

PJM Manual 15:

Cost Development Guidelines

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Prepared By
Cost Development Subcommittee

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Performance Compliance Department

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- Periodic Review

Section 1: Introduction

1.1 About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of PJM and the PJM Markets.

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

1.2 How to Use This Manual

The **PJM Manual 15: Cost Development Guidelines** is one in a series of the PJM Manuals. This Manual is maintained by the [PJM Cost Development Subcommittee \(CDS\)](#) under the auspices of the PJM Market and Reliability Committee (MRC).

To use this Manual, read sections one and two then go to the chapter for unit type for possible additional information.

All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (PJM Operating Agreement), PJM Open Access Transmission Tariff (PJM Tariff) or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region. Throughout this manual, the term MMBtu is one million British Thermal Units (BTU).

1.3 The intended audiences for this Manual:

- Market Seller
- PJM staff
- MMU
- Regulators

1.4 What is 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 Market Seller actions
- Attachments

1.5 Cost Development Subcommittee Mission

The CDS reports to the MIC and is responsible for developing, reviewing, and recommending procedures for calculating the costs of products or services provided to PJM at a cost-based rate for Market Sellers. CDS responsibilities can be found in the CDS' [charter](#).

1.6 Purpose of this Manual

This document details the standards recognized by PJM for determining cost components for markets where products or services are provided to PJM at cost-based rates, as referenced in Schedule 1, Section 6 of the PJM Operating Agreement.

1.6.1 Reason for Cost Based Offers: Market Power Mitigation

The following material is provided for background and should be used for information only. Structural market power is the ability of seller, or a group of sellers, to alter the market price of a good or service for a sustained period. To mitigate the potential exercise of market power, market rules can offer cap units in various markets. The Three Pivotal Supplier (TPS) test is used to determine if structural market power exists in a given market. If structural market power is found to exist, some Market Sellers may be mitigated to cost-based offers to prevent any exercise of that market power.

The TPS test is a test for structural market power. The test examines the concentration of ownership of the supply compared to the level of demand. The test does not examine the competitiveness of offers or other factors.

The general concept of the TPS test is to control a constraint; a certain amount of MW of relief is needed. If there are not enough MWs to satisfy the constraint without using the top two suppliers' output plus the output of the supplier being tested, then those three suppliers are jointly pivotal. According to the criteria utilized by the TPS test, because the supply can be constrained by those three owners and the demand could potentially not be satisfied, they are considered to have structural market power. If any one supplier fails, then the top two suppliers also fail.

A test failure means that the ownership of the supply needed to meet is concentrated among few suppliers and therefore those suppliers have the potential to exercise market power or structural market power. It does not mean those suppliers are attempting to exercise market power.

A test failure triggers mitigation as a preventative step in the event of a concentration of ownership. If a generator is brought on for constraint control and its supplier fails a TPS test, then the unit is dispatched at the lower of the cost or price offer. The purpose of this Manual is to outline the development of the cost-based offer to ensure that PJM Members who own or control a generating unit(s) with structural market power cannot exercise it.

1.7 Components of Cost

This Manual is designed to instruct Market Sellers on how to develop their cost based offers. A Market Seller who is required to submit a cost-based offer for a resource shall be responsible for the development and accuracy of all information to support the calculation of a resource's cost-based offer and shall provide such information to PJM or the MMU, either directly or indirectly through an agent or other entity, upon request or as required by applicable PJM market rules. These cost-based offers are used by PJM to schedule generation in cases in which structural market power is found to exist. PJM uses the information provided from Market Sellers to determine each unit's production costs.

Production costs are the costs to operate a unit for a particular period. Several different cost components are needed to determine a generating unit's total production cost. The total production cost includes:

- Start-up Cost
- No-Load Cost
- Incremental costs (energy cost per segment of output range)

Production costs have a direct impact on which units are scheduled by PJM. In general, generation will be scheduled to achieve the lowest possible overall costs to the system.

The following material is provided for background and should be used for information only.

1.7.1 Generator offer curves

Generator offer curves are representations of a generator's willingness to provide energy. Offer curves are used in determining incremental and total production costs. An offer curve can have up to ten points defined. The first point describes the lowest MW amount offered for a unit. The offer curve may be a smooth line or a block curve depending on how the points between each segment are calculated. The Market Seller can determine how the slope of the offer curve is defined; however, the slope must be monotonically increasing.

1.7.2 Start-up Cost

It consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, maintenance adders, emissions allowances/adders, and station service power cost. Start Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold. Units without a soak process include, engines, combustion turbines, Intermittent, and Energy Storage resources.

For units with soak process: Start Cost shall mean the net unit costs from PJM's notification to to the level at which the unit can follow PJM's dispatch and from last breaker open to shutdown.

For units without soak process: Start Cost shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

See Start-up Cost in Section 2.4.

1.7.3 NoLoad Cost

No-Load Fuel (MMBtu/hour) is the total fuel to sustain zero net output MW at synchronous generator speed.

No-Load Cost (\$/hour) is the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no_load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, maintenance adders, and emissions allowances.

1.7.4 Incremental Cost

Hourly production cost is the cost per hour to operate a unit assuming a start has already occurred. It is calculated by summing all costs, which are incurred during one hour of operation including the hourly no-load cost and the incremental energy cost.

The incremental energy cost is the cost in dollars per MWh of providing an additional MWh from a synchronized unit.. It consists primarily of the cost of fuel, as determined by the unit's incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, maintenance adders, emissions allowances, tax credits, and energy market opportunity costs.

1.7.5 Total Production Cost

Total production cost is calculated by adding all of the costs associated with starting a unit and operating it over a period. Total production costs include two categories of costs: Start-up Costs and hourly production costs.

To determine the total production cost of a unit, the following formula is used:

$$\text{Total Production Cost} = \text{Startup Costs} + \sum_0^x \text{Hourly Production Costs}$$

Where x= Number of hours a unit is run at a certain MW level

It is important to remember that PJM will schedule generation day-ahead based on the above but dispatch using the incremental (marginal) cost, as represented by its generation offer. The incremental (marginal) cost will represent the cost to generate the next MW from the unit. See Heat Rate in Section 2.1, Performance Factor in Section 2.2, Performance Factors in Section 2.2, and Fuel Cost in Section 2.3, No-Load Cost in Section 2.5 and 2.6 Maintenance Cost.

1.8 Cost Methodology and Approval Process

A Market Seller which seeks to obtain an exemption, exception or change to any time frame, process, methodology, calculation or policy set forth in this Manual, or the approval of any cost or methodology that is not specifically permitted by this Manual not related to the Fuel Cost Policy, shall submit a request to PJM and MMU for consideration and determination along with documentation supporting the request.

After receipt of such a request, PJM and MMU will review the request and PJM will notify the Market Seller and MMU whether the request is approved no later than thirty (30) calendar days after submission of the request.

This process shall be referred to in this Manual as the “Cost Methodology and Approval Process.”

1.9 References

The references to other documents that provide background or additional detail directly related to the PJM Manual for **Cost Development Guidelines** are:

- PJM Manual for [Pre-Scheduling Operations \(M-10\)](#)
- PJM Manual for [Energy & Ancillary Services Market Operations \(M-11\)](#)
- PJM Manual for [Generator Operational Requirements \(M-14D\)](#)
- PJM Manual for [Open Access Transmission Tariff Accounting \(M-27\)](#)
- PJM Manual for [Operating Agreement Accounting \(M-28\)](#)
- [Markets Gateway User Guide](#)
- [Markets Database Dictionary](#)
- [Opportunity Cost Calculator](#)
- A Review of Generation Compensation and Cost Elements in the PJM Markets
- [Member Information Reporting Application \(MIRA\)](#)

Section 2: Policies for All Unit Types

This section contains information that is relevant for the development of a cost offer for all types of units.

2.1 Heat Input/Rates and Performance Factors

Heat Input equals a point on the heat input curve (in MMBtu/hr) describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh). Heat Input curves, also called input/output curves, represent the amount of fuel used to produce energy. Heat input curves are developed based on net energy production. Heat input curves can be developed using historical data, performance test data or Original Equipment Manufacturer (OEM) documentation..

Observed fuel heat input and electric output data during normal operation or a performance test provide a direct measure of the heat input curve. A linear regression of the heat input on the energy output can provide an estimated polynomial curve. In the typical case, the heat input curve is a second order polynomial that applies to the entire operating output range of the unit.

$$\text{Heat Input} \left(\frac{\text{MMBtu}}{\text{hour}} \right) = A + B * \text{Unit Output (MWh)} + C * \text{Unit Output}^2 \text{ (MWh)}$$

Where A, B, and C are the polynomial coefficients calculated through a linear regression.

When based on historical data, heat input curves must be developed using data points during times in which the resource was operating above its physical minimum level (e.g. do not include data points when the resource was in starting, soaking or shutdown mode).

The Incremental heat rate is the relationship between an additional MW of output and the heat input necessary to produce it. Graphically, the incremental heat rate can be determined from the ratio of the change in fuel input to the change in unit MW output; which is the slope of the input/output curve. Mathematically, the incremental heat rate curve can be expressed as the first derivative of the heat rate curve (input heat versus MW output).

$$\text{Incremental Heat Rate} = B + 2 * C * \text{Unit Output (MWh)}$$

Economic Minimum is the lowest level of energy in MW the unit can produce and maintain a stable level of operation under normal operation.

Economic Maximum is the highest unrestricted level of energy, in MW, that the operating company operates the unit under normal operation. This represents the highest output available from the unit for economic dispatch.

Heat Rate equals the MMBtu content of the heat input divided by the MWh of energy output. The smaller the heat rate value the greater the efficiency.

$$\text{Total Heat Rate} = \frac{\text{MMBtu}}{\text{MWh}} = \frac{\text{Heat Input}}{\text{Net MW}}$$

Performance Factor is the calculated ratio of actual fuel burn to either theoretical fuel burn (design heat input) or other current tested heat input. Actual burn may vary from standard burn due to factors such as unit age or modification, changes in fuel properties, seasonal ambient conditions, etc.

$$\text{PerformanceFactor} = \frac{\text{TotalActualFuelConsumed}}{\text{TotalTheoreticalFuelConsumed}}$$

2.1.1 Heat Input and Rate Policy

All Market Sellers shall develop Heat Input curves. These heat input curves show heat input in MMBtu/hr from burning fuel versus MW output for each of their generating units. The heat input curves then serve as the basis for the theoretical incremental heat rate curves for fuel consumption and performance factor development. A Market Seller is allowed to use either net or gross MW values in determination of the incremental heat rate curves as long as gross or net MW value consistency is maintained throughout the cost development process. Heat rate information provided to the Office of the Interconnection should be on a net MW basis.

- Heat input curves (one curve per fuel type for each operating mode) will be based on design or comparable unit data modified by actual unit test data (when available).
- Data for the heat input curve development, ideally, should include Economic Minimum and Economic Maximum MW points. The heat input curve will be fitted from available data.
- This heat input curve (or curves) will be used as the basis for incremental heat rate curves, incremental costs and performance factor calculations.

2.1.2 Heat Input and Performance Factor Update Frequency

The Performance Factor shall be calculated on either the total fuel consumed or a monthly spot check test basis. The Performance Factor for nuclear and steam units shall be reviewed (and updated if changed) at least once every twelve months. Market Sellers can choose to update the heat input curve instead of using performance factors. When that choice is made the performance factor is set to one (1). The Performance Factors for combustion turbine (“CT”), diesel units, and combined-cycle (“CC”) units shall be updated at least once during:

- Twelve months, or
- The year in which a unit reaches 1,000 accumulated running hours since its last Performance Factor update, whichever represents a longer period, not to exceed five years.

Requests for exemptions from these periods should be submitted to PJM and the MMU for evaluation pursuant to Section 2.3. The overall Performance Factor can be modified by a seasonal Performance Factor to reflect ambient conditions. Performance factors have to be calculated for the entire year, by month or by season (e.g. summer/winter). Performance factors

cannot be applied inconsistently (i.e. applied during the summer months and not during the winter months).

2.1.3 Engineering Judgment in Performance Factors

The calculated performance factor may be superseded by estimates based on sound engineering judgment. If the period during which estimated performance factors are used exceeds three months, documentation concerning reasons for the override must be maintained and available for review.

2.1.4 Higher Heating Value of Fuel

Higher Heating Value of Fuel - the amount of heat released by a specified quantity once it is combusted and the products have returned to an original temperature. Higher Heating Value (HHV) of fuel may be based on any of:

- As burned test
- In stock test
- As received test
- As shipped test
- Contract value
- Seller's invoice
- Seller's quote
- Nominal value based on Industry Standard

2.1.5 Calculation Methods of Performance Factors

There are three options available for use in determining a unit's performance factor:

1. Total Fuel
2. Separate
3. Fixed start approach

These three methods are described with their corresponding equations as follows:

Performance Factors are used in calculating start fuel as well as operating fuel. When the (1) **total fuel approach** is used, the Performance Factor would represent the ratio:

$$PerformanceFactor = \frac{TotalActualFuelConsumed}{TotalTheoreticalFuelConsumed}$$

With the total fuel approach, fuel quantities measured during start tests should be modified by the Performance Factor in effect at the time of the test so that theoretical or standard start fuel quantities will be on the same basis as the standard operating fuel quantity.

Conditions encountered during the start of certain units may make it preferable to assign separate Performance Factors for start and operating fuel. If (2) **separate Performance Factors** are calculated for start fuel prior to calculating the "operating fuel" Performance Factor, this Operating Fuel Performance Factor will represent the ratio:

$$\text{OperatingFuelPerformanceFactor} = \frac{\text{TotalActualFuelConsumed} - \text{ActualStartFuelConsumed}}{\text{TotalTheoreticalFuelConsumed} - \text{TheoreticalStartFuelConsumed}}$$

Due to the variability and difficulty in measuring actual start fuel, a Market Seller may choose to set a (3) **fixed start Performance Factor of one**, implicitly assigning all performance variations to no-load and incremental loading costs. In order to account for all fuel actually consumed, the operating fuel Performance Factor will represent the ratio:

$$\text{OperatingFuelPerformanceFactor} = \frac{\text{TotalActualFuelConsumed} - \text{TotalTheoreticalStartFuelConsumed}}{\text{TotalTheoreticalFuelConsumed} - \text{TotalTheoreticalStartFuelConsumed}}$$

Where total theoretical start fuel consumed = fuel quantity used in the Start-up Cost calculation

2.1.6 'Like' Units for Performance Factors

An average Performance Factor may be calculated and applied for groups of like units burning the same type of fuel. Please see the Generation sections for further detail of 'like' units.

2.2 Fuel Cost Policies and Guidelines (moved from Section 2.3)

A Market Seller may only submit a non-zero cost-based offer greater than the temporary cost offer methodology if it has a PJM-approved Fuel Cost Policy consistent with each fuel type on which the resource can operate in accordance with Section 2.2.1 of this manual and Operating Agreement, Schedule 2. Regulation only resources do not require a Fuel Cost Policy. The Fuel Cost Policy will be submitted in MIRA, or other system(s) made available for submission of such data. Submission to MIRA, or other system(s) made available is considered submission to PJM and the MMU. Market Sellers that offer a schedule with more than one fuel type must ensure that the portion of the offer for each fuel type is in accordance with the PJM approved Fuel Cost Policy.

2.2.1 Submission of and/or Modifications to Fuel Cost Policies

Prior to expiration of a Fuel Cost Policy, all Market Sellers will be required to either submit to PJM and the Market Monitoring Unit an updated Fuel Cost Policy that complies with this Operating Agreement, Schedule 2 and PJM Manual 15, or confirm that their expiring Fuel Cost Policy remains compliant. PJM and the Market Monitoring Unit may work with Market Sellers to extend their currently approved Fuel Cost Policy prior to expiration.

A Market Seller shall submit a new or updated Fuel Cost Policy:

- If a Market Seller has an approved Fuel Cost Policy currently in place and needs to alter it in order to conform it to the provisions of this Manual or any applicable provisions of PJM's governing documents,

- If any action by a governmental or regulatory agency external to a Market Seller results in a need for the Market Seller to change its method of fuel cost calculation,
- If there are any material changes to Fuel Cost Policy,
- If PJM requests a Market Seller to submit an updated Fuel Cost Policy, or
- If a Market Seller will be entering a non-zero cost offer for a new or existing resource without an approved policy into PJM's energy markets.

The Market Seller shall notify PJM and the MMU that an update to an existing Fuel Cost Policy or the need for a Fuel Cost Policy for a new resource is required at the earliest possible opportunity. If PJM requests the Market Seller to submit an updated Fuel Cost Policy, then the expiration of the Market Seller's current Fuel Cost Policy shall follow the process set forth in Section 2.3.1.2. The Market Seller shall provide an updated policy to PJM and the MMU:

- For new resources, following the process delineated in Operating Agreement Schedule 2 Section 2.2 (a).
- For resources transferred to another Market Seller, the new Market Seller shall submit a Fuel Cost Policy to PJM and MMU for review prior to transfer or an alternative date agreed to by PJM. The new Market Seller may use the temporary cost offer methodology described in Section 2.2.1.3 for making cost based offers, as an alternative to offering zero, while a new policy is under evaluation. Note: Changes in dispatch agent do not require submission of a new policy.
- For existing resources, the Market Seller may use the temporary cost offer methodology described in Section 2.2.1.3 for making cost-based offers, as an alternative to offering zero, while the requested update or new policy is under evaluation, in the absence of an approved Fuel Cost Policy.

2.2.1.1 PJM and MMU Review Timelines and Fuel Cost Policy Effective Date

The MMU shall have an initial 10 Business Days to review a submitted Fuel Cost Policy and an additional 5 Business Days every time the Market Seller revises the Fuel Cost Policy. At any time, the Market Seller may request:

- PJM begin its review prior to the completion of the MMU review; or
- PJM delay its review until after the completion of the MMU review.

Immediately following the MMU's review, or at the Market Seller's request for PJM to review, PJM shall have 20 Business Days to review a submitted Fuel Cost Policy and an additional 5 Business Days or an agreed upon date between PJM and the Market Seller every time the Market Seller revises the Fuel Cost Policy. If PJM rejects a Market Seller's updated Fuel Cost Policy, PJM must include an explanation for why the Fuel Cost Policy was rejected in its written notification. All approved Fuel Cost Policies will have an effective date of the next operating day following approval, or a later date as indicated by PJM in its written notification to the Market Seller and MMU. The approved policy will be in effect until superseded or expired.

2.2.1.2 Expiration of a Fuel Cost Policy

(a) PJM, in consultation with the Market Seller and with timely input and advice from the Market Monitoring Unit, may:

- i. Update the Market Seller's Fuel Cost Policy expiration date, with at least 90 days notification to the Market Seller, due to a business rule change in the PJM governing documents.
- ii. Immediately expire the Market Seller's Fuel Cost Policy with written notification to the Market Seller when a change in circumstance causes the Market Seller's fuel pricing and/or cost estimation method to be no longer consistent with the approved Fuel Cost Policy, this Operating Agreement, Schedule 2 or PJM Manual 15.

(b) If the Market Seller of a generation resource that has transferred from another Market Seller does not affirm the current approved Fuel Cost Policy on file, then such Fuel Cost Policy shall expire upon the generation resource's transfer of ownership.

(c) PJM shall notify the Market Seller and the Market Monitoring Unit in writing the updated Fuel Cost Policy expiration date and rationale for changing the expiration date.

(d) On the next business day following immediate expiration of a Fuel Cost Policy, the Market Seller may only submit a cost-based offer of zero or a cost-based offer that is consistent with the temporary cost offer methodology in Section 2.2.1.3 until a new Fuel Cost Policy is approved by PJM for the relevant resource.

(e) Market Sellers who have a Fuel Cost Policy that has been immediately expired by PJM will be provided a three (3) Business Day rebuttal period, starting from the date of expiration, to submit supporting documentation to PJM demonstrating that the expired Fuel Cost Policy accurately reflects the fuel pricing and/or estimation method documented in the previously approved Fuel Cost Policy that was expired. However, if, upon review of the Market Seller's supporting documentation, PJM determines that the expired policy accurately reflects the Market Seller's actual methodology used to develop the cost-based offer that was submitted at the time of expiration and that the Market Seller has not violated its Fuel Cost Policy, then PJM will make whole the Market Seller via uplift payments for the time period for which the applicable Fuel Cost Policy had been expired and the generation resource was mitigated to its cost-based offer.

2.2.1.3 Temporary Cost Offer Methodology

The temporary cost offer methodology is intended to serve as a temporary Fuel Cost Policy for Market Sellers negotiating a new policy with PJM in good faith for the following:

- Generation resources that initiate participation in the PJM Energy Market
- Generation resources transferring from one Market Seller to another
- If the Market Seller does not have an approved Fuel Cost Policy in place upon expiration of its previously approved policy

The temporary cost offer methodology shall be comprised of the index settle price at the PJM assigned commodity pricing point multiplied by heat input curves submitted by the Market Seller, in accordance with Section 2.1:

- For generation resources that opt-out of intraday offers, the last published closing index settle price shall be used for all hours of the Operating Day
- For generation resources that opt-in to intraday offers, index settle prices shall be based on the last published closing settle price for a 11 hours of the Operating Day to reflect the:
 - Last published closing settle price, if decreased, for hours ending 11 through 24 for natural gas
 - Last published closing settle price, if decreased, for all hours of the Operating Day for all other fuel types

The commodity pricing point and index publication source shall be assigned by PJM in consultation with the Market Seller and with timely input and advice from the IMM.

2.2.2 Fuel Cost Calculation

The method of calculation of fuel cost may be updated by the Market Seller no more frequently than once every 12 months, on a rolling basis, unless required to be changed per Section 2.2.1.

Each Market Seller must review and document its fuel costs in MIRA, or other system(s) made available for submission of such data, at minimum once per month (12 times per year). Additionally, each review must occur within forty (40) days of the preceding review. The results of this review will be used to determine whether a fuel cost update and subsequent change to the Fuel Cost Policy is necessary.

The method of calculation of fuel cost in MIRA, or other system(s) made available for submission of such data, may include the use of actual fuel prices paid, e.g. the contract price paid for fuel, or the spot price for fuel. The contract price for fuel must include the locational cost of fuel for the generating unit. The source used for spot price for fuel must be publicly available, reflect the locational cost of fuel for the generating unit, and be verifiable by PJM or the IMM after-the-fact. The locational cost of fuel shall include specification of any additional incremental costs of delivery for the generating unit.

Gas pipeline penalties are not permitted to be included with a Market Seller's cost-based offer. Gas pipeline penalties, as referenced herein, are charges that are incurred for taking unauthorized gas in violation of an interstate pipeline and/or LDC tariff or contract. In addition, gas balancing charges from ratable take gas cannot be included in a Market Seller's cost-based offer. However, gas pipeline storage, park and loan, or other similar tariff-based rate for gas balancing can be included in the cost-based offer once these expenses are incurred. Gas balancing due to a change in ownership cannot be included.

Each Market Seller must document a standardized method or methods for calculating fuel costs in the Day Ahead offer period. Fuel cost updates in the Rebid and Intraday periods are optional.

If a Market Seller chooses to update fuel cost in the Rebid and/or Intraday they must document a standardized method or methods for those updates and define objective triggers like specific time periods, Hot/Cold Weather Alerts, pipeline events or notices, or liquidity volumes for optional updates during those periods in their Fuel Cost Policy.

In order to Opt In to Intraday Offers, Market Seller must validate their cost offers once per day or business day at a defined time period specified in the Fuel Cost Policy during the Intraday and update their cost-based offer intraday if costs change from original input used to create the day-ahead cost offer. During the Intraday update, cost-based offers may be increased but must be decreased. Additional updates during the Intraday are optional. However, Market Sellers must define objective triggers like specific time periods, Hot/Cold Weather Alerts, pipeline events or notices, or liquidity volumes for each additional update.

Each Market Seller must account for situations where applicable indices or other objective market measures are not sufficiently liquid by documenting in the Fuel Cost Policy the alternative means actually utilized by the Market Seller to price the applicable fuel used in the determination of its cost-based offers, such as specifying alternative pricing points or documented quotes for the procurement of natural gas.

Each Market Seller will be responsible for establishing its own method of calculating delivered fossil fuel cost, limited to inventoried cost, replacement cost or a combination thereof, which reflects the way fuel is purchased or scheduled for purchase.

The method of calculation will be consistent with the current effective Fuel Cost Policy and may only be changed by receipt of final approval pursuant to Section 2.2.1. Fossil fuel cost adjustments compensating for previous estimate inaccuracies should not be considered when determining the basic fossil cost component of Total Fuel Related Cost.

Units that co-fire more than one fuel shall weight average the cost of the fuel on a per MMBtu basis. Units that fire solid waste, bio-mass, or landfill gas shall include the cost of such fuel when calculating the average even when the cost of such fuel is negative. However, cost offers for units that fire solid waste, biomass, or landfill gas are not required to be less than zero.

For all units receiving Renewable Energy Credits (RECs) and/or Production Tax Credits (PTCs) that plan to submit a non-zero cost-based offer shall identify how RECs and/or PTCs are accounted for in the unit's Fuel Cost Policy.

2.2.3 Total Fuel Related Costs

Total Fuel Related Cost is the sum of fuel costs, emission allowance cost, maintenance cost, and operating cost.

$$\text{TotalFuelRelatedCosts} =$$

$$\text{FuelCosts} + \text{SO}_2 \text{ AllowanceCost} + \text{CO}_2 \text{ AllowanceCost} + \text{NO}_x \text{ AllowanceCost} + \text{MaintenanceAdder} + \text{OperatingCostAdder}$$

Escalation of previous year dollar amounts is permitted when the term of calculation exceeds twelve months. When used, escalation indexes will be the same as those developed for calculation of incremental Maintenance Adders.

2.2.4 Types of Fuel Costs

Basic Fuel Cost – The cost of fuel calculated as stated in the Market Sellers’ Fuel Cost Policy (excluding fixed lease expenses).

Note:

Basic Fuel Cost for each unit type will be addressed in subsequent sections.

Incremental Energy Cost –The incremental heat or fuel required to produce an incremental MWh at a specific unit loading level multiplied by the applicable Performance Factor, multiplied by the fuel cost plus the appropriate maintenance & operating cost.

Total Cost – The total theoretical heat input minus the no-load heat input at a specific unit loading level, multiplied by the applicable Performance Factor, multiplied by the fuel cost plus the appropriate maintenance & operating cost, plus the no-load cost.

2.2.5 Emission Allowances

Each unit that requires SO₂ /CO₂ /NO_x emission allowances (EAs) to operate may include in and emissions allowance adder in the unit's TFRC cost (\$/MMBtu) as determined in the Market Seller's Emissions Allowances/Adders, described in the Operating Agreement, Schedule 2, Section 3, which will be included in the same document(s) as the Fuel Cost Policy.

The emissions allowance section, included in the same document(s) as the Fuel Cost Policy must include:

- The type of emissions adders that are included in the cost-based offer (CO₂/ SO₂/NO_x), and the compliance period if applicable
- The source and frequency of updates for emissions rates
- The source and frequency of updates for emissions allowances
- Units with dual-fuel firing capability must use different emission rates based on the CO₂/ SO₂/NO_x emitted for each particular fuel or fuel mix

An example of the emission allowance adder calculation must be included in the numerical example of the unit’s Fuel Cost Policy. The emission allowance adder may be included in the unit’s TFRC once the Fuel Cost Police has been approved by PJM.

Emissions rates must be submitted to PJM and the Market Monitoring Unit through the Cost Offer Assumptions (COA) module in MIRA and changed if no longer accurate, in accordance with Operating Agreement Schedule 2 Section 3 and the Market Seller’s approved Fuel Cost

Policy. PJM will review the emissions rates upon submittal of a new or revised Fuel Cost Policy and on an as needed basis.

PJM shall establish an expiration date for emissions rates in alignment with the Fuel Cost Policy expiration, with timely input and advice from the Market Monitoring Unit and Market Seller, and notify the Market Seller of such date at the time of the emissions rate approval. Market Sellers must submit updated rates prior to the expiration of the current adder. Once the emissions rate approval expires, the Market Seller must submit \$0 for the generation unit's emissions adder until a new rate is approved. Market Seller should submit updated emissions rates at least 30 days prior to expiration of the currently approved rates to ensure timely review and approval.

2.2.6 Leased Fuel Transportation Equipment (moved to 2.6.8)

2.2.7 Engineering Judgement in Fuel Cost Calculations

A Market Seller may apply engineering judgement to manufacturer's data, operating data or the results of start and run tests in order to derive the components of the total fuel cost. A record of the results of these determinations shall be kept on file by each Market Seller for use as a single, consistent basis for scheduling, operating, and accounting applications. These records shall be made available to PJM or the MMU upon request.

2.2.8 Required Documentation for Cost Offer Development

The Market Seller shall maintain all documentation needed to verify the development of cost-based energy offers and validate offers intraday. The documentation may include, but is not limited to, invoices, contracts, screenshots, instant messages, text messages, e-mails, or recorded phone calls. This information may be requested by PJM or the IMM to verify the development of cost-based energy offers.

2.3 Incremental Energy Cost

The incremental energy cost is the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit's incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs. A Market Seller may submit sloped, stepped, or blocked loaded offers into PJM's Markets Gateway system. The formula for calculating a sloped, stepped, or block loaded incremental offer are show in Section 2.3.1, 2.3.2, and 2.3.3 below.

2.3.1 Sloped Offer Incremental Energy Cost

The sloped function is the continuous first derivative of the heat input function. Units offered using a sloped function must select the "use offer slope" option in Markets Gateway. Generators offered using a sloped function must start their incremental offer curve with a zero MW segment.

The incremental heat rate at zero MW is the y axis intercept of the incremental heat rate function (the incremental heat rate when MW = 0.).

Incremental Energy Cost in dollars per MWh for a sloped offer can be calculated by:

$$\begin{aligned} \text{Incremental Energy Cost (Slope Offer)} &= \text{Incremental Heat Rate}^* \\ &\text{Total Fuel Related Cost } \left(\frac{\$}{\text{MMBtu}} \right) + \text{Maintenance Adder } (\$ / \text{MWh}) + \\ &\text{Operating Cost Adder } \left(\frac{\$}{\text{MWh}} \right) + \text{Opportunity Cost Adder } (\$ / \text{MWh}) \end{aligned}$$

Incremental Heat Rate – See Section 2.1

- Total Fuel Related Cost – See Section 2.2.3
- Maintenance Adder – See Section 2.6
- Operating Cost Adder – See Section 2.6.8
- Opportunity Cost Adder – See Section 12

2.3.2 Stepped Load Offer Incremental Energy Cost

The stepped incremental heat rate curve is derived from heat input curves, and direct measurements at different discrete output levels. Units offered using a stepped function must not select the “use offer slope” option in Markets Gateway. Generators offered using a stepped function should submit a nonzero first MW segment.

