



Working to Perfect the Flow of Energy

PJM Manual 19:

Load Forecasting and Analysis

Revision:28

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Prepared by

Resource Adequacy Planning

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PJM Manual 19:

Load Forecasting and Analysis

Table of Contents

Table of Contents..... **ii**

Table of Exhibits **iii**

Approval **1**

Current Revision **1**

Introduction..... **2**

 ABOUT PJM MANUALS..... 2

 ABOUT THIS MANUAL..... 2

 USING THIS MANUAL 3

What You Will Find In This Manual..... 4

Section 1: Overview..... **5**

 1.1 OVERVIEW OF LOAD FORECASTING AND ANALYSIS 5

Section 2: PJM Hourly Load Data..... **6**

 2.1 LOAD DATA OVERVIEW 6

 2.2 LOAD DATA REPORTING BUSINESS RULES..... 6

Section 3: PJM Load Forecast Model **9**

 3.1 FORECAST MODEL OVERVIEW 9

 3.2 DEVELOPMENT OF THE FORECAST..... 9

 3.3 NON-ZONE PEAK FORECAST 13

 3.4 REVIEW OF THE FORECAST 13

Section 4: Weather Normalization and Coincident Peaks..... **20**

 4.1 WEATHER NORMALIZATION OVERVIEW 20

 4.2 WEATHER NORMALIZATION PROCEDURE 20

 4.3 NORMALIZED PEAK APPEAL PROCESS 20

 4.4 PEAK LOAD ALLOCATION (5CP) 21

Attachment A: Load Drop Estimate Guidelines **23**

 LOAD DROP ESTIMATES FOR LOAD MANAGEMENT CUSTOMERS 23

 EVENT COMPLIANCE FOR GUARANTEED LOAD DROP (GLD) CUSTOMERS 25

 LOAD DROP ESTIMATES FOR PRD CUSTOMERS 26

Attachment B: Legacy Direct Load Control Load Research Guidelines **28**

Attachment C: Load Forecast Adjustment Guidelines **31**

Attachment D: Residential Non-Interval Metered Guidelines **34**

Revision History..... **41**



Table of Exhibits

EXHIBIT 1: MODEL VARIABLE DEFINITIONS	17
EXHIBIT 2: ASSIGNMENT OF WEATHER STATIONS TO ZONES	18
EXHIBIT 3: ASSIGNMENT OF METROPOLITAN AREAS AND STATES TO ZONES	19

Approval

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Current Revision

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.

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 www.pjm.com and select “Manuals” under the “Documents” pull-down menu.

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 ii.

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 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
- eLRS documentation
- PJM Load Forecast Report
- [PJM Manual for Emergency Operations \(M-13\)](#)
- Reliability Assurance Agreement
- [Behind-the-Meter Generation Business Rules \(in Manual M-14D\)](#)
- Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region

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 the 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 normalization factors, 1CP zonal load contributions for Network Service billing, charts contained in the PJM Load Forecast Report, and the Monthly Operations Report.

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, and determining RTO unrestricted coincident 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 InSchedules.

Curtailement 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 will 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.

Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 13 of the Reliability Assurance Agreement and the PJM West 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 eLRS 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 the OI 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.

- *Distribute Reports:* — By the 10th of each month, PJM makes reports of load data from the previous month available to the EDCs. These data include a summary Daily Load Report for each day of the month, showing daily peak loads and the monthly energy total for each LSE and for the PJM RTO. A monthly summary report also is provided.
- *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, and 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 15-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, load deliverability area and the RTO. The model uses anticipated economic growth 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 econometric multiple regression models to estimate daily peak load for each PJM zone (the non-coincident peak), the zone’s contribution to the daily RTO peak (the coincident peak), and monthly net energy for load. Definitions of each model variable are presented in Exhibit 1. The variables included are:

Dependent Variable - Load:

For the non-coincident models, zonal hourly metered load data are supplemented with estimated load drops (as outlined in Attachment A) to obtain unrestricted hourly load. The maximum value for each day is used in the regressions. For the coincident models, the zone’s contribution to the daily RTO unrestricted peak load is used in the regressions. For the net energy models, the sum of each day’s hourly loads is used in the regressions.

