



Working to Perfect the Flow of Energy

PJM Manual 15:
Cost Development Guidelines

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Prepared by:

Cost Development Subcommittee

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 Cost Development Guidelines**

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Manual 15: Cost Development Guidelines
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Approval

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Jeffrey R Schmitt, Chairman
Cost Development Subcommittee

Current Revision

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.



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.

[Complete list of all PJM Manuals.](#)

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.

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 MBTU is defined as millions of BTUs.

1.3 The intended audiences for this Manual:

- Unit Owner
- PJM staff
- MMU
- Regulators
- Market Participants

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 PJM Member actions
- Attachments



1.5 Cost Development Subcommittee Mission

The Cost Development Subcommittee (CDS) reports to the PJM Markets and Reliability Committee (MRC) 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 generators. CDS responsibilities can be found in the [Subcommittee's 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 Operating Agreement of PJM Interconnection, L.L.C.

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 Unit Owner 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 Unit Owner fails a TPS test, then 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 Unit Owners on how to develop their cost based offers. 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 PJM Members 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 participant can determine how the slope of the offer curve is defined; however, the slope must be monotonically increasing.

1.7.2 Start Cost

Start costs are defined as the costs to bring the boiler, turbine and generator from shutdown conditions to a state ready to connect to the transmission system. Start costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold. Start cost is a dollar cost and is incurred once each time the unit operates regardless of the period of operation. See Start Cost in Section 2.4 and in each Generator Section under Start.

1.7.3 No Load Cost

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

No-load cost is the cost needed to create the starting point of a monotonically increasing incremental cost curve. The calculated no-load cost may have to be adjusted to ensure that the slope of the Generator Offer Curve is monotonically increasing.

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 per output segment.

The incremental energy cost is the cost per MWh to produce all of the energy segments above the economic minimum level (minimum generation level with the unit available for economic dispatch). No-load costs are not included in the incremental costs. It is calculated



by summing the cost of each segment of energy in the unit's incremental cost curve up to the generation level. This cost is a dollar per hour (\$/MWh) rate.

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 costs and hourly production costs.

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

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

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 PJM Member 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 that is not specifically permitted by the PJM Tariff, PJM Operating Agreement or this Manual, shall submit a request to the PJM Market Monitoring Unit (MMU) for consideration and determination, except as otherwise specified herein.

After receipt of such a request, the PJM MMU shall notify the PJM member of its determination of the request no later than fifteen (15) calendar days after the submission of the request. If the PJM member and the PJM MMU agree on the determination of the request, the request shall be deemed to be approved.

If the PJM member and the PJM MMU cannot agree on the determination of the request, the PJM member may submit its request to PJM in writing for consideration and approval. In its written request to PJM, the PJM member must notify PJM of all prior determinations of the PJM MMU with respect to any such request and must provide a copy of such request to the PJM MMU within one (1) calendar day of submitting the request to PJM.

This process shall be referred to in this Manual as the "Cost and Methodology 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 [Scheduling 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 \(M-28\)](#)
- PJM Manual for [Definitions and Acronyms \(M-35\)](#)
- [eMKT User Guide](#)
- [PJM Markets Database Dictionary](#)
- [Energy Market Opportunity Cost Calculator in eMKT](#)
- [A Review of Generation Compensation and Cost Elements in the PJM Markets](#)
- [Cost Offer Development Application \(CODA\) User Guide](#)



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 Rates

Heat Rate equals the MBTU content of the heat input divided by the MWh of power output. The smaller the heat rate value the greater the efficiency. The heat rate can also be referred to as the input-output function. Throughout this manual, the term “MBTU” is defined as millions of British Thermal Units.

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

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).

$$\begin{aligned} \text{Incremental Heat Rate} &= \Delta\text{MBTU}/\Delta\text{MWh} \\ &= (\text{Change in Fuel Going In})/(\text{Change in Energy Coming Out}) \\ &= \partial y / \partial x \text{ Total Heat Rate} \end{aligned}$$

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.

2.1.1 Heat Rate Policy

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

- Heat rate curves (one curve per fuel type of operating mode) will be based on design or comparable unit data modified by actual unit test data (when available).



- Data for the heat rate curve development, ideally, should include economic minimum and economic maximum MW points. The heat rate curve will be fitted from available data.
- This heat rate curve (or curves) will be used as the basis for incremental heat rate curves, incremental costs and performance factor calculations.

2.2 Performance Factors

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.

$$\text{Performance Factor} = \frac{\text{Total Actual Fuel Consumed}}{\text{Total Theoretical Fuel Consumed}}$$

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. Factors for combustion turbine, diesel units, and combined-cycle 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 first be submitted to the PJM MMU for evaluation pursuant to the Cost and Methodology Approval Process. The overall performance factor can be modified by a seasonal performance factor to reflect ambient conditions.

2.2.1 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.

2.2.2 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, and 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

2.2.3 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:

$$\text{Performance Factor} = \frac{\text{Total Actual Fuel Consumed}}{\text{Total Theoretical Fuel Consumed}}$$

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:

$$\text{Operating Fuel Performance Factor} = \frac{\text{Total Actual Fuel Consumed} - \text{Actual Start Fuel Consumed}}{\text{Total Theoretical Fuel Consumed} - \text{Theoretical Start Fuel Consumed}}$$

Due to the variability and difficulty in measuring actual start fuel, a Unit Owner 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:

$$\text{Operating Fuel Performance Factor} = \frac{\text{Total Actual Fuel Consumed} - \text{Total Theoretical Start Fuel Consumed}}{\text{Total Theoretical Fuel Consumed} - \text{Total Theoretical Start Fuel Consumed}}$$



Where total theoretical start fuel consumed = fuel quantity used in the start cost calculation

2.2.4 '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.

2.3 Fuel Cost Guidelines

Any Unit Owner must submit a fuel cost policy to the PJM MMU pursuant to the Cost and Methodology Approval Process.

2.3.1 Modifications to Fuel Cost Policies

A request to change the method of calculation of Basic Fossil or Nuclear Fuel Cost shall be submitted to the PJM MMU for evaluation pursuant to the Cost and Methodology Approval Process in advance of the proposed change (this is referred to below as "the proposal".)

Any Unit Owner and the PJM MMU shall discuss the proposal and the PJM Member will provide documentation supporting its request to the PJM MMU. The PJM MMU shall provide an initial response to the PJM Member in writing within 30 days of the member's submission of the request to the PJM MMU, indicating its agreement with the request or areas of concern pursuant to the Cost and Methodology Approval Process. The changed method of calculation may be implemented immediately upon final approval pursuant to the Cost and Methodology Approval Process.