Incremental Energy Cost in dollars per MWh for a stepped offer can be calculated by:

$$\begin{aligned} \text{Incremental Energy Cost (Stepped Offer)} &= \\ &[\text{Heat Input}(i) - \text{Heat Input}(i - 1)] / [\text{MWh}(i) - \text{MWh}(i - 1)] \\ &^* \text{Total Fuel Related Cost } (\$ / \text{MMBtu}) + \text{Maintenance Adder } (\$ / \text{MWh}) \\ &+ \text{Operating Cost Adder } (\$ / \text{MWh}) + \text{Opportunity Cost Adder } (\$ / \text{MWh}) \end{aligned}$$

- Heat Input – See section 2.1
 - Heat Input (i) is the heat input at the MWh output at the end of the block
 - Heat Input (i-1) is the heat input at the MWh output at the beginning of the block
 - MWh(i) is the the MWh at the end of the block
 - MWh(i-1) is the MWh at the beginning of the block
- Total Fuel Related Cost – See Section 2.2.3
- Maintenance Adder – See Section 2.6
- Operating Cost Adder – See Section 2.6.8
- Opportunity Cost Adder – See Section 12

2.3.3 Block Load Offer Incremental Energy Cost

Block Load offers are used when a unit offers only one incremental energy step. The average heat rate of a block loaded offer is equal to the total heat input needed to run the unit divided by the total output. When using an average heat rate all the fuel cost is in the incremental offer so when using a block offer the no-load cost must be set to zero. Units offered block loaded must not select the “use offer slope” option in Markets Gateway. Generators offered block loaded should submit a nonzero MW segment.

Incremental Energy Cost in dollars per MWh for a block loaded offer can be calculated by:

Incremental Energy Cost (Block Offer) =

$$\left(\text{Average Heat Rate} \left(\frac{\text{MMBtu}}{\text{MWh}} \right) \right)$$

or Heat Input@EcoMax (MMBtu) / EcoMax (MWh)

*Total Fuel Related Cost (\$ / MMBtu) + Maintenance Adder (\$ / MWh)

+ Operating Cost Adder (\$ / MWh) + Opportunity Cost Adder (\$ / MWh)

- Total Fuel Related Cost – See Section 2.2.3
- Maintenance Adder – See Section 2.6
- Operating Cost Adder – See Section 2.6.8
- Opportunity Cost Adder – See Section 12

2.4 Start-up Cost

2.4.1 Start-up Cost Definitions

- **For units with soak process:** Start Cost shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch and from last breaker open to shutdown.
- **For units without soak process:** Start Cost shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

Start – upCost (\$ / Start) =

*[StartFuel (MMBtu / (Start))*TotalFuelRelatedCost(\$ / MMBtu)*PerformanceFactor]*

*+ [StationService(MWh) * StationServiceRate(\$ / MWh)] + StartMaintenanceAdder(\$ / Start)*

- **Start Fuel –**
 - **For units without soak process** - Fuel consumed from first fire of start process to first breaker closing plus fuel expended from last breaker opening to shutdown. **For units with soak process** - Fuel consumed from first fire of start process (initial reactor criticality for nuclear units) to to the level at which the unit can follow PJM's

dispatch (including auxiliary boiler fuel) plus fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements.

- **Total Fuel Related Cost** – See Section 2.2.3
- **Station Service** –
 - **For units without soak process** – Station service consumed from PJM’s notification to first breaker close and electricity consumed after last breaker open to shutdown above normal base station use. Normal base station service is the consumption prior to PJM’s notification.
 - **For units with soak process** – Station service consumed from PJM’s notification to first breaker close and electricity consumed after last breaker open to shutdown above normal base station use minus net generation produced from first breaker close to the level at which the unit can follow PJM’s dispatch. Normal base station service is the consumption prior to PJM’s notification.
- **Station Service Rate** – A \$/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection.
- **Start Maintenance Adder** – Maintenance adder calculated in \$/start (See Section 2.6)

2.4.2 Engineering Judgment in Start Costs

A Market Seller may apply engineering judgment to manufacturers’ data, operational data, or the results of start tests in order to derive the components of unit Start-up Cost. A record of the results of these determinations shall be kept on file by each Market Seller for use as a single, consistent basis for scheduling, operating, and accounting applications. These records shall be made available to the MMU or PJM upon request.

2.4.3 Additional Start Cost Rules

- Pseudo Tied units can only include Start Costs if the entire unit is transferred into PJM.
- Cogenerators cannot include start and no-load cost when they are needed online to meet host/internal load.

2.5 No_Load

2.5.1 No-Load Definitions

No-Load Cost (\$/hour) - The hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no_load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances. .

2.5.2 No-Load Fuel

All Market Sellers shall develop no-load costs for their units. The no-load heat input may be determined by collecting heat input values as a function of output and performing a regression analysis. The heat input values as a function of output may be either created from heat rate test data or the initial design heat input curve for an immature unit.

For units that use a different starting fuel (e.g. coal units), the fuel in the no-load cost calculation cannot be the fuel used during startup and synchronization, but must be the fuel used during normal operation.

The minimum number of points to develop a heat input curve shall be 2 points for a dispatchable unit with a variable output and 1 point for a unit with a fixed output.

Sufficient documentation for each generating unit's no-load point in MMBtu's (or fuel) per hour shall consist of a single contact person and/or document to serve as a consistent basis for scheduling, operating and accounting applications PJM and the MMU can verify calculation methods used are in accordance with the currently approved Fuel Cost Policy and the elements of Attachment B.

2.5.3 No_Load Calculation

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is the no-load fuel Cost multiplied by the Performance Factor, multiplied by the (Total Fuel-Related Cost (TFRC))

$$\begin{aligned}
 \text{No - Load Cost}(\$/\text{Hour}) = & \\
 & (\text{No - Load Fuel}) * (\text{Performance Factor} * \text{Total Fuel Related Cost}) \\
 & + \text{Maintenance Adder} \left(\frac{\$}{\text{hour}} \right) + \text{Operating Cost Adder} \left(\frac{\$}{\text{hour}} \right)
 \end{aligned}$$

- Performance Factor – See Section 2.1
- Total Fuel Related Cost – See Section 2.2.3
- Maintenance Adder – See Section 2.6
- Operating Cost Adder – See Section 2.6.8

Units that only operate block loaded (i.e. no dispatchable range) must be offered using an average heat rate and zero no_load cost. All the hourly costs of operating the unit must be included in the incremental energy offer.

2.6 Variable Operating and Maintenance Cost

Variable Maintenance cost is the parts and labor expenses of maintaining equipment and facilities in satisfactory operating condition.

$$\text{TotalMaintenanceCost}_{\text{NextYear}} =$$

$$\begin{aligned} & \left(\text{AnnualMaintenanceCost} * \frac{\text{EscalationIndex}_{\text{NextYear}}}{\text{EscalationIndex}_{\text{CurrentYear}}} \right) + \\ & \left(\text{AnnualMaintenanceCost} * \frac{\text{EscalationIndex}_{\text{NextYear}}}{\text{EscalationIndex}_{\text{LastYear}}} \right) + \\ & \left(\text{AnnualMaintenanceCost} * \frac{\text{EscalationIndex}_{\text{NextYear}}}{\text{EscalationIndex}_{\text{LastYear} - 1}} \right) + \\ & \dots + \left(\text{AnnualMaintenanceCost} * \frac{\text{EscalationFactor}_{\text{NextYear}}}{\text{EscalationIndex}_{\text{LastYear} - (\text{Maintenance Period} - 1)}} \right) \end{aligned}$$

There are three components in Variable Operating & Maintenance costs: major maintenance, minor maintenance and Operating Costs. These costs must be submitted to PJM/IMM for review and approval prior to the inclusion of such adder (or prior to the expiration of a previously approved adder) in cost-based offers. Notwithstanding, Market Sellers may elect to utilize the default minor maintenance adder and/or default operating costs adder.

- Major Maintenance: The Market Seller must submit major maintenance costs (see 2.6.1.1) to PJM/IMM for review and approval when new major maintenance costs added or previous costs rolled off maintenance history. Major maintenance must be approved before they can be included in the cost-based energy offer.
- Minor Maintenance: The Market Seller may use the default adder specified in OA, Schedule 2 (see 2.6.11) for unit's technology type if available. The default minor maintenance adder is calculated to represent the minor maintenance costs (see 2.6.1.2). In the alternative, the Market Seller may submit unit-specific minor maintenance to PJM/IMM for review if default adder is not available for unit's technology type or the Market Seller elects not to use the default minor maintenance adder. Minor maintenance other than default adder must be approved before they can be included in the cost-based energy offer.
- Operating Costs: The Market Seller may use the default adder specified in OA, Schedule 2 (see 2.6.11) for unit's technology type if available. Otherwise, the Market Seller may submit Operating Costs (see 2.6.8) to PJM/IMM annually for review. Operating Costs other than default adder must be approved before they can be included in the cost-based energy offer.

The Maintenance Adder is based on the actual maintenance expense history of the unit for the defined Maintenance Period (See 2.6.4) and must be justified with supporting documentation. The Market Seller shall submit supporting documentation (see 2.6.9) for all costs that are included in the unit's historical Maintenance Period. Only expenses incurred as a result of electric production based on operating hours, starts, or a combination of operating hours and starts qualify for inclusion. Fixed costs cannot be included. Maintenance Adders may be included as part of the start cost, no_load, or incremental energy offer. Maintenance Adders may be specified as \$/Start, \$/Hour, \$/MMBtu, \$/Equivalent Service Hour (ESH), and/or \$/MWh. Multiple Maintenance Adders cannot be used unless multiple variable maintenance payment criteria (specified in both starts and hours or starts/hours ratios, etc.) specified in LTSA (see

2.6.10). If multiple Maintenance Adders are used for the same unit(s), the total maintenance costs must be split into multiple Maintenance Adders to prevent double counting.

The Market Seller can use one Maintenance Adder for multiple units at the same generating plant only when units are the same technology type, such as aero-derivative CT. And the Market Seller must include total operating history for all units (for example, total operating hours for unit 1 plus total operating hours for unit 2 plus total operating hours for unit 3).

A Market Seller who elects to use a default minor maintenance adder specified in OA, Schedule 2 (see 2.6.11) may only submit unit-specific major maintenance costs for review. The major maintenance costs shall be submitted when major maintenance costs are added to or removed from the maintenance period. Regardless of when the maintenance is completed, the major maintenance adder shall include a minimum of 10 years of operating history. PJM will specify an expiration date upon approval of the major maintenance adder. Market Sellers that are using the default minor maintenance adder for black start service units shall not use 1% of the total maintenance dollars as part of their black start service annual revenue requirement.

A Market Seller may submit a unit-specific minor maintenance if the unit does not have a default minor maintenance adder available for its technology type or the Market Seller elects not to use the default minor maintenance adder. A Market Seller with tolling agreement must use zero for the default minor maintenance adder, but may include the variable tolling fees in the Maintenance Adder. The default minor maintenance adder may be included in the cost-based energy offer.

The Maintenance Adder may be submitted to PJM and the MMU for review annually, in accordance with Operating Agreement Schedule 2 Section 4. Market Sellers may only use the PJM-approved unit-specific Maintenance Adder in their unit's cost-based offer. PJM will specify an expiration date upon approval of the Maintenance Adder. Upon the transfer of ownership to a new Market Seller, the new Market Seller must submit a new Maintenance Adder for PJM review if a non-zero major maintenance adder and/or unit-specific minor maintenance adder is desired.

A Market Seller may include a default operating costs adder (see 2.6.11) in the cost-based energy offer and shall not be required to submit Operating Costs for review. If the Market Seller elects not to use the default operating costs adder, or the unit does not have a default operating costs adder available for its technology type, the Market Seller may submit the Operating Costs to PJM and the MMU for review annually, in accordance with Operating Agreement Schedule 2 Section 4. Market Sellers may only use the PJM-approved unit-specific Operating Costs in their unit's cost-based offer. PJM will provide the expiration date of a PJM-approved Operating Costs upon approval of the Operating Costs. Upon the transfer of ownership to a new Market Seller, the new Market Seller must submit a new Operating Costs for PJM review if a non-default operating costs adder is desired.

Market Sellers may only change the format of the major maintenance Adder (i.e., \$/MMBtu, \$/MWh, \$/Start, etc.) once per calendar year. In addition, once the Maintenance adder is

approved by PJM, the adder can only be included in the corresponding portions of the associated cost based energy offer components (i.e., no-load costs, Incremental Energy Costs, Start-Up Costs).

Market Sellers may only change the format of the Operating Costs (i.e., \$/MMBtu, \$/MWh) once per calendar year. In addition, once the Operating Costs have been approved by PJM, the adder can only be included in the corresponding portions of the associated cost based energy offer components (i.e., no-load costs, Incremental Energy Costs, Start-Up Costs).

The Maintenance Adder or Operating Costs and corresponding supporting documentation shall be submitted to PJM/IMM by June 15 of the year that adder expires; PJM shall provide final approval decisions by December 31.

If a Market Seller feels that a unit modification or required change in operating procedures will affect the unit's Maintenance Adder, the revised Maintenance Adder must be submitted to PJM and the MMU for review and PJM-approval prior to use in cost-based offers.

2.6.1 Allowable Maintenance Expenses

Maintenance Costs are expenses incurred as a result of electric production. Allowable expenses can include repair, replacement, inspection, and overhaul expenses, including Long Term Service Agreements (LTSA), related to the following systems and/or their associated FERC accounts identified later in this manual – steam turbine, gas turbine, generator, boiler, Heat Recovery Steam Generators (HSRG), main steam, feed water, condensate, condenser, cooling towers, transformers, and fuel systems. Allowable expenses are maintenance costs that vary directly with the electric production, such as run hours or starts. The maintenance listed below are not exhaustive. A Market Seller may include capital costs or expense costs in cost-based offers if those costs are similar to the costs outlined in this provision, so long as they are variable costs that are directly attributable to the production of electricity.

2.6.1.1 Major Maintenance

Major maintenance are overhauls, repairs, or refurbishments that require disassembly to complete of boiler, reactor, heat recovery steam generator, steam turbine, gas turbine, hydro turbine, generator, or engine. Major maintenance include, but are not limited to, the following costs:

- turbine blade repair/replacement;
- turbine diaphragm repair;
- turbine casing repair/replacement;
- turbine bearing repair/refurbishment;
- turbine seal repair/replacement and generator refurbishment;
- Selective Catalytic Reduction and CO Reduction Catalyst replacement;
- compressor blade repair/replacement;

- hot gas path inspections, repairs, or replacements;
- steam stop valve repairs;
- steam throttle valve repairs;
- steam nozzle block repairs;
- steam intercept valve repairs;
- generator stator or rotor rewind, refurbishment, or replacement;
- scrubber refurbishment;
- water wall panel replacement;
- pendant or super heater replacement;
- economizer replacement;
- diesel/reciprocating engine overhaul;
- reactor refueling;
- steam generator overhaul/replacement.

2.6.1.2 Minor Maintenance

Minor maintenance are repairs or refurbishments on equipment and components directly related to electric production, such as main steam, feed water, condensate, condenser, cooling towers, transformers, gas turbine inlet air and exhaust, and fuel systems. Minor maintenance include but are not limited to, the following costs associated with the aforementioned systems:

- heat transfer replacement and cleaning;
- cooling tower fan motor and gearbox inspection;
- cooling tower fill and drift eliminators replacement;
- air filter replacement;
- repair and replacement of valves & piping components, control equipment, pumps, motors, condenser components, transformers, cabling, breakers, motor control centers, switch gear, fuel & ash handling, SCR & Scrubber emission control equipment and components, mills burners, boiler components, fan components, reactor recirculation components, hydraulic control rod drive system components and reactor components.

Minor Maintenance include repairs and replacements done as the result of component failure or prior to failure due to limited remaining life. They could include maintenance work done while the unit is operating or during unplanned or scheduled outages. Maintenance work during annual or otherwise time based outages could also be considered minor maintenance as long as the repairs and replacements are due to wear and tear from electrical production.

Minor Maintenance do not include preventative maintenance surveys done on a time basis such as oil sampling, vibration surveys, infrared surveys, or annual or time based oil or filter changes. However, any repair or replacements that are done as the result of the survey for wear and tear from electric production or limited remaining life are considered minor maintenance.

2.6.1.3 Unallowable Expenses

Maintenance Costs that cannot be included in a unit's cost-based offer are expenses that are not a function of starts or run hours, such as annual or time-based preventative maintenance (vibration surveys, oil sampling, infrared surveys, conditioning monitoring, annual condenser cleaning, weekly filter changes, annual or monthly CT borescope inspection, etc.), buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, control room equipment and software, reactor safety system and plant water treatment systems. Typically, if the system is needed to remain in-service when the unit is not in operation expenses related to it cannot be included in a unit's cost based offer.

Upgrades or replacement of existing equipment with capital upgrades/enhancements typically cannot be included in the calculation of a unit's maintenance adder. If the equipment is being upgraded because the original equipment is obsolete and can no longer be procured, this expense is considered a replacement and can be included.

Expenses for repairs and or replacements due to weather events also cannot be included in a unit's maintenance history, items that have failed, for example, due to a lighting strike or external weather corrosion are not directly related to electric production.

2.6.2 Labor Costs

Labor costs included in cost-based offers are limited to start-up costs for additional staffing requirements and do not include straight-time labor costs. Only staff overtime or contractor labor incurred for costs referenced in Section 2.6.1 of Manual 15 can be included in maintenance adder. Staff overtime or contractor labor to augment existing operations staff to run the unit cannot be included in the unit's cost-based offer.

2.6.3 Escalation Index

Escalation Index is the annual escalation index derived from the Handy - Whitman Index Table published at the PJM website link below:

<https://www.pjm.com/committees-and-groups/subcommittees/cds/handy-whitman-index.aspx>

These escalation indices could be used in the calculation of generating unit Maintenance Adders and Operating Costs.

2.6.4 Maintenance Period

A unit must choose a rolling historical period based on calendar year. A unit may choose a 10-year or 20-year period for maintenance cost, or all available actual maintenance history if a unit has less than 20 years of maintenance history. Once a unit has chosen the historical period length, the unit must stay with that period until a significant unit configuration change. Significant unit configuration change is defined as any change to the physical unit's system that significantly affects the maintenance cost for a period greater than 10 years. Examples of a significant unit configuration may include but are not limited to:

- Flue Gas Desulfurization (FGD or scrubber)
- Activated Carbon Injection (ACI)
- Selective Catalytic NOx Reduction (SCR)
- Selective Non-Catalytic NOx Reduction (SNCR)
- Low-NOx burners
- Bag House addition
- Long-term Fuel change (greater than 10 years)
- Water injection for NOx control
- Turbine Inlet Air Cooling

A maintenance period choice may also be given in circumstances of change in ownership necessitating a new Generation Interconnection Agreement (GIA). Change of ownership within the same holding company is not eligible to change the historical maintenance period.

2.6.5 Incremental Adjustment Parameter

Incremental Adjustment Parameter is defined as any variable cost incurred in the production of energy for PJM dispatch that is not included in the CDS guidelines for Total Fuel Related Costs or Maintenance Adder. This includes any variable cost that has been previously approved pursuant to Cost Methodology and Approval Process for inclusion. These records shall be made available to PJM and MMU upon request.

2.6.6 Equivalent Service Hours Maintenance Cost

- The Equivalent Service Hours Maintenance Cost. This is defined as total maintenance dollars divided by equivalent service hours.

$$\text{EquivalentServiceHoursMaintenanceCost } (\$/\text{ESH}) = \frac{\text{TotalMaintenanceDollars}}{\text{EquivalentServiceHours}}$$

- Estimated Year 2011 Total Maintenance Cost calculation example for a CT:

$$\text{TotalMaintenanceCost}_{2011} =$$

$$\begin{aligned} & \left(\text{AnnualMaintenanceCost}_{2010} * \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2010}} \right) + \\ & \left(\text{AnnualMaintenanceCost}_{2009} * \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2009}} \right) + \\ & \left(\text{AnnualMaintenanceCost}_{2008} * \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2008}} \right) + \\ & \dots + \left(\text{AnnualMaintenanceCost}_{2000} * \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2000}} \right) \end{aligned}$$

- Equivalent Service Hours calculation example:

$$\begin{aligned} \text{EquivalentServiceHours} = & \\ & (\text{CyclicStartingFactor} * \text{NumberOfStarts}) + \text{TotalOperatingHours} + \\ & (\text{CyclicPeakingFactor} * \text{NumberOfHoursAboveBaseload}) \end{aligned}$$

Note:

Cyclic Starting Factors and Cyclic Peaking Factors can be used only when the maintenance adder is in \$/ESH and the values can be supported by LTSA or OEM. They shall be consistently used for equivalent service hours and cost based offer calculations for simple cycle or combined cycle CT major maintenance costs only. Cyclic Fuel Factors can be used in the calculation of ESH if specified in the LTSA or OEM. Multiple cyclic peaking factors can be included in the calculation of ESH if specified in the LTSA or OEM. Cyclic Starting Factors and Cyclic Peaking Factors values shall be consistently used for equivalent service hours and cost based offer calculations for CC and CT Units. See cyclic starting factor and cyclic peaking factor in sections 5.6.3 & 6.6.3.

2.6.7 Immature Units: Maintenance Costs

Immature Units - Units with neither 10 years of operation nor 50,000 Operating Hours.

Immature Units should use actual available costs. Maintenance costs, operating costs and operating history must correspond to the number of years for which supporting documentation is available.

When a resource has less than one calendar year of operating history available, the Market Seller may use the default minor maintenance adder and default operating costs adder specified in OA, Schedule 2 (see 2.6.11). The major maintenance adder must be 0.

Once a unit reaches either 10 years of operation or 50,000 Operating Hours, it is considered a mature unit. Once a unit is mature, it will use actual historical maintenance cost and the Market Seller will decide to use a 10 or 20 year history (See section 2.6.2). If a mature unit has less maintenance history than its elected historical period, the Market Seller will use all available

history to calculate the Maintenance Adder. For mature units that transferred ownership, the new owner should include maintenance and operating costs for which supporting documentation is available. Operating history must reflect at least 10 (up to 20) years.

2.6.8 Operating Costs

The Operating Costs can be represented by the default adder specified in OA, Schedule 2 (see 2.6.11) or submitted by the Market Seller to PJM/IMM to review.

The **Operating Costs** may be calculated based on a fixed or rolling average of values from one to five years in length, reviewed (and updated if changed) annually, or a rolling average from twelve to sixty months in length, reviewed (and updated if changed) monthly. Both the term and the frequency of the Operating Cost calculation shall be included in the Market Seller's Operating Costs.

- Allowable Operating Cost include lubricants, chemicals, Limestone, Trona, Ammonia, acids, caustics, water injection, demineralizers, ash disposal, and waste disposal. Operating Cost also include variable Title V and other applicable emissions fees.
- Allowable Operating Costs must be directly related to electric production. They are incurred or used during startup, while operating producing MWs, or during shutdown. If any of the operating costs incurred have already been included in the start-up cost, such costs will not be allowed as operating costs.
- Market Sellers will be allowed to include additional operating costs via the Section 1.8 cost methodology and approval Process. Acceptable items will be added to M15 during the biennial revision.
- Operating Costs may be specified as \$/MMBtu or \$/MWh only.
- Escalation of previous year's Operating Costs dollar amounts is permitted when the term of calculation exceeds twelve months. When used, escalation indexes will be the same as those developed for calculation of incremental Maintenance Adders.
- Market Sellers that elect to use monthly rolling average shall submit the operating cost adder value to PJM and IMM via COA monthly if no cost items change; If cost items change, Market Sellers must also submit a new Operating Costs to PJM and IMM.

2.6.8.1 Leased Fuel Transportation Equipment

Leased Fuel Transportation Equipment Cost –Expenses incurred using leased equipment to transport fuel to the plant gate.

Only the leased equipment costs that vary with electric production can be included in the Operating Costs. If the costs are fixed, they must be excluded. If the costs are based on a charge for every unit of fuel delivered, such costs should be included in the fuel costs and not included in Operating Costs.

2.6.9 Supporting Documentations

The supporting documentations for the Maintenance Adder and Operating Costs may be in the format of maintenance management system records, general ledger data, accounting records or invoices. The maintenance expenses and operating costs and supporting documentation must be linked and traceable. The supporting documentation must clearly show how each cost item was calculated.

Supporting documentations for maintenance expenses shall include the work order and/or description of maintenance activities performed.

Supporting documentations for operating costs shall include the amount of each consumable used while in operation, and the cost per unit of each consumable.

2.6.10 Maintenance Adder with LTSA

When LTSA costs are included, the Market Seller shall use the format of adder consistent with the variable maintenance payment criteria (i.e. \$/starts, \$/hours, etc.) specified in LTSA.

The adder format shall be consistent with the maintenance expense and is a function of units starts or run hours. For example, if the maintenance expenses are a function of starts, the Maintenance Adder shall be in \$/start.

Units that have LTSA or OEM documentation which specifies N-Ratio (i.e. run hours divided by number of starts) for maintenance payments will apply those in consistent manner in submitting Maintenance Adder. For example, a Market Seller allocates the dollars charged based on starts and divide by total starts to get a \$/start adder; and allocates the other dollars charge based on hours and divide by total hours to get a \$/hour adder.

2.6.11 Default Adders

A Market Seller may elect to utilize a default minor maintenance adder or submit unit-specific minor maintenance costs to the Office of Interconnection and the Market Monitoring Unit. All maintenance costs on a unit-specific basis must be submitted to the Office of Interconnection and the Market Monitoring Unit.

A Market Seller may include a default operating costs adder in the cost-based energy offer in lieu of submitting unit-specific operating costs for review and approval.

The default adders shall be escalated annually utilizing the Handy-Whitman Index and shall be posted annually by the Office of Interconnection. The default adders may not be utilized by a Market Seller prior to the expiration of a unit-specific maintenance adder or operating costs adder previously approved by the Office of Interconnection.

2.7 Synchronized Reserve

Synchronized Reserve is the capability that can be converted fully into energy within 10 minutes or customer load that can be removed from the system within 10 minutes of the request from the PJM dispatcher, and must be provided by equipment electrically synchronized to the system.

Market Sellers that request and receive reimbursement from PJM for the costs associated with operating a generating unit in the condensing mode or for altering the output of a generator at the request of PJM in order to provide Synchronized Reserves must maintain records to document how those costs were calculated. These records shall be made available to PJM upon request.

2.8 Regulation Service

Regulation is the capability of a specific resource with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal to control for frequency deviations

The cost-based regulation offer is split into two portions:

- The Regulation Capability portion consists of the fuel cost increase and unit specific heat rate degradation due to operating at lower loads and the margin risk adder;
- The Regulation Performance portion consists of the cost increase in VOM, cost increase due to heat rate increase during non-steady state operation and, where applicable, energy losses for energy storage devices. The \$/MW value determined in the performance offer will be converted to cost per mileage \$/ΔMW by dividing the value by the mileage ΔMW/MW for the applicable signal for that offer as described in Manual 11.
- Regulation Capability costs to provide Regulation Service from a unit shall include the following components up to but not exceeding:

$$\text{Regulation Capability Costs} (\$/MWh) \leq$$

$$\begin{aligned} & (\text{Fuel Cost Increase and Unit Specific Heat Rate Degradation due to Operating at Lower Loads}) \\ & + \text{Margin Risk Adder} \end{aligned}$$

- Regulation Performance costs to provide Regulation Service from a unit shall include the following components up to but not exceeding:

$$\text{Regulation Performance Costs} \left(\frac{\$}{\Delta MW} \right) \leq$$

$$\begin{aligned} & \{ \text{Cost Increase in VOM} + \text{Cost Increase due to Heat Rate Increase during nonsteady state operation} \\ & \text{(above heat rate factor not to exceed 0.35\%)} + (\text{Energy Storage Unit Losses}) \} / \Delta MW / MW \end{aligned}$$

Fuel Cost Increase and Unit Specific Heat Rate Degradation due to Operating at lower loads

The costs (in \$/MWh of Regulation) to provide Regulation Service from units shall not exceed the fuel cost increase due to operating the unit at lower loads than at the optimal economic dispatch level load and the unit specific heat rate degradation from operating at lower loads, resulting from operating the unit at lower MW output incurred from the provision of Regulation over the entire generator MW range of providing Regulation Service.

Cost Increase due to Heat Rate increase during non-steady state

The cost (in \$/MWh of Regulation) increase due to the heat rate increase resulting from operating the unit at a non-steady-state condition. This heat rate loss factor rate shall not exceed 0.35% of the top Regulation load MW heat rate value.

Margin/Risk Adder

Margin Risk Adder shall not exceed \$12.00 per MWh of Regulation Service provided.

Energy Storage Unit Losses

Energy storage unit losses can only be greater than zero for energy storage type devices and calculated in accordance with the guidance provided in section 11.8.

Cost increase in VOM

The cost increase (in \$/MWh of Regulation) of variable operations and maintenance (VOM) cost resulting from operating the unit at lower MW output incurred from the provision of Regulation. VOM costs shall be calculated by the following methods and shall not exceed those levels below:

For any unit that does not have a PJM approved Maintenance Adder, the following variable operation and maintenance (VOM) costs can be applied by unit type to the following:

Unit Type	VOM
Super-critical Steam:	\$10.00 per MWh of Regulation
Sub-critical Steam:	\$3.50 per MWh of Regulation
Combined Cycle:	\$2.50 per MWh of Regulation
Combustion Turbine:	\$2.00 per MWh of Regulation
Hydro:	\$1.00 per MWh of Regulation

Unit Type	VOM
Energy Storage:	Based on OEM estimates initially and actual as history is available

Exhibit 1: VOM for all Hydro Units or Non-Hydro Units providing service for less than 10 years

Any unit that has a PJM approved Maintenance Adder can use the VOM rates above if the annual VOM dollar amounts resulting from those rates included in Regulation cost based offers, are subtracted from the escalated 10 or 20 year historical total VOM accounts and the Regulation MWh based on the average of the last three years.

Energy storage units that participate only in regulation Service shall include all their VOM Cost increase in VOM adder in Regulation cost offers.

For example, a 100 MW sub-critical coal fired steam unit that has been providing Regulation Service for 30 years. The unit averaged 5,000 MWh of Regulation Service over the last three years and the escalated 20 year historical total VOM = \$10,000,000.

Annual VOM Costs to Subtract
= (\$3.50 per Regulation MWh * 5,000 MWh) * 20 years
= \$17,500 per year * 20 years
= \$350,000
20-year balance of historical total VOM accounts
= \$10,000,000 - \$350,000
= \$ 9,650,000

Exhibit 2: Example of VOM for Non-Hydro Units providing Regulation for more than 10 years

Actual Regulation VOM incremental costs submitted and evaluated pursuant to the Cost Methodology and Approval Process.

