



Ohio Choice Market Settlement Policies & Procedures

Revised 1/2017

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AEP Ohio Glossary of Settlement Acronyms

Source of acronyms are noted in parenthesis. Those not noted are considered standard industry terms.

AEPCH	AEP Clearing House (AEP)
BTCR	Basic Transmission Cost Recovery Rider (AEP)
CP	Coincident Peak
CRES	Competitive Retail Electric Supplier (Ohio Market)
CSP	Curtailement Service Provider
DOPLSR	Daily Obligation Peak Load Scaling Factor (PJM)
DR	Demand Response
DZF	Daily Zonal Scaling Factor (PJM)
EDC	Electric Distribution Company
EDI	Electronic Data Interchange
EDU	Electric Distribution Utility
FSL	Firm Service Load
FPR	Forecast Pool Requirement (PJM)
FZSF	Final Zonal Scaling Factor (PJM)
LRA	Load Research and Analysis
LMP	Locational Marginal Price (PJM)
LASOR	Load Accounting System of Record (AEP)
LDC	Local Distribution Company
LEERS	Load Estimation and Reallocation System (AEP)
LSE	Load Service Entity (PJM)
MACSS	Marketing Accounting and Customer Services System (AEP)
MV90	Multi-Vendor Version 90 (Interval meter interrogation software by Itron)
NEMS	Net Energy Metering Service
NITS	Network Integration Transmission Services (PJM)
NSPL	Network Service Peak Load (PJM)

PIPP	Percentage of Income Payment Plan (Ohio Market)
PLC	Peak Load Contribution (PJM)
RPM	Reliability Pricing Model (PJM)
RTO	Regional Transmission Organization
SAS	Statistical Analysis System (business analytics software tool)
SDI	Service Delivery Identifier (AEP)
SOX	Sarbanes-Oxley
SSO	Standard Service Offer (default rate) (Ohio Market)
UFE	Unaccounted For Energy
WNF	Weather Normalization Factor (PJM)

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AEP Ohio CRES Capacity Obligation Calculation Process

Overview Individual Service Delivery Identifier (SDI) capacity tags (also referred to as PLC tags) are calculated annually for each SDI in the AEP Ohio territory based upon the five PJM Peak date/times (PLC hours) published by PJM. For SDIs which are interval metered, the actual hourly usage at those five hours is averaged to determine the at-the-meter PLC component. For non-interval metered customers, their at-the-meter PLC component is calculated using load profile customer class load shapes.

Load Profiling Cumulative Metered SDIs For SDIs which are not interval metered only total usage and maximum demand over the billing cycle may be known, so the at-the-meter usage at the five PLC hours must be estimated. This estimation is accomplished by performing a load profiling process. In the load profiling process, each SDI is assigned a load_profile_id defining the load characteristic group to which it belongs. Each load_profile_id has an associated hourly load profile, normally computed from actual interval metered usage of randomly selected sample customers within each profile_id group. The PLC tag calculation algorithm then utilizes the individual SDI monthly billing cycle usage spanning each PLC date/time to scale the hourly profile usage over that time to the appropriate level for the SDI, thus providing a reasonable representation of the hourly usage of each SDI. Once that is accomplished for all hours throughout the billing cycle periods spanning the five PLC date/times, the resulting hourly usage estimates at the five PLC hours are averaged to determine the at-the meter PLC component.

**PJM
Demand
Response
Add-Backs**

If a customer has a PJM interruptible component to their load and was interrupted as a result of the program on one or more of the PLC hours, the best estimate of the amount of load interrupted is added back to the interval data to provide the best estimate of normal uninterrupted PLC values. Add backs are only calculated for customers that participate in a PJM program, and curtail during one of the five PLC hours.

Customers that participate in other non-PJM Curtailment Service Provider demand response programs, AEP Ohio system emergency curtailments, or intentionally curtail on their own for operational reasons are not included in the add-back process.

For example, if ‘ABC’ customer has an estimated base-line load of 110 MW during the PJM peak hour, with a firm service level of 10 MW, and curtails pursuant to a PJM program event to 10 MW, AEP Ohio would report 110 MW if the hour were one of PJM’s 5CP hours. However, if under the same scenario, the company curtails on their own, curtails in response to an AEP Ohio system emergency, or curtails under a non-PJM program, AEP Ohio would report 10 MW if the hour were one of PJM’s 5CP hours.