If any action by a governmental or regulatory agency external to a Unit Owner that results in a need for the Unit Owner to change its method of fuel cost calculation, the affected PJM Member may immediately submit a request to the PJM MMU for evaluation, pursuant to the Cost and Methodology Approval Process to change the method of calculation in advance of the proposed change.

2.3.2 Fuel Cost Calculation

The method of calculation of fuel cost may be updated no more frequently than once every 12 months, on a rolling basis.

Each company must review and document their fuel costs 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 is necessary. The documentation of fuel costs must be filed via CODA.

The method of calculation of fuel cost 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 and reflect the locational cost of fuel for the generating unit. The locational cost of fuel shall include specification of any additional incremental costs of delivery for the generating unit.



Each PJM Member Company will be responsible for establishing its own method of calculating delivered fossil fuel cost, limited to inventoried cost, replacement cost or a combination thereof, that reflect the way fuel is purchased or scheduled for purchase.

The method of calculation only may be changed by receipt of final approval pursuant to the Cost and Methodology Approval Process in advance of the proposed change.

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.

2.3.3 Total Fuel Related Costs

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

$$\begin{aligned} \text{Total Fuel Related Costs} = \\ \text{fuel costs} + \text{fuel related costs} + \text{SO}_2\text{Allowance cost} + \text{CO}_2\text{Allowance cost} + \\ \text{NOx allowance costs} + \text{maintenance adder} \end{aligned}$$

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.

The other fuel-related cost components of TFRC 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 other fuel-related costs calculation shall be included in the Unit Owner's fuel cost policy.

2.3.4 Types of Fuel Costs

Basic Fuel Cost – The cost of fuel calculated as stated in the companies' fuel pricing 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 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 cost, plus the no-load cost.

2.3.5 Emission Allowances

Each unit that requires SO₂ /CO₂ /NO_x emission allowances (EAs) to operate may include in the unit's TFRC the cost (\$/MBTU) of the EAs as determined in the Unit Owner's allowance cost policy.

Each PJM Member must submit a policy that would state its method of determining the cost of SO₂ /CO₂ /NO_x EAs for evaluation pursuant to the Cost and Methodology Approval Process. An example of the calculation must be included in the policy. The method of calculation may be changed only after evaluation pursuant to the Cost and Methodology Approval Process.

The period used for determining the projected SO₂ /CO₂ /NO_x discharge and the MBTUs burned must be included in the Unit Owner's policy and may be based on historical or projected data.

For units that have dual fuel firing capability, a Unit Owner should use different EA factors based on the SO₂ /CO₂ /NO_x emitted for each particular fuel or fuel mix.

NO_x/ CO₂ emissions costs will be included in TFRC only during a NO_x/ CO₂ compliance period and only by affected generating units. Details of the cost calculation methodology and example calculations will be contained in each Unit Owner's NO_x / CO₂ Cost Policy. Compliance requirements and dates may vary by geographic region.

2.3.6 Leased Fuel Transportation Equipment

Leased Fuel Transportation Equipment Cost –Expenses incurred using leased equipment to transport fuel to the plant gate. If expenses are fixed, they must be excluded from fuel cost determination.

When calculating the total fuel related costs, fixed charges for transportation equipment (e.g., pipelines, train cars, and barges) should be excluded. Dollars that represent lease charges are considered fixed charges if the total amount to be paid over a period is fixed regardless of the amount of fuel transported. Should the terms of the lease agreement be such that there is a fixed charge plus a charge for every unit of fuel delivered, the "charge per unit of fuel delivered" should be included in the Fuel on Board (FOB) delivered cost or in the calculation of the "other fuel related costs" as per the documented fuel pricing policy.

The above guideline applies when a unit, plant, or system is served totally by leased fuel transportation equipment. When fuel is supplied by both leased and common carrier fuel transportation systems, the common carrier rate should be included in the Fuel On Board (FOB) delivered cost or included in the calculation of the "other fuel related costs" as per the documented fuel pricing policy of each Unit Owner. This assumes that the leased fuel transportation equipment would serve base fuel requirements, while common carrier deliveries would change, based on incremental generation changes.



2.4 Start Cost

2.4.1 Start Cost Definitions

Start Cost – is the dollars per start as determined from start fuel, total fuel-related cost, performance factor, electrical costs, start maintenance adder, and additional labor cost, if required above normal station manning levels.

$$\begin{aligned} \text{Start Cost (\$ / (Start))} = & \\ & [\text{Start Fuel (MBTU / (Start)) * TFRC(\$ / (MBTU) * Performance Factor)] \\ & +[\text{Station Service (MWh) * Station Service Rate (\$ / (MWh))}] \\ & +\text{Start Maintenance Adder (\$ / Start) + Start Additional Labor Cost (\$ / Start)} \end{aligned}$$

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. [Station Service Rates Link](#).

Start Fuel - Fuel consumed from first fire of start process (initial reactor criticality for nuclear units) to breaker closing (including auxiliary boiler fuel) plus fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements

Start Maintenance Adder – see Section 2.6

Start Additional Labor Cost – Additional labor costs for startup required above normal station manning levels.

2.4.2 Engineering Judgment in Start Costs

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

2.5 No Load

2.5.1 No-Load Definitions

No-load cost is the hourly fixed cost, expressed in \$/hr, required to create the starting point of a monotonically increasing incremental cost curve.

2.5.2 No-Load Fuel

All PJM members 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.



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 MBTUs (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. The MMU can verify calculation methods used subject to the Cost Methodology and Approval Process including 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))

$$\text{No Load Cost}(\$/\text{ Hour}) = \\ (\text{No Load Fuel} * \text{Performance Factor} * \text{TFRC})$$

The unit's generator offer curve must comply with PJM's monotonically increasing curve requirement. In some instances, the calculated no-load cost may have to be adjusted to ensure that the slope of the generator offer curve is monotonically increasing. The No-Load cost adjustment is limited to a maximum difference of \$1/MW between the unit's first and second incremental cost offers.

As an alternative to adjusting the no-load cost, The no-load cost may also be 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.

$$\text{No Load Cost}(\$/\text{ Hour}) = \\ (\text{Economic Minimum Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM})) \\ - (\text{Economic Minimum Incremental Cost} (\$/\text{MWH}) * \text{Economic Minimum} (\text{MW}))$$

Note that if the unit of VOM is in terms of dollars per Equivalent Service Hours (ESH), the equation changes to:

$$\text{No Load Cost}(\$/\text{ Hour}) = \\ (\text{Economic Minimum Heat Input} * \text{Performance Factor} * \text{TFRC}) + \text{VOM} \\ - (\text{Economic Minimum Incremental Cost} (\$/\text{MWH}) * \text{Economic Minimum} (\text{MW}))$$

When using No Load Fuel to calculate No Load Cost, the user must submit block average cost and cannot select "Use Offer Slope" when entering cost information into eMKT. When using the alternative incremental cost method to calculate No-Load, the user must submit incremental cost and select "Use Offer Slope" when entering cost information into eMKT.