For Example for a Sub-critical Coal-Fired Steam Unit providing Regulation Service for the last seven years:

Data Submitted by Participant	Value	Units
Fuel	\$1.50	\$/MMBtu
Heat Rate @ EcoMax	9,000.00	MMBtu/KWh
Heat Rate @ RegMin	12,5000.00	MMBtu/KWh

Data Submitted by Participant	Value	Units
VOM	\$3.50	\$/MW of Regulation
EcoMax	100.0	MW
RegMin	40.0	MW
Unit Reg Band	10.0	MW
Margin Adder	\$12.00	\$/MW of Regulation

Heat Rate Adjustment (Operating Range)	Value	Units
Unit Base Load Heat Rate Fuel Input	360.0	MMBtu/Hr
Unit Reduced Load Heat Rate Fuel Input	500.0	MMBtu/Hr
Difference	140.0	MMBtu/Hr

$$\text{UnitBaseLoadHeatRateFuelInput} =$$

$$\text{UnitBaseLoadHeatRate} * \text{RegMin} * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW}$$

$$\text{UnitBaseLoadHeatRateFuelInput} =$$

$$9,000 \text{ MMBtu} / \text{kWh} * 40 \text{ MW} * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW} = 360 \text{ MMBtu} / \text{Hr}$$

$$\text{UnitReducedLoadHeatRateFuelInput} =$$

$$\text{UnitReducedLoadHeatRate} * \text{RegMin} * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW}$$

$$\text{UnitReducedLoadHeatRateFuelInput} =$$

$$12,500 \text{ MMBtu} / \text{kWh} * 40 \text{ MW} * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW} = 500 \text{ MMBtu} / \text{Hr}$$

$$\text{Difference} = \text{UnitBaseLoadHeatInput} - \text{UnitReducedLoadHeatInput}$$

$$\text{Difference} = 500 \text{ MMBtu} / \text{Hr} - 360 \text{ MMBtu} / \text{Hr} = 140 \text{ MMBtu} / \text{Hr}$$

Heat Rate Adjustment (Non-Steady State Operation)	Value	Units
Total Operating Point Heat Rate	9,000.0	MMBtu/kWh
Heat Rate Loss Factor (Max per M15)	0.35%	

Heat Rate Adjustment (Non-Steady State Operation)	Value	Units
Heat Rate Loss	3.15	MMBtu/Hr

$$\text{HeatRateLoss} =$$

$$(\text{EconomicMaximumHeatRate} * 0.35\%) * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW} * \text{EconomicMaximumMW}$$

$$\text{Heat Rate Loss} =$$

$$(9,000 \text{ MMBtu} / \text{kWh} * 0.35\%) * 1 \text{ MMBtu} / 1,000,000 \text{ MMBtu} * 1,000 \text{ kW} / \text{MW} = 3.15 \text{ MMBtu} / \text{Hr}$$

(a) Heat Rate Adjustment (Operating Range)	Value	Units
Fuel Cost Adder – Operating Range	\$3.50	\$/Hr/MW of Regulation

$$\text{FuelCostAdder} =$$

$$(\text{Difference} * \text{FuelCost}) / (\text{EconomicMaximumMW} - \text{RegulationMinimumMW})$$

For Example:

$$\text{FuelCostAdder} =$$

$$(140 \text{ MMBtu} / \text{Hr} * \$1.50 / \text{MMBtu}) / (100 \text{ MW} - 40 \text{ MW}) = \$3.50 / \text{Hr} / \text{MW}$$

(b) Margin Risk Adder	Value	Units
Margin/Risk Adder	\$12.00	\$/Hr/MW of Regulation

Maximum Capability Offer	Value	Units
Heat Rate Adjustment(Operating Range) + Margin Adder	15.5	\$/Hr/MW of Regulation

Historic Mileage	Value
RegA	5

** This value is an example substitute for the average value for RegA.

(c) Heat Rate Adjustment (Non Steady-State Operation)	Value	Units
Fuel Cost Adder – Non Steady-State Operation	\$0.50	\$/Hr/MW of Regulation

$$FuelCostAdder = (HeatRateLoss * FuelCost) / RegulationBandMW$$

For Example:

$$FuelCostAdder = (3.15 \text{ MMBtu} / \text{Hr} * \$1.50 / \text{MMBtu}) / 10\text{MW} = \$0.50 / \text{Hr} / \text{MW}$$

(d) VOM Adder	Value	Units
Regulation VOM Adder	\$3.50	\$/Hr/MW of Regulation

Maximum Performance Offer	Value	Units
(c+d)/Historic Mileage	\$0.80	\$/ΔMW

$$MaximumPerformanceOffer =$$

$$[FuelCostAdder (NonSteadyStateOperation) + RegulationVOMAdder] / HistoricMileage$$

Regulation Maximum Allowable Cost Adder Example:

$FuelCostAdder =$
$[\$0.50 / \text{Hr} / \text{MW} + \$3.50 / \text{Hr} / \text{MW}] / 5 \Delta \text{MW} / \text{MW} = \$0.80 / \text{Hr} / \text{MW of Regulation}$

Exhibit 3: Regulation Maximum Allowable Cost Adder Example

2.9 Ten Percent Adder

In accordance with the Operating Agreement, Market Sellers can include a ten percent adder in their start-up, no-load, and incremental energy offers. The ten percent adder is limited in the following situations:

- For incremental energy offers less than \$2,000/MWh the ten percent adder is limited to the lesser of 10% or \$100 MWh, the sum of which shall not exceed \$2,000/MWh
- And for incremental energy offers greater than \$2,000/MWh, the ten percent adder is limited to \$0/MWh.

For example a Market Seller calculates the following incremental energy costs for the unit

MW	Incremental Cost (\$/MWh)
100	800
200	1100
300	1950
400	2005

Then the allowable ten percent adder for each MW step would be

MW	Incremental Cost (\$/MWh)	Calculated 10% Adder (\$/MWh)	Limitation	Allowable 10% Adder (\$/MWh)
100	800	\$80	N/A	\$80
200	1100	\$110	Lessor of 10% or \$100	\$100
300	1950	\$195	Sum shall not exceed \$2000/ MWh	\$50
400	2010	\$201	10% Adder = \$0	\$0

Section 3: Nuclear Unit Cost Guidelines

This section presents information relevant for cost development for nuclear units.

Nuclear Plant – A facility that is licensed to produce commercial power from controlled nuclear reactions to heat water to produce steam that drives steam turbines generators.

3.1 Nuclear Heat Input/Rate and Performance Factors

Note:

The information in Section 2.1 contains basic Heat Input/Rate and Performance Factor information relevant for all unit types including nuclear units.

3.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following information only pertains to nuclear units.

3.2.1 Basic Nuclear Fuel Cost

Basic Nuclear Fuel Cost -Basic nuclear fuel cost shall be based on the dollars in FERC Account 518, less in-service interest charges (whether related to fuel that is leased or capitalized). This quantity shall be calculated in units of dollars per MMBtu, as forecast for the applicable fuel cycle.

$$\frac{\text{BasicNuclearFuelCost (\$/ MMBtu)}}{\text{Fuel Cycle Heat Input (MMBtu)}} = \frac{\text{(Dollars in FERC Account 518 - InterestCost)}}{\text{Fuel Cycle Heat Input (MMBtu)}}$$

See definition in FERC account 518 in Attachment A, A2.5

3.2.2 Total Fuel-Related Costs for Nuclear Units

Note:

$$\text{TotalFuelRelatedCostsforNuclearUnits} = \text{BasicNuclearFuelCost} + \text{MaintenanceAdder}$$

3.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following information only pertains to nuclear units.

3.4 Start-up Costs

Note:

The information in Section 2.4 contains basic Start-up Cost information relevant for all unit types. The following information only pertains to nuclear units.

Start-up Cost – The dollars per start as determined from start fuel, Total Fuel-Related Cost, Performance Factor, electrical costs, and start maintenance adder. . Start-up Costs for nuclear units include a soak process and shall never be less than zero.

$$\begin{aligned} \text{Start up Cost (\$/ Start)} = & \\ & (\text{Start Fuel Consumed (MMBtu / Start)} * \text{TFRC} (\$/ \text{ MMBtu}) * \text{Performance Factor}) \\ & + (\text{Station Service (MWh)} * \text{Station Service Rate (\$/ MWh)}) \\ & + \text{Start Maintenance Adder (\$/ Start)} \end{aligned}$$

Start Fuel Consumed is the start fuel during the unit specific start time plus notification time to to the level at which the unit can follow PJM’s dispatch (including auxiliary boiler fuel) plus the shutdown fuel from last breaker opening to shutdown (not to exceed the unit specific minimum down time minus the unit specific hot start time) excluding normal plant heating/auxiliary equipment fuel requirements. Start fuel included for each temperature state from breaker closure to the level at which the unit can follow PJM’s dispatch shall not exceed the unit specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time
- Hot Soak Time = 0.43 * unit specific Minimum Run Time

Market Sellers can request unit specific soak times through the PJM/IMM unit specific parameter review process.

TFRC = Total Fuel Related Cost (See Section 2.2.3)

Station Service is Station power consumed from PJM notification to first breaker close,

Plus (+) station power consumed after breaker open to shutdown above normal base unit use,

Minus (-) net generation produced from first breaker close to the level at which the unit can follow PJM's dispatch.

Normal base station use is the consumption prior to PJM's notification. Net generation included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults above.

Station Service Rate - A \$/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection.

Start Maintenance Adder - (See Section 2.6)

3.4.1 Hot Start-up Cost

Hot Start-up Cost is the expected cost to start a steam unit, which is in the "hot" condition. Hot conditions vary unit by unit, but in general, a unit is hot after an overnight shutdown.

3.4.2 Intermediate Start-up Cost

Intermediate Start-up Cost is the expected cost to start a steam unit during a period where neither hot or cold conditions apply. Use of intermediate start cost is optional based on Market Seller's policy and physical machine characteristics. The only restriction is that once an intermediate Start-up Cost is defined for a unit, the cost must be used consistently in scheduling and accounting.

3.4.3 Cold Start-up Cost

Cold Start-up Cost is the expected cost to start a steam unit that is in the "cold" condition. Cold conditions vary unit by unit, but in general, a unit is cold after a two or three-day shutdown.

3.5 No-Load Cost

Note:

The information in Section 2.5 contains basic no-load cost information relevant for all unit types including nuclear units.

3.6 Maintenance Cost

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types including nuclear units.

Nuclear Maintenance Adder - The dollars per unit of fuel (or heat) as derived from FERC Accounts 530 and 531 for nuclear steam units. Market Sellers that use FERC Accounts must remove straight time labor when calculating the Maintenance Adder.

3.6.1 Configuration Addition Maintenance Adder

For units undergoing a significant system or unit Configuration Addition the use of an additional “Configuration Addition Maintenance Adder” may be included in the determination of the total maintenance adder. It is not intended to be used for upgrades to existing equipment

Examples of significant system or unit Configuration Additions may include but are not limited to:

- Conversion from open loop to closed loop circulation water systems

The specific system or unit configuration system change must be reviewed by PJM and the MMU for evaluation pursuant to the Cost Methodology and Approval Process prior to approving the use of a Configuration Addition Maintenance adder.

To calculate Total Maintenance Dollars for 2011, this example assumes a maintenance period of 10 years; please see section 2.6.3 for further explanation of Maintenance Periods.

$$\begin{aligned}
 & \textit{TotalMaintenanceCost}_{2011} = \\
 & \left((FERC\ 530\ \&\ FERC\ 531 - \textit{StartCosts\ in\ FERC\ 530\ \&\ FERC\ 531}_{2010}) * \frac{\textit{EscalationIndex}_{2011}}{\textit{EscalationIndex}_{2010}} \right) \\
 & + \left((FERC\ 530\ \&\ FERC\ 531 - \textit{StartCosts\ in\ FERC\ 530\ \&\ FERC\ 531}_{2009}) * \frac{\textit{EscalationIndex}_{2011}}{\textit{EscalationIndex}_{2009}} \right) \\
 & + \left((FERC\ 530\ \&\ FERC\ 531 - \textit{StartCosts\ in\ FERC\ 530\ \&\ FERC\ 531}_{2008}) * \frac{\textit{EscalationIndex}_{2011}}{\textit{EscalationIndex}_{2008}} \right) + \\
 & \dots \left((FERC\ 530\ \&\ FERC\ 531 - \textit{StartCosts\ in\ FERC\ 530\ \&\ FERC\ 531}_{2000}) * \frac{\textit{EscalationIndex}_{2011}}{\textit{EscalationIndex}_{2000}} \right)
 \end{aligned}$$

This formula calculates total fuel for the maintenance period:

$$\textit{TotalFuel} = \textit{Fuel}_{2010} + \textit{Fuel}_{2009} + \textit{Fuel}_{2008} + \dots \textit{Fuel}_{2000}$$

These allow for the calculation of the maintenance adder.

Example of Nuclear Unit’s Formula of Maintenance Adder:

$$\textit{MaintenanceAdder}_{2011} = \frac{\textit{TotalMaintenanceDollars}}{\textit{TotalFuel}}$$

To calculate the Start Maintenance Adder, calculate the total Start Maintenance Cost. Please note the expenses in the maintenance adder and the expenses in the start maintenance adder are mutually exclusive.

$$\begin{aligned}
 & \text{TotalStartMaintenanceCost} = \\
 & \left(\left(\text{StartCosts in FERC 530 \& FERC 531} \right)_{2010} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2010}} \right) \\
 & + \left(\left(\text{StartCosts in FERC 530 \& FERC 531} \right)_{2009} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2009}} \right) \\
 & + \left(\left(\text{StartCosts in FERC 530 \& FERC 531} \right)_{2008} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2008}} \right) + \\
 & \dots \left(\left(\text{StartCosts in FERC 530 \& FERC 531} \right)_{2000} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2000}} \right)
 \end{aligned}$$

This formula calculates the total number of starts:

$$\text{TotalStarts} = \text{Starts}_{2010} + \text{Starts}_{2009} + \text{Starts}_{2008} + \text{Starts}_{2000}$$

These allow for the calculation of the start maintenance adder:

$$\begin{aligned}
 & \text{StartMaintenanceAdder}_{2011} (\$/\text{Start}) \\
 & = \frac{\text{InflationAdjusted TotalStartMaintenanceCost}_{2011}}{\text{TotalStarts}_{2000}}
 \end{aligned}$$

3.6.2 Calculation of the Configuration Addition Maintenance Adder:

The Configuration Addition Maintenance adder is to be calculated in the same manner as the maintenance cost adder described in this section with the exception that the Configuration Addition Maintenance total maintenance dollars (CATMD) are only the incremental additional costs incurred because of the system or unit configuration change.

As with the current maintenance adder calculation, the adder for year (Y) uses the actual costs beginning with year (Y-1). Therefore, the first year of actual incremental additional expenses will be captured by the **CAMA** in the second year.

Following the initial year of use of the **CAMA**, each additional year's Configuration Addition Maintenance cost will be incorporated into the Configuration Addition Maintenance adder until the end of the historical maintenance cost period selected for the unit.

To calculate the Configuration Addition Maintenance Adder, calculate the solely incremental Maintenance Cost for the Configuration Change. Please note these expenses are purely incremental.

$$\begin{aligned}
 & \text{TotalConfigurationAdditionMaintenanceDollars} = \\
 & \left(\text{Incremental}(\text{FERC 530} + \text{FERC 531} - \right. \\
 & \left. \text{StartCost FERC 530} + \text{FERC 531})_{2010} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2010}} \right) +
 \end{aligned}$$

$$\left(\begin{array}{c} \text{Incremental}(\text{FERC 530} + \text{FERC 531} - \\ \text{StartCost FERC 530} + \text{FERC 531})_{2009} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2009}} \end{array} \right) +$$

$$\left(\begin{array}{c} \text{Incremental}(\text{FERC 530} + \text{FERC 531} - \\ \text{StartCost FERC 530} + \text{FERC 531})_{2008} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2008}} \end{array} \right) +$$

$$\dots \left(\begin{array}{c} \text{Incremental}(\text{FERC 530} + \text{FERC 531} - \\ \text{StartCost FERC 530} + \text{FERC 531})_{2000} \times \frac{\text{EscalationIndex}_{2011}}{\text{EscalationIndex}_{2000}} \end{array} \right)$$

$\text{ConfigurationAdditionMaintenanceAdder} = \frac{\text{TotalConfigurationAdditionDollars}}{\text{TotalFuel}}$
--

Exhibit 4: Nuclear Unit's Formula of Configuration Addition Maintenance Adder

3.6.3 Reductions in Total Maintenance Costs

While it is expected that the Configuration Addition Maintenance adder will most often be used to cover step increases in maintenance costs, it is also to be used to capture step decreases in maintenance costs resulting from a significant system or unit configuration change that results in a significant reduction in maintenance costs. Any equipment that falls into disuse or is retired because of the configuration change must have its maintenance expenses removed from the historical record used to develop the maintenance adder. An example of a significant system or unit configuration change that may result in a step decrease in qualified maintenance costs includes, but is not limited to, conversion from open loop to closed loop circulation water systems.

3.7 Synchronized Reserve Cost

Note:

The information in Section 2.7 contains basic Synchronized Reserve information relevant for all unit types including nuclear units where applicable.

3.8 Regulation Cost

Note:

The information in Section 2.8 contains basic Regulation information relevant for all unit types including nuclear units where applicable.

Section 4: Fossil Steam Unit Cost Development

This section contains information pertaining to Fossil Steam Unit Cost development.

Fossil Steam Turbine plants use combusted fossil fuels to heat water and create steam that generates the dynamic pressure to turn the blades of a steam turbine generator.

Units that fire solid waste, biomass, or landfill gas solely or in conjunction with fossil fuels to heat water and create steam to drive a steam turbine generator are considered to be **Fossil Steam Turbine plants**.

4.1 Heat Input/Rate and Performance Factor

Note:

The information in Section 2.1 contains basic Heat Input/Rate and Performance Factor information relevant for all unit types including fossil steam units.

Like units that can be used for calculation of Performance Factors are units having similar ratings, steam conditions, make or model and same site location.

Fossil steam units with multiple boilers can use two methods to develop heat input curves

Heat input based on the unit's entire operational range: This method uses all the historical operating data to calculate a single heat input curve. The start heat input is calculated as the heat input of starting the full configuration.

Heat input based on the unit's operation in each boiler configuration: This method uses all the historical operating data per configuration to calculate a heat input curve for each configuration. The start heat input is calculated as the heat input of starting each configuration. The configurations differ depending on the number of boilers in operation.

4.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following information only pertains to fossil steam units.

Fossil fuel cost adjustments compensating for previous estimate inaccuracies should not be considered when determining the basic fossil cost component of Total Fuel Related Cost.

Fossil Operating Costs

The dollars in FERC Account 501 Fuel plus incremental expenses for fuel treatment and pollution control (excluding SO₂ and NO_x emission allowance costs) that were not included in FERC Account 501; minus the fuel expenses from FERC Account 151 that were charged into FERC Account 501, all divided by the fuel (heat content or quantity) shifted from FERC Account 151 into FERC Account 501.

4.2.1 Total Fuel Related Cost

Total Fuel Related Cost is the sum of the Basic Fuel Cost, and the Maintenance Adder, Operating Cost Adder, CO₂, SO₂ and NO_x emission allowance costs.

$$\begin{aligned} \text{Total Fuel Related Cost (\$/MMBtu)} = \\ & \text{Fuel Cost} + \text{SO}_2 \text{ Allowance Cost} + \text{CO}_2 \text{ Allowance Cost} \\ & + \text{NO}_x \text{ Allowance Cost} + \text{Maintenance Adder} + \text{Operating Cost Adder} \end{aligned}$$

4.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following information only pertains to fossil steam units.

4.4 Start-up Cost

Note:

The information in Section 2.4 contains basic Start-up Cost information relevant for all unit types. The following information only pertains to fossil steam units.

Note:

In some instances, a Steam Unit with a Start-up plus Notification time greater than 48 hours may enter a state called “Extended Cold Start” as defined in M10, M13, M14D and the Markets Gateway User Guide. Steam units in this state, calculate the Start Cost information associated with this state in accordance with the “Cold Start Cost” Section below and enter this value into the “Cold Start Cost” field in Markets Gateway

Steam units include a soak process during startup for the steam turbine. Start-up Costs for steam units shall include only the following components and shall never be less than zero:

$$\begin{aligned} \text{Start up Cost}(\$/\text{Start}) = \\ & [\text{Start Fuel Consumed (MMBtu / Start)} * \text{TFRC}(\$/\text{MMBtu}) * \text{Performance Factor}] \\ & + [\text{Station Service (MWh)} * \text{Station Service Rate}(\$/\text{MWh})] \end{aligned}$$

+ Start Maintenance Adder (\$ / Start)

Start Fuel Consumed is the start fuel during the unit specific start time plus notification time to dispatchable output (including auxiliary boiler fuel) plus the shutdown fuel from last breaker opening to shutdown (not to exceed the unit specific minimum down time minus the unit specific hot start time) excluding normal plant heating/auxiliary equipment fuel requirements. Start fuel included for each temperature state from breaker closure to the level at which the unit can follow PJM's dispatch shall not exceed the unit specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults below:

- Cold Soak Time = $0.73 * \text{unit specific Minimum Run Time}$
- Intermediate Soak Time = $0.61 * \text{unit specific Minimum Run Time}$
- Hot Soak Time = $0.43 * \text{unit specific Minimum Run Time}$

Market Sellers can request unit specific soak times through the PJM/IMM unit specific parameter review process.

TFRC = Total Fuel Related Cost (See Section 2.2.3)

Station Service is Station power consumed from PJM notification to first breaker close,

Plus (+) station power consumed after breaker open to shutdown above normal base unit use,

Minus (-) net generation produced from first breaker close to level at which the unit can follow PJM's dispatch.

Normal base station use is the consumption prior to PJM's notification. Net generation included for each temperature state from breaker closure to the level at which the unit can follow PJM's dispatch shall not exceed the unit specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults above.

Station Service Rate - A \$/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection.

Start Maintenance Adder. This quantity includes the previously defined steam turbine Starting Maintenance Cost in \$/start. (See Section 2.6).

4.4.1 Hot Start-up Cost

Hot Start-up Cost is the expected cost to start a steam unit, which is in the "hot" condition. Hot conditions vary unit by unit, but in general, a unit is hot after an overnight shutdown.

4.4.2 Intermediate Start-up Cost

Intermediate Start-up Cost is the expected cost to start a steam unit during a period where neither hot nor cold conditions apply. Use of intermediate Start-up Cost is optional based on company policy and physical machine characteristics. The only restriction is that once an

intermediate Start-up Cost is defined for a unit, the cost must be used consistently in scheduling and accounting.

4.4.3 Cold Start-up Cost

Cold Start-up Cost is the expected cost to start a steam unit that is in the "cold" condition. Cold conditions vary unit by unit, but in general, a unit is cold after a two or three-day shutdown.

4.5 No-Load Cost

Note:

The information in Section 2.5 contains basic no-load cost information relevant for all unit types including fossil steam units.

4.6 Maintenance Cost

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following information only pertains to fossil steam units.

Fossil Steam - Maintenance Adder - is the dollars per unit of fuel (or heat) as derived from FERC Accounts 512 and 513 for fossil steam units. Market Sellers that use FERC Accounts must remove straight-time labor when calculating the Maintenance Adder.

Note:

Total Maintenance Dollars (TMD) plus (+) Total Start Maintenance Dollars (TSD) cannot exceed Total Dollars in FERC Accounts 512 and 513 minus labor.

Calculate total Maintenance Dollars for 2011, this example assumes a maintenance period of 10 years; please see section 2.6.3 for further explanation of Maintenance Periods.

Total Maintenance Dollars =

$$\left(\left(\left(FERC\ 512 + FERC\ 513 \right) - Start\ Cost \left(FERC\ 512 + FERC\ 513 \right)_{2010} \right)^* \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2010}} \right) +$$

$$\left(\left(\left(FERC\ 512 + FERC\ 513 \right) - Start\ Cost \left(FERC\ 512 + FERC\ 513 \right)_{2009} \right)^* \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2009}} \right) +$$

$$\left(\left(\left(FERC\ 512 + FERC\ 513 \right) - Start\ Cost \left(FERC\ 512 + FERC\ 513 \right)_{2008} \right)^* \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2008}} \right) + \dots$$

$$\left((FERC\ 512 + FERC\ 513) - Start\ Cost\ (FERC\ 512 + FERC\ 513)_{2000} \right) * \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2000}} +$$

Calculate total fuel burned (heat input in MMBtu) for the maintenance period.

$$Total\ Fuel = Fuel_{2010} + Fuel_{2009} + Fuel_{2008} + \dots + Fuel_{2000}$$

These allow for the calculation of the maintenance adder:

$$Maintenance\ Adder_{2011}\ (\$/\ MMBtu) = \frac{Total\ Maintenance\ Dollars}{Total\ Fuel}$$

Exhibit 5: Fossil Steam Unit's Sample Formula of Maintenance Adder

To Calculate the Start Maintenance Adder, Calculate the total Start Maintenance Cost. Please note the expenses in the maintenance adder and the expenses in the start maintenance adder are mutually exclusive.

Total Start Maintenance Cost =

$$\begin{aligned} & \left(Start\ Cost\ (FERC\ 512 + FERC\ 513)_{2010} * \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2010}} \right) + \\ & \left(Start\ Cost\ (FERC\ 512 + FERC\ 513)_{2009} * \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2009}} \right) + \\ & \left(Start\ Cost\ (FERC\ 512 + FERC\ 513)_{2008} * \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2008}} \right) + \dots \\ & \left(Start\ Cost\ (FERC\ 512 + FERC\ 513)_{2000} * \frac{Escalation\ Index_{2011}}{Escalation\ Index_{2000}} \right) + \end{aligned}$$

This formula calculates the total number of starts:

$$Total\ Starts = Starts_{2010} + Starts_{2009} + Starts_{2008} + \dots + Starts_{2000}$$

These allow for the calculation of the start maintenance adder:

$$Start\ Maintenance\ Adder\ (\$/\ Start) = \frac{Total\ Start\ Maintenance\ Cost}{Total\ Starts}$$

Exhibit 6: Fossil Steam Unit's Sample Formula of Start Maintenance Adder

4.6.1 Configuration Addition Maintenance Adder

For units undergoing a significant system or unit Configuration Addition the use of an additional "Configuration Addition Maintenance Adder" may be included in the determination of the total maintenance adder. It is not intended to be used for upgrades to existing equipment (i.e.: replacement of a standard burner with a low NO_x burner).

Examples of significant system or unit Configuration Additions may include but are not limited to:

- Installation of Flue Gas Desulfurization (FGD or scrubber) systems
- Activated Carbon Injection (ACI) or other sorbent injection systems
- Installation of SCR or SNCR NOx removal systems
- Conversion from open loop to closed loop circulation water systems
- Bag House addition
- Water injection for NOx control
- Turbine Inlet Air Cooling

The specific system or unit configuration system change needs to be reviewed by PJM and the MMU pursuant to the Cost Methodology and Approval Process and receive final approval thereof prior to the use of a Configuration Addition Maintenance adder.

4.6.2 Calculation of the Configuration Addition Maintenance Adder:

The Configuration Addition Maintenance adder is to be calculated in the same manner as the maintenance cost adder described in this section with the exception that the Configuration Addition Maintenance total maintenance dollars (CATMD) are only the incremental additional costs incurred because of the system or unit configuration change.

As with the current maintenance adder calculation, the adder for year (Y) uses the actual costs beginning with year (Y-1). Therefore, the first year of actual incremental additional expenses will be captured by the **CAMA** in the second year.

Following the initial year of use of the **CAMA**, each additional year's Configuration Addition maintenance cost will be incorporated into the Configuration Addition maintenance adder until the end of the historical maintenance cost period selected for the unit.

To Calculate the Configuration Addition Maintenance Adder, Calculate the solely incremental Maintenance Cost for the Configuration Change. Please note these expenses are purely incremental and adhere to the requirements in section 3.8.1. Also note that labor must be removed from all applicable FERC Accounts.

$$\begin{aligned}
 & \text{Total Configuration Addition Maintenance Dollars} = \\
 & \left(\text{Incremental} \left(\text{FERC 512} + \text{FERC 513} - \text{Start Cost FERC 512} + \text{FERC 513} \right)_{2010} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2010}} \right) + \\
 & \left(\text{Incremental} \left(\text{FERC 512} + \text{FERC 513} - \text{Start Cost FERC 512} + \text{FERC 513} \right)_{2009} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2009}} \right) + \\
 & \left(\text{Incremental} \left(\text{FERC 512} + \text{FERC 513} - \text{Start Cost FERC 512} + \text{FERC 513} \right)_{2008} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2008}} \right) + \dots
 \end{aligned}$$

$$\left(\text{Incremental} \left(\text{FERC 512} + \text{FERC 513} - \text{Start Cost FERC 512} + \text{FERC 513} \right)_{2000} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2000}} \right)$$

Exhibit 7: Fossil Unit's Sample Formula of Configuration Addition Maintenance Adder

4.6.3 Reductions in Total Maintenance Costs:

While it is expected that the Configuration Addition Maintenance adder will most often be used to cover step increases in maintenance costs, it is also to be used to capture step decreases in maintenance costs resulting from a significant system or unit configuration change that results in a significant reduction in maintenance costs. Any equipment that falls into disuse or is retired because of the configuration change must have its maintenance expenses removed from the historical record used to develop the maintenance adder. An example of a significant system or unit configuration change that may result in a step decrease in qualified maintenance costs includes, but is not limited to, a fuel change from coal to gas fuel.

4.7 Synchronized Reserve

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following information only pertains to fossil steam units.

Total costs to provide Synchronized Reserve from a steam unit shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

$$\text{Expected Value of Penalty} \left(\frac{\$}{\text{MWh}} \right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty} \left(\frac{\$}{\text{MWh}} \right) = \frac{\text{Total Penalty} (\$)}{\text{Total Shortfall} (\text{MWh})}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events} \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

4.8 Regulation

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types including fossil steam units.

Section 5: Combined Cycle (CC) Cost Development

This section contains information pertaining to CC Cost development.

Combined Cycle - An electric generating technology in which electricity is generated by both a CT generator (the Brayton Cycle) and a steam turbine generator (the Rankine Cycle) hence the name CC. The CT exhaust heat flows to a conventional boiler or to a heat recovery steam generator (HRSG) to produce steam for use by a steam turbine generator in the production of electricity.

Heat recovery steam generator (HRSG) – A CT exhaust feeds hot gas into a heat to steam exchanger installed on combined-cycle power plants designed to utilize the heat in the CT exhaust to produce steam to drive a conventional steam turbine generator.

5.1 Heat Input/Rate and Performance Factor

Note:

The information in Section 2.1 contains basic Heat Input/Rate and Performance Factor information relevant for all unit types including CC.

Combined cycles with a 2x1 configuration (two combustion turbines and one steam turbine) or higher can use three methods to develop heat input curves.

1. Heat input based on the unit's entire operational range: This method uses all the historical operating data to calculate a single heat input curve. The start heat input is calculated as the heat input of starting the full configuration.
2. Heat input based on the unit's operation in each configuration: This method uses all the historical operating data per configuration to calculate a heat input curve for each configuration.
3. Pseudo heat input curve: The pseudo combined cycle model is a type of generator modeling in which a combined cycle is divided into separate units depending on the number of combustion turbines and the output of the steam turbine is assigned evenly across the combustion turbines.