***Disclaimer:** Although AEP Ohio makes a good faith effort to document policy and procedures as comprehensively as possible within this document, there may be unforeseen SDI-level special circumstances that arise and are evaluated on a case-by-case basis that could result in the requirement of an add-back, including but not limited to power outages, metering errors or changes in PJM policy.*

**Net
Metered
Customers**

Customers on a net-metered (NEMS) tariff receive benefit from their generation in the PLC tag calculation process. For NEMS customers with hourly interval metering, any generation they may have had at the time of the PLC peak hours offsets their load (up to zero) for those hours. For non-hourly metered cumulative usage customers, their generation for each month is deducted from their usage, which decreases their cumulative usage at-the-meter amounts for the month. The reduced cumulative usage then follows the Load Profile process above.

**Loss
Adjustment
to At-The-
Meter
Values**

All at-the-meter values are then loss adjusted to the generation level based upon loss factors as filed in the Company tariffs. A check is performed to ensure that the sum of all loss adjusted SDI tags compares closely to the interruption adjusted AEP Ohio system load at the 5 CP hours providing evidence that the capacity tags in total reasonably represent the system total load.

**Completion
and
Availability
to Market
Participants**

The individual SDI capacity tags are then stored for use in the daily CRES capacity obligation calculations, are made available to CRES suppliers via the Business Partner Portal and customer enrollment list, and sent via EDI transactions to the customer's assigned CRES. Capacity tags become effective June 1st of every year and the Business Partner Portal will show effective dates where multiple year tags are available. Tags remain unchanged until the next PJM year calculation is performed, even though some SDIs may experience significant load growth or load reduction in the period between the five hours on which the tag is based and the load days to which it is applied.

CRES Capacity Aggregation and Weather Normalization Factor CRES daily capacity obligations are computed from the summation of the capacity tags for each of the SDIs for which the CRES has responsibility for that day. The appropriate PJM-provided forecast/weather adjustment factor is applied to the sum, which ensures all AEP Ohio weather normalized capacity is allocated among the AEP Ohio PJM zone customers.

New Premise Installs During the Year There are normally a limited number of new SDIs that were either not active during the five PJM PLC hours, or are installed during the year, and which therefore had no interval usage or monthly billing usage for that period. Those SDIs are assigned a default PLC tag, based upon the profile group average value. In the rare instance when new facilities are built for an existing premise resulting in an additional SDI, but with no expected net load change at the combined facilities, the new SDI will receive a tag equivalent to the estimated portion of load delivered through the new service point, rather than a class average. The tag for the original SDI will be accordingly adjusted downward so that the combined capacity tags will match the original load. New SDIs with behind-the-meter generation or on a NEMS tariff will be assigned a default PLC.

Section continued on next page

Example of Calculation and Aggregation

		Capacity Calculation and Settlement Steps	Value
Calculate Variables	pjm	Each year PJM Identifies the Five Coincident (5CP) Summer Peaks	
		PJM Identifies the EDU Zone Weather Normalized Coincident Peak (e.g. 2016 Peak year)	22,320 MW
Calculate Variables	pjm	AEP periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.0932 Primary - 1.0552 Sub-Tran - 1.0341
		AEP calculates the weather normalization factor (WNF)	1.022
Calculate Yearly Customer PLCs	AEP	AEP identifies and averages the 5CP at-the-meter hourly loads for 'XYZ' customer (customers without hourly metering are profiled using sample customer hourly data)	90 MW
		Where necessary, AEP calculates "add-backs" for customers that participated in a PJM demand response event during one or more of the 5CP hours.	100 MW
		AEP applies transmission and distribution losses to the metered 5CP values to arrive at 'XYZ' Customer' PLC. (e.g. a Sub-Tran customer value of 1.0341)	103.41 MW
		AEP publishes PLC values via EDI, the customer enrollment list, and the Business Partner Portal	103.41 MW
Daily Settlement	pjm	'ABC' CRES' daily customer PLC tags are aggregated	500 MW
		WNF is applied to 'ABC' CRES' tag allotment (WNF = 1.0218)	510 MW
		'ABC' CRES' daily obligation is submitted to PJM	510 MW
	pjm	PJM applies Forecast Pool Requirement (FPR)	515 MW*
		PJM applies Daily Zonal RPM Scaling Factor (DZF)	515 MW*
		PJM applies Final Zonal Scaling Factor (FZSF)	520 MW*
		PJM applies the daily RPM rate to 'ABC' CRESs capacity obligation	\$2.1M*

