement and furnish to PJM within 2 business days of request.
- CSP must maintain list of customers who were cycled during an event.
- All customer lists, meter data, and documentation must be furnished to PJM within 2 business days of request and be maintained by CSP for 2 years.

Applicable to interval-metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be selected to maintain PLC and load drop.

- CSP must maintain list of customers for each event and maintain for 2 years from event date.
- CSP may not add/remove customers (other than replacement). If number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to non-interval metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be randomly selected to maintain integrity of strata, and if applicable PLC and load drop.
- CSP must maintain list of customers for each event and maintain for 2 years from event date.
- CSP may not add/remove customers (other than replacement). If the number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to interval metered Economic Energy and Synchronized Reserve:

- There are no restrictions on replacement customers since actual meter data is submitted.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, but must maintain documentation and update the value on the location in DR Hub. This value must be accurate every day an offer is submitted.
- List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Applicable to non-interval metered Economic Energy and Synchronized Reserve:

- Replacement customers must be randomly selected to maintain the integrity of the strata.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, if it can be done such that the sample remains representative of the population. CSP must maintain documentation and update the value on the location in DR Hub. This value must be accurate every day an offer is submitted.
- If CSP offers partial list of customers to market, then such customers must be randomly assigned from pool of all registered customers. List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Attachment D: Peak Shaving Adjustment Plan and Performance Rating

Peak Shaving Adjustment Plan

The Peak Shaving Adjustment Plan is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Peak Shaving Officer Certification Form. A completed Peak Shaving Adjustment Plan (including a signed Peak Shaving Adjustment Officer Certification Form) must be submitted to PJM no later than 10 business days prior to September 30 to be effective for the next PJM load forecast update. The Peak Shaving Adjustment Plan must provide information that supports the authorized entity's intended Peak Shaving Adjustment and demonstrates that the peak shaving program(s) is/are being offered with the intention that the MW quantity is reasonably expected to be physically delivered through program registrations for the relevant summer period. The Peak Shaving registrations shall be finalized before the start of the Delivery Year and on same time line as Load Management registrations. The Peak Shaving registration process will be based on the Economic DR registration process to ensure the accuracy of the retail customer information with the electric distribution company.

The Peak Shaving Adjustment Plan encompasses both existing peak shaving and planned peak shaving. Existing peak shaving is identified as end-use customer sites that the authorized entity has under contract for the current summer period (i.e. end-use customer sites registered in the PJM DR Hub system for the current summer period) and that the authorized entity intends to have under contract for the summer period.

Both the signed PJM Peak Shaving Officer Certification Form and the completed Peak Shaving Adjustment Plan template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 10 business days prior to September 30. PJM will review the Peak Shaving Adjustment Plan and notify the authorized entity via email no later than September 30 if another authorized entity has identified the same end-use customer site(s) in their Peak Shaving Adjustment Plan or DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the relevant period. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than October 15. PJM will notify all authorized entities via e-mail of the approved peak shaving MW quantity by zone that will be included in the next update of the PJM load forecast.

I. PJM Peak Shaving Officer Certification Form

A Peak Shaving Officer Certification Form is located in Attachment E of Manual 19 and is posted on the PJM web site. A signed Peak Shaving Officer Certification Form must accompany the Peak Shaving Adjustment Plan. The Peak Shaving Officer Certification Form specifies that the signing officer has reviewed the Peak Shaving Adjustment Plan, that the information

provided therein is true and correct, and that the MW quantity that will be included in the PJM load forecast is reasonably expected to be physically delivered through customer registrations for the relevant summer period.

II. Peak Shaving Adjustment Plan Template

A Peak Shaving Adjustment Plan template (in Excel format) is provided on the PJM web site, and consists of the following five sections:

A. Peak Shaving Adjustment Plan Summary

B. Planned Peak Shaving Details

C. Program Details

D. Historic Program Impacts

E. Schedule

A. Peak Shaving Adjustment Plan Summary

The Peak Shaving Adjustment Plan requires the following information to be provided:

• Company name

• Contact information (name, phone number and email address of submitter)

• Expected peak shaving value in MWs by zone

• Copy of tariff or an order approved by the Relevant Electric Retail Regulatory Authority

Existing peak shaving is identified as end-use customer sites that the authorized entity has under contract and registered in the PJM DR Hub System for the current summer period and that the authorized entity also intends to have under contract for the forecasted summer period. Planned peak shaving is identified by the authorized entity as described in the Peak Shaving Plan Details section of the Peak Shaving Adjustment Plan template.