For example, a 600 MW 2x1 combined cycle comprised of two 200 MW combustion turbines and a 200 MW steam turbine can be modeled as two separate 300 MW units (200 MW for each combustion turbine plus 100 MW assigned from the steam turbine assigned evenly).

When using the pseudo combined cycle model, the heat input curve must be adjusted. A typical heat input curve is defined by a quadratic equation.

Typical Heat Input Equation:

$$\text{Heat Input} \left(\frac{\text{MMBtu}}{\text{hour}} \right) = A + B * \text{Unit Output MW h} + C * \text{Unit Output}^2 (\text{MW h})$$

In order to use this equation in pseudo model, the constant coefficient (term A) must be divided by the number of combustion turbines in the combined cycle, the linear coefficient (term B) remains the same and the quadratic coefficient (term C) is multiplied by the number of combustion turbines.

For example, if the equation represents a 2x1 configuration, the constant coefficient used in each pseudo model must be divided by two and the quadratic coefficient must be multiplied by two.

The equation below shows the pseudo combined cycle model heat input equation.

$$\text{Heat Input} \left(\frac{\text{MMBtu}}{\text{hour}} \right) = \frac{A}{CT_Count} + B * \text{Unit Output (MW h)} + CT_Count * C * \text{Unit Output (MW h)}^2$$

Where:

A = The constant coefficient of the heat input curve of the full configuration

B = The linear coefficient of the heat input curve of the full configuration

C = The quadratic coefficient of the heat input curve of the full configuration

CT_Count = Number of combustion turbines in the full configuration

5.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types including CC units.

5.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types including CC units.

5.4 Start-up Cost

Note:

The information in Section 2.4 contains basic Start-up Cost information relevant for all unit types. The following additional information only pertains to CC units.

Combined Cycle (CC) units include a soak process during startup for the steam turbine. Start-up Costs for Combined Cycle plants shall include only the following components and shall never be less than zero:

$$\begin{aligned} \text{Start up Cost (\$/ Start)} = & \\ & (\text{Start Fuel Consumed (MMBtu / Start)} * \text{TFRC}(\$/ \text{ MMBtu}) * \text{Performance Factor}) \\ & + (\text{Station Service (MWh)} * \text{Station Service Rate (\$/ MWh)}) \\ & + \text{Start Maintenance Adder (\$/ Start)} \end{aligned}$$

Start Fuel Consumed is the start fuel during the unit specific start time plus notification time to the level at which the unit can follow PJM's dispatch (including auxiliary boiler fuel) plus the shutdown fuel from last breaker opening to shutdown (not to exceed the unit specific minimum down time minus the unit specific hot start time). Additionally, this includes the start fuel for any CT unit/HRSG combinations started prior to reaching the level at which the unit can follow PJM's dispatch. Start fuel included for each temperature state from breaker closure to the level at which the unit can follow PJM's dispatch shall not exceed the unit specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time
- Hot Soak Time = 0.43 * unit specific Minimum Run Time

Market Sellers can request unit specific soak times through the PJM/IMM unit specific parameter review process.

TFRC = Total Fuel Related Cost (See Section 2.2.3)

Station Service is Station power consumed from PJM notification to first breaker close,

Plus (+) station power consumed after breaker open to shutdown above normal base unit use,

Minus (-) net generation produced from first breaker close to the level at which the unit can follow PJM's dispatch.

Normal base station use is the consumption prior to PJM's notification. Net generation included for each temperature state from breaker closure to dispatchable output shall not exceed the unit

specific soak time period reviewed and approved as part of the PJM/IMM unit specific parameter process or the defaults above.

Station Service Rate - A \$/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection.

Start Maintenance Adder. This quantity includes the previously defined CC Starting Maintenance Cost in \$/start. (See Section 2.6).

5.5 No-Load Cost

Note:

The information in Section 2.5 contains basic -no-load cost information relevant for all unit types including CC units.

5.6 Maintenance Cost

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to CC units.

Combined Cycle Maintenance Adder – The dollars per unit of fuel (or heat) as derived from actual maintenance expenses or FERC Accounts 512, 513, and 553. If submitting as a simple cycle CT, use actual maintenance expenses or total dollars from FERC Account 553 divided by Equivalent Service Hours (ESH), MWh, starts, or hours. Market Sellers that use FERC Accounts must remove straight time labor when calculating the Maintenance Adder.

5.6.1 Combined Cycle / CT Long Term Service Agreement Cost Recovery

A Market Seller that has a currently in effect Long Term Service Contract (LTSA) with a third party vendor to provide overhaul and maintenance work on a CT either as part of a CC plant or as a stand-alone CT, may file with PJM and the MMU for inclusion of any variable long term maintenance costs in cost based offer bids pursuant to the Cost Methodology and Approval Process, if the following conditions are met:

- The included variable long-term maintenance costs are consistent with the definition of such costs in the Cost Development Guidelines
- And the dollar value of each component of the variable long-term maintenance costs is set specifically in the LTSA.
- Costs are specified on either an operating hour or number of starts basis.

5.6.2 Long Term Maintenance Expenses

Long Term Maintenance Expenses - CC Plant major inspection and overhaul expenses can be included in the calculation of a combustion turbine's or diesel engine's maintenance adder if they were not included in the unit's capacity offer for a Delivery Year in which the unit cleared a Base Residual or Incremental Auction.

5.6.3 Equivalent Service Hours (ESH)

CC CTs shall use OEM supplied values for cyclic starting factors and cyclic peaking factors and formulas even if the CT technology is no longer being built. Some OEMs use ESH to trigger when a major overhaul should be performed. These are typically found in OEM or LTSA documentation under "equivalent hours", "equivalent starts", "factored hours", or "factored starts".

Only OEM-specified cyclic starting and peaking factors can be applied to the Maintenance Adder of the unit's cost-based offer. If the OEM documentation does not specify a cyclic starting factor and/or cyclic peaking factor, then the cyclic starting factor and/or cyclic peaking factor shall be zero.

5.7 Synchronized Reserve

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following information only pertains to CC units.

Total costs to provide Synchronized Reserve from a CC unit shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

$$\text{Expected Value of Penalty} \left(\frac{\$}{\text{MWh}} \right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty} \left(\frac{\$}{\text{MWh}} \right) = \frac{\text{Total Penalty} (\$)}{\text{Total Shortfall} (\text{MWh})}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events} \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

5.8 Regulation

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types including CC units.

Section 6: Combustion Turbine (CT) and Diesel Engine Costs

This section details specific information for the cost development of units that are CTs or diesel engines.

Combustion Turbine Unit – A generating unit in which a natural gas or oil fired CT engine is the prime mover for an electrical generator. CTs that fire landfill gas solely or in conjunction with fossil fuels as a prime mover for an electrical generator are considered to be a Combustion Turbine Unit.

Diesel Engine – A generating unit in which a diesel reciprocating engine is the prime mover for an electrical generator. Reciprocating engines that fire landfill gas solely or in conjunction with fossil fuels as a prime mover for an electrical generator are considered to be a Diesel Engine.

6.1 Combustion Turbine and Diesel Engine Heat Input/Rate and Performance Factor

Note:

The information in Section 2.1 contains basic Input/Heat Rate and Performance Factor information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

‘Like’ CT Units - An average Performance Factor may be calculated and applied for groups of like units burning the same type of fuel. Like includes same primary manufacturer not necessarily engine or generator manufacturer, but one with overall system responsibility. The following are two examples:

- Worthington sells CT's with P&W engines and a GE generator. Worthington would be considered the primary manufacturer.
- Same general frame size - a manufacturer may modify a basic design to produce units with varying capabilities. Units built with such variations may be placed in a may be placed in a single group.

6.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost Factor information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

CT Maintenance Adder is included directly with the individual operating cost components on a \$/hour basis.

6.2.1 Combustion Turbine Operating Costs

The dollars in FERC Account 547, plus incremental expenses for fuel treatment and pollution control excluding SO₂ and NO_x emission allowance costs that were not included in Account 547; minus the fuel expenses from FERC Account 151 that were charged into Account 547, all divided by the fuel (heat content or quantity) shifted from Account 151 into Account 547.

6.2.2 Total Fuel Related Cost (TFRC) Equation for CTs

$$\begin{aligned} \text{Total Fuel Related Costs for Combustion Turbines} = \\ \text{Basic Fossil Fuel Cost} + \text{operating cost adder} \\ \text{SO}_2 \text{ emission costs} + \text{NO}_x \text{ emission costs} + \text{CO}_2 \text{ emission costs} \end{aligned}$$

Note:

CT Maintenance Adder is included directly in start, no-load and peak segment components.

6.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

6.4 Start-up Cost

Note:

The information in Section 2.4 contains basic Start-up Cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

Combustion turbine and diesel engine units do not include a soak process during startup. Aggregated combustion turbine or diesel engine market units can only include the start cost of the first combustion turbine or engine if the other combustion turbines or engines are offered as dispatchable points in the incremental offer. Start-up costs for all CTs and diesel units shall include only the following components and shall never be less than zero:

$$\begin{aligned} \text{Start up Cost} \left(\frac{\$}{\text{Start}} \right) \\ = (\text{Start Fuel Consumed (MMBtu / Start)} * \text{TFRC} (\$ / \text{MMBtu}) * \text{Performance Factor}) \end{aligned}$$

$$\begin{aligned} & +(\text{Station Service (MWh)} * \text{Station Service Rate (\$/MWh)}) \\ & + \text{Start Maintenance Adder (\$/Start)} \end{aligned}$$

Start Fuel Consumed is the start fuel during the unit specific start time plus notification time to first breaker closing, Plus (+) shutdown fuel from unit breaker opening to fuel valve closure.

TFRC = Total Fuel Related Cost (See Section 2.2.3)

Station Service from initiation of start sequence to breaker closing (total station use minus normal base station use). Plus (+) station service after breaker opening during shutdown (station service during shutdown should be that associated with the normal unit auxiliary equipment operated during shutdown in excess of base unit use, this station service is not to include maintenance use or non-normal uses).

Station Service Rate - A \$/MWh value based on the 12-month rolling average off-peak energy prices updated quarterly by the Office of the Interconnection.

Start Maintenance Adder. please see section 6.6.3

Reminder: CT Maintenance Adder is included directly in start, no-load and peak segment components.

6.5 No-Load Cost Calculation for CTs

Note:

The information in Section 2.5 contains basic no-load cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

Note:

CT Maintenance Adder is included directly in start, no-load and peak segment components.

For CT generating units, no-load fuel shall be the theoretical or actual fuel burn rate expressed in MMBtu/Hr at the point of electric bus synchronization.

6.6 Maintenance Cost

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

CT - Maintenance Adder – The total dollars from actual maintenance expenses or FERC Account 553 divided by Equivalent Service Hours (ESH), MWh, starts, hours, or per unit of fuel (or heat). Market Sellers that use FERC Accounts must remove straight time labor when calculating the Maintenance Adder.

Industrial CT – This is a CT developed specifically for power generation.

Aircraft - Type CT – These are CTs originally designed for aircraft and modified for power generation.

Diesel - Maintenance Adder – The total dollars from FERC Account 553 divided by total fuel burned (in MMBtu's).

Combustion Turbine Start – For calculating CT maintenance cost, only the number of successful starts to synchronization shall be used. Successful starts should include those at the direction of PJM and for company tests.

Long Term Maintenance Expenses – CT Plant major inspection and overhaul expenses can be included in the calculation of a combustion turbine's or diesel engine's maintenance adder if they were not included in the unit's capacity offer for a Delivery Year in which the unit cleared a Base Residual or Incremental Auction.

6.6.1 Combustion Turbine Long Term Service Agreement Cost Recovery

A Market Seller that has a currently effective LTSA with a third party vendor to provide overhaul and maintenance work on a CT may file a request to PJM and the MMU for inclusion of any variable long term maintenance costs in cost based offer bids, pursuant to the Cost Methodology and Approval Process if the following conditions are met:

- The included variable long-term maintenance costs are consistent with the definition of such costs in the Cost Development Guidelines
- And the dollar value of each component of the variable long-term maintenance costs is set specifically in the LTSA.
- Costs are specified on either an operating hour or number of starts basis.

6.6.2 Long Term Maintenance Expenses

- **Long Term Maintenance Expenses** - Major inspection and overhaul expenses can be included in the calculation of a combustion turbine's or diesel engine's maintenance adder if they were not included in the unit's capacity offer for a Delivery Year in which the unit cleared a Base Residual or Incremental Auction.

6.6.3 Equivalent Service Hours (ESH)

CTs shall use OEM supplied values for cyclic starting factors and cyclic peaking factors and formulas even if the CT technology is no longer being built. Only OEM-specified cyclic starting

and peaking factors can be applied to the Maintenance Adder of the unit's cost-based offer. If the OEM documentation does not specify a cyclic starting factor and/or cyclic peaking factor, then the cyclic starting factor and/or cyclic peaking factor shall be zero.

6.6.4 Combustion Turbine Maintenance Adder Example

$$\text{Equivalent Service Hours Maintenance Cost} = \frac{\text{Total Maintenance Dollars}}{\text{Equivalent Service Hours}}$$

(Industrial Unit)

Peak Hours = 200 Hrs
Service Hours = 2000 Hrs
No. of Starts = 300
Peak Pickup = 5 MW

Peak Hours are the hours run above base load temperature rating.

Total Maintenance Dollars =\$100,000

(Actual historical maintenance data escalated to present value).

Cyclic starting factor = 10, Cyclic peaking factor = 3

Equivalent Service Hours Maintenance Cost =

$$\frac{\$100,000}{(10*300) + 2,000 + (3*200)} = \frac{\$17.86}{ESH}$$

Calculation of maintenance rates

Starting Maintenance Cost

= Cyclic Starting Factor*Equivalent Service Hours Maintenance Cost

= 10*\$17.86 = \$178.60 per start

Hourly Maintenance Rate = Equivalent Service Hours Maintenance Cost = \$17.86 / hour

Peak Incremental Maintenance Rate =

$$\frac{\text{Cyclic Peaking Factor} *}{\text{Peak Pickup}}$$

Peak Segment Equivalent Maintenance Cost = $\frac{3\$17.86}{5} = \10.72 per MWh*

Exhibit 8: Combustion Turbine Maintenance Cost Adder Example

6.6.5 Diesel Incremental Maintenance Adder Calculation

The incremental Maintenance Adder for diesel units will be calculated and applied on a "per MMBtu (or other unit of fuel)" basis. The calculation will be based on actual operation and escalated maintenance expenses for all available history in the Maintenance Period.

6.7 Synchronized Reserve: Costs to Condense

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

Total synchronous condensing costs for CTs and diesel units shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

$$\text{Expected Value of Penalty} \left(\frac{\$}{MWh} \right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty} \left(\frac{\$}{MWh} \right) = \frac{\text{Total Penalty} (\$)}{\text{Total Shortfall} (MWh)}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events} \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

- **Start-up Costs** if applicable, shall be applied when a unit moves from cold to condensing operations and when a unit moves from condensing operations to energy generation, but shall not be applied when a unit moves from energy generation to condensing operations.
- **Actual cost of power consumed during condensing operations** at real time bus LMP as determined by Market Settlements. MW consumed must be included in the offer.

6.8 Regulation Cost

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types. The following additional information only pertains to CT and diesel engine units.

Section 7: Hydro

This section contains information for the development of Hydro or Pumped Storage Hydro cost offers.

Hydro Units – Generating unit in which the energy of flowing water drives the turbine generator to produce electricity. This classification includes pumped and run-of-river hydro.

Pumped Storage Hydro Unit – Hydroelectric power generation that stores energy in the form of water by pumping from a lower elevation source to a higher elevation reservoir, then allowing the upper reservoir to drain turning the turbines to produce power.

7.1 Pumping Efficiency (Pumped Storage Hydro Only) and Performance Factor

Note:

The information in Section 7.2 contains basic Heat Input/Rate and Performance Factor information relevant for all unit types. The following additional information only pertains to hydro units.

Pumping Efficiency is the Pumped Storage Hydro Unit's version of a heat rate. It measures the ratio of generation produced to the amount of generation used as fuel.

Pumping Efficiency (PE) is calculated by dividing the MWh of generation produced while operating in generation mode by the MWh required to pump the water needed to produce the generation MWh.

$$\text{Pumping Efficiency} = \frac{\text{MWh Generation Produced}}{\text{MWh Generation Pumped as Fuel}}$$

For example, it requires 1,000 ft³ to produce one MWh of generation as water flows from the pond to the sink and it requires 1.4 MWh of pumping load to pump 1,000 ft³ of water from the sink to the pond. The resultant efficiency is:

$$\text{Pumping Efficiency} = \frac{\text{MWh Generation Produced}}{\text{MWh Generation Pumped as Fuel}} = \frac{3.5 \text{ MWh (Generated)}}{5 \text{ MWh (Pumped)}} = 0.70$$

In order to account for environmental and physical factors associated with the characteristics of the pond and pumping operations that limit the accuracy of calculating short term pumping efficiency, a seven day rolling total of pumping and generation MWh are utilized for pumping efficiency calculations.

PE can be calculated by one of three methods. A Market Seller must make the choice of method by December 31 prior to the year of operation and cannot change to another method for a period of one calendar year.

- Option 1: Twelve month calendar actual Pumping Efficiency.
 - The previous 12-month calendar year average Pumping Efficiency based on actual pumping operations.
- Option 2: Three month rolling Pumping Efficiency.
 - The previous three months rolling actual efficiency where the average monthly availability is 50% or greater. The calculation must be updated after each month.
- Option 3: The previous month actual Pumping Efficiency.
 - The previous month actual efficiency where the availability is 50% or greater. The calculation must be updated monthly.

7.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to hydro units.

The fuel costs for a run-of-river hydro Unit are equal to zero.

For a Pumped Storage Hydro Unit to be consistent with other PJM units within this manual the term fuel cost is used to account for the energy necessary to pump from the lower reservoir to the upper reservoir.

Note:

The information in Section 2.3 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to Pumped Storage Hydro Units.

If a Market Seller wishes to change its method of calculation of pumped storage TFRC, the Market Seller shall notify PJM and the MMU in writing by December 31 prior to the year of operation, to be evaluated pursuant to the Cost Methodology and Approval Process before the beginning of the cycle in which the new method is to become effective. The new cycle starts on February 1st and continues for a period of one year

Basic Pumped Storage Fuel Cost – Pumped storage fuel cost shall be calculated on a seven (7) day rolling basis by multiplying the real time bus LMP at the plant node by the actual power consumed when pumping divided by the pumping efficiency. The pumping efficiency is determined annually based on actual pumping operations or by OEM curves if annual data is

not available due to the immaturity of the unit. The following equations govern pumping storage fuel cost:

$$Pumping\ Power\ Cost\ \left(\frac{\$}{MWh}\right) = \left(\frac{\sum_1^{168} Real\ Time\ LMP\ \left(\frac{\$}{MWh}\right) * Pumping\ Power\ (MWh)}{\sum_1^{168} Pumping\ Power\ (MWh)} \right)$$

$$Pumped\ Storage\ Fuel\ Cost\ (\$ | MWh) = \frac{Pumping\ Power\ Cost\ (\$/MWh)}{Pumping\ Efficiency}$$

7.2.1 Total Energy Input Related Costs for Pumped Storage Hydro Plant Generation

Total energy input-related costs for all pumped storage hydro units shall be defined as follows:

$$Pumped\ Storage\ Hydro\ Total\ Energy\ Input\ Related\ Cost$$

$$= Basic\ Pumped\ Storage\ Energy\ Input\ Cost + Maintenance\ Cost$$

7.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following additional information only pertains to hydro units.

7.4 Start-up Cost

See section 7.7 Condensing Start Costs.

7.5 No-Load Cost

Hydro Units do not have no-load Costs.

7.6 Maintenance

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to hydro units.

This account shall include the, materials used and expenses incurred in the maintenance of plant, includible in Account 332, Reservoirs, Dams, and Waterways. (See operating expense instruction 2.) However, the cost of materials used and expenses incurred in the maintenance of fish and wildlife, and recreation facilities, the book cost of which is includible in Account 332,

Reservoirs, Dams, and Waterways, shall be charged to Account 545, Maintenance of Miscellaneous Hydraulic Plant. Further, Pumped Storage Hydro Units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market may not include maintenance costs in their offers because such offers may not exceed an energy offer price of \$0.00/MWh. Market Sellers that use FERC accounts must remove straight time labor expenses from the accounts as those costs are typically recovered in the capacity market.

7.7 Synchronized Reserve: Hydro Unit Costs to Condense

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following additional information only pertains to hydro units if applicable.

Some Hydro Units have the ability to purge the turbines of water and run backwards effectively creating a capacitor. This method of operation of the machine is referred to as operating the Hydro unit in synchronous condensing mode.

Total synchronous condensing costs for Hydro units shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

$$\text{Expected Value of Penalty } \left(\frac{\$}{\text{MWh}} \right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty } \left(\frac{\$}{\text{MWh}} \right) = \frac{\text{Total Penalty } (\$)}{\text{Total Shortfall (MWh)}}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events } \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

$$\begin{aligned} &\text{Hydro Costs to Condense } (\$ / \text{MWh}) \\ &= \text{Condensing Start Costs} + \text{Expected Value of Penalty} \end{aligned}$$

Condensing Start costs if applicable, start costs shall be applied when a unit moves from cold to condensing operations and when a unit moves from condensing operations to energy generation, but shall not be applied when a unit moves from energy generation to condensing operations.

7.8 Regulation Cost

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types.

Section 8 : Demand Resource (DR)

Demand Resource – DR means a resource that has the capability to provide a reduction in load.

8.1 Demand Resource (DR) Cost to Provide Synchronized Reserves

The cost to provide synchronized reserves from DR resources shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

$$\text{Expected Value of Penalty} \left(\frac{\$}{\text{MWh}} \right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty} \left(\frac{\$}{\text{MWh}} \right) = \frac{\text{Total Penalty} (\$)}{\text{Total Shortfall (MWh)}}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events} \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

Demand Resource shutdown costs shall be zero.

Section 9: Wind Units

This section contains information for the development of Wind unit cost offers.

Wind Units – Generating unit in which the energy of blowing wind drives the turbine generator to produce electricity.

9.1 Heat Input/Rates and Performance Factor

Wind units do not burn fuel so heat rates are not applicable.

Wind units do not burn fuel so Performance Factors are equal to 1.0.

9.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to Wind units.

The Fuel Cost Policy should include how the generator intends to account for Renewable Energy Credits (RECs) and Production Tax Credits (PTCs).

9.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following additional information only pertains to wind units.

9.4 Start-up Cost

Note:

The information in Section 2.3 contains basic Start-up Cost information relevant for all unit types. The following additional information only pertains to wind units.

Start-up cost for a wind unit is station service cost.

9.5 No-Load Cost

Wind Units do not have no-load costs.

9.6 Maintenance

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to wind units.

Maintenance Cost includes major overhauls and inspections, as well as short run Wear and Tear on the Unit (including preventative and scheduled; not including capital). Rolling twelve-month historic maintenance cost divided by MWh for the same period.

9.7 Synchronized Reserve

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following additional information only pertains to wind units if applicable.

9.8 Regulation Cost

The information in section 2.8 contains basic Regulation Cost information relevant for all unit types.

Section 10: Solar Units

This section contains information for the development of solar unit cost offers.

Solar Units – Solar units use photovoltaic cell collectors made from semiconductors to convert solar radiation directly to electricity.

10.1 Heat Input/Rates and Performance Factor

Solar units do not burn fuel so heat rates are not applicable.

Solar units do not burn fuel so Performance Factors are equal to 1.0.

10.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to solar units.

Solar unit's fuel costs are equal to zero.

10.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following additional information only pertains to solar units.

10.4 Start-up Cost

Note:

The information in Section 2.3 contains basic Start-up Cost information relevant for all unit types. The following additional information only pertains to solar units.

Solar unit's Start Fuel and Total Fuel Related Costs are equal to zero.

10.5 No-Load Cost

Solar units do not have no-load Costs.

10.6 Maintenance

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to solar units.

10.7 Synchronized Reserve Cost

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types.

10.8 Regulation Cost

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types.

Section 11: Batteries and Flywheels

This section contains information for the development of battery and flywheel cost offers. .
Regulation only resources should see Section 11.8.

Battery- device to store electrical energy via chemicals

Flywheel- mechanical device for storing rotational energy

11.1 Efficiency Factor and Performance Factor

Efficiency factor is a battery or flywheel version of a heat rate. Efficiency factors measure the ratio of generation produced to the amount of electricity used to charge.

$$\text{Efficiency Factor} = \frac{\text{MWh Discharged}}{\text{MWh Charged}}$$

Efficiency factors can be calculated over the time period specified by the Market Seller in the Fuel Cost Policy. A Market Seller must make the choice of method in their fuel cost policy and cannot change to another method for a period specified in Section 2.1

Battery and flywheel Performance Factors are equal to 1.0.

11.2 Fuel Cost

Note:

The information in Section 2.2 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to batteries and flywheels.

To be consistent throughout the manual, the term fuel cost is used to account for the energy necessary to charge the battery or flywheel.

11.2.1 Total Fuel Cost

Market Sellers for batteries and flywheels must identify in their Fuel Cost Policies the methodology they are using to calculate fuel cost (charging cost).

$$\text{Fuel Cost} \left(\frac{\$}{\text{MWh}} \right) = \left(\text{average charge cost} \left(\frac{\$}{\text{MWh}} \right) \right) / \text{efficiency factor}$$

11.2.2 Operating Costs

Operating Costs may include, but are not limited to: acids and lithium ion replacements

11.3 Incremental Energy Cost

Note:

The information in Section 2.3 contains basic Incremental Energy Cost information relevant for all unit types. The following additional information only pertains to batteries and flywheels:

11.4 Start-up Cost

Battery and flywheel Start Fuel and Total Fuel Related Costs are equal to zero.

11.5 No-Load Cost

Battery and flywheel no-load costs are equal to zero.

11.6 Maintenance

Note:

The information in Section 2.6 contains basic Maintenance Cost information relevant for all unit types. The following additional information only pertains to batteries and flywheels.

Batteries and flywheels cannot include costs that can be included in their capacity offer such as straight time labor. Maintenance costs for batteries and flywheels may include, but are not limited to: cell repairs/replacements, inverter maintenance, and generation owned GSU/ Interconnection Transmission maintenance.

11.7 Synchronized Reserve Cost

Note:

The information in Section 2.7 contains basic Synchronized Reserve Cost information relevant for all unit types. The following additional information only pertains to batteries and flywheels if applicable.

The cost to provide synchronous reserves from battery or flywheel resources shall be capped at the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be posted on Markets and Operations > Ancillary Services > Synchronized Reserve page. The expected value of the penalty is calculated using the equation below:

Expected Value of Penalty $\left(\frac{\$}{MWh}\right) = \text{Average Penalty} * \text{Average Rate of Nonperformance} * \text{Probability an event will occur}$

Where:

Average Penalty is expressed in \$/MWh and calculated as

$$\text{Average Penalty} \left(\frac{\$}{\text{MWh}} \right) = \frac{\text{Total Penalty} (\$)}{\text{Total Shortfall} (\text{MWh})}$$

Average Rate of Nonperformance during Synchronized Reserve events is calculated as

$$\text{Average Rate of Nonperformance} = 1 - \text{Average Synchronized Reserve Response Rate}$$

Probability an event will occur is the probability a Synchronized Reserve event that will qualify for nonperformance assessments will occur and calculated as

$$\text{Probability an event will occur} = \frac{\text{Total Hours of Synchronized Reserve Events} \geq 10 \text{ Minutes}}{\text{Total Hours in the Period}}$$

11.8 Regulation Cost

Note:

The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types. The following additional information only pertains to batteries and flywheels.

Batteries and flywheels shall calculate Energy Storage Unit Losses in accordance with the equation below. The “Cost Increase due to Heat Rate Increase during non-steady state operation” and the “Fuel Cost Increase and Unit Specific Heat Rate Degradation due to Operating at lower loads” shall be equal to zero.

If a Market Seller wishes to change its method of calculating these losses, the Market Seller shall submit a request pursuant to Section 1.8. The approved method of calculation may be implemented upon approval and may be updated no more frequently than once every 12 months. If any action by a government or regulatory agency that results in a need for the Market Seller to change its method of cost calculation, the affected Market Seller may submit a request, or notification as appropriate, to PJM and the MMU for evaluation, pursuant to Section 2.3.1.

Energy Storage Unit Losses (\$/MW) – shall be the calculated average of seven (7) days of rolling hourly periods where the real time bus LMP (\$/MWh) at the plant node is multiplied by the net energy consumed (MWh) when regulating divided by the regulation offer (MW). The seven (7) days of rolling hourly periods shall consist of the unit’s last 168 hour periods with accepted regulation offers. The following equation governs energy storage unit’s fuel cost increase:

$$\text{Energy Storage Unit Losses} (\$ / \text{MW})$$

$$= \text{Average of 7 Days} \left\{ \frac{\left(\text{Hourly LMP} \left(\frac{\$}{\text{MWh}} \right) * \text{Hourly Net Energy Consumed (MWh)} \right)}{\text{Hourly Accepted Regulation Offers (MW)}} \right\}$$

Section 12: Energy Market Opportunity Cost and Non-Regulatory Opportunity Cost Guidelines

12.1 Opportunity Cost Policy

Opportunity Cost may be a component of cost under certain circumstances.

- Specific business rules for Opportunity Costs have been defined in the Operating Agreement for various products including energy and regulation.
- Requests for recovery of Opportunity Costs not defined in the Operating Agreement should be submitted to PJM and the MMU pursuant to the Cost Methodology and Approval Process.

The Opportunity Cost Calculator described in Section 12.3 through 12.6 of this manual is suspended as of June 1, 2020. Market Sellers that wish to include an Opportunity Cost in a unit's cost based offers should use the IMM Opportunity Cost Calculator described in Section 12.7 of this manual.

For details on how to obtain an opportunity cost adder from the IMM Opportunity Cost Calculator, contact the IMM at MMU_Energy_Offers_Review@monitoringanalytics.com.

For any other questions related to Opportunity Cost adders please contact PJM at FuelCostPolicyAnalysis@pjm.com.

12.2 Basis for Opportunity Cost to be included in Cost Offers

There are three reasons for the application of Opportunity Costs as contained in this section.

12.2.1 Energy Market Opportunity Costs

Energy Market Opportunity Costs associated with an externally imposed environmental run-hour restriction on a generation unit. Examples would include a limit on emissions for the unit imposed by a regulatory agency or legislation, a direct run hour restriction in the operating permit, or a heat input limitation defined by a regulatory decision or operating permit.

12.2.2 Non-Regulatory Opportunity Cost: Physical Equipment Limitations:

Physical Equipment Limitations must have supporting evidence submitted by the Market Seller. Documentation such as an OEM recommendation or bulletin and/or insurance carrier restrictions would meet this criterion. Only limitations that cause the unit to experience a restriction in the number of starts or run hours would be eligible for Non-Regulatory Opportunity Cost.