2.6 Variable Maintenance Cost



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

$$\begin{aligned}
 &\text{Total Maintenance Cost}_{\text{next year}} = \\
 &\left(\text{Annual Maintenance Cost} * \frac{\text{Escalation Index}^{\text{next year}}}{\text{Escalation Index}^{\text{current year}}} \right) + \\
 &\left(\text{Annual Maintenance Cost} * \frac{\text{Escalation Index}^{\text{next year}}}{\text{Escalation Index}^{\text{last year}}} \right) + \\
 &\left(\text{Annual Maintenance Cost} * \frac{\text{Escalation Index}^{\text{next year}}}{\text{Escalation Index}^{\text{last year}-1}} \right) + \\
 &\dots + \left(\text{Annual Maintenance Cost} * \frac{\text{Escalation Factor}^{\text{next year}}}{\text{Escalation Index}^{\text{last year}-(\text{maintenance period}-1)}} \right)
 \end{aligned}$$

The PJM MMU will review the Maintenance Adders for all units pursuant to the Cost and Methodology Approval Process which Schedule 1, Section 6 of the Operating Agreement of PJM Interconnection, L.L.C. applies.

The Maintenance Adder is based on all available maintenance expense history for the defined Maintenance Period (See 2.6.3) regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. The Maintenance Adder should be reviewed (and updated if changed) at least annually.

If a Unit Owner 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 the PJM MMU for consideration pursuant to the Cost and Methodology Approval Process.



2.6. 1 Escalation Index

Escalation Index is the annual escalation index is derived from the July 1 Handy - Whitman Index Table E-1, line 6, "construction cost electrical plant".

YEAR	INDEX	ESCALATION FACTOR
1993	334	2.009
1994	346	1.939
1995	358	1.874
1996	363	1.848
1997	375	1.789
1998	383	1.752
1999	389	1.725
2000	415	1.617
2001	425	1.579
2002	438	1.532
2003	441	1.522
2004	465	1.443
2005	493	1.361
2006	515	1.303
2007	546	1.229
2008	596	1.126
2009	578	1.161
2010	604	1.111
2011	631	1.063
2012	645	1.040
2013	671 (est)	1.000

Exhibit 1: Handy Whitman Index

2.6.2 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. 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 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



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- 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 Interconnection Service Agreement (ISA). Change of ownership within the same holding company is not eligible to change the historical maintenance period.

Note: Total Maintenance Dollars must be calculated for the same historical period as Equivalent Service Hours.

2.6.3 Incremental Adjustment Parameter

Any variable cost incurred in the production of energy for PJM dispatch, not included in the CDS guidelines for Total Fuel Related Costs or Maintenance Adder. This includes water injection costs, Title 5 emission fees, and any other variable cost that has been previously approved pursuant to the Cost and Methodology Approval Process for inclusion.

2.6.4 Equivalent Hourly Maintenance Cost

The hourly Maintenance Cost in dollars per hour. This is defined as total maintenance dollars divided by equivalent service hours or total fuel, depending on unit type.

$$\text{Equivalent Hourly Maintenance Cost (\$/Hour)} = \frac{\text{Total Maintenance Dollars}}{\text{Equivalent Service Hours}}$$

Or

$$\text{Equivalent Hourly Maintenance Cost (\$/mmbtu)} = \frac{\text{Total Maintenance Dollars}}{\text{Total Fuel}}$$

Estimated Year 2011 Total Maintenance Example for a Combustion Turbine

$$\begin{aligned} \text{Total Maintenance Cost}_{2011} = & \\ & \left(\text{Annual Maintenance Cost}_{2010} * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2010}} \right) + \\ & \left(\text{Annual Maintenance Cost}_{2009} * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2009}} \right) + \\ & \left(\text{Annual Maintenance Cost}_{2008} * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2008}} \right) + \end{aligned}$$

$$\dots \left(\text{Annual Maintenance Cost}_{2000} * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2000}} \right)$$

Estimated Year 2011 Equivalent Service Hours

Equivalent Service Hours =

$$(\text{Cyclic Starting Factor} * \text{Number of Starts}) + \text{Total Operating Hours} + (\text{Cyclic Peaking Factor} * \text{Number of Hours above Baseload})$$

Cyclic Starting Factors and Cyclic Peaking Factors values shall be consistently used for equivalent service hours and cost based offer calculations for Combined Cycle and Combustion turbine Units. See cyclic starting factor and cyclic peaking factor in section 5.6.3 & 6.6.3.

Equivalent Hourly Maintenance Cost (\$/Hour) =

$$\frac{\text{Total Maintenance Dollars}}{\text{Equivalent Service Hours}} = \frac{\$406,236}{118,348 \text{ Hours}} = \$3.43/\text{Hour}$$

Exhibit 2: Example Calculation of Maintenance Adder for a CT using a 10 year Maintenance Period

2.6.5 Immature Units: Maintenance Costs

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

Immature Units should use a blend of actual, calculated or forecasted costs. The weighted blend should be based on the ratio of historical operating hours to projected hours to meet 50,000 or achieving ten years of operation whichever comes first. All historical, calculated, and/or forecasted costs are to be converted to current year dollars.

When information is not available to the Market Participant, estimates may be developed based on a methodology consistent with the provisions of Manual 15 related to VOM, such as, but not limited to:

- Regional industry average
- Industry average in PJM
- Forecasted value based on Long Term Business Plan
- Information from OEM
- or information from sister units



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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 owner 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 unit owner will use all available history to calculate VOM.