Based on the information provided above, a total peak shaving value in MWs will be calculated by PJM for each zone as the addition of the peak shaving value of existing peak shaving plus the peak shaving value of planned peak shaving. The total peak shaving value represents the maximum MW amount that the authorized entity intends to offer for the zone.

B. Peak Shaving Plan Details

The Peak Shaving Plan Details section describes the program(s) and provides the details and key assumptions behind the development of the peak shaving quantities contained in the

entity's Peak Shaving Adjustment Plan. The Peak Shaving Plan Details section is comprised of three sub-sections.

1. Description and Key Assumptions of Peak Shaving Program

The authorized entity must describe the program(s) to be employed to achieve the peak shaving value indicated on the Peak Shaving Adjustment Plan Summary. This section must describe key program attributes and assumptions used to develop the peak shaving value.

This section must include, but is not limited to, discussion of:

• Method(s) of achieving load reduction at customer site(s)

• Equipment to be controlled or installed at customer site(s), if any

• Plan and ability to acquire customers

• Types of customer targeted

• Support of market potential and market share for the target customer base, with adjustments for existing peak shaving customers within this market and the potential for CSPs targeting the same customers

• Assumptions regarding regulatory approval of program(s), if applicable

• If offering a Legacy Direct Load Control (LDLC) program, the following additional LDLC program details must be provided:

o Description of the cycling control strategy

o A list of all load research studies (with study dates) used to develop the estimated nominated ICAP value (kW) per customer (i.e., the per-participant impact). A copy of all studies must be provided with the Peak Shaving Plan. If the LDLC program employs a radio signal, the CSP may elect to either submit a load research study to support the estimated nominated ICAP value per customer or utilize the per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region" Report.

o Assumptions regarding switch operability rate (%)

2. Planned Peak Shaving Value by Customer Segment

For those planned peak shaving values for which an end-use customer site is not identified in section 3 of the Peak Shaving Plan Details, the program administrator must identify the planned peak shaving values by zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3

MW and 10 MW) and large industrial (greater than 10 MW). If known, the program administrator may identify more specific customer segments within the commercial and industrial category.

By zone and by end-use customer segment, the program administrator must provide estimates of the following information:

• Number of end-use customers to be registered for each summer period

• Average Peak Load Contribution (PLC) per end-use customer in kW

• Average Peak Shaving Value per customer in kW

Based on the above provided information, a total peak shaving value in MW will be calculated for each end-use customer segment and for each zone. The total peak shaving value identified by customer segment and aggregated for each zone in Section 2 of the Peak Shaving Plan Details plus the total peak shaving values identified by end-use customer site(s) and aggregated for each zone in Section 3 of the Peak Shaving Plan Details must equal the total peak shaving value for each zone as identified in the Peak Shaving Plan Summary.

3. Peak Shaving Value by End-Use Customer Site

This section must be completed by the program administrator when the end-use customer is known at the time of the submittal of the Peak Shaving Adjustment Plan. This section must also be completed for peak shaving quantities identified in the Peak Shaving Plan Summary as requiring site-specific information, since this identified quantity should reflect planned peak shaving associated with specific end-use customer sites for which the program administrator has a high degree of certainty that it will physically deliver for the relevant summer period.

The program administrator must provide the following information:

• Customer EDC account number (if known)

• Customer name

• Customer premise address

• Zone

• Customer segment

• Actual value (if known) or estimate of current PLC and estimate of expected PLC in kW

• Estimated Peak Shaving Value in kW

In the event that multiple entities identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction or inclusion in the peak

shaving adjustment by any of the entities, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP/program administrator and are likely to execute a contract with that CSP/program administrator for the relevant summer period. In the event that multiple letters of support indicating different entities are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for inclusion in the load forecast by any of the entities.

C. Program Details

The Program Details section describes the operating characteristics of the program(s). The program administrator must provide a brief description of each submitted program, the THI threshold at which peak shaving must be operated, the hours over which the program will operate once triggered, the total peak shaving value (consistent with the Peak Shaving Plan Details), and a table of program impacts over a range of hours and THI, showing the impact for the hour/THI combination as a percentage of the total peak shaving value.