Calendar Effects:

Days of the week, month of the year, holiday, and Daylight Saving Time impacts are included in the model using binary variables. Holiday seasonal lighting load is reflected using a trend variable. Minutes of daylight are also included.

Weather Data:

Weather is included in the models using different variables for heating, cooling and shoulder seasons. For the heating season (December, January and February), the Winter Weather Parameter is defined as:

$$\begin{aligned} & \text{If } WIND > 10 \text{ mph,} \\ & WWP = DB - (0.5 * (WIND - 10)) \\ & \text{If } WIND \leq 10 \text{ mph,} \\ & WWP = DB \end{aligned}$$

Where: *WIND* = Wind velocity, in miles per hour;

WWP = Wind speed adjusted dry bulb temperature;

DB = Dry bulb temperature ($^{\circ}F$).

For the cooling season (June, July, August, and September), Temperature-Humidity Index (THI) is used as the weather variable:

$$\begin{aligned} & \text{If } DB \geq 58, \\ & THI = DB - 0.55 * (1 - HUM) * (DB - 58) \\ & \text{If } DB < 58, \\ & THI = DB \end{aligned}$$

Where: *THI* = Temperature humidity index;

DB = Dry bulb temperature ($^{\circ}F$);

HUM = Relative Humidity (where 100% = 1).

For shoulder months (March, April, May, October and November), the average daily dry bulb temperature serves as the weather variable.

Additionally, measures of heating and cooling degree days are included. These readings are divided into separate morning, afternoon, evening, and night effects, as well as

weekends. They are also lagged over three days. Weather data for each PJM zone are calculated according to the mapping presented in Exhibit 2.

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 Exhibit 3. Models for each PJM zone share the same general specification.

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 in one of two ways: 1) for identified changes that have not yet occurred, by an explicit adjustment to the modeled forecast; and 2) for changes that have already occurred, by the introduction of a binary variable into the affected zone's model specification.

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 C provides load forecast adjustment guidelines.

In cases where a zone has experienced a large, sudden shift in load (or following the use of a manual load adjustment in a prior forecast), a load adjustment dummy (binary) variable may be added to the zone's model specification. The resulting model coefficient must satisfy the following criteria:

- Be explained by an identifiable occurrence (such as the migration of load from another service territory, factory shutdown, or a price shock);
- Be statistically significant;
- Have a sign in the expected direction;
- Have a magnitude that is consistent with the expected load shift;
- Have a magnitude, relative to the zone's metered peak, large enough to make a discernible difference in the forecast; and
- Make an appreciable improvement to model fit statistics.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. Monte Carlo simulation is useful for simulating a phenomenon (in this case, electrical load) with significant uncertainty with regard to one or more of its driving influences (in this case, the weather conditions that will occur in the future). Using the Monte Carlo 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 peak forecast, the solution for each of the zonal coincident peak (CP) models are summed by day and weather scenario to obtain the RTO peak for the day. By weather scenario, the maximum daily RTO value for the season is found. For the RTO, a distribution of the seasonal RTO 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.

To determine the final zonal RTO-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 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 Monte Carlo 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 daily values per forecast year for each weather scenario.

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

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

For Demand Resources (DR), forecasted values for each zone are computed based on the following procedure. The forecast is based on the PJM final summer season Committed DR amount, where the Committed DR means all DR 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 for each of the most recent three Delivery Years. Express the Committed DR amount 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 for each zone.
3. The DR forecast for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the result from Step 2.

The forecasted impact of approved Energy Efficiency programs equals the amount cleared in RPM auctions, and represents accelerated efficiency increases that would not otherwise occur, or would occur at a later time, without the EE program.

The impact of price responsive demand equals the amount subscribed through the RPM process. The amount subscribed for the last RPM auction year is held constant for the remainder of the forecast.

[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.

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.