Example: Immature Unit

A Combustion Turbine with 5,000 operating hours after 10 years of operation with an unknown maintenance history

In this example the unit owner does not have the necessary information to compute historical maintenance costs. This unit could use:

- a. Regional industry average
- b. Industry average in PJM
- c. Forecasted value based on Long Term Business Plan
- d. Information from OEM
- e. Information from sister units

The unit owner decides to use the forecasted value based on the Long Term Business Plan of \$25/ESH initially and a ten year maintenance history. In the following years the unit's VOM would be calculate as follows:¹

Year	Cumulative OH	VOM Calculation
1	6000	$(\text{Year 1 Total Actual Maintenance } \$ + (9 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
2	7000	$(\text{Year 1+2 Total Actual Maintenance } + (8 * 1,000 * \$25/\text{OH})) / 10,000 \text{ OH}$
3	8000	$(\text{Year 1+2+3 Total Actual Maintenance } + (7 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
4	9000	$(\text{Year 1+2+3+4 Total Actual Maintenance } + (6 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
5	10000	$(\text{Year 1+2+3+4+5 Total Actual Maintenance } + (5 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
6	11000	$(\text{Year 1+2+3+4+5+6 Total Actual Maintenance } + (4 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
7	12000	$(\text{Year 1+2+3+4+5+6+7 Total Actual Maintenance } + (3 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
8	13000	$(\text{Year 1+2+3+4+5+6+7+8 Total Actual Maintenance } + (2 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
9	14000	$(\text{Year 1+2+3+4+5+6+7+8+9 Total Actual Maintenance } + (1 * 1000 * \$25/\text{OH})) / 10,000 \text{ OH}$
10	15000	$(\text{Year 1+2+3+4+5+6+7+8+9+10 Total Actual Maintenance}) / 10,000 \text{ OH}$
		Unit is now Mature

Exhibit 3: Immature Unit

¹ We are ignoring the effects of inflation and use of the Handy Whitman Index for simplicity.



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.

Companies 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 \$/ΔMW by multiplying the value by the ratio of 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:

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

$$\text{(Fuel Cost Increase and Unit Specific Heat Rate Degradation due to Operating at Lower Loads)}$$

$$+ \text{Margin Risk Adder}$$

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

$$\text{Regulation Performance Costs (\$/\Delta MW)} \leq$$

$$\{ \text{Cost Increase in VOM}$$

$$+ \text{Cost Increase due to Heat Rate Increase during nonsteady state operation}$$



$(\text{above heat rate factor not to exceed } 0.35\%) + (\text{Energy Storage Unit Losses}) / \Delta\text{MW}/\text{MW}$

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 non-hydro units that have been providing Regulation service for less than 10 years, or all hydro units regardless of the historical years of Regulation service, the following variable operation and maintenance (VOM) costs can be applied by unit type up to the following:

- 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
- Energy Storage: Based on OEM estimates initially and actual as history is available

Exhibit 4: VOM for All Hydro Units or Non-Hydro Units providing service for less than 10 years



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For non-hydro units that have been providing Regulation service for more than 10 years, the VOM rates above can be utilized only if the annual VOM dollar amounts resulting from those rates and 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 in the 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.

$$\begin{aligned}
 &\text{Annual VOM costs to subtract} \\
 &= (\$3.50 \text{ per Regulation MWh} * 5,000 \text{ MWh}) * 20 \text{ years} \\
 &= \$17,500 \text{ per year} * 20 \text{ years} \\
 &= \$350,000 \\
 &\text{20-year balance of historical total VOM accounts} \\
 &= \$10,000,000 - \$350,000 \\
 &= \$ 9,650,000
 \end{aligned}$$

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

Exhibit 5: Example of VOM for Non-Hydro Units providing Regulation for more than 10 years:

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	\$/MBTU
Heat Rate @ EcoMax	9,000.0	Btu/KWh
Heat Rate @ RegMin	12,500.0	Btu/KWh
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	MBTU/Hr
Unit Reduced Load Heat Rate Fuel Input	500.0	MBTU/Hr
Difference	140.0	MBTU/Hr



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Unit Base Load Heat Rate Fuel Input

$$= \text{Unit Base Load Heat Rate} * \text{RegMin} * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \text{ kW/MW}$$

$$\text{Unit Base Load Heat Rate Fuel Input} = 9,000 \frac{\text{BTU}}{\text{kWh}} * 40 \text{ MW} * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \text{ kW/MW}$$

$$= 360 \text{ MBTU/Hr}$$

Unit Reduced Load Heat Rate Fuel Input

$$= \text{Unit Reduced Load Heat Rate} * \text{RegMin} * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \text{ kW/MW}$$

$$\text{Unit Base Load Heat Rate Fuel Input} = 12,500 \frac{\text{BTU}}{\text{kWh}} * 40 \text{ MW} * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \text{ kW/MW}$$

$$= 500 \text{ MBTU/Hr}$$

Difference = Unit Base Load Heat Input – Unit Reduced Load Heat Input

$$\text{Difference} = 500 \frac{\text{MBTU}}{\text{hr}} - 360 \frac{\text{MBTU}}{\text{hr}} = 140 \frac{\text{MBTU}}{\text{hr}}$$

Heat Rate Adjustment (Non-Steady State Operation)	Value	Units
Top Operating Point Heat Rate	9,000.0	BTU/kWh
Heat Rate Loss Factor (Max per M15)	0.35%	
Heat Rate Loss	3.15	MBTU/Hr

$$\text{Heat Rate Loss} = (\text{Economic Maximum Heat Rate} * 0.35\%) * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \frac{\text{kW}}{\text{MW}}$$

$$* \text{Economic Maximum MW}$$

$$\text{Heat Rate Loss} = (9,000\text{BTU/kWh} * 0.35\%) * \frac{1\text{MBTU}}{1,000,000 \text{ BTU}} * 1,000 \frac{\text{kW}}{\text{MW}} * 100 \text{ MW}$$

$$= 3.15 \text{ MBTU/Hr}$$

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

Fuel Cost Adder

$$= \left(\frac{(\text{Difference} * \text{Fuel Cost})}{(\text{Economic Maximum MW} - \text{Regulation Minimum MW})} \right)$$

$$\text{Fuel Cost Adder} = \left(\frac{(140 \text{ MBTU/Hr} * \$1.50/\text{MBTU})}{(100 \text{ MW} - 40 \text{ MW})} \right) = \$3.50 \text{ /Hr/MW}$$

(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



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 Section 2: Policies for All Unit Types

Historic Mileage Ratio	Value
Ratio	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

$$\text{Fuel Cost Adder} = \frac{(\text{Heat Rate Loss} * \text{Fuel Cost})}{\text{Regulation Band MW}}$$

$$\text{Fuel Cost Adder} = \frac{(3.15 \text{ MBTU/Hr} * \$1.50/\text{MBTU})}{10 \text{ MW}} = \$0.50/\text{Hr/MW}$$

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

MAXIMUM PERFORMANCE OFFER	Value	Units
(c+d)/Historic Mileage Ratio	\$ 0.80	\$/ΔMW

Maximum Performance Offer

$$= [\text{Fuel Cost Adder (Non Steady State Operation)} + \text{Regulation VOM Adder}] / \text{Historic Mileage Ratio}$$

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

Exhibit 6: Regulation Maximum Allowable Cost Adder Example

How to Use this Manual

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

Section 3: Nuclear Unit Cost Guidelines

Section 4: Fossil Steam Unit Cost Development

Section 5: Combined Cycle (CC) Cost Development

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

Section 7: Hydro

Section 8: Demand Side Response (DSR)



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Section 2: Policies for All Unit Types

Section 9: Wind Units

Section 10: Solar Units

Section 11: Energy Storage

Attachment A: Applicable FERC System of Accounts



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 Rate

Note: The information in Section 2.1 contains basic Heat Rate information relevant for all unit types including nuclear units.