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AEP Ohio CRES Transmission Obligation Calculation Process

Overview Individual Service Delivery Identifier (SDI) transmission tags (also referred to as NSPL tags) are calculated annually for each SDI in the AEP Ohio territory based upon the PJM published date and time of the PJM AEP Zonal maximum demand from the previous November 1 to October 31 year. For SDIs which are interval metered, the actual hourly usage at that hour provides the at-the-meter NSPL tag component. For non-interval metered customers, their at-the-meter NSPL component is calculated using load profile customer class load shapes.

Load Profiling Cumulative Metered SDIs For SDIs which are not interval metered only total usage and maximum demand over the billing cycle may be known, so the at-the-meter usage at the NSPL hour must be estimated. This estimation is accomplished by performing a load profiling process. In the load profiling process, each SDI is assigned a load_profile_id defining the load characteristic group to which it belongs. Each load_profile_id has an associated hourly load profile, computed from actual interval metered usage of randomly selected sample customers within each profile_id group. The NSPL tag calculation algorithm then utilizes the individual SDI monthly billing cycle usage spanning the NSPL date/time to scale the hourly profile usage over that time to the appropriate level for the SDI, thus providing a reasonable representation of the hourly usage of each SDI. Once that is accomplished for all hours throughout the billing cycle periods spanning the NSPL date/time, the resulting hourly usage estimates at the NSPL time determines the at-the-meter NSPL component.

Net Metered Customers Customers on a net-metered (NEMS) tariff receive benefit from their generation in the NSPL tag calculation process. For NEMS customers with hourly interval metering, any generation they may have had at the time of the peak hour offsets their load (up to zero) for the hour. For non-hourly metered cumulative usage customers, their generation for each month is deducted from their usage, which decreases their cumulative usage at-the-meter amounts for the month. The reduced cumulative usage then follows the Load Profile process above.

Loss Adjustment to At-The-Meter Values All at-the-meter values are then loss adjusted to the generation level based upon loss factors listed in the Company Tariffs. A check is performed to ensure that the sum of all loss adjusted SDI tags compares closely to the AEP Ohio system load at the NSPL peak hour providing evidence that the tags in total reasonably represent the system total load.

Completion and Availability to Market Participants The individual SDI tags are then stored for use in the daily CRES NSPL obligation calculations, made available to CRES Providers via the Business Partner Portal and customer enrollment list, and sent via EDI transactions to the customer's assigned CRES. NSPL tags become effective January 1st of every year and the Business Partner Portal will show effective dates where multiple year tags are available. Tags remain unchanged until the next calendar year calculation is performed, even though some SDIs may experience significant load growth or load reduction in the period between the period upon which the tag is based and the days to which it is applied.

**New Premise
Installs
During the
Year**

There are normally a limited number of new SDIs that were either not active during the NSPL peak hour, or are installed during the year, and which therefore had no interval usage or monthly billing usage for that period. Those SDIs are assigned a default tag, based upon the profile group average value. In the rare instance when new facilities are built for an existing premise resulting in an additional SDI, but with no expected net load change at the combined facilities, the new SDI will receive a tag equivalent to the estimated portion of load delivered through the new service point, rather than a class average. The tag for the original SDI will be accordingly adjusted downward so that the combined transmission tags will match the original load. New SDIs with behind-the-meter generation or on a NEMS tariff will be assigned a default NSPL value.

**CRES NSPL
Aggregation**

CRES daily NSPL obligations are then calculated from the summation of the tags for each of the SDIs for which the CRES has responsibility on the day, with a calibration factor applied by PJM to ensure that the total AEP Ohio load is fully allocated among the AEP Ohio SDIs.