12.2.3 Non-Regulatory Opportunity Cost: Fuel Limitations

Fuel Limitations are eligible for Non-Regulatory Opportunity Costs for a fuel supply limitation, for up to one year, resulting from an event of force majeure.

Force Majeure is defined as: Any cause beyond the control of the affected Interconnection Party or Construction Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by the exercise of due diligence such party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include (i) a failure of performance that is due to an affected party's own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected party.

12.3 Calculation Method Options: Two Methodologies for calculating Opportunity Cost

Market Sellers may opt to follow one of the two following methodologies; the difference between the methodologies being the applicable time period. Market Sellers may develop alternative methods specific to their units and submit those methods for approval. Requests for recovery of opportunity costs using other methods not defined in the Operating Agreement should be submitted to PJM and the MMU for evaluation under the Cost Methodology and Approval Process and shall receive PJM's approval prior to using the alternative method

Energy Market Opportunity Costs and Non-Regulatory Opportunity Costs are a distinct component of the cost-based offer. As is the case with any computation of the cost-based offer in Manual 15, Market Sellers may elect to enter their cost-based offer at a value less than the computed cost-based offer. However, they may not exceed the computed value.

12.3.1 Long Term Method (greater than 30 days)

This method uses monthly forward prices as the basis for forecasts of fuel and electricity costs in the future. Opportunity costs calculated with this method will change frequently. Given that electricity and fuel futures can change daily, the opportunity costs computed can likewise change daily. Market Sellers who include opportunity costs in their cost-based offers must recalculate their long-term opportunity cost no less frequently than once per every 7 days.

12.3.2 Short Term Method (30 days or less)

This method uses daily forward prices as the basis for forecasts of fuel and electricity costs in the future. Market Sellers who include opportunity costs in their cost-based offers must recalculate their short term opportunity cost every day.

12.4 Definitions

VALUE	DEFINITION
N	number of hours in the month (on-peak/off-peak)
Y	Year
m	month
d	day of the month
h	hour
t	Number of hours remaining in the compliance period
Peak	off-peak hours only or on-peak hours only
FY	future year
BUSLMP	LMP at the unit's bus
PJMWHLMP	PJM Western Hub LMP
PJMWHFRP	PJM Western Hub Forward Price
DAPJMWHFRP	Day Ahead PJM Western Hub Forward Price
Trading Day	In respect of a particular futures market a day on which that Market open for trading
Dm	Delivery Month; Month the commodity contract is to deliver the commodity in the future.
Base year	one of the three historical years used to create volatility in the fuel and power forecasts
Peak	Peak hours are from 7:00 AM to 11:00 PM (the hour ending 0800 to the hour ending 2300) prevailing local time. Peak days are Mondays through Fridays, excluding North American Electric Reliability Corporation (NERC) holidays.
Off-peak	Off-peak hours are from midnight to 7:00 AM (the hour ending 0100 to the hour ending 0700) and 11:00 PM to midnight (the hour ending 2400) Mondays through Fridays; also, all day Saturdays and Sundays (the hour ending 0100 to the hour ending 2400) and North American Electric Reliability Corporation holidays

VALUE	DEFINITION
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Unit Cost	Cost of Dispatch without Start-up Cost
Unit Dispatch Cost	Cost of Dispatch with Start-up Cost Included

All inputs use prevailing width preserving decimal precision of historical record.

12.5 Long Term Methodology

12.5.1 Step 1: Derive Historical Monthly LMP Basis Differential between the generation bus and western hub

Inputs required for STEP 1: Platts-ICE Forward Curve for "PJM west" from the recent trading day, Three years of historical hourly real-time LMPs at the generation bus, and Three years of historical hourly real-time PJM Western Hub LMPs

The mismatch between the location of the forward contract delivery point (Western Hub) and the relevant generator bus can be accounted for in the historic, monthly average basis differential for both peak and off-peak hours. This basis differential can be expressed as the average, over all peak or off-peak hours in a month, of the ratio of the hourly bus LMP to the hourly Western Hub LMP. If this ratio is greater than one, it means the bus LMP is greater than the Western Hub LMP on average. If this ratio is less than one, it means the bus LMP is less than the Western Hub LMP on average.

Platts-ICE Forward Curve for "PJM west" (PJM Western Hub) must be collected for this first step (<http://www.platts.com/>). These PJM Western Hub Forwards multiplied by a historical basis adjustment ratio for delivery to the generator's bus creates monthly delivered bus prices. The three prior calendar year's historical data is used to make this calculation. For example, when calculating opportunity costs for July 2, 2010 for a unit with a calendar year compliance period, use historical LMP data from July 2nd (2007,2008,2009) to December 31st (2007,2008,2009). The Opportunity Cost Calculator is also able to provide forecasts for a rolling compliance period (e.g. a rolling 12 months) rather than a calendar year period. For units with a 12 month rolling compliance period, use LMP data from the previous three years, beginning on the date calculated and ending two days previous. For example, when a unit is calculating opportunity

cost for July 2nd, 2010 with a rolling 12 month compliance period, use historical LMP data from July 2nd (2007,2008,2009) to June 30th (2008, 2009, 2010). Begin by taking the hourly bus prices for the three prior calendar years at the generator’s bus, and for every hour, divide that hour’s price by the corresponding price at PJM Western Hub. The historic hourly basis differential in hour h, day d, month m, and year y is:

$$\text{HourlyBasisDifferentialRatio}_{y, m, d, h} = \frac{\text{BUSLMP}_{y, m, d, h}}{\text{PJMWHLMP}_{y, m, d, h}}$$

Note:

When PJMWHLMP is zero and the BUSLMP is zero, then the ratio value is one. If PJMWHLMP is zero and the BUSLMP is not zero then value is null and it is not included in the average.

$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2007 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2007 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2007 H11}}}$
$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2008 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2008 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2008 H11}}}$
$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2009 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2009 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2009 H11}}}$

Exhibit 9: Three hourly basis differential ratios variables for the same hour in each of three historical years

Once the hourly basis ratios are calculated for every hour during the three-year history, for each historic month take the sum of the on-peak hourly basis differentials in the month, and divide by the number of peak hours in the month (observations). Similarly, for every month, sum the off-peak hourly basis ratios, and then divide by the number of off-peak hours within that month. When calculating the monthly peak basis ratio all days in the month will be used for the average. These monthly basis differentials adjust PJM Western Hub monthly peak and off-peak forward prices to expected peak and off-peak monthly forward prices delivered to the generator’s bus.

$$\text{MonthlyPeakBasisDifferentialRatio}_{y, m}^{\text{peak}} =$$

$$\frac{\sum_{\text{peak hours}} \left(\text{HourlyBasisDifferentialRatio}_{y, m, d, h}^{\text{peak}} \right)}{\text{Number of Peak Hours in month } m}$$

$$\text{MonthlyOffPeakDifferentialRatio}_{y, m}^{\text{peak}} =$$

$$\frac{\sum_{\text{peak hours}} \left(\text{HourlyBasisDifferentialRatio}_{y, m, d, h}^{\text{off-peak}} \right)}{\text{Number of Off - Peak Hours in month } m}$$

$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios in June 2007})}{\text{Number of Peak Hours in June 2007}}$
$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios in June 2008})}{\text{Number of Peak Hours in June 2008}}$
$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2009}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios in June 2009})}{\text{Number of Peak Hours in June 2009}}$

Exhibit 10: Monthly Peak Basis Differentials for the three historical periods

Multiply monthly peak and off-peak basis differential ratios by the respective monthly peak and off-peak PJM Western hub forwards to derive forecasted monthly peak and off-peak bus prices from the historical year. When calculating the monthly peak basis differential ratio all days in the month will be used for the average.

$$\text{Forecasted Monthly Bus Price}_{fy, m}^{\text{peak}} * [\text{PJMWesternHub}_{fy, m}^{\text{peak}} * \text{MonthlyPeakBasisRatio}_{y, m}^{\text{peak}}]$$

$\text{ForecastedMonthlyBusPrice}_{\text{June 2010, base 2007}}^{\text{OFFpeak}}$ $=$ $\left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) \right]$
$\text{ForecastedMonthlyBusPrice}_{\text{June 2010, base 2008}}^{\text{OFFpeak}}$ $=$ $\left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) \right]$
$\text{ForecastedMonthlyBusPrice}_{\text{June 2010, base 2009}}^{\text{OFFpeak}}$ $=$ $\left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) \right]$

Exhibit 11: Forecasted monthly bus prices for three historical periods

Outputs required for STEP 1: Three peak and off-peak monthly BUS LMP forecasts for each month remaining in the compliance period.

12.5.2 Step 2: Derive hourly volatility scalars to incorporate hourly volatility into the LMP forecast

Inputs required for STEP 2: Three years of historical hourly real-time LMPs at the generation bus

The monthly futures prices quoted only consider the average peak and off-peak prices for the month and do not consider hourly LMP volatility. Step 2 derives will develop an hourly volatility scalar. This scalar will later be multiplied against the forecast in Step 1 to derive an hourly bus LMP forecast that incorporates historic hourly peak and off-peak LMP volatility as well as monthly peak and off-peak basis differentials from the historical year with PJM Western Hub.

First, for each historic month compute the average peak and off-peak price at the unit's bus for each remaining month in the compliance period. When calculating the monthly average bus LMP all days in the month will be used for the average.

$$\text{MonthlyAverageBusLMP}_{y, m}^{\text{peak}} = \frac{\sum_{\text{peak hours}} (\text{HourlyBusLMP}_{y, m, d, h}^{\text{peak}})}{\text{Number of Peak Hours in month } m}$$

$$\text{MonthlyAverageBusLMP}_{y, m}^{\text{off-peak}} = \frac{\sum_{\text{off-peak hours}} (\text{HourlyBusLMP}_{y, m, d, h}^{\text{off-peak}})}{\text{Number of Off-Peak Hours in month } m}$$

Next, for every hour, take the hourly bus LMP divided by the relevant monthly average peak or off-peak bus LMP computed above. If the hour is an on-peak hour, divide by the average peak LMP for the month.

$$\text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{peak}} = \frac{\text{BUSLMP}_{y, m, d, h}^{\text{peak}}}{\text{MonthlyAverageBusLMP}_{y, m}^{\text{peak}}}$$

If the hour is off-peak, divide that hour by the monthly off-peak average price for the corresponding month.

$$\text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{off-peak}} = \frac{\text{BUSLMP}_{y, m, d, h}^{\text{off-peak}}}{\text{MonthlyAverageBusLMP}_{y, m}^{\text{off-peak}}}$$

Example 2.1: Volatility scalar for the each of the three historical years:

$$\text{HourlyVolatilityScalar}_{\text{June3,2007 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2007 H23}}}{\text{Average Offpeak June 2007 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June3,2008 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2008 H23}}}{\text{Average Offpeak June 2008 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June3,2009 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2009 H23}}}{\text{Average Offpeak June 2009 BUSLMP}}$$

Outputs from STEP 2: Three ratio values per hour for each of the historical years used for volatility.

12.5.3 Step 3: Create three sets of hourly forecasted bus values

Inputs to STEP 3: Output from STEP 1: On-peak/off-peak monthly bus LMP Forecast Output from STEP 2: Hourly volatility scalars

Step 3 creates three hourly forecasts from the volatility scalars developed in step 2 and the monthly bus LMP forecasts developed in Step 1. Multiply the hourly volatility scalars developed in step 2 by the corresponding peak or off-peak from the historical year forecasted monthly bus price calculated in Step 1.

The expected or forecasted LMP for hour h, day d, month m, based on year y that is a peak hour is:

$$\text{ForecastedBUSLMP}_{y, m, d, h}^{\text{peak}} = \text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{peak}} * \text{ForecastedMonthlyBusPrice}_{fy, m}^{\text{peak}}$$

The expected or forecasted LMP for hour h, day d, month m, based on year y that is an off-peak hour is:

$$\text{ForecastedBUSLMP}_{y, m, d, h}^{\text{off - peak}} = \text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{off - peak}} * \text{ForecastedMonthlyBusPrice}_{fy, m}^{\text{off - peak}}$$

Assume that it is April 5, 2010. To create the set of three forecasted prices for each hour of June 3, 2010:

ForecastedBUSLMP _{June 3, 2010 H23, base 2007} = HourlyVolatilityScalar _{June 3, 2007 H23} * ForecastedMonthlyBusPrice _{June 2010} ^{offpeak}
ForecastedBUSLMP _{June 3, 2010 H23, base 2008} = HourlyVolatilityScalar _{June 3, 2008 H23} * ForecastedMonthlyBusPrice _{June 2010} ^{offpeak}
ForecastedBUSLMP _{June 3, 2010 H23, base 2009} = HourlyVolatilityScalar _{June 3, 2009 H23} * ForecastedMonthlyBusPrice _{June 2010} ^{offpeak}

Exhibit 12: Forecasted bus LMPs for one hour for each of the three historical base years

Outputs from STEP 3: Three hourly bus LMP forecasts for each hour remaining in the compliance period

12.5.4 Step 4: Create a daily fuel volatility scalar

Inputs to STEP 4: Three years historical hourly daily fuel prices at the generator bus (\$/MMBtu) Fuel Weights if dual fuel

Step 4 creates a daily fuel volatility scalar using historic daily delivered fuel prices (as used to develop a unit's TFRC) from the previous three calendar years. Take each daily bus-delivered fuel price and divide it by the monthly average bus delivered fuel price to create a ratio for every day in the three-year history. In calculating monthly average bus price, all days in the month will be used for the average. For units that have dual fuels; the daily delivered fuel prices need to be

multiplied by their respective weights and then added together. N_m is the number of days in month m .

Units with Single Fuel Type:

$$DailyFuelVolatilityScalar_{y, m, d} = \frac{DeliveredFuelPrice_{y, m, d}}{\left(\frac{\sum_{n=1}^{N_m} (DeliveredFuelPrice_{y, m})}{N_m} \right)}$$

Units with Dual Fuel:

$$DailyFuelVolatilityScalar_{y, m, d} = \frac{\left((DeliveredFuelPrice_{FuelTypeA}_{y, m, d} * Weight_{FuelTypeA}) + (DeliveredFuelPrice_{FuelTypeB}_{y, m, d} * Weight_{FuelTypeB}) \right)}{\sum_{n=1}^{N_m} \left((DeliveredFuelPrice_{A_{y, m}} * WeightA) + (DeliveredFuelPrice_{B_{y, m}} * WeightB) \right)}$$

DailyFuelVolatilityScalar _{June, 3, 2007}	$= \frac{DeliveredFuelPrice_{June\ 3,\ 2007}}{Average\ June\ 2007\ DeliveredFuelPrice}$
DailyFuelVolatilityScalar _{June, 3, 2008}	$= \frac{DeliveredFuelPrice_{June\ 3,\ 2008}}{Average\ June\ 2008\ DeliveredFuelPrice}$
DailyFuelVolatilityScalar _{June, 3, 2009}	$= \frac{DeliveredFuelPrice_{June\ 3,\ 2009}}{Average\ June\ 2009\ DeliveredFuelPrice}$

Exhibit 13: Three daily fuel volatility scalars values developed for June 3 in each of three historic years for a unit with a single fuel

If there is not fuel cost record for a given date, use the pervious available date.

Outputs from STEP 4: Three years of historic daily scalars for fuel volatility

12.5.5 Step 5: Create three daily delivered fuel forecasts

Inputs for STEP 5: Platts Forward Curve for Fuels from the most recent trading day, for delivery in the compliance period (\$/MMBtu) with a daily delivery charge adjustment Fuel Weights if dual fuel Fuel Contract monthly prices, if applicable

Output from STEP 4: Three historic years daily scalars for fuel volatility

Step 5 takes fuel futures and/or contract prices and the daily delivered fuel scalars from step 4 and multiplies them to create a fuel forecast that corresponds on an average monthly basis to the fuel futures, yet maintains historical volatility. For units that have dual fuels, the fuel forwards for the two fuels will be multiplied by their respective weights (derived from expected use of each fuel), added together, and then multiplied by the daily fuel volatility scalar. For units with some or all of their fuel procured by contract, the contract and fuel forwards are multiplied by their respective weights (derived from expected use of each fuel) and added together and then multiplied by the daily fuel volatility scalar. The current daily delivery charge adjustment will be applied through the compliance period.

Unit with a single fuel:

$$\begin{aligned}
 \text{DailyDeliveredFuel}_{fy, m, d} = & \\
 & \text{DailyFuelVolatilityScalar}_{y, m, d} * \\
 & [((\text{WeightSpot}_m * \text{FuelForward}_{fy, m}) + (\text{WeightContract} * \text{ContractPrice}))]
 \end{aligned}$$

Where $\text{WeightContract}_m + \text{WeightSpot}_m = 1$

Unit with dual fuel:

Permits the use of dual fuels for units that may burn multiple fuels or source fuels from different areas at different prices. For units with restrictions on consumption of specific fuels, this method allows accounting for both fuels in the same calculation.)

$$\begin{aligned}
 \text{DailyDeliveredFuel}_{fy, m, d} = & \\
 & \text{DailyFuelVariabilityScalar}_{y, m, d} * [\text{WeightFuelTypeA}_m \\
 & * (\text{WeightContractFuelTypeA}_m * \text{ContractPriceFuelTypeA}_m \\
 & + \text{WeightSpotFuelTypeA}_m * (\text{DeliveryAdjustmentFuelTypeA} \\
 & + \text{FuelForwardFuelTypeA}_{fy, m})) + \text{WeightFuelTypeB}_m * (\text{WeightContractFuelTypeB}_m \\
 & * \text{ContractPriceFuelTypeB}_m + \text{WeightSpotFuelTypeB}_m \\
 & * (\text{DeliveryAdjustmentFuelTypeB} + \text{FuelForwardFuelTypeB}_{fy, m}))]
 \end{aligned}$$

Where $\text{WeightFuelTypeA}_m + \text{WeightFuelTypeB}_m = 1$

Where $\text{WeightContractFuelTypeA}_m + \text{WeightSpotFuelTypeA}_m = 1$

Where $\text{WeightContractFuelTypeB}_m + \text{WeightSpotFuelTypeB}_m = 1$

Unit with a single fuel:

$\text{DailyDeliveredFuelForecast}_{\text{June 3, 2009, base 2007}}^{\text{base 2007}} = \text{DailyFuelVolatilityScalar}_{\text{June 3, 2007}} * \text{FuelForward}_{\text{June 2010}}$
$\text{DailyDeliveredFuelForecast}_{\text{June 3, 2009, base 2008}}^{\text{base 2008}} = \text{DailyFuelVolatilityScalar}_{\text{June 3, 2008}} * \text{FuelForward}_{\text{June 2010}}$
$\text{DailyDeliveredFuelForecast}_{\text{June 3, 2009, base 2009}}^{\text{base 2009}} = \text{DailyFuelVolatilityScalar}_{\text{June 3, 2009}} * \text{FuelForward}_{\text{June 2010}}$

Exhibit 14: Create three daily delivered fuel forecasts from the volatilities of three historic years

Outputs from STEP 5: Daily generator-bus delivered fuel forecast

12.5.6 Step 6: Create generating unit(s) cost for each of the three forecasts

**Inputs for STEP 6: Expected future full load seasonal (May-September/October-April) heat rate for the compliance period
 Fuel Prices output from STEP 5 Unit SO₂, CO₂ and NO_x
 Emission Rates (lbs/MMBtu) – Futures prices for SO₂, CO₂
 and NO_x from Evolution Markets (\$/ton) modified to \$/lb
 Maintenance Adder, VOM and FMU, as defined in Manual 15**

In step 6, take the unit characteristics, future emission allowance prices, the three daily fuel forecasts and create a daily unit cost for the three forecasts using the appropriate heat rate for the forecast day. Unit costs do not include Start-up Costs will be added later in the calculation of Unit Dispatch Cost. For each day in the three fuel forecasts, a unit dispatch cost is calculated as follows:

$$\text{Unit Cost}_{\text{fy, m, d}}^{\text{base year}} = \left\{ \left[\text{UnitHeatRate} \left(\frac{\text{MMBtu}}{\text{mwh}} \right) * \text{DailyDeliveredFuelForecast} \left(\frac{\$}{\text{MMBtu}} \right)_{\text{Future year, m, d}}^{\text{base year}} \right] + \left[\text{UnitHeatRate} \left(\frac{\text{MMBtu}}{\text{mwh}} \right) * \text{UnitNOxEmissionRate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of NO}_x \left(\frac{\$}{\text{lb}} \right) \right] + \left[\text{UnitHeatRate} \left(\frac{\text{MMBtu}}{\text{mwh}} \right) * \text{UnitSO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of SO}_2 \left(\frac{\$}{\text{lb}} \right) \right] + \left[\text{UnitHeatRate} \left(\frac{\text{MMBtu}}{\text{mwh}} \right) * \text{UnitCO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of CO}_2 \left(\frac{\$}{\text{lb}} \right) \right] + \text{VOM} + \right\} \text{either a } \left\{ \begin{array}{l} 10\% \text{ margin} \\ \text{OR FMU adder} \end{array} \right.$$

Unit Heat Rate 10.35 MMBtu/MWH

Unit NO_x Emission Rate 0.328 lbs/MMBtu

Unit SO2 Emission Rate 1.2 lbs/MMBtu

Unit CO2 Emission Rate 117 lbs/MMBtu

DailyDeliveredFuelForecast \$5.56/MMBtu

Combined NOx Allowance cost \$1375/ton

SO2 Allowance cost \$200/ton

CO2 emission cost \$8.00/ton

VOM & Maintenance Adder \$2.22/MWh

FMU \$0.00/MWh

$$\begin{aligned}
 \text{UnitCost} = & \left[\left(\frac{10.35 \text{ MMBtu}}{\text{mwh}} \right) * \left(\frac{\$5.56}{\text{MMBtu}} \right) \right] \\
 & + \left[\left(\frac{10.35 \text{ MMBtu}}{\text{mwh}} \right) * \left(\frac{0.328 \text{ lbs}}{\text{MMBtu}} \right) * \left(\frac{\$1375.00}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{ lbs}} \right) \right] \\
 & + \left[\left(\frac{10.35 \text{ MMBtu}}{\text{mwh}} \right) * \left(\frac{1.2 \text{ lbs}}{\text{MMBtu}} \right) * \left(\frac{\$200.00}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{ lbs}} \right) \right] \\
 & + \left[\left(\frac{10.35 \text{ MMBtu}}{\text{mwh}} \right) * \left(\frac{117 \text{ lbs}}{\text{MMBtu}} \right) * \left(\frac{\$8.00}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{ lbs}} \right) \right] + \left(\frac{\$2.22}{\text{MWh}} \right) + \left(\frac{\$0}{\text{MWh}} \right)
 \end{aligned}$$

$$\text{UnitCost}_{\text{fy, m, d}}^{\text{base year}} = \left(\frac{\$58.58}{\text{MWh}} \right) + \left(\frac{\$2.33}{\text{MWh}} \right) + \left(\frac{\$1.24}{\text{MWh}} \right) + \left(\frac{\$4.84}{\text{MWh}} \right) + \left(\frac{\$2.22}{\text{MWh}} \right) = \$69.21 / \text{MWh}$$

Exhibit 15: Daily Unit Cost

Outputs for STEP 6: Three forecasts based on historic year factors for daily generator unit cost

12.5.7 Step 7: Calculate the margin for every hour in the three hourly forecasts

Inputs for STEP 7: Daily Generator Unit Cost from STEP 6
 Hourly Generator bus LMP forecast from STEP 3
 All future maintenance outage information
 Unit-specific minimum runtime parameter restriction
 Unit-specific Start-up costs (cold Start-up Costs for CC and CT units and hot Start-up Costs for steam units)
 Unit economic maximum

Step 7 calculates the hourly margin the generator would receive by comparing the cost offer developed in step 6 against the hourly forecasted bus LMPs developed in step 3. To remove planned outages, for any future date that the unit will be offline, set the outage hours to unavailable for all three forecasts.

For Units with minimum run time restrictions, this step calculates the total margins in blocks of adjacent hours, based on the sum of the margins of each block and the minimum runtime parameter restriction of the unit. Blocks may include additional incremental hours, if these hours are found to be more valuable than the additional block, up to double the unit's minimum runtime. Adjacent hour blocks with equal or greater number of hours than double a unit's minimum run time will be split into multiple blocks (however, adjacent blocks do not use an additional Start-up Cost). For units with Start-up Costs, the value of the unit's Start-up Cost divided by economic maximum will be subtracted from the total margin of each block that contains a new start, but not from each subsequent incremental hour added to the block, in order to correctly value hours that do not incur Start-up Costs. Calculate the total margins for all blocks of hours in the three forecasts.

$$\sum_{t = \text{block}}^{\text{TotalMarginBlock}_{\text{block}}^{\text{base year}} + \text{MRT} - 1} \left(\text{ForecastedBusLMP}_{y(t), m(t), d(t), h(t)}^{\text{base year}} - \text{UnitDispatchCost}_{\text{future } y, m, d}^{\text{base year}} \right)$$

**MRT = Minimum Run Time

*** Unit Dispatch Cost include Start-up cost when applicable

Where the block ranges from one to **[total number of hours – min run time + 1]**

[total number of hours – min run time + 1] and y(t), m(t), d(t), h(t) are the year, month, day and

hour corresponding to the ^{tth} overall hour of the time period spanning from the date calculated to the end of the compliance period forecasted.

The **totalNumberOfHours** Total Number of Hours variable represents the number of hours left in the compliance period to be forecasted, and is based on the date calculated and whether or not the unit has a rolling 12 month run-hour restriction.

This example uses block # 3788:

$\text{TotalMarginBlock}_{\text{block } 3788}^{2007}$
$= \sum_{t = \text{block}}^{t = \text{block} + \text{MRT} - 1} \left(\text{ForecastedBusLMP}_{y(t), m(t), d(t), h(t)}^{\text{base year}} - \text{UnitDispatchCost}_{\text{future year}}^{\text{base year}} \right)$
$\sum_{t = 3788}^{t = 3788 + 1 - 1} \left(\text{ForecastedBusLMP}_{y, m, d, h(t)}^{2007} - \text{UnitDispatchCost}_{y, m, d(t)}^{2007} \right)$

$\text{ForecastedBusLMP}_{y, m, d, h (3788)}^{2007} = \text{UnitDispatchCost}_{y, m, d, h (3788)}^{2007}$
$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H07}}^{2007} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2007} = \$78.27 - \$69.21 = \9.06
<p>Similarly,</p> $\text{TotalMarginBlock}_{\text{block 3788}}^{2008}$
$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H07}}^{2008} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2008}$
$= \$58.00 - \$52.41 = \$5.59$
<p>And,</p> $\text{TotalMarginBlock}_{\text{block 3788}}^{2009}$
$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H07}}^{2009} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2009}$
$= \$63.78 - \$76.72 = -\$12.94$

Exhibit 16: Calculating total margins with a minimum runtime of one hour (i.e. no minimum runtime restriction), using historical data from the past three calendar years

At this point, the blocks of hours would be ranked according to the value of their total margins.

Outputs from STEP 7: Three sets of ranked blocks of total margin forecasts including each hour in the compliance period, adjusted to include Start-up Costs for each block that contains a new start, with all future outage hours removed.

12.5.8 Step 8: Determine the opportunity cost component

Inputs to STEP 8: Three sets of ranked blocks of total margin forecasts

For each of the three years, the opportunity cost component for that year will be the average total margin of the lowest value block added before the run hour limit was reached. The three opportunity costs will then be averaged to get the opportunity cost component available to the generator. If the final opportunity cost component is less than zero then the opportunity cost component will be set to zero.

The average value of the block which includes the

$700^{\text{th}} \text{ hour}_{\text{base } 2007} = \$7.99 / \text{MWh}$
The average value of the block which includes the $700^{\text{th}} \text{ hour}_{\text{base } 2008} = \$ - 2.54 / \text{MWh}$
The average value of the block which includes the $700^{\text{th}} \text{ hour}_{\text{base } 2009} = \$10.59 / \text{MWh}$
$700^{\text{th}} \text{ hour opportunity cost component} =$ $\frac{\$7.99 + (-\$2.54) + \$10.59}{3} = \$5.33 / \text{MWh}$

Exhibit 17: A unit with 700 run hours

Outputs from STEP 8: Maximum Opportunity Cost Component that can be included in an environmentally run limited generator's cost offer

12.6 Short Term Methodology

Short Term Opportunity Costs are of limited duration where the event lasts 30 days or less. The Short Term Method modifies the method in Section 12.5 to capture intra-month price movements in fuel and electricity markets on a daily basis. The proposal requires Market Sellers to recalculate opportunity costs every day during the short-term episode, using daily forward prices for both fuel and electricity costs instead of monthly forwards.

12.6.1 Step 1: Derive Historical Monthly LMP Basis Differential between the generation bus and western hub

Inputs required for STEP 1: Platts-ICE Forward Curve for "PJM west" from the recent trading day, Three years of historical hourly real-time LMPs at the generation bus, and Three years of historical hourly real-time PJM Western Hub LMPs

As before with Opportunity Costs, PJM Western Hub (Western Hub) is a liquid trading point for forward LMP prices. The mismatch between the location of the forward contract delivery point Western Hub and the relevant generator bus can be accounted for in the historic monthly average basis differential for peak and off-peak hours. The basis differential is an average for the peak or off-peak hours intra-month of the hourly bus LMP to the hourly Western Hub LMP. The result is a ratio of the bus to the hub by time. If this ratio is greater than one, it means the bus LMP is greater than the Western Hub LMP. If this ratio is less than one, it means the bus

LMP is less than the Western Hub LMP on average. The resultant ratio can be applied to the PJM Western Hub to shape it into the specific generator bus.

Platts-ICE Forward Curve for “PJM west” (PJM Western Hub) must be collected for this first step (<http://www.platts.com/>). The PJM Western Hub daily forward prices are multiplied by the historical basis adjustment ratio or shaping factor at the generator’s bus to approximate the intra-month delivered bus prices.

Begin by taking the hourly intra-month bus prices for the three prior calendar years at the generator’s bus, and for every hour, divide that hour’s price by the corresponding price at PJM Western Hub. The historic hourly basis differential in hour h, day d, month m, and year y is:

$$\text{HourlyBasisDifferentialRatio}_{y, m, d, h} = \text{BUSLMP}_{y, m, d, h} / \text{PJMWHLMP}_{y, m, d, h}$$

Note:

When PJMWHLMP is zero and the BUSLMP is zero, then the ratio value is one. If PJMWHLMP is zero and the BUSLMP is not zero then value is null and it is not included in the average.