Calendar Data

Day of week

<u>Variable Name</u>	Type or <u>Formula</u>	<u>Description</u>
Monday	Binary	Day of the Week
Tuesday	Binary	Day of the Week
Wednesday	Binary	Day of the Week
Thursday	Binary	Day of the Week
Friday	Binary	Day of the Week
Saturday	Binary	Day of the Week

Holiday

MartinLutherKingDay	Fuzzy	MLK Day Holiday
PresidentsDay	Fuzzy	President's Day Holiday
GoodFriday	Binary	Good Friday Religious Holiday
MemorialDay	Fuzzy	Memorial Day Holiday
July4th	Fuzzy	Independence Day and surrounding days
LaborDay	Fuzzy	Labor Day Holiday
Thanksgiving	Binary	Thanksgiving Holiday
FridayAfterThanksgiving	Fuzzy	Friday After Thanksgiving Holiday
XMasWkB4	Fuzzy	Week Before Christmas
ChristmasEve	Fuzzy	Christmas Eve (value depends on day of week)
ChristmasDay	Binary	Christmas Day
XMasWk	Fuzzy	Week after Christmas Holiday
NewYearsEve	Fuzzy	New Years Eve(value depends on day of week)
NewYearsDay	Binary	New Years Day Holiday
XMasLights	Trend	Christmas Lights/Retail Operations Trend

Month

January	Binary	Month of the Year
February	Binary	Month of the Year
March	Binary	Month of the Year
April	Binary	Month of the Year
May	Binary	Month of the Year
June	Binary	Month of the Year
July	Binary	Month of the Year
August	Binary	Month of the Year
September	Binary	Month of the Year
October	Binary	Month of the Year
November	Binary	Month of the Year

Notes:

Binary – A variable which has a value of 1 for the indicated characteristic, otherwise the value is 0.

Fuzzy – A variable which has a conditional value for the indicated characteristic, otherwise the value is 0.

Trend - A variable which has a value with increasing then decreasing value for the indicated characteristic, otherwise the value is 0.

Weather Data

<u>Variable Name</u>	<u>Type or Formula</u>	<u>Description</u>
NightHDD	$\text{Max}(50 - \text{NightWWP}^1, 0)$	Night heating degree days
MornHDD	$\text{Max}(55 - \text{MornWWP}^2, 0)$	Morning heating degree days
AfterHDD	$\text{Max}(62 - \text{AftWWP}^3, 0)$	Afternoon heating degree days
EvenHDD	$\text{Max}(55 - \text{EvenWWP}^4, 0)$	Evening heating degree days
NightCDD	$\text{Max}(\text{NightTHI}^5 - 60, 0)$	Night cooling degree days
MornCDD	$\text{Max}(\text{MornTHI}^6 - 65, 0)$	Morning cooling degree days
AfterCDD	$\text{Max}(\text{AftTHI}^7 - 72, 0)$	Afternoon cooling degree days
EvenCDD	$\text{Max}(\text{EvenTHI}^8 - 65, 0)$	Evening time cooling degree days
WkEndCDD	$\text{WkEnd}^9 * \text{CDD}^{10}$	Weekend cooling degree days
WkEndHDD	$\text{WkEnd}^9 * \text{HDD}^{11}$	Weekend heating degree days
ColdWind	$\text{Min}(\text{Max}(60 - \text{AftTHI}^7, 0) / 20, 1) * \text{AvgWind}^{12}$	Wind speed index on cold days
HotWind	$\text{Min}(\text{Max}(\text{AftTHI}^7 - 60, 0) / 15, 1) * \text{AvgWind}^{12}$	Wind speed index on hot days
LagHDD	IF (month \leq 5 or month \geq 10) THEN .75 * Lag(HDD ¹¹ , 1) + .25 * Lag(HDD, 2) ELSE 0	Lagged heating degree days
LagCDD	IF (month \geq 6 & month \leq 9) THEN .75 * Lag(CDD ¹⁰ , 1) + .25 * Lag(CDD, 2) ELSE 0	Lagged cooling degree days
FuzzyHum	$\text{Min}(\text{Max}(\text{AvgTmp}^{13} - 60, 0) / 15, 1) * \text{AvgHum}^{14}$ Humidity index, triggered at 60 degrees	

Intermediate Calculations:

1 NightWWP	Average of WWP for hours ending 1 through 6	
2 MornWWP	Average of WWP for hours ending 7 through 12	
3 AftWWP	Average of WWP for hours ending 13 through 18	
4 EvenWWP	Average of WWP for hours ending 19 through 24	
5 NightTHI	Average of THI for hours ending 1 through 6	
6 MornTHI	Average of THI for hours ending 7 through 12	
7 AftTHI	Average of THI for hours ending 13 through 18	
8 EvenTHI	Average of THI for hours ending 19 through 24	
9 WkEnd	Weekend Binary	
10 CDD	$\text{Max}(\text{AvgTmp} - 65, 0)$	Cooling degree days
11 HDD	$\text{Max}(60 - \text{AvgTmp}, 0)$	Heating degree days
12 AvgWind	24 hour average wind speed	
13 AvgTmp	24 hour average temperature (Fahrenheit)	
14 AvgHum	24 hour average humidity (percent)	

Seasonal Weather Variables

S_THI	IF (month \geq 6 & month \leq 9) For cooling months, use MaxTHI THEN MaxTHI ¹⁵ ELSE 0
W_WWP	IF (month \leq 2 or month = 12) For heating months, use MinWWP THEN MinWWP ¹⁶ ELSE 0
SH_AvgTmp	IF (month = 3, 4, 5, 10 or 11) For shoulder months, use AvgTemp THEN AvgTemp ¹³ ELSE 0

Intermediate Calculations:

15 MaxTHI	Maximum THI over 24 hours
16 MinWWP	Minimum WWP over 24 hours

Economic Data

<u>Variable Name</u>	<u>Description</u>
DailyEconIndex	Economic index quarterly values converted to daily

$$\begin{aligned}
 EconIndex = & ResWt \times (HH_{y,m}/HH_{base})^{0.47} \times (Pop_{y,m}/Pop_{base})^{0.26} \times (PInc_{y,m}/PInc_{base})^{0.27} \\
 & + ComWt \times (NMEmp_{y,m}/NMEmp_{base})^{0.47} \times (GDP_{y,m}/GDP_{base})^{0.20} \times (GMP_{y,m}/GMP_{base})^{0.16} \times (Pop_{y,m}/Pop_{base})^{0.17} \\
 & + IndWt \times (GDP_{y,m}/GDP_{base})^{0.47} \times (GMP_{y,m}/GMP_{base})^{0.53}
 \end{aligned}$$

Where: ResWt is the residential sector sales percentage to total zonal electric sales in year (y);
 HH is the number of households in year (y) and month (m);
 Pop is the population in year (y) and month (m);
 PInc is the value of total real personal income in year (y) and month (m);
 ComWt is the commercial sector sales percentage to total zonal electric sales in year (y);
 NMEmp is the number of non-manufacturing employees in the metro area(s) in year (y) and month (m);
 GDP is the value of total real gross domestic product in the United States in year (y) and month (m);
 GMP is the value of total real gross metropolitan product in the metro area(s) in year (y) and month (m);
 IndWt is industrial sector sales percentage to total zonal electric sales in year (y);
 And base indexes the base year.

Economic/Weather Data

Econ_HDD	HDD ¹¹ * DailyEconIndex	Heating Degree Days interacted with economic index
Econ_CDD	CDD ¹⁰ * DailyEconIndex	Cooling Degree Days interacted with economic index

Solar Data

DLSav_EPA2005	Binary	Daylight Savings Time conversion
MinutesDaylight	Minutes	Minutes of daylight at local airport

Load Adjustment

LA_<yy>	Binary	Adjustment for year 20yy forward
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Exhibit 1: Model Variable Definitions

