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Working to Perfect the Flow of Energy

PJM Manual 19:

Load Forecasting and Analysis

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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 12
- 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

Attachment B: Direct Load Control Load Research Guidelines 28

Revision History 30

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 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.

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:

- eMTR 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 eMTR 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 eMTR application. For EDCs submitting all internal generation, eMTR will calculate a revenue-quality load based on submitted tie and generation meter values. 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 eMTR screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into eMTR, refer to the information posted on the PJM Website (under "eTools", select "eMTR.")]

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 eMTR 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 eSchedules.

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 eMTR will reflect each entity's total impact to the system, 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 eMTR 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 eMTR, 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 eMTR, 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.

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, holidays, minutes of daylight, and Daylight Savings Time impacts are included in the model using binary variables. Holiday seasonal lighting load is reflected using a trend variable.

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:

If WIND > 10 mph,

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

If WIND ≤ 10 mph,

$$WWP = DB$$

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

WWP = Wind speed adjusted dry bulb temperature;

DB = Dry bulb temperature (^oF).

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

If DB ≥ 58,

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

If DB < 58,

$$THI = DB$$

Where: THI = Temperature humidity index;

DB = Dry bulb temperature (^oF);

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

For shoulder months (March, April, May, September, 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 a large, sudden shift in load, 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, relative to the zone‘s metered peak, large enough to make a discernable 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. The weather distributions are developed using observed historical weather data. 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 equal the amount of DR cleared in Reliability Pricing Model (RPM) auctions. The value cleared in the last auction is held constant for the remainder of the forecast.

For winter Load Management, only estimates of non-weather sensitive (Contractually Interruptible) DR and ILR are used.

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

Variable Name	Type or Formula	Description
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

Variable Name	Type or Formula	Description
NightHDD	Max(50 - NightWWP[1],0)	Night heating degree days
MornHDD	Max(55 - MornWWP[2],0)	Morning heating degree days
AfterHDD	Max(62 - AftWWP[3],0)	Afternoon heating degree days
EvenHDD	Max(55 - EvenWWP[4],0)	Evening heating degree days
NightCDD	Max(NightTHI[5] - 60,0)	Night cooling degree days
MornCDD	Max(MornTHI[6] - 65,0)	Morning cooling degree days
AfterCDD	Max(AftTHI[7]- 72,0)	Afternoon cooling degree days
EvenCDD	Max(EvenTHI[8]- 65,0)	Evening time cooling degree days
WkEndCDD	WkEnd[9] * CDD[10]	Weekend cooling degree days
WkEndHDD	WkEnd[9] * HDD[11]	Weekend heating degree days
ColdWind	Min(Max(60 - AftTHI[7],0) /20,1) * AvgWind[12]	Wind speed index on cold days
HotWind	Min(Max(AftTHI[7] - 60,0) /15,1) * AvgWind[12]	Wind speed index on hot days
LagHDD	IF (month ≤ 5 or month ≥ 10) THEN .75 * Lag(HDD[11], 1) + .25 * Lag(HDD, 2) ELSE 0	Lagged heating degree days
LagCDD	IF (month ≥ 6 & month ≤ 9) THEN .75 * Lag(CDD[10], 1)+.25*Lag(CDD,2) ELSE 0	Lagged cooling degree days
FuzzyHum	Min(Max(AvgTmp[13]- 60,0) /15,1) * 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	Max(AvgTmp-65,0)	Cooling degree days
11 HDD	Max(60 - 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 ≥ 6 & month ≤ 9) For cooling months, use MaxTHI THEN MaxTHI[15] ELSE 0
W_WWP	IF (month ≤ 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 AvgTmp[13] ELSE 0

Intermediate Calculations:

15 MaxTHI Maximum THI over 24 hours

16 MinWWP Minimum WWP over 24 hours

Economic Data

Variable Name	Type or Formula	Description
DailyEconIndex	Convstock(EconIndex)	Economic index quarterly values converted to daily

$$EconIndex = ResWt \ x \ (HH_{y,m}/HH_{base})^{0.47} \ x \ (Pop_{y,m}/Pop_{base})^{026} \ x \ (PInc_{y,m}/PInc_{base})^{027}$$
$$+ ComWt \ x \ (NMEmp_{y,m}/NMEmp_{base})^{0.47} \ x \ (GDP_{y,m}/GDP_{base})^{020} \ x \ (GMP_{y,m}/GMP_{base})^{016} \ x \ (Pop_{y,m}/Pop_{base})^{017}$$
$$+ IndWt \ x \ (GDP_{y,m}/GDP_{base})^{047} \ x \ (GMP_{y,m}/GMP_{base})^{053}$$

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

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
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
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 eMTR, 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 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 program either as a Load Management resource (Demand Resource and Interruptible Load for Reliability) or an Emergency – Energy Only resource.

2. Voltage Reductions implemented by PJM or an EDC

3. Significant losses of load.

PJM is responsible for producing Load Management/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.

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, Interruptible Load for Reliability, 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 (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 CSP-Initiated Test***	***Economic***	***EDC- or CSP-Initiated***
Program Registration	***DR / ILR***	***Load Drop Estimates must be produced for any interruptions from June 1 through September 30. Load drop is capped at the nominated DR/ILR amount.***	***Load Drop Estimates must be produced for any settled interruptions from June 1 through September 30. Load drop is capped at the nominated DR/ILR amount.***	***No Load Drop Estimates required.***
	Emergency Energy Only	***Load Drop Estimates must be produced for any interruptions during Emergency hours from June 1 through September 30.***	***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.***

Non-Interval Metered Customers Including Direct Load Control

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 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.

Contractually Interruptible

The estimated load drop for Firm Service Level and Guaranteed Load Drop customers is calculated as follows:

- If there is an event and the metered load (MW) * Loss Factor is less than or equal to the current PLC, then the addback which will be used in the determination of the subsequent delivery year‘s retail PLC and the determination of the unrestricted peak load is the lesser of:
    - the nominated Load Management (MW) on the existing emergency registration or

- the current delivery year PLC (MW) minus the metered load (MW) * Loss Factor.

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 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 event day selected by the CSP which best represents what the load level would have been absent the 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 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 event or test day and must comply with the provisions contained in the PJM Manuals.

Missing Data

If an end use customer meter malfunctions during a Load Management test, retest or 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 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, retest or 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: Direct Load Control Load Research Guidelines

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

Curtailment Service Providers with 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. 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

DLC load research 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%.

Utilizing the Deemed Savings Estimates

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

Eligibility

Load Management Providers with 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

All Providers utilizing the modeled base per-participant impacts must submit to PJM a switch operability rate study, reflecting the percentage of all active switches which both receive the control signal and operate. This study must be designed to achieve a minimum accuracy of 90% Confidence with 10% error. Any Provider without a switch operability study, or with one older than five years will be given a switch operability rate of 50%.

Revision History

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 eMTR 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.