$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2007 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2007 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2007 H11}}}$
$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2008 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2008 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2008 H11}}}$
$\text{HourlyBasisDifferentialRatio}_{\text{June 3, 2009 H11}} = \frac{\text{BUSLMP}_{\text{June 3, 2009 H11}}}{\text{PJMWHLMP}_{\text{June 3, 2009 H11}}}$

Exhibit 18: Three Hourly Basis Differential Ratios Values for the same hour in Each of Three Historical Years

Once the hourly basis ratios are calculated for every hour in the historic period take the sum of the on-peak hourly basis differentials, and divide by the number of peak hours. Similarly sum the off-peak hourly basis ratios, for the month then divide by the number of off-peak hours. When calculating the intra-month peak basis differential ratio, all days in the month will be used for the average. The intra-month basis differentials adjust PJM Western Hub daily peak and off-peak DA prices to expected peak and off-peak daily forward prices delivered to the generator’s bus.

$$\begin{aligned} & \text{MonthlyPeakBasisDifferentialRatio}_{y, m}^{\text{peak}} \\ &= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatio}_{y, m}^{\text{peak}})}{\text{Number of Peak Hours in month } m} \\ & \text{MonthlyPeakBasisDifferentialRatio}_{y, m}^{\text{peak}} \end{aligned}$$

$$= \frac{\sum_{\text{off-peak hours}} (\text{HourlyBasisDifferentialRatios}_{y, m}^{\text{off-peak}})}{\text{Number of Off - Peak Hours in month } m}$$

$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios}_{\text{June 2007}}^{\text{peak}})}{\text{Number of peak hours in June 2007}}$
$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios}_{\text{June 2008}}^{\text{peak}})}{\text{Number of peak hours in June 2008}}$
$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2009}}^{\text{peak}}$ $= \frac{\sum_{\text{peak hours}} (\text{HourlyBasisDifferentialRatios}_{\text{June 2009}}^{\text{peak}})}{\text{Number of peak hours in June 2009}}$

Exhibit 19: Monthly Peak Basis Differentials for the Three Historical Periods

Multiply peak and off-peak basis differential ratios by the respective peak and off-peak PJM Western hub forwards to derive forecasted peak and off-peak bus prices for each historical year. When calculating the intra-monthly peak basis differential ratio all days in the month will be used for the average.

$$\text{Forecasted Montly Bus Price}_{fy, m}^{\text{peak}}$$

$$= \left[(\text{PJMWesternHub}_{fy, m}^{\text{peak}}) * (\text{MonthlyPeakBasisRatio}_{y, m}^{\text{peak}}) \right]$$

$\text{Forecasted Montly Bus Price}_{\text{June 2010, base 2007}}^{\text{OFFpeak}}$ $= \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{OFFpeak}}) \right]$
$\text{Forecasted Montly Bus Price}_{\text{June 2010, base 2008}}^{\text{OFFpeak}}$ $= \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{OFFpeak}}) \right]$
$\text{Forecasted Montly Bus Price}_{\text{June 2010, base 2009}}^{\text{OFFpeak}}$ $= \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2009}}^{\text{OFFpeak}}) \right]$

Exhibit 20: Forecasted Monthly Bus Prices for Three Historical Periods

Outputs for STEP 1: Three peak and off-peak monthly BUS LMP forecasts for the remaining days in a month

12.6.2 Step 2: Derive hourly volatility scalars to incorporate hourly volatility into the LMP forecast

Inputs required for STEP 2: Three years historical hourly real-time LMPs at the generation bus

Daily forward prices are the average peak and off-peak prices for the next day and do not include hourly LMP volatility. Step 2 derives an hourly volatility scalar. This scalar will later be multiplied against the forecasted prices in Step 1 to develop an hourly bus LMP forecast that incorporates historic hourly peak and off-peak LMP volatility.

First, for each historic month compute the average peak and off-peak price at the unit's bus for the intra-month. When calculating the monthly average bus LMP all days in the month will be used for the average.

$$\begin{aligned} \text{MonthlyAverageBusLMP}_{y, m}^{\text{peak}} &= \frac{\sum_{\text{peak hours}} (\text{HourlyBusLMP}_{y, m, d, h}^{\text{peak}})}{\text{Number of Peak hours in month } m} \\ \text{MonthlyAverageBusLMP}_{y, m}^{\text{off-peak}} &= \frac{\sum_{\text{off-peak hours}} (\text{HourlyBusLMP}_{y, m, d, h}^{\text{off-peak}})}{\text{Number of Off-Peak hours in month } m} \end{aligned}$$

Next, for every hour, take the hourly bus LMP divided by the relevant monthly average peak or off-peak bus LMP computed above. If the hour is an on-peak hour, divide by the average peak LMP for the month.

$$\text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{peak}} = \frac{\text{BUSLMP}_{y, m, d, h}^{\text{peak}}}{\text{MonthlyAverageBusLMP}_{y, m}^{\text{peak}}}$$

If the hour is off-peak, divide that hour by the monthly off-peak average price for the corresponding month.

$$\text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{off-peak}} = \frac{\text{BUSLMP}_{y, m, d, h}^{\text{off-peak}}}{\text{MonthlyAverageBusLMP}_{y, m}^{\text{off-peak}}}$$

Example 10.1: Volatility scalar for the each of the three historical years:

$$\text{HourlyVolatilityScalar}_{\text{June 3, 2007 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2007 H23}}}{\text{Average Offpeak June 2007 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June 3, 2008 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2008 H23}}}{\text{Average Offpeak June 2008 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June 3, 2009 H23}} = \frac{\text{BUSLMP}_{\text{June 3, 2009 H23}}}{\text{Average Offpeak June 2009 BUSLMP}}$$

Outputs from STEP 2: Three ratio values per hour for each of the historical years used for volatility.

12.6.3 Step 3: Create three sets of hourly forecasted bus values

Inputs required for STEP 3: Output from Step 1: On-peak/off-peak monthly bus LMP Forecast Output from Step 2: Hourly volatility scalars

Step 3 creates three hourly forecasts from the volatility scalars developed in step 2 and the monthly bus LMP forecasts developed in Step 1. Multiply the hourly volatility scalars developed in step 2 by the corresponding peak or off-peak from the historical year forecasted monthly bus price calculated in Step 1.

The expected or forecasted LMP for hour h, day d, month m, based on year y that is a peak hour is:

$$\begin{aligned} & \text{ForecastedBUSLMP}_{y, m, d, h}^{\text{peak}} \\ &= \text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{peak}} * \text{ForecastedMonthlyBusPrice}_{fy, m}^{\text{peak}} \end{aligned}$$

The expected or forecasted LMP for hour h, day d, month m, based on year y that is an off-peak hour is:

$$\begin{aligned} & \text{ForecastedBUSLMP}_{y, m, d, h}^{\text{off-peak}} \\ &= \text{HourlyVolatilityScalar}_{y, m, d, h}^{\text{off-peak}} * \text{ForecastedMonthlyBusPrice}_{fy, m}^{\text{off-peak}} \end{aligned}$$

Example 11.1: Forecasted bus LMPs for one hour for each of the three historical base years:

To create the set of three forecasted prices for each hour of June 3, 2010:

$$\begin{aligned} & \text{ForecastedBUSLMP}_{\text{June 3, 2010 H00, base 2007}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3, 2007 H00}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \\ & \text{ForecastedBUSLMP}_{\text{June 3, 2010 H00, base 2008}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3, 2008 H00}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \\ & \text{ForecastedBUSLMP}_{\text{June 3, 2010 H00, base 2009}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3, 2009 H00}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \end{aligned}$$

Outputs from STEP 3: Three hourly bus LMP forecasts for each hour remaining in the compliance period

12.6.4 Step 4: Fuel Price

Inputs required for STEP 4: Fuel Weights if dual fuel
 Contract Fuel Prices if Applicable

In the short term method, no volatility is applied to the fuel prices. Take the Day Ahead Price for the appropriate fuel; add the delivery adder and this is the appropriate fuel price to use.

For units that have dual fuels; the daily delivered fuel prices need to be multiplied by their respective weights and then added together. If there is no fuel cost record for a given date, use the previous available value.

For units with some or all of their fuel procured by contract, the contract and DA fuel prices are multiplied by their respective weights (derived from expected use of each fuel) and added together and then multiplied by the daily fuel volatility scalar. The current daily delivery charge adjustment will be applied through the compliance period.

Unit with a single fuel:

$$\begin{aligned}
 & \text{Daily Delivered Fuel}_{y, m, d} \\
 &= \text{WeightSpot}_m * (\text{Day Ahead Fuel Price} + \text{Delivery Adjustment}) \\
 & \quad + (\text{WeightSpot}_m + (\text{WeightContract}_m * \text{ContractPrice}_m)) \\
 & \quad \text{Where Weight Contract}_m + \text{Weight Spot}_m = 1
 \end{aligned}$$

Unit with dual fuel:

The following equation permits use of dual fuels for units that may burn multiple fuels or source fuels from different areas at different prices. For units with restrictions on consumption of specific fuels, this method allows accounting for both fuels in the same calculation.

$$\begin{aligned}
 & \text{DailyDeliveredFuel}_{fy, m, d} \\
 &= [\text{WeightFuelTypeA}_m \\
 & \quad * (\text{WeightContractFuelTypeA}_m \\
 & \quad \quad * \text{ContractPriceFuelTypeA}_m \\
 & \quad \quad + \text{WeightSpotFuelTypeA}_m \\
 & \quad * (\text{DeliveryAdjustmentFuelTypeA} + \text{FuelForwardFuelTypeA}_{fy, m})) \\
 & + \text{WeightFuelTypeB}_m * \text{ContractPriceFuelTypeB}_m + \text{WeightSpotFuelTypeB}_m
 \end{aligned}$$

$$*(DeliveryAdjustmentFuelTypeB + FuelForwardFuelTypeB_{fy, m})$$

Where Weight Fuel Type $A_m + \text{Weight Fuel Type } B_m = 1$

Where Weight Contract Type $A_m + \text{Weight Spot Type } A_m = 1$

Where Weight Contract Type $B_m + \text{Weight Spot Type } B_m = 1$

Output from STEP 4: Daily generator-bus delivered fuel forecast

12.6.5 Step 5: Create generating unit's cost for each of the three forecasts

Inputs required for STEP 5: Expected future full heat rate intra-month Fuel Prices output from Step 4 Unit SO₂, CO₂, and NO_x Emission Rates (lbs/M (Note that the CO₂ adder is in effect only for incurring carbon emission charges) Futures prices for SO₂, CO₂ and NO_x from Evolution Markets (\$/ton) modified to \$/lb Maintenance Adder, VOM and FMU as defined in Manual 15

In Step 5, take the unit characteristics, future emission allowance prices, the three daily fuel forecasts and create a daily unit cost for the three forecasts using the appropriate heat rate for the forecast day. Unit costs do not include Start-up Costs, Start-up Costs will be added later in the calculation of Unit Dispatch Cost. For each day in the three fuel forecasts, a unit dispatch cost is calculated as follows:

$$\begin{aligned} & \text{UnitCost}_{fy, m, d}^{\text{base year}} \\ &= \left[\left[\text{Unit Heat Rate} \left(\frac{\text{MMBtu}}{\text{MWh}} \right) * \text{Daily Delievered Fuel Forecast} \left(\frac{\$}{\text{MMBtu}} \right)_{\text{Future } y, m, d}^{\text{base year}} \right] \right. \\ & \quad + \left[\text{Unit Heat Rate} \left(\frac{\text{MMBtu}}{\text{MWh}} \right) * \text{Unit NO}_x \text{Emission Rate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of NO}_x \left(\frac{\$}{\text{lb}} \right) \right] \\ & \quad + \left[\text{Unit Heat Rate} \left(\frac{\text{MMBtu}}{\text{MWh}} \right) * \text{Unit SO}_2 \text{Emission Rate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of SO}_2 \left(\frac{\$}{\text{lb}} \right) \right] \\ & \quad + \left[\text{Unit Heat Rate} \left(\frac{\text{MMBtu}}{\text{MWh}} \right) * \text{Unit CO}_2 \text{Emission Rate} \left(\frac{\text{lbs}}{\text{MMBtu}} \right) * \text{Cost of CO}_2 \left(\frac{\$}{\text{lb}} \right) \right] \\ & \quad \left. + \text{VOM} \right\} + \text{either a } \left\{ \begin{array}{l} 10\% \text{ margin or} \\ \text{FMU adder} \end{array} \right. \end{aligned}$$

Unit heat rate=10.345 MMBtu/MWh

Unit NO_x emission rate =0.328 lbs/MMBtu

Unit SO₂ emission rate=1.2 lbs/MMBtu

Unit CO₂ emission rate=117 lbs/MMBtu

DailyDeliveredFuelForecast=\$3.01/MMBtu

Combined NO_x Allowance cost=\$1375/ton

SO₂ Allowance cost=\$200/ton

CO₂ emission cost = \$8/ton

VOM & Maintenance Adder=\$2.22/MWh

FMU= \$0.00/MWh

$\text{Unit Cost} = \{ [10.345(\text{MMBtu} / \text{MWh}) * \$3.01(\$/ \text{MMBtu})] + [10.345(\text{MMBtu} / \text{MWh})$
$*0.328(\text{lbs} / \text{MMBtu}) * 0.6875(\$/ \text{lb})] + [10.35(\text{MMBtu} / \text{MWh}) * 1.2(\text{lbs} / \text{MMBtu})$
$*0.1(\$/ \text{lb})] + [10.345(\text{MMBtu} / \text{MWh}) * 117(\text{lbs} / \text{MMBtu}) * 0.004(\$/ \text{lb})] + \$2.22 \}$
$\text{Unit Cost} = \{ [(\$31.14 / \text{MWh})] + [(\$2.33 / \text{MWh})] +$
$[\$1.24] + [\$4.84 / \text{MWh}] + \$2.22 \} = \$41.77 / \text{MWh}$

Exhibit 21: Daily Unit Cost

Outputs from STEP 5: Three forecasts based on historic year factors for daily generator unit cost

12.6.6 Step 6: Calculate the margin for every hour in the three hourly forecasts

Inputs required for STEP 6: Daily Generator Unit Cost
Hourly Generator bus LMP forecast from Step 3 Unit-specific minimum run-time parameter restriction Unit-specific Start-up Costs (cold Start-up costs for CC and CT units and hot Start-up Costs for steam units) Unit economic maximum

Step 6 calculates the hourly margin the generator would receive by comparing the cost offer developed in step 5 against the hourly forecasted bus LMPs developed in step 3.

For units with minimum run time restrictions, this step calculates total margins in blocks of adjacent hours, based on the sum of the margins of each block and the minimum run time parameter restriction of the unit. Blocks may include additional incremental hours, if these hours are found to be more valuable than an additional block, up to double a unit's minimum run time. Adjacent hour blocks with equal or greater number of hours than double a unit's minimum run time will be split into multiple blocks (however adjacent blocks do not use an additional Start-up

Cost). For units with Start-up Costs, the value of the unit's Start-up Cost divided by economic maximum will be subtracted from the total margin of each block that contains a new start, but not from each subsequent incremental hour added to the block, in order to correctly value hours that do not incur Start-up Costs. Calculate the total margins for all blocks of hours in the three forecasts:

$$= \sum_{t = \text{block}}^{\text{TotalMarginBlock}_{t = \text{block} + \text{MRT} - 1}^{\text{base year block}}} \left(\text{ForecastedBusLMP}_{y(t), m(t), d(t), h(t)}^{\text{base year}} - \text{UnitDispatchCost}_{\text{future } y, m, d}^{\text{base year}} \right)$$

**MRT= minimum run time

Where block ranges from 1 to [totalNumberofHours – MinRunTime + 1] and y(t), m(t), d(t), h(t) are the year, month, day and hour corresponding to the overall hour of the time period spanning from the date calculated to the end of the intra-month period.

The totalNumberofHours variable represents the number of hours left intra-month to be forecasted, and is based on the date.

This example uses block # 3679:

$\text{TotalMarginBlock}_{\text{block } 3679}^{2007}$ $= \sum_{t = \text{block}}^{t = \text{block} + \text{MRT} - 1} \left(\text{ForecastedBUSLMP}_{y(t), m(t), d(t), h(t)}^{\text{block}} - \text{UnitDispatchCost}_{\text{future } y, m, d}^{\text{base year}} \right)$
$\sum_{t = 3678}^{t = 3679 + 1 - 1} \left(\text{ForecastedBUSLMP}_{y(t), m(t), d(t), h(t)}^{2007} - \text{UnitDispatchCost}_{\text{future } y, m, d}^{2007} \right)$
$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H02}}^{2007} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2007}$ $= \$53.23 - \$41.77 = -\$11.46$
<p>Similarly</p> $\text{TotalMarginBlock}_{\text{block } 3679}^{2008}$ $= \text{ForecastedBusLMP}_{\text{June 3, 2010 H02}}^{2008} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2008}$ $= \$55.44 - \$57.88 = -\$2.44$
<p>And</p> $\text{TotalMarginBlock}_{\text{block } 3679}^{2009}$ $= \text{ForecastedBusLMP}_{\text{June 3, 2010 H02}}^{2009} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2009}$

$$= \$49.78 - \$49.72 = -\$0.06$$

Exhibit 22: Calculating Total Margins with a minimum run time of one hour (i.e. no minimum run time restriction), using historical data from the past three calendar years

At this point, the blocks of hours would be ranked according to the value of their total margins.

Outputs from STEP 6: Three sets of ranked blocks of total margin forecasts including each hour in the compliance period, adjusted to include Start-up Costs for each block that contains a new start, with all future outage hours removed

12.6.7 Step 7: Determine the opportunity cost adder

Inputs required for STEP 7: Three sets of ranked blocks of total margin forecasts

For each of the three years, the opportunity cost for that year will be the average total margin of the lowest value block added before the run hour limit was reached. The three opportunity costs will then be averaged to get the opportunity cost adder available to the generator. If the opportunity cost adder is less than 0, the opportunity cost adder will be set to 0.

<i>The average value of the block which includes the 700th hour_{base2007} = \$18.33 MWh</i>
<i>The average value of the block which includes the 700th hour_{base2008} = \$ - 2.50 MWh</i>
<i>The average value of the block which includes the 700th hour_{base2009} = \$1.59 MWh</i>
<i>700th hour opportunity cost adder = $\\$18.33 + (-\\$2.50) + \\$1.59 / 3 = \\$5.81 / MWh$</i>

Exhibit 23: A Unit with 700 run hours left

Output from STEP 7: Maximum Opportunity Cost Component that can be added to an environmentally run limited generator's cost offer.

12.7 IMM Opportunity Cost Calculator

The IMM Opportunity Cost Calculator is a constrained optimization software application independently developed and owned by Monitoring Analytics, LLC. Any changes to the IMM Calculator must be approved by Monitoring Analytics, LLC. The IMM will notify PJM of any significant changes to the IMM Opportunity Cost Calculator and any such changes will be reflected in updates to Manual 15 Section 12.7. PJM will review any such changes to verify that

the IMM Opportunity Cost Calculator continues to meet the requirements of Schedule 2 of the Operating Agreement.

On an annual basis, PJM will review the inputs and results of the IMM Opportunity Cost Calculator in consultation with the IMM to verify that the IMM Opportunity Cost Calculator continues to meet the documented requirements.

12.7.1 Calculation Method

The Opportunity Cost Calculator selects the hours of operation that will maximize the generator's energy market revenue net of the generator's short run marginal cost of producing energy, subject to the unit specific environmental or operational limits. The duration and structure (i.e. rolling compliance periods or a single compliance period) of the optimization period will be as specified in an environmental permit for environmental limitations, or as specified by the original equipment manufacturer or insurance carrier for physical equipment limitations. In the case of a fuel supply limitation, the duration of the optimization period must be approved by PJM and the MMU.

Inputs into the Opportunity Cost Calculator will include unit specific forward LMPs based on futures prices, unit specific forward fuel prices based on futures or contract prices, and unit specific operating parameters.

The opportunity cost is the shadow price corresponding to the binding environmental or operational limit. The shadow price is defined as the marginal decrease in the net revenue due to a one hour equivalent decrease in the binding environmental or operational limit. Opportunity cost therefore is the marginal value of the foregone opportunity to earn higher profits for an environmentally or operationally constrained unit¹.

Energy Market Opportunity Costs and Non-Regulatory Opportunity Costs are a distinct component of the cost-based offer. As is the case with any computation of the cost-based offer in Manual 15, Market Sellers may elect to enter their cost-based offer at a value less than the computed cost-based offer. However, they may not exceed the computed value.

12.7.2 Forward LMP

Unit specific hourly forward LMPs are based on off peak and on peak future contracts for PJM Western Hub or any neighboring frequently traded PJM hub with expiration dates during the optimization period. The futures contract price will be multiplied by a basis differential and an

¹ A separate opportunity cost adder, applicable to a specific portion of the generator's offer curve, may be appropriate for an environmental or operational limitation that applies to the duct fire capability of the generator (e.g. duct fire hours limit). If it is determined that a duct fire limit is binding, the corresponding opportunity cost is the shadow price corresponding to the duct fire limit.

hourly volatility scalar. The basis differential accounts for the price difference between the location of the forward contract delivery point (PJM Western Hub) and the relevant generator bus. The hourly volatility scalar incorporates hourly volatility into the forward LMP.

Three different historical time periods will be identified and mapped on an hourly basis to the optimization period. Historical on peak hours will be mapped to on peak hours in the optimization period, and historical off peak hours will be mapped to off peak hours in the optimization with adjustments made to ensure historical holiday and weekend days are mapped to holiday and weekend days during the optimization period. For example, if the calculation date is January 25, 2019 and the optimization period is one year into the future, then three different historical time periods, each consisting of 8,760 hours from the three year period preceding January 25, 2019, will be identified. Each of the three historical time periods will be mapped to the 8,760 hours in the optimization period such that on peak hours are mapped to on peak hours, off peak hours are mapped to off peak hours, holidays are mapped to holidays, and weekend days are mapped to weekend days.

Three on peak and three off peak basis differentials will be computed for each futures contract used in the calculation of the forward LMPs using the three historical time period mappings. The on peak basis differential will be calculated as the average of the ratio of the hourly bus LMP to the hourly Western Hub LMP, with the average being taken over all on peak hours during the identified historical time period where the month corresponds to the futures contract month of expiry. The off peak basis differential will be calculated as the average of the ratio of the hourly bus LMP to the hourly Western Hub LMP, with the average being taken over all off peak hours during the identified historical time period where the month corresponds to the futures contract month of expiry.

Three hourly volatility scalars will be computed for each hour during the optimization period based on the three different historical time period mappings. For an on peak hour in the optimization period, the hourly volatility scalar will be calculated as the ratio of the historical bus LMP to the average historical bus LMP, with the average being taken over all on peak hours during the identified historical time period where the month corresponds to the month of the on peak hour in the optimization period. For an off peak hour in the optimization period, the hourly volatility scalar will be calculated as the ratio of the historical bus LMP to the average historical bus LMP, with the average being taken over all off peak hours during the identified historical time period where the month corresponds to the month of the off peak hour in the optimization period.

12.7.3 Forward Delivered Fuel Price

Unit specific daily forward delivered fuel prices are based on traded forward fuel prices from a published source or prior contractually agreed prices. A fuel delivery charge is added to the monthly forward fuel prices to obtain delivered fuel prices, and the delivered fuel prices are multiplied by daily volatility scalars to obtain a daily forward delivered fuel price for the generator. For generators procuring fuel at a contractual rate, a volatility scalar is not applied and a constant contracted price is used. Three volatility scalars are computed for each day in

the optimization period based on the three different historical time period mappings. The daily volatility scalar is computed as the ratio of the historical daily delivered fuel price to the average monthly historical delivered fuel price.

12.7.4 Operating Cost

The hourly operating cost (\$ per MWh) is the short run marginal cost of generating energy. Inputs into the calculation of the hourly operating cost consist of the forward delivered fuel price, the generator's heat rate data, emission rate data, and VOM cost available in the Member Information Reporting Application (MIRA), and emission futures prices. The calculation of hourly operating cost is consistent with the calculation of cost based offers specified in PJM Manual 15.

The hourly operating cost or operating parameters may be adjusted in cases where the unit's historical offer behavior deviates from the short run marginal cost or the commitment and dispatch of the generator has historically differed from expected economic outcomes due to actions taken by the Transmission Provider or other factors outside the control of the Market Participant. The application, and the magnitude and direction, of any adjustment is dependent upon an expectation that the offer behavior or conditions that cause the noneconomic commitment and dispatch of the unit will persist into the optimization period and that the unit will be subject to mitigation.

12.7.5 Emissions and Operating History

Up to date emissions totals, hours of operations, or number of starts are critical inputs into the Opportunity Cost Calculator. Market Participants are required to provide these values on a routine basis and as requested by the MMU. If Market Participants fail to provide emissions data at the required temporal granularity, actual generation history and the generator's emissions rates and heat rate will be used to calculate daily emissions. Opportunity cost adders will not be calculated for generators that do not have up to date emissions totals, hours of operations, or number of starts, and Market Participants will not be allowed to include an opportunity cost adder in the generator's cost based offer.

12.7.6 Opportunity Cost Adder

For each of the three sets of forward LMPs and forward delivered fuel prices, the Opportunity Cost Calculator selects the hours of operation that maximize the generator's energy market revenue net of the generator's short run marginal cost of producing energy, subject to the unit specific environmental or operational limits. The duration and structure (i.e. rolling compliance periods or a single compliance period) of the optimization period will be as specified in an environmental permit for environmental limitations, as specified by the original equipment manufacturer or insurance carrier for physical equipment limitations, or as agreed upon by the Market Participant, PJM and the MMU in cases of fuel supply limitations².

For resources with a single compliance period (e.g. calendar year), the opportunity cost is the shadow price corresponding to the binding environmental or operational limit. For resources with rolling compliance periods, the opportunity cost is the shadow price corresponding to the earliest binding environmental or operational limit. The shadow price is defined as the marginal decrease in the net revenue due to a one hour equivalent decrease in the binding environmental or operation limit.

The opportunity cost adder is calculated as the average of the three opportunity cost values corresponding to the three sets of forward LMPs and forward delivered fuel prices.

12.7.7 Market Participant Requirements

Market Participants must make available to the MMU the following information:

- Permits describing environmental limitations imposed on the generator;
- OEM documentation or insurance carrier documentation for physical equipment limitations;
- Operating parameters necessary for the calculation (Economic Minimum, Economic Maximum, heat rate curve, minimum downtime, maximum weekly starts, maximum daily starts, emission rates, start-up emission rates, fuel consumption rates during start-up);
- Fuel price information;
- Emission levels for the previous 12 month period in the case of environmental limitations;
- Hours of operation and number of starts for generators subject to operational limitations.

Information that is currently included in the Cost Offer Assumptions (COA) or the Fuel Policy as part of the Member Information Reporting Application (MIRA) does not need to be resubmitted.

12.7.8 Dual Fuel Opportunity Cost Adder

Dual fuel generators with an environmental or operational limitation that applies regardless of the fuel type may use the dual fuel opportunity cost adder in the cost schedule associated with the secondary fuel. The dual fuel opportunity cost adder is determined under the assumption that the generator operated for the minimum run time on the first day of the optimization period using the secondary fuel. For the remaining days in the optimization period, the generator is dispatched according to a daily determination of the cheaper fuel based on forward prices modified by the historical daily volatility. The opportunity cost adder applicable to the cost schedule associated with the primary fuel is determined according to Sections 12.7.1-12.7.7.

² The required opportunity cost is a solution of a constrained optimization problem and the IMM Opportunity Cost Calculator uses an integer programming solver that finds the maximum energy market revenue net of the generator's short run marginal cost of producing energy while simultaneously satisfying all generator parameter limits (e.g. minimum run time, economic minimum economic maximum) and environmental or operational limits.

12.7.9 Minimum Run Time Logic

For a generator with a minimum runtime of one hour or less, the Opportunity Cost Calculator will commit the unit only in the case that the revenue net of startup and hourly operating cost for the first hour is greater than \$0 or the revenue net of startup and hourly operating cost for the first hour plus the next hour is greater than \$0. If a generator has a minimum runtime greater than one hour, the Opportunity Cost Calculator will commit the unit only in the case that the revenue net of startup and hourly operating cost for the minimum runtime is greater than \$0. The Opportunity Cost Calculator will commit the unit for an hour beyond the minimum runtime only in the case that the revenue net of hourly operating cost for the hour is greater than \$0 or the revenue net of hourly operating cost for the hour plus the next hour is greater than \$0.

Section 13 Black Start Capital Recover Factor (CRF) Calculation

13.1 Black Start Service

A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in Schedule 6A of the Tariff and PJM Manual 12.

13.2 Black Start Service Annual Revenue Requirements

Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6 of Schedule 6A, as applicable, or (ii) the formula rates set forth in section 18 of Schedule 6A for the commitment term set forth in section 5 or 6 of Schedule 6A as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation performed in May and effective June 1 through May 31 of the following year.

Owners of Black Start Units selected to provide Black Start Service electing to recover new or additional Black Start Capital Costs in accordance with section 6 of Schedule 6A generally calculate the Fixed Black Start Service Costs (Fixed BSSC) Portion of their Black Start service annual revenue requirement by the following equation:

$$\text{Fixed BSSC} = \text{Incremental Black Start Capital Costs} * \text{CRF}$$

Where

“Incremental Black Start Capital Costs” are the new or additional capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Unit owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. However, Incremental Black Start Capital Costs shall not include any capital costs that the Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.

“CRF” or “Capital Recovery Factor “ is equal to the Levelized CRF based on the age of the Black Start Unit

13.3 Capital Recovery Factors

Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6 of Schedule 6A, as applicable, or (ii) the formula rates set forth in section 18 of Schedule 6A for the commitment term set forth in section 5 or 6 of Schedule 6A as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation performed in May and effective June 1 through May 31 of the following year.

Black Start Units selected prior to June 6, 2021 will utilize the Capital Recovery Rates as published in Tariff, Schedule 6A. Black Start Units selected after June 6, 2021 will utilize the CRFs as posted on the PJM website and updated annually as described in section 13.4 below.

Capital Recovery Factors (CRF) are calculated using the equation below:

$$CRF = \frac{r(1+r)^N \left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r} \sum_{j=1}^L \frac{m_j}{(1+r)^j} \right]}{(1-s)\sqrt{1+r}[(1+r)^N - 1]} \dots$$

Where:

- r is the After Tax Weighted Average Cost of Capital (ATWACC)

ATWACC =

$$(\% \text{ equity})(\text{cost of equity}) + (\% \text{ debt})(\text{debt interest rate})(1 - \text{effective tax rate})$$

- s is the effective tax rate which is calculated as

Effective Tax Rate =

$$(1 - \text{state tax rate})(\text{federal tax rate}) + \text{state tax rate}$$

- B is the bonus depreciation percent in effect at the Black Start in-service date
- N is the cost recovery period based on the age of the unit in years
- L is the lesser of N or 16 years
- m is the Modified Accelerated Cost Recovery System (MACRS) depreciation

The following assumptions are used in the calculation:

- current federal tax and depreciation rates as established by U.S. Internal Revenue Service,
- the state tax rate is an average of the income tax rates for all the states in the PJM Region,
- 50 percent equity for the capital investment necessary to make a unit qualify for Black Start Service,

- 50 percent debt for the capital investment necessary to make a unit qualify for Black Start Service,
- debt interest rate based on the most recent Net CONE quadrennial review after-tax weighted average cost of capital (ATWACC) and modified on annual basis by a 200 basis points or greater changes in the Moody Utility Index for bonds rated Baa1
 - This interest rate will be updated during the Net CONE quadrennial review
 - If the 2-year change in the Moody Utility Index for bonds rated Baa1 is more than 200 basis points, this change will be added to the interest rate used in the most recent Net CONE quadrennial review and used for the current year’s interest rate
- debt term equal to the recovery period,
- cost of equity equal to an after tax internal rate of return on equity of 12%.