3.2 Performance Factor

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types including nuclear units.

3.3 Fuel Cost

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

3.3.1 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 MBTU, as forecast for the applicable fuel cycle.

$$\text{Basic Nuclear Fuel Cost (\$/ MBTU)} = \text{Dollars in FERC Account 518} - \text{Interest Cost}$$

See definition in FERC account 518 in A.2.5

3.3.2 Total Fuel-Related Costs for Nuclear Units

Total Fuel Related Costs for Nuclear Units =

Basic Nuclear Fuel Cost + Maintenance Adder



3.4 Start Costs

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

Start Cost – The dollars per start as determined from start fuel, total fuel-related cost, performance factor, electrical costs, start maintenance adder, and additional labor cost, if required above normal station manning levels.

Start Fuel – Fuel consumed from first fire of start process (initial reactor criticality for nuclear units) to breaker closing and fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements.

3.4.1 Hot Start Cost

Hot start 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. Components of hot start cost include:

- Total fuel-related cost from first fire of start process (initial reactor criticality for nuclear units) to breaker closing priced at the cost of fuel currently in effect
- And shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements.

3.4.2 Intermediate Start Cost

Intermediate start 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 Unit Owner's policy and physical machine characteristics. The only restriction is that once an intermediate start cost is defined for a unit, the cost must be used consistently in scheduling and accounting. Components of intermediate start cost include:

- Total fuel-related cost from first fire (initial reactor criticality for nuclear units) to breaker closing priced at the cost of fuel currently in effect
- And shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to initialization of the (intermediate) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements.

3.4.3 Cold Start Cost

Cold start 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. Components of cold start cost include:



- Total fuel-related cost from first fire (initial reactor criticality for nuclear units) to breaker closing priced at the cost of fuel currently in effect
- And shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to shutdown of equipment needed for normal cool down of plant components, excluding normal plant heating/auxiliary equipment fuel requirements.

3.4.4 Additional Components Applied to Hot, Intermediate and Cold Start-Up Costs

These additional components for station service, labor and maintenance apply to all types of starts and should be added to the cost.

- Station service from initiation of start sequence to breaker closing (total station use minus normal base station use) priced at the Station Service rate.
- 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 use) priced at the Station Service rate.
- Additional labor costs in excess of normal station manning requirements that are incurred when starting the unit.
- Start Maintenance Adder.

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.

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



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 Section 3: Nuclear Unit Cost Guidelines

The specific system or unit configuration system change must be reviewed by the MMU for evaluation pursuant to the Cost and Methodology 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.

$$\begin{aligned} \text{Total Maintenance Cost}_{2011} = & \\ & \left((\text{FERC 530 \& 531} - \text{Start Costs in 530 \& 531}_{2010}) * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2010}} \right) + \\ & \left((\text{FERC 530 \& 531} - \text{Start Costs in 530 \& 531}_{2009}) * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2009}} \right) + \\ & \left((\text{FERC 530 \& 531} - \text{Start Costs in 530 \& 531}_{2008}) * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2008}} \right) + \\ & \dots \left((\text{FERC 530 \& 531} - \text{Start Costs in 530 \& 531}_{2000}) * \frac{\text{Escalation Index}^{2011}}{\text{Escalation Index}^{2000}} \right) \end{aligned}$$

Calculate total fuel for the maintenance period.

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

These allow for the calculation of the maintenance adder:

$$\text{Maintenance Adder}_{2011} = \frac{\text{Total Maintenance Dollars}}{\text{Total Fuel}}$$

Exhibit 7: Nuclear 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.



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 Section 3: Nuclear Unit Cost Guidelines

$$\begin{aligned}
 &\text{Total Start Maintenance Cost} = \\
 &\left((\text{Start Costs in FERC 530 \& 531})_{2010} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2010}} \right) + \\
 &\left((\text{Start Costs in FERC 530 \& 531})_{2009} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2009}} \right) + \\
 &\left((\text{Start Costs in FERC 530 \& 531})_{2008} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2008}} \right) + \\
 &\dots \\
 &\left((\text{Start Costs in FERC 530 \& 531})_{2000} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2000}} \right)
 \end{aligned}$$

This formula calculates the total number of starts:

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

These allow for the calculation of the start maintenance adder:

$$\begin{aligned}
 &\text{Start Maintenance Adder}_{2011} \left(\frac{\$}{\text{Start}} \right) = \\
 &\frac{\text{Inflation Adjusted Total Start Maintenance Cost}_{2000\text{ation}}}{\text{Total Starts}_{2000\text{Starts}}}
 \end{aligned}$$

Exhibit 8: Nuclear Unit's Sample Formula of Start Maintenance Adder

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.



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 Section 3: Nuclear Unit Cost Guidelines

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

$$\begin{aligned} &\text{Total Configuration Addition Maintenance Dollars} = \\ &\left(\text{Incremental (FERC 530 + 531 - Start Cost FERC 530 + 531)}_{2010} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2010}} \right) + \\ &\left(\text{Incremental (FERC 530 + 531 - Start Cost FERC 530 + 531)}_{2009} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2009}} \right) + \\ &\left(\text{Incremental (FERC 530 + 531 - Start Cost FERC 530 + 531)}_{2008} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2008}} \right) + \dots \\ &\left(\text{Incremental (FERC 530 + 531 - Start Cost FERC 530 + 531)}_{2000} * \frac{\text{Escalation Index}_{2011}}{\text{Escalation Index}_{2000}} \right) \end{aligned}$$

$$\text{Configuration Addition Maintenance Adder} = \frac{\text{Total Configuration Addition Dollars}}{\text{Total Fuel}}$$

Exhibit 9: Nuclear Unit's Sample 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 Rate

Note: The information in Section 2.1 contains basic Heat Rate information relevant for all unit types including fossil steam units.

4.2 Performance Factor

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types. The following information only pertains to 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.

4.3 Fuel Cost

Note: The information in Section 2.3 contains basic Fuel 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 Other Fuel-Related 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 Account 501; minus the fuel expenses from FERC Account 151 that were charged into Account 501, all divided by the fuel (heat content or quantity) shifted from Account 151 into Account 501.