Zone	Weather Station	Airport Name	Weight
AE	ACY	Atlantic City International	1
AEP	CMH	Columbus Port Columbus International	0.5
AEP	FWA	Fort Wayne International Airport	0.2
AEP	ROA	Roanoke Regional Airport	0.3
APS	IAD	Washington Dulles	0.3
APS	PIT	Pittsburgh International	0.7
ATSI	CAK	Akron-Canton Regional Airport	0.465
ATSI	CLE	Cleveland Hopkins Airport	0.3
ATSI	TOL	Toledo Express Airport	0.15
ATSI	PIT	Pittsburgh International Airport	0.085
BGE	BWI	Baltimore Washington International	1
COMED	ORD	Chicago O'Hare International	1
DAY	DAY	Cox-Dayton International	1
DEOK	CVG	Cincinnati Northern KY Airport	1
DLCO	PIT	Pittsburgh International	1
DOM	IAD	Washington Dulles	0.3333
DOM	ORF	Norfolk International	0.3333
DOM	RIC	Richmond International	0.3334
DPL	ILG	Wilmington New Castle County Airport	0.7
DPL	WAL	Wallops Island Flight Center	0.3
EKPC	LEX	Blue Grass Airport	1
JCPL	EWR	Newark International	0.75
JCPL	ACY	Atlantic City International	0.25
METED	PHL	Philadelphia International	0.5
METED	ABE	Allentown Lehigh Valley International	0.5
PECO	PHL	Philadelphia International	1
PENLC	ERI	Erie International	0.5
PENLC	IPT	Williamsport Regional	0.5
PEPCO	DCA	Washington Reagan National	1
PL	ABE	Allentown Lehigh Valley International	0.6
PL	IPT	Williamsport Regional	0.4
PS	EWR	Newark International	1
RECO	EWR	Newark International	1
UGI	AVP	Wilkes-Barre Scranton International	1

Exhibit 2: Assignment of Weather Stations to Zones

Zone	State(s)	Metro Area Name(s)
AE	NJ	Atlantic City NJ, Vineland NJ
AEP	OH, WV, VA, IN	Elkhart IN, Fort Wayne IN, South Bend IN, Canton OH, Columbus OH, Kingsport TN, Lynchburg VA, Roanoke VA, Charleston WV, Huntington WV
APS	PA, OH, WV	Hagerstown MD, Morgantown WV
ATSI	PA, OH	Akron OH, Cleveland OH, Mansfield OH, Springfield OH, Toledo OH, Youngstown OH, Pittsburgh PA
BGE	MD	Baltimore MD
COMED	IL	Chicago IL
DAY	OH	Dayton OH
DEOK	OH	Cincinnati OH
DLCO	PA	Pittsburgh PA
DOM	VA	Richmond VA, Virginia Beach VA, Roanoke VA
DPL	DE	Dover DE, Wilmington DE, Salisbury MD
EKPC	KY	Cincinnati OH, Louisville KY, Elizabethtown KY, Bowling Green KY, Lexington KY, Ashland KY
JCPL	NJ	Camden NJ, Edison NJ, Trenton NJ
METED	PA	Allentown/Bethlehem/Easton PA, Reading PA, York PA, Lebanon PA
PECO	PA	Philadelphia PA
PENLC	PA	Erie PA, Altoona PA, Johnstown PA
PEPCO	MD	Washington D.C.
PL	PA	Allentown/Bethlehem/Easton PA, Scranton Wilkes-Barre PA, Harrisburg PA, Lancaster PA, Williamsport PA
PS	NJ	Camden NJ, Edison NJ, Trenton NJ, Newark NJ
RECO	NJ	Newark NJ
UGI	PA	Scranton Wilkes-Barre PA

Exhibit 3: Assignment of Metropolitan Areas and States to Zones

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, according to the procedures described below. The Load Analysis Subcommittee reviews the normalizations, and either adopts the resulting values, or Members may challenge the results as anomalous. In the latter situation, alternate analysis will be conducted, until a consensus is reached. After the review process is completed, the results are presented to the Planning Committee. The weather normalized (W/N) peaks are then used by EDCs to determine capacity peak load shares for wholesale and retail customers.

4.2 Weather Normalization Procedure

The standard 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 load, weather, and economic data. Then, the Monte Carlo 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. These peaks are then adjusted, as described above in Section 3, to align the zones with the RTO.

4.3 Normalized Peak Appeal Process

Results of the weather-normalization analysis will be reviewed by LAS members. Members will have an opportunity at that point to trigger the following appeal process if, in their judgment, the results of the standard method described above appear inaccurate:

- Any LAS member may request review of any zone’s normalized peak, though the primary responsibility resides with the member from the zone in question.
- A request for review will be followed by further analysis, conducted by PJM and LAS members, to identify and quantify the inaccuracy in the weather-normalization of the zone.

- LAS will conduct peer review of all supplemental analysis, and seek a (supermajority) consensus before the issue is presented to the Planning Committee.
- If an adjustment needs to be made to a zonal W/N peak, LAS will forward the proposed zonal W/N peak to the Planning Committee, along with the results of the standard analysis.