Any changes to the debt/equity ratio and after tax internal rate of return on equity components stated above shall be included in revisions to Tariff, Schedule 6A, Section 18

Debt Interest Rate Example Calculation

	Value
Most recent Net CONE ATWACC	8% (2018 value)
(Current year -2) Moody Utility Index	4.68%
Current year Moody Utility Index	3.5%
Current year CRF Debt Interest Rate	ATWACC + (only if greater than 200 basis points) [2020 Moody Utility index – 2018 Moody Utility Index]
Current year CRF Debt Interest Rate	8.0% + (only if greater than 200 basis points) [3.5% - 4.68%] = 8%

13.4 Capital Recovery Factor Calculations

Capital Recovery Factors shall be calculated annually each March and posted on PJM.com by March 31st. Calculations shall include the most recent:

- federal tax rates as established by U.S. Internal Revenue Service,
- depreciation rate established by the U.S. Internal Revenue Service in effect at the time the unit entered Black Start Service
- average of all the PJM states’ income tax rates,

- and debt interest rate based on the most recent Net Cone quadrennial review ATWACC and modified on annual basis by a 200 basis points or greater changes in the Moody Utility Index for bonds rated Baa1

Effective as of March 1.

Interested parties shall have until April 15 of each year to contest PJM’s calculation of the annual CRF value before it becomes effective on June 1 of each year. The timeline of the CRF calculation process is shown below:

PJM determines annual CRF inputs	March 1
PJM posts annual CRF	March 31
Deadline for contesting annual CRF	April 15
Annual revenue requirement calculation	May 3 through 27
Annual revenue requirement with CRF in effect	June 1

13.5 Capital Recovery Factor Application

These new CRFs will be used in the Black Start annual revenue calculation performed in May each year and any Black Start request for proposal (RFP) issue after the calculation. New unit entering Black Start Service after June 6, 2021 under Section 6 of Schedule 6A will use the CRF currently in affect for the annual revenue requirement period which are updated annually in accordance with Section 13.4.

Attachment A: Applicable FERC System of Accounts

The information included in this Attachment A provides the descriptions and definitions of several account numbers and Operating Expenses Instructions as they appear in the **FERC System of Accounts** and named in this document.

The **FERC System of Accounts** was created when a predominant amount of the nation's electrical generating resources were “**utility owned**”. Although many of those resources are now owned by non-vertically integrated entities, such as, Independent Power Producers (IPPs) and Generating Companies (GENCOs), the descriptions of the accounts are the important concepts.

Accounting Principal Regarding FERC System of Accounts

Whenever there is reference in this manual to a FERC Account, it is implicitly understood that the FERC System of Accounts may be replaced by any other accounting method mapped back to the current FERC System of Accounts (see Attachment B) if approved for use by the MMU. The accounts named in this document provide the information to allow the development of cost based bids for submission to PJM.

A.1 Balance Sheet Accounts

A.1.1 FERC FORM 1 ACCOUNT 151: Fuel Stock (Major only).

This account shall include the book cost of fuel on hand.

Items

- Invoice price of fuel less any cash or other discounts.
- Freight, switching, demurrage and other transportation charges, not including, however, any charges for unloading from the shipping medium.
- Excise taxes, purchasing agents' commissions, insurance and other expenses directly assignable to cost of fuel.
- Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point.
- Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point.

A.2 Expense Accounts

A.2.1 FERC FORM 1 ACCOUNT 501: Fuel

- This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure. Records shall be maintained to show the quantity, MMBtu content and cost of each type of fuel used.
- The cost of fuel shall be charged initially to Account 151, Fuel Stock (for Non-major utilities, appropriate fuel accounts carried under Account 154, Plant Materials and Operating Supplies), and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to Account 152, Fuel Stock Expenses Undistributed (for Non-major utilities, an appropriate sub account of Account 154, Plant Materials and Operating Supplies). In the latter event, they shall be cleared to this account based on the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.

Items

Labor:

- Supervising purchasing and handling of fuel.
- All routine fuel analysis.
- Unloading from shipping facility and putting in storage.
- Moving of fuel in storage and transferring fuel from one station to another.
- Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler-house structure.
- Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.

Materials and expenses:

- Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).
- Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).
- Cost of fuel including freight, switching, demurrage and other transportation charges.
- Excise taxes, insurance, purchasing commissions and similar items.
- Stores expense to extent applicable to fuel.
- Transportation and other expenses in moving fuel in storage.

- Tools, lubricants and other supplies.
- Operating supplies for mechanical equipment.
- Residual disposal expenses less any proceeds from sale of residuals.

Note:

Abnormal fuel handling expenses occasioned by emergency conditions shall be charge to expense as incurred.

A.2.2 FERC FORM 1 ACCOUNT 509: Allowances

This account shall include the cost of allowances expensed concurrent with the monthly emission of sulfur dioxide.

A.2.3 FERC FORM 1 ACCOUNT 512: Maintenance of Boiler Plant (Major only)

- This account shall include the cost of labor, materials used and expenses incurred in the maintenance of steam plant, the book cost of which is includible in Account 312, Boiler Plant Equipment. (See operating expense instruction 2; which can be found in this manual, Attachment A.3.1)
- For the purposes of making charges hereto and to Account 513, Maintenance of Electric Plant, the point at which steam plant is distinguished from electric plant is defined as follows:
 - Inlet flange of throttle valve on prime mover.
 - Flange of all steam extraction lines on prime mover.
 - Hotwell pump outlet on condensate lines.
 - Inlet flange of all turbine-room auxiliaries.
 - Connection to line side of motor starter for all boiler-plant equipment.

A.2.4 FERC FORM 1 ACCOUNT 513: Maintenance of Electric Plant (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of electric plant, the book cost of which is includible in Account 313, Engines and Engine-Driven Generators, Account 314, Turbogenerator Units, and Account 315, Accessory Electric Equipment. (See operating expense instruction 2, which can be found in this manual, Attachment A.3.1 and paragraph B of Account 512, which can be found above in A.2.3)

A.2.5 FERC FORM 1 ACCOUNT 518: Nuclear Fuel Expense (Major only)

- This account shall debit and Account 120.5, Accumulated Provision for Amortization of Nuclear Fuel Assemblies, credited for the amortization of the net cost of nuclear fuel assemblies used in the production of energy. The net cost of nuclear fuel assemblies subject to amortization shall be the cost of the nuclear fuel assemblies plus or less the expected net salvage of uranium, plutonium, and other byproducts and unburned fuel. The

utility shall adopt the necessary procedures to assure that charges to this account are distributed according to the thermal energy produced in such periods.

- This account shall also include the costs involved when fuel is leased.
- This account shall also include the cost of other fuels, used for ancillary steam facilities, including superheat.
- This account shall be debited or credited as appropriate for significant changes in the amounts estimated as the net salvage value of uranium, plutonium, and other byproducts contained in Account 157, Nuclear Materials Held for Sale and the amount realized upon the final disposition of the materials. Significant declines in the estimated realizable value of items carried in Account 157 may be recognized at the time of market price declines by charging this account and crediting Account 157. When the declining change occurs while the fuel is recorded in Account 120.3, Nuclear Fuel Assemblies in Reactor, the effect shall be amortized over the remaining life of the fuel.

A.2.6 FERC FORM 1 ACCOUNT 530: Maintenance of Reactor Plant Equipment (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of reactor plant, the book cost of which is includible in Account 322, Reactor Plant Equipment.

A.2.7 FERC FORM 1 ACCOUNT 531: Maintenance of Electric Plant (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of electric plant, the book cost of which is includible in Account 323, Turbo-generator Units, and account 324, Accessory Electric Equipment.

A.2.8 FERC FORM 1 ACCOUNT 543: Maintenance of Reservoirs, Dams, and Waterways (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of plant, includible in Account 332, Reservoirs, Dams, and Waterways. (See operating expense instruction 2, which can be found in this manual, Attachment A.3.1.) However, the cost of labor materials used and expenses incurred in the maintenance of fish and wildlife, and recreation facilities, the book cost of which is includible in Account 332, Reservoirs, Dams, and Waterways, shall be charged to Account 545, Maintenance of Miscellaneous Hydraulic Plant.

A.2.9 FERC FORM 1 ACCOUNT 544: Maintenance of Electric Plant (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of plant includible in Account 333, Water Wheels, Turbines and Generators, and Account 334, Accessory Electric Equipment. (See operating expense instruction 2, which can be found in this manual, Attachment A.3.1.)

A.2.10 FERC FORM 1 ACCOUNT 553: Maintenance of Generating and Electrical Equipment (Major only)

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of plant, the book cost of which is includible in Account 343, Prime Movers, Account 344, Generators, and Account 345, Accessory Electric Equipment.

A.3 Operating Expense Instructions 2 and 3

A.3.1 OPERATING EXPENSE INSTRUCTION 2: Maintenance

- The cost of maintenance chargeable to the various operating expense and clearing accounts includes labor, materials, overheads and other expenses incurred in maintenance work. A list of work operations applicable generally to utility plant is included hereunder. Other work operations applicable to specific classes of plant are listed in functional maintenance expense accounts.
- Materials recovered in connection with the maintenance of property shall be credited to the same account to which the maintenance cost was charged.
- If the book cost of any property is carried in Account 102, Electric Plant Purchased or Sold, the cost of maintaining such property shall be charged to the accounts for maintenance of property of the same class and use, the book cost of which is carried in other electric plant in service accounts. Maintenance of property leased from others shall be treated as provided in operating expense instruction 3.

Items

- Direct field supervision of maintenance
- Inspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting and testing the adequacy of repairs that have been made
- Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life of plant
- Rearranging and changing the location of plant not retired
- Repairing for reuse materials recovered from plant
- Testing for locating and clearing trouble
- Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in service
- Replacing or adding minor items of plant that do not constitute a retirement unit (See electric plant instruction 10)

Note:

ELECTRIC PLANT INSTRUCTION 10 Rents includes amounts paid for the use of construction quarters and office space occupied by construction forces and amounts properly includible in construction costs for such facilities jointly used.

A.3.2 OPERATING EXPENSE INSTRUCTION 3: Rents

- The rent expense accounts provided under the several functional groups of expense accounts shall include all rents, including taxes paid by the lessee on leased property, for property used in utility operations, except (1) minor amounts paid for occasional or infrequent use of any property or equipment and all amounts paid for use of equipment that, if owned, would be includible in plant Accounts 391 and 398, inclusive, which shall be treated as an expense item and included in the appropriate functional account and (2) rents which are chargeable to clearing accounts, and distributed there from/to the appropriate account. If rents cover property used for more than one function, such as production and transmission, or by more than one department, the rents shall be apportioned to the appropriate rent expense or clearing accounts of each department on an actual, or if necessary, an estimated basis.
- When a portion of property or equipment rented from others for use in connection with utility operations is subleased, the revenue derived from such subleasing shall be credited to the rent revenue account in operating revenues; provided, however, that in case the rent was charged to a clearing account, amounts received from subleasing the property shall be credited to such clearing account.
- The cost, when incurred by the lessee, of operating and maintaining leased property, shall be charged to the accounts appropriate for the expense if the property were owned.
- The cost incurred by the lessee of additions and replacements to electric plant leased from others shall be accounted for as provided in electric plant instruction.

Attachment B: No-Load Calculation Examples

The information included in this Attachment B provides guidance for calculating no-load costs for various types of generating units.

B.1 No-Load Fuel

All Market Sellers shall use no-load fuel to develop no-load costs for their units. Since generating units cannot normally be run stable at zero net output, the no-load fuel may be determined by:

Collecting heat input values as a function of output and performing a regression analysis,

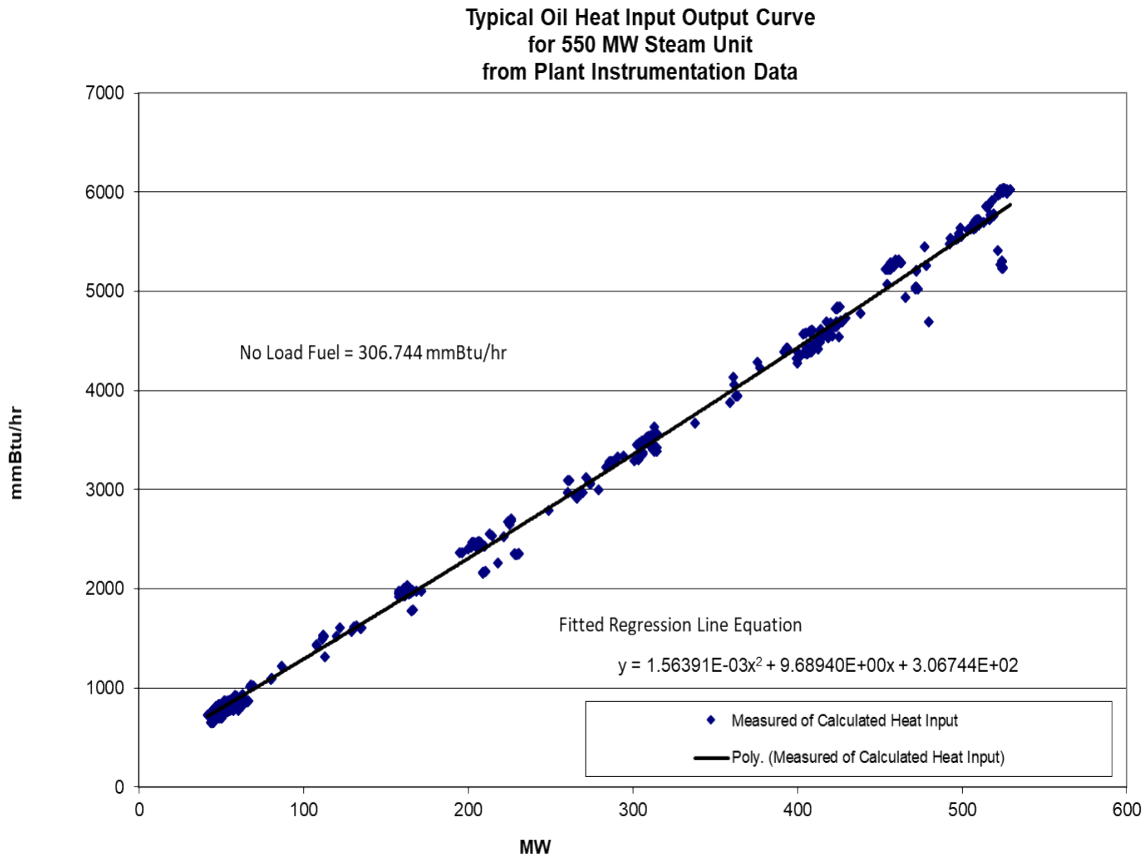
Using heat input values as provided by OEM and performing a regression analysis,

Using the initial design heat input curve for an immature unit and performing a regression analysis

Determining the measured value of fuel consumed at zero net output from test data (moment of generator output breaker closure).

B.2 Typical Steam Unit Example

An example of collecting heat input values as a function of unit's output and performing a regression analysis on the data to obtain the no-load fuel for a typical fossil steam unit is shown below:



Each diamond in the graph above indicates one hourly heat input data point calculated from plant instrumentation during operations. A regression analysis was performed on the data collected to obtain the unit's Heat Input curve as a function of unit's output with oil as a fuel:

$$\text{Heat Input (MMBtu / Hr)} = 0.00156391 * \text{MW}^2 + 9.6894 * \text{MW} + 306.744$$

Then the No-Load Fuel at zero output is

$$\text{No - Load Fuel} = 306.744 \text{ MMBtu / Hr}$$

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is:

$$\text{Performance Factor} = 1.02$$

$$\text{Total Fuel related Cost (TFRC)} = \$14.00 \text{ MMBtu}$$

$$\text{No - Load Cost} \left(\frac{\$}{\text{Hour}} \right) = (\text{No - Load Fuel} * \text{Performance Factor} * \text{TFRC})$$

$$= 306.744 \frac{\text{MMBtu}}{\text{hr}} * 1.02 * \frac{\$14.00}{\text{MMBtu}} = \frac{\$4,380}{\text{hr}}$$

The unit's Cost Curve must be developed to determine if adjustments are needed for the unit's no-load cost. The Heat Input Curve Equation is used to determine the units heat input at various outputs. Total Operating Cost is calculated by:

$$VOM = \$0.15/\text{MMBtu}$$

$$\text{Total Operating Cost}\left(\frac{\$}{\text{hr}}\right) = \text{Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Heat Input (MMBtu/hr)	Total Operating Cost (\$/hr)
50	795.12	11,476
160	1897.08	27,381
310	3460.75	49,949
410	4542.29	65,559
525	5824.73	84,068
550	6109.00	88,171

The unit's Incremental Cost (\$/MWh) at various outputs can be determined arithmetically by the following equation:

$$\text{Incremental Cost}\left(\frac{\$}{\text{MWh}}\right) = \text{Total Operating Cost MW2} - \frac{\text{Total Operating Cost MW1}}{(\text{MW2} - \text{MW1})}$$

Output (MW)	Incremental Cost (\$/MWh)
50	141.91
160	144.59
310	150.46
410	156.10
525	160.95
550	164.11

When calculating the first increment, MW1 is zero and the Total Operating Cost MW1 is the no-load cost. Since the Incremental Costs are monotonically increasing, no adjustment to the no-load cost is required.

The unit's Incremental Cost (\$/MWh) at various output levels can also be determined by using the derivative of the Heat Input Curve:

$$\text{Incremental Cost } \left(\frac{\$}{\text{MWh}} \right) \\ = (2 * 0.00156391 * \text{MW} + 9.6894) * \text{PerformanceFactor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Incremental Cost (\$/MWh)
50	142.10
160	147.07
310	153.84
410	158.36
525	163.55
550	164.68

B.3 Typical Combustion Turbine Example

An example of using the design heat input curve and performing a regression analysis to obtain the no-load fuel for a simple cycle CT with peak firing is shown below:

Each diamond in the graph above is a design heat input data point obtained from the original equipment manufacturer or calculated by heat balance. A regression analysis was performed on the design data to obtain the unit's Heat Input curve as a function of unit's output with natural gas as a fuel:

Heat Input (MMBtu/Hr) =

$$0.0498 * \text{MW}^2 + 0.8122 * \text{MW} + 578.23$$

Then the No-Load Fuel at zero output is:

$$\text{No - Load Fuel} = 578.23 \text{ MMBtu / hr}$$

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is:

Performance Factor = 1.02

Total Fuel Related Cost (TFRC) = \$4.00/MMBtu

$$\text{No - Load Cost} (\$ / \text{hr}) = (\text{No - Load Fuel} * \text{Performance Factor} * \text{TFRC}) \\ = 578.23 \text{ MMBtu / hr} * 1.02 * \$4.00 / \text{MMBtu} = \$2,359 / \text{hr}$$

The unit's Cost Curve must be developed to determine if adjustments are needed for the unit's no-load cost. The Heat Input Curve Equation is used to determine the unit's heat input at various unit output levels. Total Operating Cost is calculated by:

Maintenance Factor = 1.0 for Minimum & Base (= 3.0 for Peak)

VOM = \$75.00/ESH

$$\begin{aligned} & \textit{Total Operating Cost}(\$ / \textit{hr}) \\ & = \textit{Heat Input} * \textit{Performance Factor} * \textit{TFRC} + \textit{Maintenance Factor} * \textit{VOM} \end{aligned}$$

Output (MW)	Heat Input (MMBtu/hr)	Total Operating Cost (\$/hr)
70	879.02	3,662
90	1054.57	4,378
100	1157.28	5,022

The unit's Incremental Cost (\$/MWh) at various unit output levels can be determined arithmetically by the following equation:

$$\begin{aligned} & \textit{Incremental Cost}(\$ / \textit{MWh}) \\ & = \left(\frac{\textit{Total Operating Cost MW2} - \textit{Total Operating Cost MW1}}{\textit{MW2} - \textit{MW1}} \right) \end{aligned}$$

Output (MW)	Incremental Cost (\$/MWh)
70	18.61
90	35.82
100	64.42

When calculating the first increment, MW1 is zero and the Total Operating Cost MW1 is the no-load cost. Since the Incremental Costs are monotonically increasing, no adjustment to the no-load cost is required.

The unit's Incremental Cost (\$/MWh) at various unit output levels can also be determined by using the derivative of the Heat Input Curve:

$$\begin{aligned} & \textit{Incremental Cost}(\$ / \textit{MWh}) \\ & = \left((2 * 0.0498 * \textit{MW} + 0.8122) * \textit{Performance Factor} * \textit{TFRC} \right) + \frac{\Delta \textit{VOM}}{\Delta \textit{MW}} \end{aligned}$$

Since VOM is in the units of \$/hr it can only be added to the first incremental and any incremental where the maintenance factor changes.

Output (MW)	Incremental Cost (\$/MWh)
70	32.83
90	39.89
100	66.45

The no-load cost is calculated by subtracting the incremental cost (unit's economic minimum cost-offer value multiplied by MW value) at the unit's economic minimum point from the total cost (from the heat input at economic minimum value) at the unit's economic minimum point.

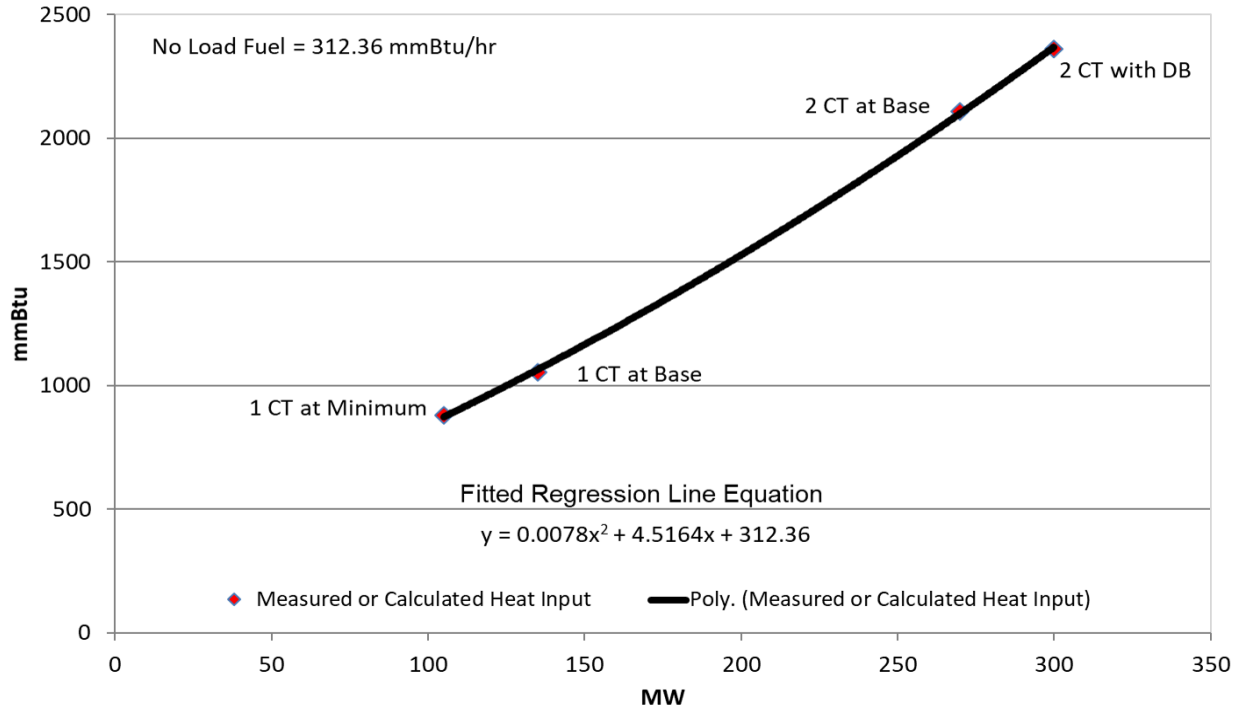
$$\begin{aligned}
 & \text{No - Load Cost} (\$/hr) \\
 &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * \text{TFRC}) \\
 &+ \text{VOM} - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\
 &= (879.02 \text{ MMBtu} / \text{hr} * 1.02 * \$4.00 / \text{MMBtu}) \\
 &+ (\$75.00 / \text{ESH}) - (\$32.83 / \text{MWh} * 70 \text{ MW}) = \$1,363.30 / \text{hr}
 \end{aligned}$$

Differences in the calculated no-load cost between the two methods are due to the differences in using a block average cost offer method versus a sloped derivative cost offer. When using the derivative method, user must select "Use Sloped Offer" when entering cost information into Markets Gateway.

B.4 Typical 2 on 1 Combined Cycle with Duct Burning Example

An example of using the design heat input curve and performing a regression analysis of the data to obtain the no-load fuel for a two on one CC with duct burners is shown below:

2 on 1 Combined Cycle with Duct Burning Heat Input Curve



Each diamond in the graph above is a design heat input data point obtained from the original equipment manufacturer or calculated by heat balance. A regression analysis was performed on the design data to obtain the unit's Heat Input curve as a function of unit output levels with natural gas as a fuel:

$$\text{Heat Input (MMBtu / Hr)} = 0.0078 * MW^2 + 4.5164 * MW + 312.36$$

Then the No-Load Fuel at Zero output is:

$$\text{No - Load Fuel} = 312.36 \text{ MMBtu / hr}$$

The initial estimate of a unit's **No-Load Cost (\$/hr)** is:

Performance Factor = 1.02

Total Fuel related Cost (TFRC) = \$4.00/MMBtu

$$\begin{aligned} \text{No - Load Cost (\$/hr)} = \\ (\text{No - Load Fuel} * \text{Performance Factor} * \text{TFRC}) \end{aligned}$$

$$= 312.36 \text{ MMBtu} / \text{hr} * 1.02 * \$4.00 / \text{MMBtu} = \$1,274 / \text{hr}$$

The unit's Cost Curve must be developed to determine if adjustments are needed for the unit's no-load cost. The Heat Input Curve Equation is used to determine the units heat input at various unit output levels. Total Operating Cost is calculated by:

Maintenance Factor = 1.0

VOM = \$75.00/ESH

$$\begin{aligned} & \text{Total Operating Cost (\$/hr)} \\ & = \text{Heat Input} * \text{Performance Factor} * \text{TFRC} + \text{Maintenance Factor} * \text{VOM} \end{aligned}$$

Output (MW)	Heat Input (MMBtu/hr)	Total Operating Cost (\\$/hr)
105	872.58	3,635
135	1064.23	4,417
270	2100.41	8,720
300	2369.28	9,817

The unit's Incremental Cost (\$/MWh) at various unit output levels can be determined arithmetically by the following equation:

$$\begin{aligned} & \text{Incremental Cost (\$/MWh)} = \\ & \text{Total Operating Cost MW2} - \frac{\text{Total Operating Cost MW1}}{(\text{MW2} - \text{MW1})} \end{aligned}$$

Output (MW)	Incremental Cost (\$/MWh)
105	22.48
135	26.06
270	31.87
300	32.72

When calculating the first increment, MW1 is zero and the Total Operating Cost MW1 is the no-load cost. Since the Incremental Costs are monotonically increasing, no adjustment to the no-load cost is required.

The unit's Incremental Cost (\$/MWh) at various unit output levels can also be determined by using the derivative of the Heat Input Curve:

$$\text{Incremental Cost (\$/MWh)} = ((2 \times 0.0078 \times \text{MW} + 4.5164) \times \text{Performance Factor} \times \text{TFRC}) + \Delta \text{VOM} / \Delta \text{MW}$$

Since VOM is in the units of \$/hr it can only be added to the first incremental and any incremental where the maintenance factor changes.

Output (MW)	Incremental Cost (\$/MWh)
105	25.82
135	27.02
270	36.17
300	37.52

The no-load cost is calculated by subtracting the incremental cost (unit's economic minimum cost-offer value multiplied by MW value) at the unit's economic minimum point from the total cost (from the heat input at economic minimum value) at the unit's economic minimum point.

$$\begin{aligned} & \text{No - Load Cost (\$/ hr)} \\ &= \text{Economic Minimum Heat Input} \times \text{Performance Factor} \times \text{TFRC} + \text{VOM} \\ & - (\text{Economic Minimum Incremental Cost} \times \text{Economic Minimum MW}) \\ &= (872.58 \text{ MMBtu / hr} \times 1.02 \times \$4.00 / \text{MMBtu}) + (\$75.00 / \text{ESH}) \\ & - (\$25.82 / \text{MWh} \times 105 \text{ MW}) = \$924.03 / \text{hr} \end{aligned}$$

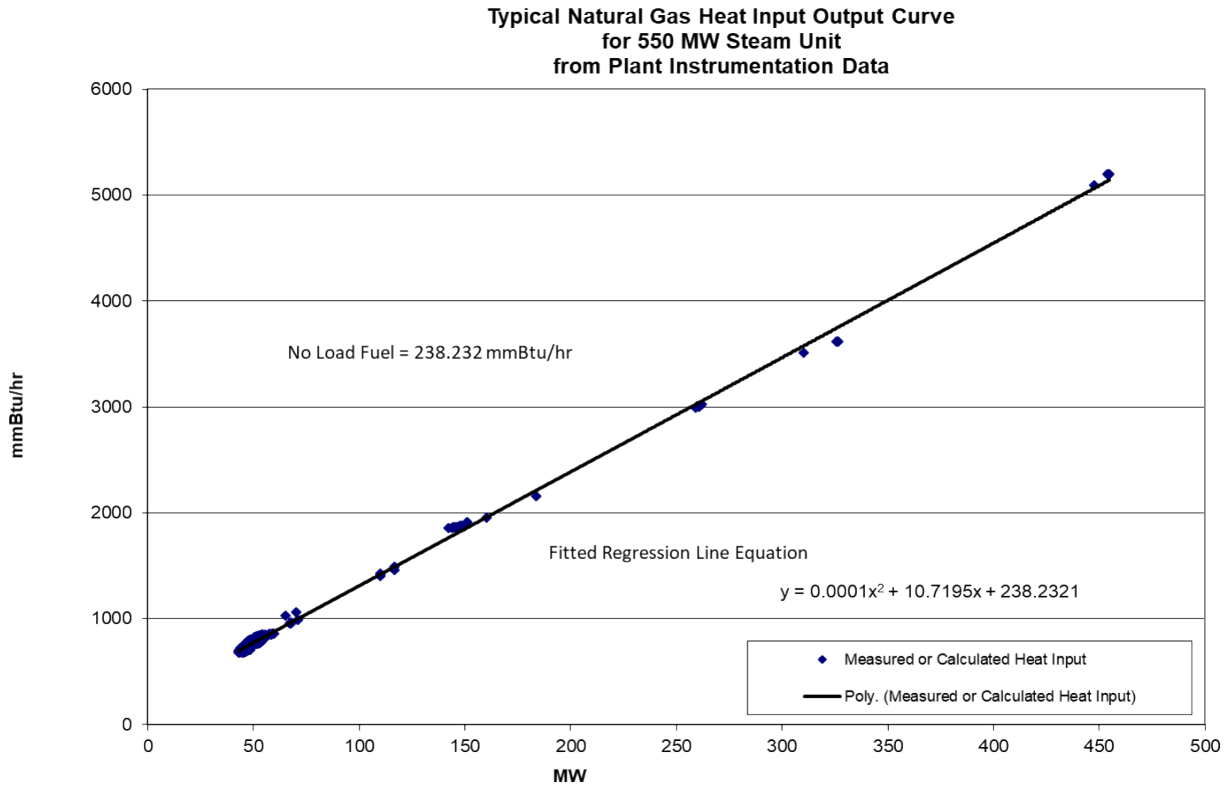
Since VOM is in the units of \$/hr it can only be added to the first incremental and any incremental where the maintenance factor changes.