4.3.1 Total Fuel Related Cost

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

$$\text{Total Fuel Related Cost (\$/MBTU)} =$$

$$\text{Fuel Cost} + \text{Other Fuel Related Cost} + \text{SO}_2 \text{ Allowance Cost} + \text{CO}_2 \text{ Allowance Cost} \\ + \text{NO}_x \text{ Allowance Cost} + \text{Maintenance Adder}$$



TFRC = Total Fuel Related Cost

4.4 Hot Start Cost, Intermediate Start Cost, and Cold Start cost

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

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 eMKT 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 eMKT

Start Cost (\$ / Start) =

$$[\text{Start Fuel Consumed (MBTU / Start)} * \text{TFRC}(\$/ \text{MBTU}) * \text{Performance Factor}] +$$
$$[\text{Station Service (MWh)} * \text{Station Service Rate}(\$/ \text{MWh})] + \text{Start Maintenance Adder} (\$/ \text{Start}) + \text{Start Additional Labor Cost} (\$/ \text{Start})$$

4.4.1 Hot Start Cost

Hot start 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. Components of hot start cost include:

Total fuel-related cost are the costs from first fire of start process to breaker closing (including auxiliary boiler fuel) priced at the cost of fuel currently in effect including shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements.

Station Service from initiation of start sequence to breaker closing (total station use minus normal base station use) priced at the Station Service rate and 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 use) priced at the Station Service rate.

Additional labor costs in excess of normal station manning requirements that are incurred when starting the unit.

Start Maintenance Adder Section 2.6 contains information regarding calculation of Maintenance Adder.

4.4.2 Intermediate Start Cost

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



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Section 4: Fossil Steam Unit Cost Development

intermediate start cost is defined for a unit, the cost must be used consistently in scheduling and accounting. Components of intermediate start cost include:

Total fuel-related cost is the cost from first fire to breaker closing (including auxiliary boiler fuel) priced at the cost of fuel currently in effect, and shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to initialization of the (intermediate) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements.

Station Service from initiation of start sequence to breaker closing (total station use minus normal base station use) priced at the Station Service rate and 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 use) priced at the Station Service rate.

Additional labor costs in excess of normal station manning requirements that are incurred when starting the unit.

Start Maintenance Adder Section 2.6 contains information for calculation of the Maintenance Adder.

4.4.3 Cold Start Cost

Cold start 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. Components of cold start cost include:

Total fuel-related cost from first fire to breaker closing (including auxiliary boiler fuel) priced at the cost of fuel currently in effect, and shutdown fuel cost defined as the cost of fuel expended from breaker opening of the previous shutdown to shutdown of equipment needed for normal cool down of plant components, excluding normal plant heating/auxiliary equipment fuel requirements.

Station Service from initiation of start sequence to breaker closing (total station use minus normal base station use) priced at the Station Service rate and 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) priced at the Station Service rate.

Additional labor costs in excess of normal station manning requirements that are incurred when starting the unit.

Start Maintenance Adder Section 2.6 contains information for calculation of the Maintenance Adder.

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.

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

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 Configuration Addition Maintenance Dollars =

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

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

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

These allow for the calculation of the maintenance adder:

$$\text{Maintenance Adder}_{2011} (\$/\text{MBTU}) = \frac{\text{Total Maintenance Dollars}}{\text{Total Fuel}}$$



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 Section 4: Fossil Steam Unit Cost Development

Exhibit 10: 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.

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

This formula calculates the total number of starts:

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

These allow for the calculation of the start maintenance adder:

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

Exhibit 11: 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



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 Section 4: Fossil Steam Unit Cost Development

- 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 the MMU pursuant to the Cost and Methodology 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.

Total Configuration Addition Maintenance Dollars =

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

Exhibit 12: Fossil Unit's Sample Formula of Configuration Addition Maintenance Adder

4.6.3 Reductions in Total Maintenance Costs:



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 Section 4: Fossil Steam Unit Cost Development

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 Tier 2 Synchronized reserve from a steam unit shall include the following components:

$$\text{Total Costs Tier 2 Synchronized Reserve (\$/MW) =}$$

$$\frac{\text{Heat Rate Increase} * \text{Variable Cost Rate}}{\text{MW of Synchronized Reserve}} + \text{Margin (less than \$7.50)} + \text{Lost Opportunity Costs}$$

Further information on Tier 1 and Tier 2 Synchronized Reserve can be found in [PJM Manual 11: Scheduling Operations](#). Heat Rate Increase is the incremental increase resulting from operating the unit at lower MW output resulting from the provision of Synchronized reserve service

Total Steam Unit offers must be expressed in dollars per hour per MW of Synchronized Reserve (\$/MWh) and must specify the total MW of Synchronized Reserve offered.

For Example:

	Output	Heat Rate
Steam Unit Full Load:	100 MW	9,000 BTU/kWh
Steam Unit Reduced Load:	70 MW	9,500 BTU/kWh
VOM Rate:	\$0.50/MBTU	
Heat Rate Penalty =	$(9,500 - 9,000)/9,000 = 5.56\%$	
Adjusted VOM =	$\$0.50 * 1.0556 = \$0.5278/\text{MBTU}$	
Steam Unit Reduced Load Heat Input =	$9,500 * 70 / 1000 = 665 \text{ MBTU/Hr}$	



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Heat Rate VOM Penalty =	$(\$0.5278/\text{MBTU} - \$0.50/\text{MBTU}) * 665 \text{ MBTU}/\text{Hr} =$ \$18.487/Hr
Synchronized Reserve VOM Adder =	$\$18.487/\text{Hr} / (100 \text{ MW} - 70 \text{ MW}) =$ \$0.6162/Synchronized MW

Exhibit 13: Steam Unit Synchronized Reserve Example

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 Combined Cycle Cost development.

Combined Cycle - An electric generating technology in which electricity is generated by both a combustion turbine generator (the Brayton Cycle) and a steam turbine generator (the Rankine Cycle) hence the name combined cycle. 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 combustion turbine exhaust to produce steam to drive a conventional steam turbine generator.

5.1 Heat Rate

Note: The information in Section 2.1 contains basic Heat Rate information relevant for all unit types including combined cycle units.

5.2 Performance Factors

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types including combined cycle units.

5.3 Fuel Cost

Note: The information in Section 2.3 contains basic Fuel Cost information relevant for all unit types including combined cycle units.

5.4 Start Cost

Note: The information in Section 2.4 contains basic Start Cost information relevant for all unit types. The following additional information only pertains to combined cycle units.