The appeals process is designed to address the rare significant miscalculation of a zone's load, and is not intended as a method to "fine tune" the results of the standard method.

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 eLRS application
- Submit voltage reduction and loss of Load Drop Estimates as described in Attachment A of this manual.
- Participate in review of seasonal load studies, through the Load Analysis Subcommittee.

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. Provide recommendation to PJM Planning Committee, by its October meeting, to accept the results of the standard normalization procedure, or to use the alternate methodology.
- If necessary, produce analysis to establish alternate estimate of zonal W/N CP Load.

4.4 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. For purposes of 5CP identification, PRD Providers that registered price responsive demand to satisfy a PRD commitment for either RPM or FRR Alternative must provide PJM with meter data for a set of high load days to be identified by PJM by the end of each September. Meter data is entered at the site level; load drop estimates will be calculated at the registration level. Load drop estimates will only be applied for Maximum Emergency Generation hours as well as for any 5CP hours when there was no Maximum Emergency Generation event.

Load drop estimates 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 (Legacy Direct Load Control, Firm Service Level, and Guaranteed Load Drop).

Requirements for Production of Load Drop Estimates

Reason for Load Drop		PJM-Initiated Emergency or Pre-Emergency or CSP-Initiated Test	Economic	EDC- or CSP-Initiated
Program Registration	Emergency/Pre-Emergency Full (DR) or Emergency/Pre-Emergency Capacity Only (DR)	<i>Load Drop Estimates must be produced for any interruptions from June 1 through September 30.</i>	<i>Load Drop Estimates must be produced for any settled interruptions from June 1 through September 30.</i>	<i>No Load Drop Estimates required.</i>
	Emergency Energy Only	<i>Load Drop Estimates must be produced for any interruptions during Emergency/Pre-Emergency hours from June 1 through September 30.</i>	<i>No Load Drop Estimates required.</i>	<i>No Load Drop Estimates required.</i>
	Economic	<i>No Load Drop Estimates required.</i>	<i>No Load Drop Estimates required.</i>	<i>No Load Drop Estimates required.</i>

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 which occur from June 1 through September 30, 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 Including Legacy Direct Load Control

Prior to June 1, 2016: the nominated quantity (MW) of Load Management provided by non-interval metered customers * Loss Factor will be the estimated load drop added back to the zone for a load management emergency, pre-emergency or test event. If the resource participates as an economic resource, then the hourly MW settled under the economic program will be used for the load drop that is added back to the zone. Non-interval metered customers may not participate in Load Management under Legacy Direct Load Control (LDLC) after May 31, 2016.

Contractually Interruptible

The estimated load drop 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”). 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. The calculation is represented by:

Minimum of $\{(comparison\ load - Load) * LF, PLC - (Load * LF)\}$

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”). The calculation is represented by:

$PLC - (Load * LF)$

Note: 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. 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.

Event Compliance for Guaranteed Load Drop (GLD) Customers

For purposes of determining compliance with a PJM-initiated Load Management event or 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.

For Maximum Emergency Generation hour or a 5CP hour without Maximum Emergency Generation:

$$\text{Load Drop Estimate} = \text{Customer Expected Peak Load} - (\text{Metered Load} * \text{EDC Loss Factor})$$

$$\text{Where: Expected Peak Load} = \text{PLC} * \text{Final Zonal Peak Load Forecast}_{DY} / \text{Zonal Weather Normalized Peak}_{DY-1};$$

$$\text{PLC} = \text{Peak Load Contribution for the registration};$$

$$\text{DY} = \text{Delivery Year}$$

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: Legacy Direct Load Control Load Research Guidelines

These guidelines are in effect prior to June 1, 2016 only.

The intention of these guidelines is to ensure that the estimated per-participant impacts of Legacy Direct Load Control program reliably represent the amount of load shed, on average, for active program participants.

Curtailement Service Providers with Legacy Direct Load Control programs which employ a radio signal may elect to either submit a load research study supporting base per-participant impacts for their program, or utilize the base per-participant impacts contained in the “Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region” report (<http://www.pjm.com/~media/documents/reports/20070406-deemed-savings-report-ac-heat.ashx>). Providers utilizing other technology must submit a load research study. All Providers must submit switch operability studies once every five years.