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Example of Calculation and Aggregation

		NSPL Calculation and Settlement Steps	Value
Calculate Variables	pjm	AEP periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.0932 Primary - 1.0552 Sub-Tran - 1.0341
		Each year PJM Identifies the Coincident (1CP) Peak	
Calculate Yearly Customer Tags	AEP	AEP identifies the 1CP at-the-meter hour load for 'XYZ' customer (customers with-out hourly metering are profiled using sample customer hourly data)	100 MW
		AEP applies transmission and distribution losses to the metered 1CP value to arrive at 'XYZ' Customer's NSPL tag. (e.g. a Sub-Tran customer value of 1.0341)	103.41 MW
		AEP publishes NSPL values via EDI, the customer enrollment list, and the Business Partner Portal	103.41 MW
		'ABC' CRES' daily customer NSPL tags are aggregated	500 MW
Daily Settlement	pjm	'ABC' CRES' daily NSPL obligation is submitted to PJM	500 MW
		PJM applies Daily Zonal Scaling Factor	500.1 MW*
		PJM uses the aggregated NSPL values to calculate appropriate Transmission Charges and Credits for the CRES	\$750k*
		PJM posts the CRES Charges and Credits to the CRES' PJM sub-account.	\$750k*
		PJM performs a bill-line item transfer for select transmission charges and credits which AEP Ohio is responsible for, transferring to AEP Ohio's PJM sub-account.	\$0*
Wires Charge	AEP	AEP Ohio bills customers for transmission under the Basic Transmission Cost Recovery Rider (BTCR).	\$750k*

** Values are for demonstration purposes only*

Weather Normalization Factor Calculation and Application Process

Background Each year AEP Ohio calculates the Weather Normalization Factor (WNF) used to adjust the aggregation of daily LSE capacity obligations for year-to-year changes due to weather or load growth within the zone. PJM places the responsibility of allocating this adjustment with the Electric Distribution Company (EDC).

“To account for the load growth from a prior-year summer to each Delivery Year, PJM determines Zonal Weather Normalized Summer Peaks by October 31 prior to the start of the Delivery Year.”

“The process used by the EDC to determine these Peak Load Contributions is based on rules negotiated with its regulators.”

Reference PJM Manual 18 – PJM Capacity Market

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Calculation Overview

The Weather Normalization Factor (WNF) calculation is the ratio of PJM’s Summer Weather Normalized RTO Coincident Peak (MW), and the average of the EDC’s five coincident peaks (5CP). The yearly calculation variables are usually available in October each year and available on PJM’s website at:

www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx

Home » Planning » Resource Adequacy Planning » Load Forecast Development Process

Load Forecast Development Process

The processes for development and implementation of the PJM Forecasts are maintained in this section along with [Manual 19: Load Forecasting and Analysis \(PDF\)](#). The normalized peak and allocations for the past several planning periods are also maintained here along with the current Load Forecast Report, PJM Entity Forecast and Load Management historical data.

Forecasts & Reports

	Date
5CPs and W/N Zonal Peaks PDF	Summer 2016
Load Forecast Update - July 2016 XLS	6.23.2016
2016 Load Forecasting Whitepaper	4.27.2016
2016 Load Forecast: Report PDF Data XLS	12.30.2015
5CPs and W/N Zonal Peaks PDF	Summer 2015
Previous Load Forecast Reports	

Supplemental Materials

	Date
2016 Statistical Appendix XLS	12.30.2015
2016 Economic Variable Data XLS	12.30.2015
2016 Distributed Solar Forecast Data XLS	12.30.2015
2015 Heating and Cooling Index Data XLS	12.30.2015
2015 Other Index Data XLS	12.30.2015
Weather Normalized Peaks XLS	12.30.2015
Hourly Unrestricted Load 1998-2015 XLS	12.30.2015

RELATED INFORMATION

- [Manuals](#)
- [Compliance](#)
- [Transmission Expansion Advisory Committee](#)
- [Regional Planning Process Task Force](#)
- [2012 Regional Transmission Expansion Plan Report](#)

RECENT DOCUMENTS

- [Zonal Weather Standards for Weather-Sensitive EE Demand Reductions](#) [PDF](#)
2016 Posted 21 days ago
- [PJM Peak Hour History](#) [PDF](#)
2016 Posted 25 days ago

CONTACT INFORMATION

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PJM Interconnection

Summer 2016 Weather Normalized RTO Coincident Peaks (MW)

Zone	Peak
AE	2,460
AEP	22,320
APS	8,440
ATSI	12,660
BGE	6,330
COMED	20,560
DAYTON	3,270
DEOK	5,020
DLC _o	2,750
DOM	18,450

PJM INTERCONNECTION Summer 2016 - Coincident Peaks, By Zone (MW)