Start costs for Combined Cycle (CC) plants shall include only the following components and shall never be less than zero:



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 Section 5: Combined Cycle (CC) Cost Development

TFRC = Total Fuel Related Cost

$$\begin{aligned} \text{Start Cost } (\$/\text{start}) = & \\ & \left(\text{Start Fuel Consumed } (\text{MBtu}/\text{Start}) * \text{TFRC} (\$/\text{MBtu}) * \text{Performance Factor} \right) \\ & + \left(\text{Station Service (MWh)} * \text{Station Service Rate} (\$/\text{MWh}) \right) \\ & + \text{Start Maintenance Adder } \left(\frac{\$}{\text{start}} \right) + \text{Start Incremental Labor Cost } \left(\frac{\$}{\text{start}} \right) \end{aligned}$$

Start Fuel Consumed Cost is the cost of start fuel (basic fuel cost plus fuel handling and other fuel-related costs) from first CT fire to breaker closing for the steam turbine generator, as measured during a normal start sequence, and the cost of shutdown fuel from breaker opening for the steam turbine generator to fuel valve closure. Additionally, this includes the cost of start fuel from CT first fire to the point where heat recovery steam generator (HRSG) steam pressure matches steam turbine inlet pressure, for any CT unit/HRSG combinations started after synchronization of the steam turbine generator.

Station service is included from initiation of start sequence of initial combustion turbine to breaker closing of the steam turbine generator (total station use minus normal base station use) priced at the Station Service Rate.

Add to this (+) station service after breaker opening of the last component when finished operating as a combined cycle unit, priced at the Station Service rate. (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.)

Minus (-) the integration of net generation from CT synchronization to steam turbine generator synchronization or to HRSG steam output at line pressure, priced at the actual cost of the unit.

Minus (-) the integration of net generation during the shutdown period, priced at the actual cost of the unit.

Incremental labor costs in excess of normal station manning requirements (only when necessary to start the CC unit).

Start Maintenance Adder. This quantity includes both the previously defined CT Starting Maintenance Cost and equivalent hourly maintenance for the periods from CT breaker closing to steam turbine generator breaker closing and from steam turbine generator breaker opening at the start of unit shutdown to CT breaker opening.

5.5 No Load Cost

Note: The information in Section 2.5 contains basic Start Cost information relevant for all unit types including combined cycle 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 combined cycle units.

Combined Cycle Maintenance Adder – The dollars per unit of fuel (or heat) as derived from FERC Accounts 512, 513, and 553. If submitting as a simple cycle combustion turbine, use total dollars from FERC Account 553 divided by Equivalent Service Hours (ESH).

5.6.1 Combined Cycle / Combustion Turbine Long Term Service Contract Cost Recovery

A generation owner that has a currently in effect Long Term Service Contract (LTSA) with a third party vendor to provide overhaul and maintenance work on a Combustion Turbine (CT) either as part of a Combined Cycle (CC) plant or as a stand-alone CT, may file with the PJM MMU or PJM for inclusion of any variable long term maintenance costs in cost based offer bids pursuant to the Cost Methodology 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.

5.6.2 Long Term Maintenance Expenses

Long Term Maintenance Expenses - Combined Cycle Plant major inspection and overhaul expenses, after being approved by the MMU, may be included until June 1, 2015 in variable maintenance expenses. Previously approved Long Term Maintenance Expenses will be removed from maintenance history as of June 1, 2015.

5.6.3 Equivalent service hours (ESH)

The estimated hours the unit will run based on history:

$$\begin{aligned} \text{Equivalent Service Hours} = & \\ & (\text{Cyclic Starting Factor} * \text{Number of Starts}) + \text{Total Operating Hours at any load level} \\ & + (\text{Cyclic Peaking Factor} * \text{Number of Hours above Base load temperature limit}) \end{aligned}$$

Combined Cycle CTs shall use OEM supplied values for Cyclic Starting Factors and Cyclic peaking factors even if the CT technology is no longer being built. In situations where cyclic Starting factors or Cyclic Peaking factors are unknown or unavailable, Combined Cycle CTs shall use:

Cyclic starting factor = 5.0 for aircraft - type CTs and 10.0 for industrial - type CTs



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And

Cyclic peaking factor = 3.0 for all CTs.

Where

A Cyclic starting factor = 10.0 for an industrial – type CT for

example, the incremental maintenance charged to one start on an industrial - type CT is equivalent to the incremental maintenance attributable to ten hours of base load operation.

And the Cyclic peaking factor = 3.0

means that the additional incremental maintenance charged to the incremental energy between base and peak loads is equivalent to the incremental maintenance attributable to three hours of base load operation.

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 Combined Cycle units.

Total costs to provide Synchronized reserve from a Combined Cycle unit shall include the following components:

$$\text{Total Costs Synchronized Reserve (\$/MW)} =$$

$$\frac{\text{Heat Rate Increase} * \text{Variable Cost Rate}}{\text{MW of Synchronized Reserve}} + \text{Margin (less than \$7.50)} + \text{Lost Opportunity Costs}$$

Heat Rate Increase is the incremental increase resulting from operating the unit at lower MW output resulting from the provision of Synchronized reserve service

Total Combined Cycle Unit offers must be expressed in dollars per hour per MW of Synchronized Reserve (\$/MWh) and must specify the total MW of Synchronized Reserve offered.

For Example:

	Output	Heat Rate
Combined Cycle Unit Full Load:	450 MW	7,500 BTU/kWh
Combined Cycle Unit Reduced Load:	400 MW	7,800 BTU/kWh
VOM Rate:	\$0.50/MBTU	
Heat Rate Penalty = $(7,800 - 7,500)/7,500 = 4\%$		
Adjusted VOM = $\$0.50 * 1.04 = \$0.52/\text{MBTU}$		
Combined Cycle Unit Reduced Load Heat Input = $7,800 * 400 / 1000 = 3,120 \text{ MBTU/Hr}$		



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Heat Rate VOM Penalty =	$(\$0.52/\text{MBTU} - \$0.50/\text{MBTU}) * 3,120 \text{ MBTU}/\text{Hr} = \$62.40/\text{Hr}$
Synchronized Reserve VOM Adder =	$\$62.40/\text{Hr} / (450 \text{ MW} - 400 \text{ MW}) = \$1.248/\text{Synchronized MW}$

Exhibit 14: Combined Cycle Unit Synchronized Reserve Example

5.8 Regulation

Note: The information in Section 2.8 contains basic Regulation Cost information relevant for all unit types including combined cycle units.



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

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

Combustion Turbine Unit – A generating unit in which a natural gas or oil fired combustion turbine engine is the prime mover for an electrical generator. Combustion Turbines 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 Rate

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

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

6.2 Performance Factor

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

‘Like’ Combustion Turbine 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.