Requirements for Provider-Submitted Studies

Study Design

LDLC load research base per-participant impact studies will be designed to achieve a minimum accuracy of 90% Confidence with 20% error.

Study Detail

Load research studies submitted must present estimated per-participant impacts in a matrix which details average impacts on non-holiday weekdays by hour, for the hours ending 13:00 through 20:00 (PJM Eastern Region) or 8:00 through 21:00 (PJM Western Region), and by weather condition (over a range of local conditions under which it can reasonably be expected that the program will be implemented). Separate matrices must be estimated:

By program (and/or cycling scheme);

By PJM zone.

Switch Operability Rate

In addition to base per-participant impacts, studies submitted to PJM must also include the average switch operability rate, reflecting the percentage of all active switches which both receive the control signal and operate. The switch operability rate must be supplied with the original base impact study, and then updated every five years. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%. See below for full requirements for switch operability studies.

Utilizing the Deemed Savings Estimates

[Note: The “Deemed Savings Estimates” study report is available on the PJM.com website.]

Eligibility

Load Management Providers with Legacy Direct Load Control programs which employ a radio signal may elect to utilize the base per-participant impacts contained in the “Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region” report.

Base Impact Value

Base impacts for air conditioning programs will be established utilizing the aggregate values detailed in Appendix F of the Deemed Savings Estimates report. The Provider must supply the applicable duty cycle strategy (percentage of each hour the unit is interrupted) and an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak). The Provider may opt to customize the base impact by supplying a research study which stratifies its program by A/C usage or connected A/C load. In this case, base impacts will be drawn from the aggregate results presented in Appendix G or H, as appropriate.

Base impacts for water heating programs will be established utilizing the aggregate values detailed in Appendix J. The Provider must supply an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak)

EDCs with base impacts presented in the Deemed Savings report (BGE, JCPL, and PSEG) may elect to use those impacts.

Switch Operability Rate

1. A random sample of customers must be selected to test. The sample must meet the following requirements:
 - a. The study must be designed for a minimum accuracy of 90% confidence, 10% error.
 - b. The sample must be randomly selected from the entire population of customers who will be counted for load reduction. No customers can be excluded and there can be no restrictions (e.g. only selecting customers within certain zip codes, only selecting customers with certain meters, only selecting customers that have enrolled in the last 12 months, etc.).
 - c. The sample must be stratified by equipment type if using multiple types of equipment to receive the signal and control the device.
 - d. The sample may be stratified by program segmentation (e.g. cycling level).

2. The following must be tested/verified at each customer in the sample:
 - a. The switching device needs to be properly installed, wired, etc.
 - b. A signal needs to be sent to the device to cycle it. Verification that the device receives this signal must be obtained. The signal must be sent in the same manner it would be sent during an event (i.e. over a public paging system, not from a local handheld device).
 - c. If the test in (2.b) does not provide verification of switch operation (i.e., it only tests signal reception), a technician must verify that the switch cycles the unit when the signal is received. This signal does not need to be sent in the same manner as it would during the event – it can be sent from a local handheld device.
 - d. If (2.a), (2.b) and (2.c) do not determine that the unit can properly receive the signal and control the device, the device is counted as inoperable. A technician may fix inoperable switches, however the device must still be counted as inoperable for the study.
3. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%

Attachment C: 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) for large load shifts (either positive or negative) which are known to the EDC 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 October/November.
- Any other load changes which are brought to PJM's attention.

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 has adjusted its own financial/planning forecast
- Ascertain that the load shift is related to a single site or a limited number of related sites (not a systemic cause)
- 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.

Adjustment Estimation- for each identified and verified issue, 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 (e.g., forecast runs with and without the load involved, trend analysis)
- Acquire any contracted amounts of load changes
- For any after-the-fact adjustments, review the zone's forecast model's residual pattern
- Review any available independent analysis of the impact of the load change.

Adjustment Review – Each proposed load forecast adjustment will be reviewed with the Load Analysis Subcommittee prior to inclusion in the load forecast. The final decision on any load adjustment is made by PJM.