D. Historic Program Impacts

The program administrator must provide estimated hourly load impacts for each peak shaving program for every implementation back to January 1, 1998.

E. Schedule

The program administrator must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total peak shaving value (existing and planned peak shaving) by zone in the Peak Shaving Plan Summary. For each zone and for each customer segment, the program administrator must specify the cumulative number of customers and the cumulative Peak Shaving Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the summer periods in the PJM load forecast horizon.

Peak Shaving Performance Rating

The peak shaving performance rating is used to correct the impact of approved peak shaving programs in the load forecast to be consistent with how the programs have performed when required to reduce load.

For each hour of a required peak shaving event, a shortfall value is calculated as the aggregated metered load of all participants minus the difference between aggregated Customer Baseline (CBL) and Total Participating MW:

$$\text{Shortfall}_{\text{hour}} = \left(\text{Metered Load} * \text{Line Losses}\right) - \left(\left(\text{CBL} * \text{Line Losses}\right) - \text{Total Participating MW}\right)$$

For the event, the performance rating is one minus the average shortfall divided by the Total Participating MW:

$$\text{Event Performance Rating} = 1 - (\text{Avg Shortfall MW} / \text{Total Participating MW})$$

~~).~~

For the year, the performance rating is the average of the event performance ratings. PJM will apply a three-year rolling average of the annual peak shaving performance ratings to the program's total participating MWs in order to determine its peak shaving adjustment. For programs with less than three years of experience, a one- or two-year average will be used.

Attachment E: Peak Shaving Officer Certification Form

PJM PEAK SHAVING OFFICER CERTIFICATION FORM

Market Participant Name: (“Participant”)

I, , a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. (“PJM”) and PJM Settlement, Inc. (“PJM Settlement”) are relying on this certification as evidence that Participant meets all requirements for inclusion in PJM’s load forecast, as set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant’s Peak Shaving Adjustment Plan (the “Plan”) and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.

2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts of peak shaving by the specified summer period.

3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant’s rights and obligations thereunder, including Participant’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: By:

(Signature)

Print Name: Title:

Revision History

Revision 37 (12/18/2024):

- Updates to Attachment A: Clarification on use of estimated load drops for load management in the Load Forecast.

Revision 36 (11/15/2023):

- Periodic Review
- Updated manual ownership to Andew Gledhill
- Section 3.2: Updated to reflect to change to hourly model and provide more clarity to load management and price responsive demand forecast procedure.
- Conforming revisions related to FERC Order ER20-217-000 in Attachment A.
- Updated Attachment B to reflect more transparency in data needs and documentation from requesting EDCs/LSEs. Examples provided updated to reflect recent requests.
- Minor revisions to correct grammar, spelling, punctuation, consistency of terms and document references in Attachment D.

Revision 35 (12/31/2021):

- Revisions proposed from cover-to-cover periodic review:
  - Revised outdated language
  - Minor revisions to correct grammar, spelling, punctuation, consistency of terms and document references.
- Section 3: Added battery storage to forecasted items.

Revision 34 (12/05/2019):

- Periodic Review updated to address:
  - Section 3: Load forecast model details are being removed from the Manual in favor of an annual whitepaper documenting the details of the load forecast.
  - Section 4: The weather normalization procedure for peak load and energy is revised to be directly tied to the load forecast model.

Revision 33 (10/25/2018):

- The following changes were made to implement the solution package of the Summer-Only Demand Response Senior Task Force:
  - Section 3: Revisions to the load forecast development process to explicitly recognize approved summer-only peak shaving programs.

- Attachment D (new): Creates the rules and timelines related to Peak Shaving Adjustment Plans.
- Attachment E (new): A template for the Peak Shaving Officer Certification Form.

Revision 32 (12/01/2017):

- Cover to Cover Periodic Review
- Section 3: Revisions to the methods used to forecast Demand Response and Price Responsive Demand
- Attachment A: Conforming changes to clarify when load drop estimates are produced and definitions of calculations for load drop estimates in non-summer period, in accordance with FERC Order E17-367 approved on March 21, 2017.

Revision 31 (06/01/2016):

- Section 3: Corrected formulas in the End-Use/Weather Variables section
- Attachment B: Removed due to expiration of load research guidelines. The former Attachments C and D have been re-lettered.