Date Hour End (EPT)	8/11/2016 16:00	7/25/2016 16:00	8/12/2016 16:00	7/27/2016 17:00	8/10/2016 17:00
AE	2,486.5	2,489.6	2,595.4	2,313.3	2,418.2
AEP	22,473.9	22,276.7	22,184.5	21,046.6	21,239.4
APS	8,652.3	8,485.6	8,542.5	8,215.3	8,261.1
ATSI	12,528.8	12,009.5	12,493.2	11,945.2	11,983.3
BGE	6,529.2	6,869.7	6,501.1	6,180.4	6,163.8
COMED	21,186.7	18,832.1	16,459.0	19,626.7	20,030.8
DAYTON	3,265.0	3,313.0	3,174.0	3,256.0	2,972.0
DEOK	5,099.1	5,238.0	5,029.0	4,953.1	4,769.3
DLC _o	2,794.0	2,640.8	2,601.7	2,650.4	2,608.1
DOM	18,408.5	19,533.2	18,812.7	18,668.4	18,013.4
DPL	3,852.2	4,066.1	3,964.8	3,752.6	3,658.3
EKPC	1,882.0	1,936.8	1,903.2	1,914.0	2,025.7
JCPL	5,750.9	5,711.4	5,954.8	5,288.7	5,042.6

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**'17-'18
Delivery
Year WNF
Calculation**

$$\text{WNF} = \frac{\text{(Zone Weather Normalized Coincident Peak)}}{\text{(Average of Zone Five Coincident Peaks)}}$$

$$\text{'17/'18 WNF} = \frac{22,320}{((22,473.9 + 22,276.7 + 22,184.5 + 21,046.6 + 21,239.4)/5)}$$

$$\text{'17/'18 WNF} = 1.0218 \text{ or } 2.18\%$$

Application AEP Ohio applies the WNF to each supplier's daily aggregated SDI PLC capacity tag obligations prior to submitting to PJM daily. This methodology allows published SDI capacity tags to accurately reflect voltage loss adjusted metered peak values, but supports more accurate and reliable demand response processes. Specifically, each SDI published capacity tag value (without WNF applied) accurately reflects the amount of demand response potential and does not over or under represent their DR potential in the market.

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Example Application of Weather Normalization Factor

		Daily Process Steps	Value
AEP		ABC CRES' daily customer tags are aggregated	500 MW
		WNF is applied to ABC CRES' tag allotment	510 MW
		ABC CRES' daily obligation is submitted to PJM	510 MW
pjm		PJM applies Forecast Pool Requirement (FPR)	515 MW*
		PJM applies Daily Zonal RPM Scaling Factor (DZF)	515 MW*
		PJM applies Final Zonal Scaling Factor (FZSF)	520 MW*
		PJM applies the daily RPM rate to CRES capacity obligation	\$2,132,000*

*Values for demonstration purposes only.

AEP Ohio CRES Hourly Energy Calculation Process

Overview Ohio rules place the responsibility for calculation of Competitive Retail Electric Service (CRES) Provider load obligations for settlement on the local distribution company. Also, as AEP Ohio is in the PJM control area, compliance with PJM procedures is necessary. The PJM energy market is an hourly market with associated bids and hourly spot market prices. Each CRES Provider is a Load Serving Entity (LSE) in the market for which the hourly energy obligation must be calculated, as it is not separately metered on the PJM power grid. This calculation is performed by AEP Ohio using automated systems which develop an hourly load estimate for each Service Delivery Identifier (SDI) and aggregates the hourly SDI usage to each CRES for the SDIs served by the CRES during each load day.

AEP Ohio's role in settlement is to provide PJM with the hourly energy supply obligation for the sum of all SDIs served for each CRES. On a daily basis, AEP submits to PJM an initial settlement of each LSE's hourly energy supply obligation from the previous day (known as the "day-after settlement" or "Settlement A") in the AEP zone. These initial values are largely comprised of estimates based upon historical SDI usage, historical load profiles, historical weather, forecasted weather on the load day, and a load obligation share of system Unaccounted For Energy (UFE).

After all meter reading schedules are completed for the month, AEP re-calculates each LSE's hourly energy usage for each day in the month using actual period meter

readings, actual period interval data, actual period load profiles from load research samples, net metered customer generation values, and actual period system UFE. AEP then submits hourly energy differences between the initial and revised loads for each LSE to PJM through the InSchedule (formerly eSchedule) system. This true-up is known as the "60-day settlement" or "Settlement B". Data submitted to PJM is available to electricity suppliers through PJM's systems.