Example 1: Loss of a Single Industrial Load

Issue Identification – In response to PJM’s annual solicitation for information regarding large load shifts, a member EDC notified PJM that it was losing a large industrial load, which was a plant scheduled to shut down in a few months (and prior to the release of the next load forecast)

Issue Verification – PJM reviewed the EDC’s request and through conference calls, e-mail exchanges, an EDC-provided case statement, and PJM independent investigation it was determined that:

- The plant closing was widely reported in local media as well as by a press release from the end-use customer;
- The EDC had adjusted its own financial and planning forecasts to reflect a closure at the plant;
- The affected load was confined to one site/customer account.
- The customer’s peak load was approximately 500 MW.

Additionally, PJM consulted with its economic forecast supplier and determined that the forecasts of metropolitan areas within the affected zone were not adjusted to reflect the plant closure. Based on these findings, PJM concluded that the load shift was factual and material.

Adjustment Estimation – PJM requested and received historical load data for the end-use customer. An attempt was made to separately model the zone’s peak load without the customer’s load in order to draw a comparison to the forecast of the zone’s full load. While the model produced a reasonable result for the first forecast year (-370MW), the difference quickly shrank and eventually became negative. As an alternative, the average daily peak over the model’s estimation was computed. This value (-369 MW) was essentially equal to the difference between the two models in the first forecast years. PJM notified the EDC and members that the zone’s load forecast would be lowered by 370MW.

Example 2: Accelerating Load

Issue Identification – A member EDC proactively notified PJM that it was in the early stages of preparing to integrate a large amount of accelerating load associated with one industry through 2023 and requested a face-to-face meeting to discuss the issue.

Issue Verification – PJM met with the EDC and through follow-up conference calls, e-mail exchanges and PJM independent investigation it was determined that:

- The load in question was associated with greenfield construction and was confined to a cluster of sites in one small area of the zone.

- The EDC had adjusted its own financial and planning forecasts to reflect the increased load;
- The new load sites have the characteristic of an extremely low number of employees per site, and therefore have a peak load impact out of proportion to their economic impact.
- Expected growth in the next three years was already underway and contracts with the EDC, construction companies, and suppliers were in place.

PJM consulted with its economic forecast supplier to verify the claim that the new load would involve very little employment increases or other economic impact and that the forecasts of metropolitan areas within the affected zone were not adjusted to reflect the activity associated with expected construction and on-going business. Based on these findings, PJM concluded that the matter merited further review.

Adjustment Estimation – The requesting EDC provided PJM with a third-party consultant's report analyzing the expected load expansion. The report detailed how the electric load in the industry had expanded within the EDC zone and how the consultants had extrapolated that growth to estimate the amount of peak load already incorporated into the PJM load forecast. Separately, a set of four forecast scenarios were generated to estimate the total industry load in the zone's subarea, representing 1) continuation of the historical trend established in the area; 2) continuation of growth at a reduction of 15% from the historical trend established in the area; 3) continuation of growth at the average industry expectation; and 4) continuation of growth at a 45% reduction in historical trends. The estimated amount of peak load already contained in the PJM forecast was netted from each scenario forecast to derive the amount of load growth not captured in the PJM forecast.

PJM was given access to the consultants who prepared the report, and through phone and e-mail reviewed the report and supplied questions to the consultants. PJM requested and received the detailed data used to generate the report's analysis and replicated it. PJM staff then reviewed the report and forecasts with PJM management. It was decided that the scenario based on the 15% reduction from the historical trend was most likely and it was used as adjustments to the PJM forecast

Attachment D: 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 energy 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:

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

$$\text{Var}(X_t) = s_{X_t}^2 = \frac{1}{n} \sum_{i=1}^n (X_{i,t} - \bar{X}_t)^2$$

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

$$M_t = \left(\frac{Z_{\alpha/2}}{e} \right)^2 \frac{s_t^2}{\bar{X}_t^2}$$

Where

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

$$e = 0.1 = \text{error}$$

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 level 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 the 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 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 = Sample size (number of EDC accounts in B)

M_c = 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 $X_{i,t}$ 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 eLRS. 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 eLRS. 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.

Revision History

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 “eSchedules” to “InSchedules”

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.