Revision 30 (12/01/2015):

- Added the following changes that were endorsed at the MRC on 12/01/2015 but were omitted from the final version:
  - Section 3 - distributed solar generation is now reflected in the historical load used for zonal models and a separate solar forecast is used to adjust zonal forecasts.

Revision 29 (12/01/2015):

- Section 3: This extensive revision incorporates changes to the load forecast model to add variables to account for trends in appliance usage and energy efficiency, revisions in weather variables, and the introduction of an autoregressive error correction. It also adds assignment of Census Divisions to zones and updates the assignments of economic regions and weather stations to zones. Section 4: the weather normalization procedure used for coincident and non-coincident peaks has been revised. This revision serves as the required periodic review of the Manual.

Revision 28 (08/03/2015):

- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific measurement and verification information for residential customers without interval metering, as outlined in Attachment D of this manual.

Revision 27 (03/26/2015):

- Section 3.2: Revised DR forecast methodology

Revision 26 (11/01/2014):

- Section 3: Revised to clarify the current process of applying adjustments to load forecasts.
- Attachment C: Added to provide guidelines for load forecast adjustments and examples.

Revision 25 (06/01/2014):

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes.
- Attachment A updated for new distinction between Emergency and Pre-Emergency DR.

Revision 24 (04/11/2014):

- Two of the eSuite Applications have been renamed. Moving forward EES will be known as ExSchedule and eMTR will be known as Power Meter.

Revision 23 (6/1/2013):

- Section 3: Exhibits 2 and 3 revised to reflect updated economic and weather station mappings. The definition of winter load management is revised.
- Attachment B; added specific requirements for load management switch operability studies.

Revision 22 (2/28/2013):

- Administrative Change: update all references of “eSchedule” to “InSchedule”

Revision 21 (10/01/2012):

- Attachment A revised to add guidelines for load drop estimates for Price Responsive Demand participants.

Revision 20 (06/28/2012):

- Attachment A updated based on PJM Interconnection, L.L.C., Docket No. ER11-3322 (Capacity measurement and verification). This tariff and RAA update specifically requires GLD to provide reductions below the PLC and aligns any recognized reductions used to determine capacity compliance with add back process.

Revision 19 (02/23/2012):

- Attachment A changed to update Comparable Day definition, clarify data required if Generation data is used to substantiate load reduction and have PJM perform the compliance calculation.

Revision 18 (11/16/2011):

- Section 3: Revisions reflect adoption of Itron, Inc recommendations regarding the economic driver used in the load forecast model. References to the now-defunct Interruptible Load for Reliability option of Load Management were removed.

Revision 17 (07/14/2011):

- Attachment A: 24 hour data submission required and additional clarification for use of generation data to substantiate compliance (FERC Docket #: ER11-2898-000, 4/18/11). Also added revisions concerning how add backs are applied to DLC as approved by the MRC.

Revision 16 (04/01/2011):

- Section 3: Integrated the description of the net energy forecast model into the general model description.
- Revised Exhibits 2 and 3 to reflect updated economic and weather station mappings.
- Attachment A: Revised load drop estimate guidelines based on Load Management Task Force proposal approved at November 2010 Markets and Reliability Committee and January 2011 Members Committee. Corresponding tariff language changes were filed with FERC under Docket ER11-2898-000.

Revision 15 (10/01/2009):

- Attachment A: Revised load drop estimate guidelines to reflect the FERC-approved business rules. Section 3: added price responsive demand to the adjustments made to the load forecast.

Revision 14 (12/01/2008):

- Section 3: Revised load forecast model specification to allow for a load adjustment dummy variable. Clarified the review and approval process for the Load Forecast Report.
- Section 4: Revised the Weather Normalization approval process to clarify that Board approval is not required.

Revision 13 (06/01/2008):

- A new Exhibit 1 was added, presenting definitions of variables used in the load forecast model. Other exhibits were re-numbered.
- Exhibit 2 was revised to reflect a new weather station assignment for the DAY zone.
- Section 4: Removed note from Weather Normalization Procedure description (the process is finalized).
- Attachment A: Revised to reflect that the guidelines apply to both capacity- and energy-related load drop estimates.