Differences in the calculated no-load cost between the two methods are due to the differences in using a block average cost offer method versus a sloped derivative cost offer. When using the derivative method, user must select "Use Sloped Offer" when entering cost information into Markets Gateway.

B.5 No-Load Cost Adjustments

The calculated n-load cost may need to be adjusted to allow for the first incremental point of the unit's generator offer curve to comply with PJM's monotonically increasing curve requirement.

An example of adjusting the no-load cost for a typical natural gas fired Steam Unit after calculation is as follows. Heat input values as a function of various unit output levels were collected for a typical fossil steam and a regression analysis was performed to obtain the no-load cost.



Each diamond in the graph above indicates one hourly heat input data point calculated from plant instrumentation during operations. A regression analysis was performed on the data collected to obtain the unit's Heat Input curve as a function of various unit output levels with oil as a fuel:

$$\text{Heat Input}(\text{MMBtu} / \text{hr}) = 0.000148321 * \text{MW}^2 + 10.7195 * \text{MW} + 238.232$$

Then the No-Load Fuel at zero output is:

$$\text{No - Load Fuel} = 238.232 \text{ MMBtu} / \text{hr}$$

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is:

Performance Factor = 1.02

Total Fuel related Cost (TFRC) = \$4.00/MMBtu

$$\begin{aligned} \text{No - Load Cost}(\$/\text{hr}) &= (\text{No - Load Fuel} * \text{Performance Factor} * \text{TFRC}) \\ &= 238.232 \text{ MMBtu} / \text{hr} * 1.02 * \$4.00 / \text{MMBtu} = \$972 / \text{hr} \end{aligned}$$

The unit's Cost Curve must be developed to determine if adjustments are needed for the unit's no-load cost. The Heat Input Curve Equation is used to determine the units heat input at various unit output levels. Total Operating Cost is calculated by:

$$\text{VOM} = \$0.15/\text{MMBtu}$$

$$\text{Total Operation Cost}(\$/\text{hr}) = (\text{Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM}))$$

Output (MW)	Heat Input (MMBtu/hr)	Total Operating Cost (\$/hr)
50	774.58	3,279
160	1957.15	8,285
310	3575.53	15,135
410	4658.16	19,718
525	5906.85	25,004
550	6178.82	26,155

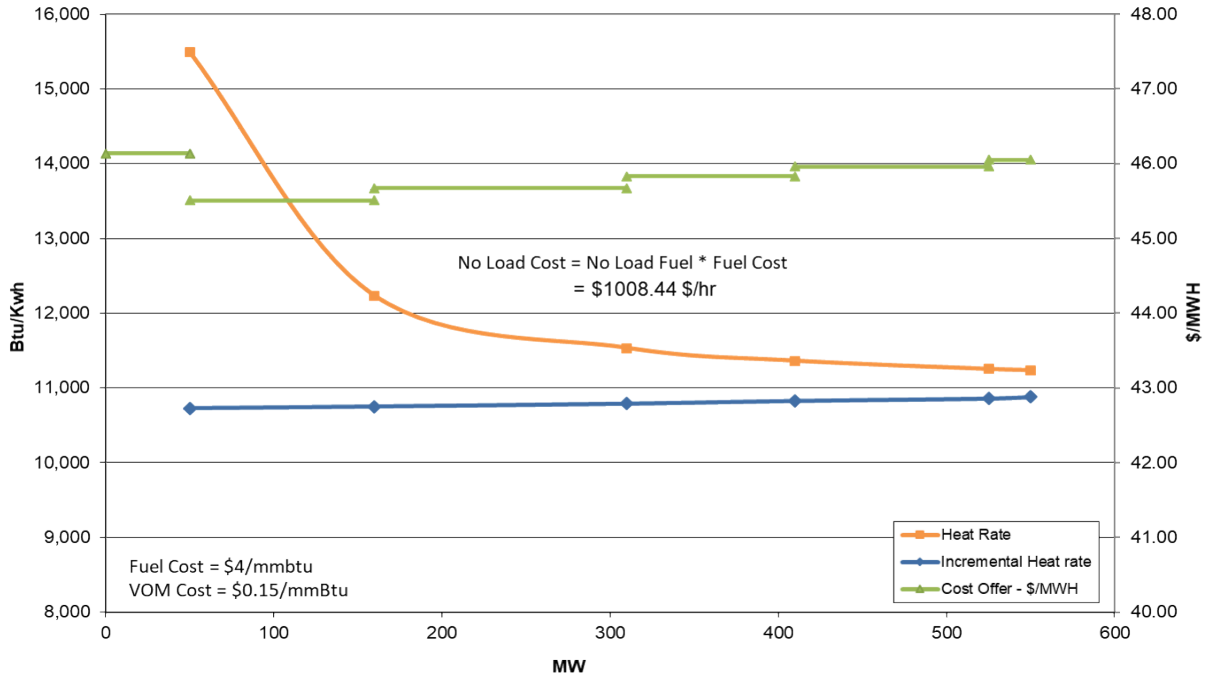
The unit's Incremental Cost (\$/MWh) at various unit output levels can be determined arithmetically by the following equation:

$$\text{Incremental Cost}(\$/\text{MWh}) = \frac{\text{Total Operating Cost MW2} - \text{Total Operating Cost MW1}}{\text{MW2} - \text{MW1}}$$

Output (MW)	Incremental Cost (\$/MWh)
50	46.14
160	45.51
310	45.67
410	45.83
525	45.96
550	46.05

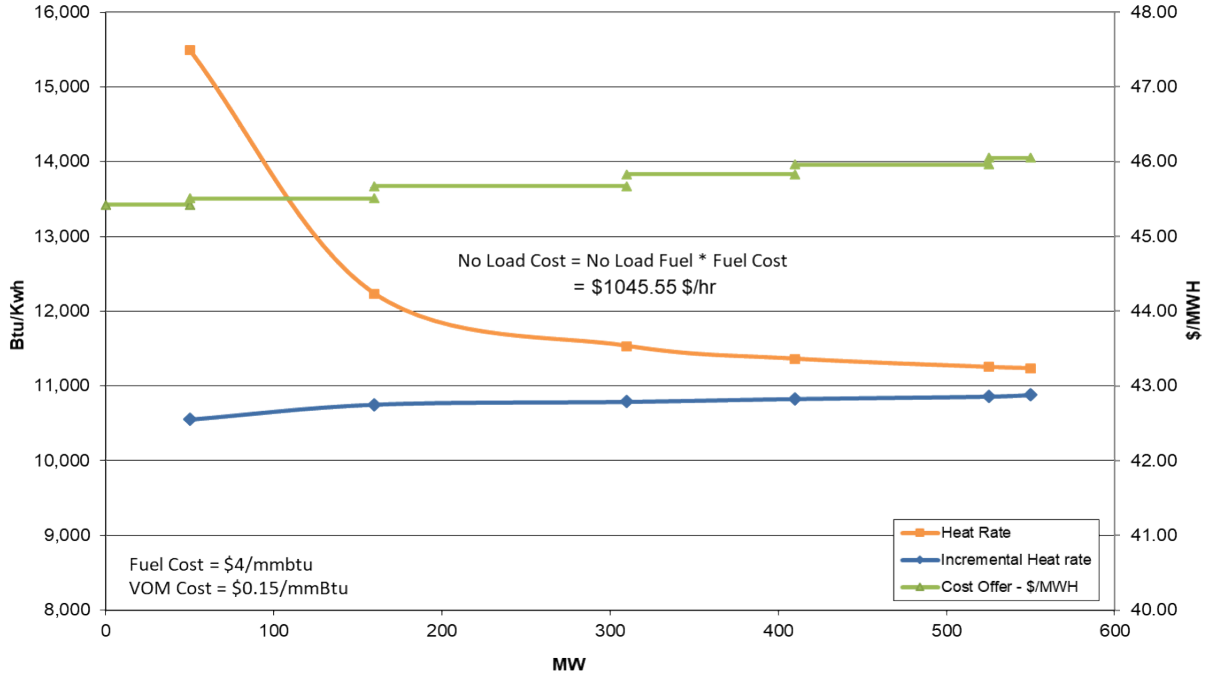
When calculating the first increment, MW1 is zero and the Total Operating Cost MW1 is the no-load cost. However due to the quality of the heat input data, the first increment of the cost offer was greater than the second increment. This is shown in the graph below:

**Typical Natural Gas
Heat Rate & Cost Curves
for 550 MW Steam Unit**



The o-load cost was then raised to \$1007.76 until the first increment of the cost offer was less than \$1/MWh below the second increment, producing a monotonically increasing curve in the graph below:

**Typical Natural Gas
Heat Rate & Cost Curves
for 550 MW Steam Unit**



To avoid making adjustments to the no-load cost, first calculate the unit's Incremental Cost (\$/MWh) at various outputs using the derivative of the Heat Input Curve:

$$\text{Incremental Cost}(\$/\text{MWh}) = (2 * 0.000148321 * \text{MW} + 10.7195) * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Incremental Cost (\$/MWh)
50	45.43
160	45.58
310	45.76
410	45.89
525	46.03
550	46.06

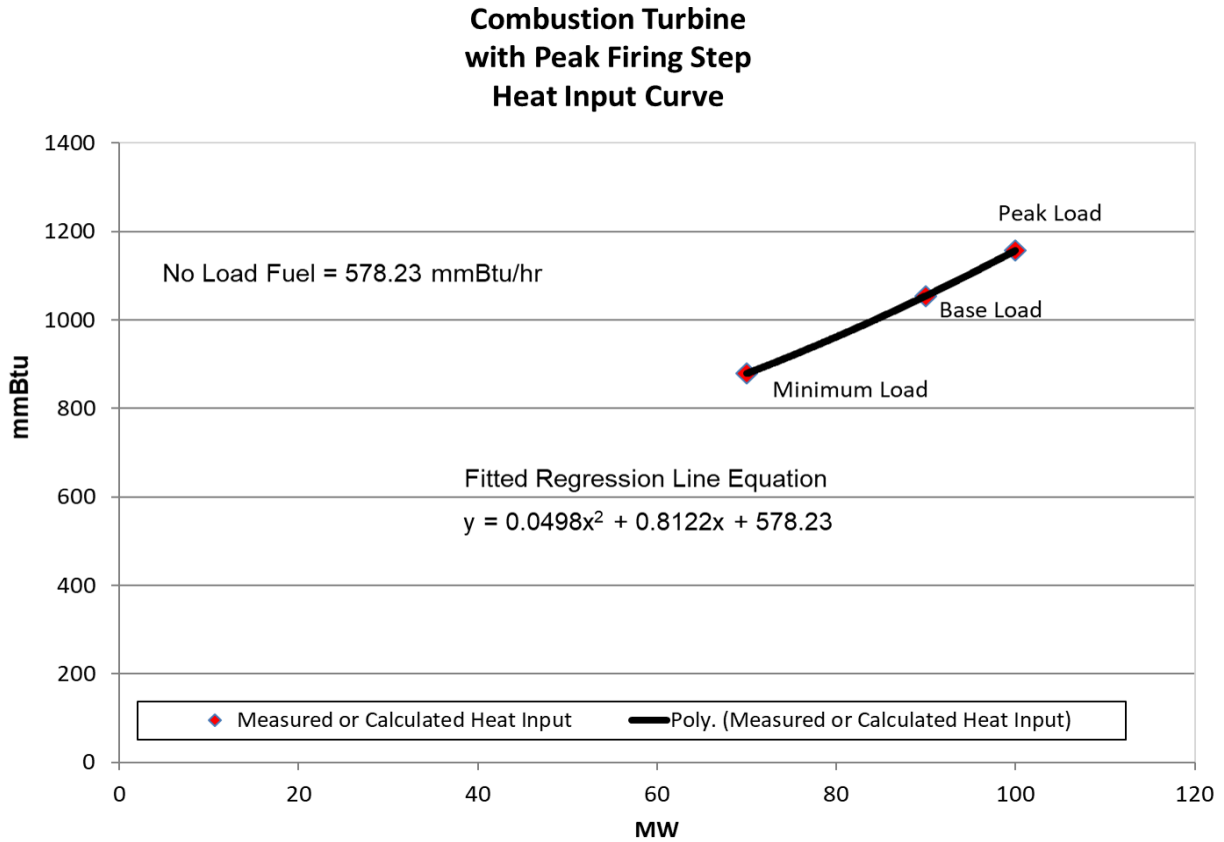
The no-load cost is calculated by subtracting the incremental cost (unit’s economic minimum cost-offer value multiplied by MW value) at the unit’s economic minimum point from the total cost (from the heat input at economic minimum value) at the unit’s economic minimum point.

$$\begin{aligned}
 & \text{No - Load Cost}(\$ / \text{hr}) \\
 &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM})) \\
 & \quad - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\
 &= (774.58 \text{ MMBtu} / \text{hr} * 1.02 * (\$4.00 / \text{MMBtu} + \$0.15 / \text{MMBtu})) - (\$45.43 / \text{MWh} * 50 \text{MW}) = \$1007.3 / \text{hr}
 \end{aligned}$$

Differences in the calculated no-load cost between the two methods are due to the differences in using a block average cost offer method versus a sloped derivative cost offer. When using the derivative method, user must select “Use Sloped Offer” when entering cost information into Markets Gateway.

B.6 Combustion Turbine Zero No-Load Example

A zero no-load example for a simple cycle combustion turbine with a single offer block is shown below:



Each diamond in the graph above is a design heat input data point obtained from the original equipment manufacturer or calculated by heat balance. A regression analysis can be performed on the design data to obtain the unit's Heat Input curve as a function of various unit output levels with natural gas as a fuel:

$$\text{Heat Input (MMBtu / Hr)} = 0.0498 * MW^2 + 0.8122 * MW + 578.23$$

Or the fuel input to the unit during operation can be directly measured.

The unit may be submitted with a single cost offer block and zero no-load cost (\$/Hr).

$$\text{No-load cost (\$/Hr)} = \$0/\text{hr}$$

The unit's Heat Input Curve Equation or actual measured fuel input data is used to determine the units heat input at its maximum output (100MW).

$$\text{Heat Input (MMBtu/Hr)} =$$

$$0.0498 * MW^2 + 0.8122 * 100 + 578.23$$

$$0.0498 * 100^2 + 0.8122 * 100 + 578.23 = 1157.28 \text{ MMBtu} / \text{hr}$$

Total Operating Cost at 100 MW is calculated by:

Maintenance Factor = 1.0 for Minimum & Base (=4.0 for Peak)

VOM = \$75.00/ESH

Total Operating Cost (\$/hr) =

$$\begin{aligned} & \text{Heat Input} * \text{Performance Factor} * \text{TFRC} + \text{Maintenance Factor} * \text{VOM} \\ & = 1157.28 \text{ MMBtu} / \text{hr} * 1.02 * \$4.00 / \text{MMBtu} + 4.0 * \$75 / \text{hr} = \$5,022 / \text{hr} \end{aligned}$$

The unit's Incremental Cost (\$/MWh) at maximum output with a zero no-load cost is calculated by:

Incremental Cost (\$/MWh) =

$$\begin{aligned} & \text{Total Operating Cost} / \text{Maximum Output} \\ & = (\$5,022 / \text{hr}) / (100 \text{ MW}) = \$50.22 / \text{MWh} \end{aligned}$$

Revision History

Revision 44 (08/01/2023):

- Updated section 4.1 to describe methods to develop heat input curves
- Updated section 5.1 to describe three methods for Combined Cycle heat input curves development and provide examples
- Added new section 12.7.9 to describe minimum run time logic in IMM Opportunity Cost Calculator

Revision 43 (06/01/2023):

- Revised Section 2.6 to provide guidance to Market Sellers on variable operating and maintenance costs for:
 - units submitting major maintenance
 - units submitting minor maintenance or using default minor maintenance adder
 - units submitting operating costs or using default operating costs adder
 - new submission and review timelines
 - definition and examples of major maintenance, minor maintenance and unallowable expenses
 - requirements for supporting documentation
- Provide guidance to Market Sellers on Start-Up Cost in Sections 1.7.2, 2.4, 3.4, 4.4, 5.4, & 6.4 for:
 - units with and without a soak process
 - clarifications to the Start-Up Cost equation
 - station service calculations
 - clarification to the start maintenance adder
 - removal of start additional labor cost
 - clarifications for aggregated, pseudo-tied, and cogeneration units
- Provide guidance to Market Sellers on changes to emissions costs and environmental credits in Section 2.2:
 - Adjust review of emissions rates from annual to periodic
 - Clearly document standards of review for emissions allowance adders
 - Remove reference to 'Emissions Policy'
 - Any resource that receives PTCs and/or RECs and submits non-zero cost-based offers, must
 - account for such credits in the resource's Fuel Cost Policy

Revision 42 (11/1/2022):

- Corrected the CDS mission statement to reflect MIC, not MRC, as the parent committee in Section 1.5
- Corrected the Incremental Heat Rate equation in Section 2.1
- Corrected the Basic Nuclear Fuel Cost equation in Section 3.3.1
- Replaced “other Fuel Related Costs” with “Operating Costs” in Sections 4.2 and 6.3.1
- Removed reference to annual Fuel Cost Policy submission in Section 9.2
- Corrected section titles in Section 9.7 and Section 13.3 Exhibit 28
- Added missing chart and removed outdated no-load calculation in Attachment B

Revision 41 (10/1/2022):

- Reserve Price Formation changes are reflected in Sections 4.7, 5.7, 6.7, 7.7, 8.1 and 11.7
 - Removed references to Tier 1 and Tier 2 due to the Tier 1/Tier 2 consolidation
 - The Variable Operations and Maintenance component was removed from Synchronized Reserve offers
 - The existing \$7.50/MWh offer margin was reduced to the expected value of the penalty
 - Added the expected value of the penalty calculations
 - Removed Exhibit 10: Steam Unit Synchronized Reserve Example

Revision 40 (06/07/2022):

- Revised Section 2.2.1 Submission of and/or Modifications to Fuel Cost Policies
- Revised Section 2.2.2 Fuel Cost Calculation

Administrative Change (03/31/2022): Approved by Glen Boyle

- Added Section 2.9 Ten Percent Adder
- Corrected/Updated Exhibit and Exhibit Language in Sections 2.6, 2.7, 2.8, 3.6, 4.6, 4.7, 5.7, 6.6, 12.5, 12.6, 13.3
- Removed extraneous “3” in section 3.3

Revision 39 (12/15/2021):

- Revised Section 1.7.3 No-Load Cost Definition
- Revised Section 1.7.4 Incremental Energy Cost Definition
- Consolidate Section 2.1 Heat Rate and Section 2.2 Performance Factor into Section 2.1 Heat Rate Input/Rates and Performance Factors
- Revised Section 2.1 Heat Input definition and Heat Input and Incremental Heat Rate equations
- Moved Section 2.3 Fuel Cost Policies and Guidelines to Section 2.2

- Revised Section 2.2.3 and 2.2.4 to replace Other Fuel Related Cost with Operating Cost
- Created new Section Incremental Energy Cost
- Revised Section 2.5.1 No-Load definition, Section 2.5.2 No-load Fuel, and Section 2.5.3 No-Load Calculation
- Added Section 2.9 Ten Percent Adder
- Consolidated Section 3.1 Nuclear Heat Rate and Section 3.2 Performance Factor into Section 3.1 Nuclear Heat Input/Rate and Performance Factor
- Moved Section 3.3 to Section 3.2
- Created New Section 3.3 Incremental Energy Cost
- Consolidated Section 4.1 Heat Rate and Section 4.2 Performance Factor into Section 4.1 Heat Input/Rate and Performance Factor
- Moved Section 4.3 to Section 4.2
- Revised Section 4.2 to replace Other Fuel Related Cost with Operating Cost
- Created New Section 4.3 Incremental Energy Cost
- Consolidated Section 5.1 Heat Rate and Section 5.2 Performance Factor into Section 5.1 Heat Input/Rate and Performance Factor
- Moved Section 5.3 to Section 5.2
- Created New Section 5.3 Incremental Energy Cost
- Revised Section 5.4 to replace Other Fuel related Cost with Operating Cost
- Revised Section 5.6.3 Equivalent Service Hour (ESH)
- Consolidated Section 6.1 Heat Rate and Section 6.2 Performance Factor into Section 6.1 Heat Input/Rate and Performance Factor
- Moved Section 6.3 to Section 6.2
- Revised Section 6.2.1 to replace Other Fuel Related Cost with Operating Cost
- Created New Section 6.3 Incremental Energy Cost
- Revised Section 6.4 to replace Other Fuel Related Cost with Operating Cost
- Revised Section 6.6.3 Equivalent Service Hour (ESH)
- Consolidated Section 7.1 Pumping Efficiency (Pumped Storage Hydro Only) and Section 7.2 Performance Factor into Section 7.1 Pumping Efficiency (Pumped Storage Hydro Only) and Performance Factor
- Moved Section 7.3 to Section 7.2
- Created New Section 7.3 Incremental Energy Cost
- Consolidated Section 9.1 Heat Rate and Section 9.2 Performance Factor into Section 9.1 Heat Input/Rate and Performance Factor
- Moved Section 9.3 to Section 9.2
- Created New Section 9.3 Incremental Energy Cost

- Consolidated Section 10.1 Heat Rate and Section 10.2 Performance Factor into Section 10.1 Heat Input/Rate and Performance Factor
- Moved Section 10.3 to Section 10.2
- Created New Section 10.3 Incremental Energy Cost
- Consolidated Section 11.1 Efficiency Factor and Section 11.2 Performance Factor into Section 11.1 Efficiency Factor and Performance Factor
- Moved Section 11.3 to Section 11.2
- Created New Section 11.3 Incremental Energy Cost

Revision 38 (6/6/2021):

- Added Section 13 Black Start Capital Recovery Guidelines

Revision 37 (12/9/2020)

- Biennial Review
 - Handy Whitman removed from M15 and moved to PJM.com (link in Section 2.6.3)
 - Generic documentation language previously included in all Fuel Cost Policies added to Section 2.3
 - Language regarding penalty gas application added for additional clarity around current PJM practices in Section 2.3.2
 - Additional clarity to Operating Costs
 - Moved Operating Costs to Section 2.6
 - Reworded Section 2.6.1 to align with OA Schedule 2
 - Additional clarity to Maintenance Costs
 - Use of Equivalent Service Hour (ESH) adder in Section 5.6.3 and 6.6.3
 - Included example of allowable/not allowable expenses

Administrative Change (10/05/2020):

- Restoring previously approved language in sections 2.3.3, 2.3.6, 2.3.7 and 2.3.8 that was mistakenly left out of the version 36 published on 9/4/2020.

Revision 36 (09/01/2020):

- Section 2.3:
 - Updates to reflect revised Fuel Cost Policy rules from Operating Agreement, Schedule 2 based on key work activities from MIC Special Session: Fuel Cost Policy Enhancements
 - Removal of Annual Review Process
 - Updates to Fuel Cost policy review process

Revision 35 (04/24/2020):

- Section 12:
 - Update to reflect suspension of PJM Opportunity Cost Calculator
 - Update Independent Market Monitor Opportunity Cost Calculator methodology

Revision 34 (02/11/2020):

- Conforming VOM adder format rules to FERC Dockets ER19-210 and EL19-8

Revision 33 (12/03/2019):

- FERC Order 841 Energy Storage Resources changes:
 - Section 11 – Batteries and Flywheels
- Equation clarified in Section 7.3
- Changes were approved by PJM Board on December 4, 2019

Revision 32 (05/13/2019):

- FERC VOM Order Docket No. ER19-210-001 conforming changes:
 - Sections 2.3, 2.6, 3.6, 4.6, 5.6, 6.6, 7.6, 9.6
- Revised Exhibit 1: Handy Whitman Index to reflect figures for the year 2019

Revision 31 (02/15/2019):

- Incorporate Independent Market Monitor Opportunity Cost Calculator methodology

Revision 30 (12/04/2018):

- Biennial Review

Revision 29 (5/15/2017):

- Fuel Cost Policy and Hourly Offers conforming changes:
 - Section 1.8, 2.3, 2.3.1, 2.3.1.1, 2.3.1.2, 2.3.1.3
- Additional changes to require submission to PJM and MMU
- Removed references to Manual 35 as this has been retired

Revision 28 (10/18/2016):

Biennial Review and Administrative Changes:

- Unit Owner changed to Market Seller
- Capitalization, Abbreviations, Grammar
- Pumped Storage Hydro
- Demand Resource

Revision 27 (04/20/2016):

Administrative Changes:

- Updated references eMKT to Markets Gateway
- Operating Parameter Definition Updates

Revision 26 (11/05/2014):

- Correct Mileage Ratio in Section 2.8 to Mileage

Revision 25 (07/28/2014):

- Update to the Handy Whitman Index numbers chart in section 2.6.1

Revision 24 (03/01/2014):

- Cyclic peaking and starting factors for combined cycle and combustion turbines in sections 2.6.4, 4, 5, and 6 were updated to reflect how to use OEM values. A reference was added for extended cold start.

Revision 23 (08/01/2013):

- Regulation Cost Based Offer update shifting manual language from Manual 11 to Manual 15
- Updated Section 2.8 related to Regulation cost based offers and 11.8 for Energy Storage units and Regulation

Revision 22 (06/01/2013):

- Update to the Handy Whitman Index numbers chart in section 2.6.1

Revision 21 (04/01/2013):

- Added sections for hydro, energy storage, wind, solar and biofuel powered generation resources.
- Added shutdown cost language for DSR resources participating in synchronous reserve.
- Modified the Cost Development and Approval process to include more than generation resources.

Revision 20 (11/01/2012):

- Added section 2.6.5 to define maintenance cost calculation for immature units
- Updated Long Term Maintenance Cost language for Combustion Turbines and Combined Cycles for additional clarity

Revision 19 (06/01/2012):

- Updated Handy Whitman Index with actual for 2011 and estimate for 2012.

Revision 18 (02/08/2012):

- Removes overhaul costs for Combined Cycles and (CCs) Combustion Turbines (CTs) from Variable Operation and Maintenance Cost (VOM). *Section 5.6, 5.6.2 and 6.2*
- Adds clarity to the development of No Load Costs. *Section 1.7.3, 2.1 and Attachment B*
- Updates Manual 15 to be consistent with the tariff with respect to Non-Regulatory and Energy Market Opportunity Costs. *Section 9*

Revision 17 (06/01/2011): Handy Whitman Update

- Section 2.6.1, Exhibit 1: Updated Handy Whitman Index Numbers for the year 2011.
- Section 9: Opportunity Cost Guideline is updated per the informational filing submitted by PJM on May 12, 2011, in Docket No. EL08-47-005.

Revision 16 (04/06/2011): Rewrite of entire Manual 15

- This revision improves readability and addresses changes as a result of FERC Order 719 (Docket Nos. ER09-1063-000 and ER09-1063-001) requirements).

Revision 15 (10/27/2010):

- Modifies Section 8: Opportunity Cost Guidelines to conform to FERC Order EL08-47-005 allowing for the inclusion of Opportunity Costs for Energy or Environmental Limitation

Revision 14 (06/01/2010):

- Section 5: Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2010.

Revision 13 (05/07/2010):

- Section 5: Updated Maintenance Period for the choice of 20 years or 10 years and added Unit Configuration Addition Maintenance Adder language

Revision 12 (02/23/2010):

- Section 9: Updated Regulation Cost Guidelines approved 8/25/2009

Revision 11 (12/02/2009):

- Section 4: Updated Fuel Cost Policy Guidelines

Revision 10 (06/01/2009):

- Section 5: Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2009.

Revision 09 (01/23/2009):

- Section 4: Added CO₂ emission allowance cost to TFRC calculation. Updates to the TFRC cost equation reflect addition of CO₂ emission allowance cost.

- Section 5L: Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2008.
- Attachment A: TFRC equation updated to reflect addition of CO₂ emission allowance cost.

Revision 08 (10/16/2007):

- Exhibit 1 — Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2007.
- Section 9 — Modified the components of cost to supply Regulation Service.

Revision 07 (08/03/2006):

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 4—Added definition for Total Fuel-Related Costs for Pumped Storage Hydro Plant Generation.
- Section 5—Added guidelines for Long Term Service Contract Cost Recovery.
- Exhibit 2—Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2006.
- Section 7—Modified terminology for Spinning Synchronized Reserve.

Revision 06 (03/02/2006):

- Added guidelines for no-load fuel costs for Combustion Turbines to Section 1 and Section 2.
- Added “Long Term Maintenance Expenses” definition for Combustion Turbine and Combined Cycle Plants to Section 5.
- Revisions were made on the following pages: 8, 9, and 20-22.

Revision 05 (08/18/2005):

- Updated Exhibit 1 to include new PJM Manuals.
- Updated Exhibit 2, Chronology of Maintenance Adder Escalation Index Numbers, for the year 2005.

Revision 04 (09/01/2004):

- Insert new section nine into the CDS Manual

Revision 03 (06/01/2004):

- Revised table "Chronology of Maintenance Adder Escalation Index Numbers" in Section 5 to reflect figures for the year 2004.
- Reformatted to reflect the new PJM format and style.
- Updated list of PJM Manuals to reflect title changes and additional Manuals

Revision 02 (06/01/2003):

- Revised table in Section 5.6, “Chronology of Maintenance Adder Escalation Index Numbers”, for the year 2003

Revision 01 (12/01/2002):

- This revision incorporates changes to Section 7: Spinning Cost Guidelines. These changes reflect the rules associated with the new PJM Spinning Reserve Market.

Revision 00 (12/01/2002):

- This revision is the preliminary draft of the PJM Manual for **Cost Development Guidelines (M-15)**. Prior to Revision 00 of this Manual, a document with this name existed under direction of the PJM Operating Committee. Revision 00 was the first issuance of this Manual under the approval of the PJM Board of Directors, pursuant to Schedule 2 of the Operating Agreement of the PJM Interconnection, L.L.C.