**CRES
Hourly
Energy
Obligation
Calculation**

Most retail SDIs do not have meters capable of registering energy usage on an hourly basis. To enable these SDIs to participate in electric customer choice, a process known as "load profiling" is used to estimate the SDI hourly energy. At the time each bill is processed, the usage for each SDI is transferred from AEP's Customer Information System to the market settlement system, which then disaggregates this total usage through the load profiling process. For SDIs which do have meters which register usage on an hourly basis, the actual interval usage is transferred to the market settlement system and load profiling is not necessary. The market settlement process runs for every SDI in AEP Ohio whether or not the SDI is a shopping customer.

**PJM
Settlement
"A"**

For the initial day-after settlement process, the load estimate process is performed during the load day itself, or on the last business day prior to weekends and holidays. Forecasted hourly temperatures for the days to be estimated are compared to the hourly temperatures from similar day-type days in a specified historical time period (the latest 15 months) and the load profiles from the most similar historical day are used as a proxy for the load day and applied to the current load day. For

each SDI in AEP Ohio, a usage scale factor is developed which relates the load level of that SDI to the load profile load level. The estimate of that SDI's load on each hour of a load day is then computed by multiplying the load profile hourly load by the SDI usage scale factor. For SDIs which do have an interval meter, the estimate of the hourly load is derived straight from the SDI's hourly load on the selected historical proxy load day. Resulting hourly load estimates are then loss adjusted to represent generation level rather than meter level loads, and are aggregated by CRES and by remaining AEP Ohio default load. Each day UFE is calculated by hour, which is the hourly difference between the total aggregation of all CRES and Standard Service Offer (SSO) estimates, and the day-after actual system "top down" hourly load. Hourly UFE values can be positive or negative, and assure all energy used on the load day is captured in the market settlement process and shared proportionally (by load share) with all CRES and SSO tranche providers. Like CRES energy obligations, the UFE is trued-up at time of 60-day Settlement "B."

**PJM
Settlement
"B"**

Approximately 45 days after the end of a calendar month, the 60-day settlement calculation process begins. The electricity supplier hourly load obligations are re-calculated using the same processing steps used to derive the original CRES values, but now all actual metered load data subsequently collected is utilized. As a result of the data collection and subsequent reprocessing:

- The hourly profiles for non-interval metered SDIs are now based on dynamic load profiles for the actual days of the settlement period, instead of on weather proxy day static load profiles.

- The actual load data for interval metered SDIs is now available to replace the estimated data used in the day-after settlement.
- The meter reading cycle is completed for the month to be settled, so the hourly load profiles of all SDIs can be scaled to match known metered usage spanning each day of the month.
- AEP Ohio's zonal hourly load is now known from actual metered values.

The CRES and default hourly load obligations are reconciled to AEP Ohio's zonal hourly load, by proportionally adding back any differences between the SDI-by-SDI analysis results and the AEP Ohio zonal load determined from generation and system interchange metering. The aggregation of all CRES and SSO load is then compared to the final hourly AEP zonal “top down” load and the final UFE calculation is performed and used to proportionally true-up the initial Settlement “A” allocation by load share to all LSEs.

**Net Metered
Customer
Generation**

Customers on a net-metered (NEMS) tariff are metered through the month using either hourly interval metering or cumulative monthly metering, depending upon the size of the customer load. After cycle bill usage calculations are performed through the month, the net-negative generation by customer is calculated, and then used to offset the aggregated load obligations for their assigned CRES in two different ways based upon the two types of metering.

- For NEMS customers with hourly interval metering, any hourly net-negative generation amount is applied as a credit for the assigned CRES aggregated settlement amount.

- For NEMS customers with non-hourly interval metering (monthly cumulative), the customer's generation offsets the load requirement for the assigned CRES up to zero. The resulting load obligation then follows the standard load profile process to establish hourly settlement values up to zero.

Unaccounted For Energy Calculation

Unaccounted for Energy (UFE) for zonal load reconciliation is determined and applied by the Company prior to submission of both the daily initial settlement obligations, and the 60-day true-up energy obligations to PJM. Final 60-day true-up hourly UFE factors are posted to the Company website within three business days after load obligations are delivered to PJM.