Revision 12 (06/01/2007):

- Removed Section 3 and moved content to Manual 18.
- Removed Section 7 and moved content to Manual 18.

Revision 11 (06/01/07):

- This extensive revision incorporates changes to Load Data Systems due to the implementation of the Reliability Pricing Model (RPM). Sections on Active Load Management and Qualified Interruptible Load have been replaced with a new Load Management section. The Zonal Scaling Factor section reflects a revised calculation. The Load Forecast Model section has been updated for enhancements made to the model specification as well as revised coincident peak forecast method. The Weather Normalization section was revised to reflect that seasonal peaks are now normalized using the load forecast model.

Revision 10 (06/01/06):

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 3—Revised to reflect changes in the handling of outlier observations in weather normalization of seasonal peaks.
- Section 4—Revised to incorporate the addition of the Full Emergency option of Load Response.
- Updated the penalties/rewards section under Compliance.

Revision 09 (01/01/06):

- This revision includes a complete revision to Section 6 to detail the PJM-produced load forecast which will be used for capacity and system planning purposes. The previous Section 3 (PJM Load Forecast Report) has been removed since Member input is no longer required for its production.

Revision 08 (06/01/05):

- Updated Exhibit 1 to include new PJM Manuals.
- This revision includes changes to Section 3 to reflect reporting requirements for sub-Zones. Section 4 was completely revised to reflect a new weather normalization method and revised basis for calculating 5CPs. Section 8 has been modified to reflect revised release dates for Zonal Scaling Factors.

Revision 07 (07/01/04):

- This revision includes changes to Section 2, to reflect that 500kV generation will be treated differently in the PJM Western and Southern regions than the Mid-Atlantic Region. Section 4 was revised to reflect that peak load allocation will be impacted for market integration. Section 5 has been modified to reflect that the Active Load Management program has been fully incorporated into the eCapacity application.

Revision 06 (10/01/03):

- This revision incorporates a new presentation format. Substantive changes were made to Section 4, to reflect changes in peak normalization procedures. Section 5 and Attachment B were revised to reflect the change in load research requirements for cycling programs to

a five year cycle. The previous Section 6 (Forecast Peak Period Load) has been deleted. The section on Qualified Interruptible Load now reflects that it is the same as Active Load Management. New sections have been added for the PJM Entity Forecast and Zonal Scaling Factors. Attachment A includes an additional load drop estimate technique, Customer Baseline. Throughout the document, changes were made to reflect the new committee structure, and the Board of Managers enhanced authority.

- Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM.*"
- Changed all references from "the PJM OI" to "PJM."
- Renamed Exhibits to consecutive numbering.
- Reformatted to new PJM formatting standard.
- Renumbered pages to consecutive numbering.

Revision 05 (01/01/03):

- This revision contains changes to Section 2, which was revised to reflect that hourly load data are reported through the new Power Meter application. Section 5 was revised to clarify wording on existing Active Load Management rules and procedures.

Revision 04 (06/01/02):

- This revision contains changes to Section 3, which was revised to reflect a new reporting format for the PJM Load Forecast Report. Section 7 was revised to incorporate firm level customers into the Qualified Interruptible Load program.

Revision 03 (01/01/02):

- This revision incorporates changes resulting from the addition of PJM West into the Interconnection. Section 4 was revised to add a description of the peak normalization process for PJM West. Sections 6 (Qualified Interruptible Load) and 7 (Forecast Period Peak Load) were added.

Revision 02 (10/01/00):

- This revision contains changes to Section 4 to include a clarification of the weather normalization overview, and revises the summer season weather normalization to reflect the newly adopted PJM summer weather parameter. Also, the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for *Definitions and Abbreviations (M-35)*. Attachments B, C, and D have been renamed A, B, and C respectively. Also, changes to the 'new' Attachment A: ALM Load Drop Estimate Guidelines (previously listed as Attachment B) have been in effect since 6/01/00; however, they are now being addressed in this revision.

Revision 01 (06/01/00):

- This revision contains changes to Sections 3, 4, and 5, to reflect the influence of retail choice, including the creation of a peak allocation, revamped Active Load Management

rules and procedures, and revamped PJM Load Forecast Report. Also, it details a revised weather normalization procedure.

Revision 00 (07/15/97):

- This revision is the complete draft of the PJM Manual for Load Data Systems.