UFE is computed for each respective hour by comparing the aggregate load estimates for all CRES Providers and the Company Standard Service Offer (SSO) Retail Customers at the generation level (including losses) to the Ohio Power Company zonal load determined from system interchange metering less non-retail load. The difference is then proportionally allocated based upon the ratio of each CRES Provider's load to the total load of the CRES Providers and the Company SSO load. Hourly UFE values may be either positive or negative.

The algorithms used for UFE calculation and application are as follows:

$$\begin{aligned}
 \text{UFE}_{\text{Hourly}} &= \text{Company_Zonal_Load}_{\text{Hourly}} - \text{Sum}(\text{CRES_LOAD}_{\text{Hourly}} + \text{SSO_LOAD}_{\text{Hourly}}) \\
 \text{UFE_FACTOR}_{\text{Hourly}} &= 1 + (\text{UFE}_{\text{Hourly}} / \text{Sum}(\text{CRES_LOAD}_{\text{Hourly}} + \text{SSO_LOAD}_{\text{Hourly}})) \\
 \text{CRES_LOAD_OBLIGATION}_{\text{Hourly}} &= \text{CRES_LOAD}_{\text{Hourly}} \times \text{UFE_FACTOR}_{\text{Hourly}}
 \end{aligned}$$

Example Settlement "A"

		PJM Settlement "A" - Initial Settlement	Value
Calculate Variables		AEP periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.0932 Primary - 1.0552 Sub-Tran - 1.0341
		Customer load profiles are derived for different customer usage classes, calculated from sample customer data with hourly metering, and assigned to each SDI.	
Usage Forecast and Aggregation	AEP	Customer historical usage is stored. For customers without hourly metering, profiled hourly usage is created from customer class profile IDs.	
		Weather forecast data and historical usage are used to select a proxy day hourly usage for the daily load estimate.	
		Example: 'XYZ' customer's estimated hourly load for the initial settlement day.	100 kwh/day
		AEP applies system losses to the energy forecast based upon premise voltage delivery level. (e.g. a Primary customer value of 1.0552)	105 kwh/day
		Sum of 'ABC' CRES' assigned customer's forecasted usage is aggregated by hour.	200,000 kwh/day*
		AEP calculates unaccounted for energy (UFE), representing the difference between total actual system load and aggregation of all LSE load estimates. Each LSE receives a load-share equivalent UFE factor, which can be positive or negative.	202,000 kwh/day*
		AEP submits 'ABC CRES' forecasted settlement A to PJM via InSchedule.	202,000 kwh/day*
Settlement "A"	pjm	PJM applies a deration factor to calculate energy and transmission costs separately	195,900 kwh/day*
		PJM applies initial hourly LMP values to energy = Settlement A	\$1M*

* Values are for demonstration purposes

Example Settlement "B"

		PJM Settlement "B" - Final 60 Day Settlement	Value
Calculate Usage		AEP reads meters for all customers during the revenue month, and calculates final metered usage.	
		For customers without hourly metering, profiled hourly usage is created from customer class profile id.	
Usage True-up and Aggregation	AEP	AEP aggregates by hour the sum of the usage, with losses, for 'ABC' CRES' assigned customers for the settlement month, to arrive at their actual final usage.	6,067 MWH/month
		AEP calculates all distributed generation (net metering) customer values for the customers net-negative values (excess generation on to the grid). A credit is calculated by hour for the assigned CRES for all of their assigned customers. (e.g. 100,000 kwh credit)	5,967 MWH/month
		AEP calculates final unaccounted for energy (UFE), representing the difference between total actual hourly system load for the settlement month and aggregation of all LSE metered loads. Each LSE receives a load-share equivalent UFE factor, which can be positive or negative. (e.g. average hourly UFE of +0.06%)	5,970.6 MWH/month
		AEP calculates (by hour) the hourly variance between the initial settlement submitted to PJM, and final values, arriving at the final 60 day settlement true-up values for each CRES.	10.5 MWH/month*
		AEP submits 'ABC' CRES' final settlement B true-up to PJM.	10.5 MWH/month*
Settlement "B"	pjm	PJM applies a deration factor to calculate energy and transmission costs separately	10.17 MWH/month*
		PJM applies final hourly LMP values to energy = Settlement B	\$305.10*

* Values are for demonstration purposes