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6.3 Fuel Cost

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

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

6.3.1 Combustion Turbine other Fuel-Related 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.

6.3.2 Total Fuel Related Cost Equation for CTs

Total Fuel Related Costs for Combustion Turbines =

Basic Fossil Fuel Cost + Other Fuel Related Cost + SO₂ emission costs + NO_x emission costs
 + CO₂ emission costs

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

6.4 Start Cost

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

Start costs for all combustion turbines and diesel units shall include only the following components:

$$\begin{aligned} \text{Start Cost } (\$/\text{start}) = & \\ & \left(\text{Start Fuel Consumed } (\text{MBtu}/\text{Start}) * \text{TFRC} (\$/\text{MBtu}) * \text{Performance Factor} \right) \\ & + \left(\text{Station Service (MWh)} * \text{Station Service Rate} (\$/\text{MWh}) \right) \\ & + \text{Start Maintenance Adder } \left(\frac{\$}{\text{start}} \right) + \text{Start Incremental Labor Cost } \left(\frac{\$}{\text{start}} \right) \end{aligned}$$



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TFRC = Total Fuel Related Cost

Start Fuel Consumed * Total Fuel Related Cost (TRFC) * Performance Factor is the cost of start fuel (basic fuel cost plus fuel handling and other fuel-related costs) from first fire to unit breaker closing, Plus (+) cost of shutdown fuel from unit breaker opening to fuel valve closure (basic fuel cost plus fuel handling and other fuel-related costs).

Incremental labor costs are the costs in excess of normal station manning requirements (only when necessary to start a combustion turbine unit).

Station Service * Station Service Rate from initiation of start sequence to breaker closing (total station use minus normal base station use) priced at the Station Service rate. 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) priced at the Station Service rate.

NOTE: Starting Maintenance Cost, 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 Start 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.

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.

Combustion Turbine - Maintenance Adder – The total dollars from FERC Account 553 divided by Equivalent Service Hours (ESH).

Industrial Combustion Turbine – This is a combustion turbine developed specifically for power generation.

Aircraft - Type Combustion Turbine – These are combustion turbines 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 MBTUs).



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Combustion Turbine Start – For calculating combustion turbine 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 – Combustion Turbine Plant major inspection and overhaul expenses, after being approved by the MMU, may be included until June 1, 2015 in variable maintenance expenses. Previously approved Long Term Maintenance Expenses will be removed from maintenance history as of June 1, 2015.

6.6.1 Combustion Turbine Maintenance Adder Example

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

(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 (Note: Cyclic Starting Factor = 5 for aircraft engine CT's).

$$\begin{aligned} \text{Equivalent Hourly Maintenance Cost (EHMC)} &= \frac{\$100,000}{(10 * 300) + 2,000 + (3 * 200)} \\ &= \$17.86/\text{Hr.} \end{aligned}$$

Calculation of maintenance rates

$$\begin{aligned} \text{Starting Maintenance Cost} &= \text{Cyclic Starting Factor} * \text{Equivalent Hourly Maintenance Cost} \\ &= 10 * \$17.86 = \$178.60 \text{ per start} \end{aligned}$$

$$\text{Hourly Maintenance Rate} = \text{Equivalent Hourly Maintenance Cost} = \$17.86/\text{hour}$$



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$$\begin{aligned} & \text{Peak Incremental Maintenance Rate} \\ &= \frac{\text{Cyclic Starting Factor}}{\text{Peak Pickup}} * \text{Equivalent Hourly Maintenance Cost} \\ &= \frac{3 * \$17.86}{5} \\ &= \$10.72 \text{ per MWh} \end{aligned}$$

Exhibit 15: Combustion Turbine Maintenance Cost Adder Example

6.6.2 Combustion Turbine Long Term Service Contract Cost Recovery

A generation owner that has a currently effective Long Term Service Contract (LTSA) with a third party vendor to provide overhaul and maintenance work on a Combustion Turbine (CT) may file a request for inclusion of any variable long term maintenance costs in cost based offer bids, pursuant to the Cost and Methodology 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.

6.6.3 Equivalent service hours (ESH)

The estimated hours the unit will run based on history.

$$\begin{aligned} & \text{Equivalent Service Hours} = \\ & (\text{Cyclic Starting Factor} * \text{Number of Starts}) + \text{Total Operating Hours at any load level} \\ & + (\text{Cyclic Peaking Factor} * \text{Number of Hours above Base load temperature limit}) \end{aligned}$$

Combustion turbines shall use OEM supplied values for Cyclic Starting Factors and Cyclic peaking Factors even if the CT technology is no longer being built. In situations where Cyclic Starting Factors or cyclic Peaking factors are unknown or unavailable, Combustion Turbines shall use:

Cyclic starting factor = 5.0 for aircraft - type CTs and cyclic starting factor= 10.0 for industrial - type CTs

And

Cyclic Peaking factor = 3.0 for all CTs

Where:

A Cyclic starting factor = 10.0 for an industrial - type CTs



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for example, the incremental maintenance charged to one start on an industrial - type CT is equivalent to the incremental maintenance attributable to ten hours of base load operation.

And a Cyclic peaking factor = 3.0

means that the additional incremental maintenance charged to the incremental energy between base and peak loads is equivalent to the incremental maintenance attributable to three hours of base load operation.

6.6.4 Diesel Incremental Maintenance Adder Calculation

The incremental Maintenance Adder for diesel units will be calculated and applied on a "per MBTU (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 combustion turbines and diesel units shall include the following components:

- **Start 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.
- **Variable Operating and Maintenance cost (EHMC)** in \$/Hr divided by the Synchronized MW provided.
- **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.
- **Margin** up to \$7.50 per MW of Synchronized, reserve service provided.

The combustion turbine condensing offers must be expressed in dollars per hour per MW of Synchronized Reserve (\$/MWh) and must specify the total MW of Synchronized Reserve offered.

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 Hydro Pumped Storage 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 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 Hydro Only)

Pumping Efficiency is the Pumped 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. An owner 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 Performance Factors

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types. The following additional information only pertains to hydro units.

7.3 Fuel Cost

The fuel costs for a Run-of-River Hydro Unit are equal to zero.

For a Pumped 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 hydro units.

If, a Unit Owner wishes to change its method of calculation of pumped storage TFRC, the PJM Member shall notify the PJM MMU in writing by December 31 prior to the year of operation, to be evaluated pursuant to the Cost and Methodology 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 Original Equipment Manufacturer (OEM) curves if annual data is not available due to the immaturity of the unit. The following equations govern pumping storage fuel cost:

$$\text{Pumping Power Cost (\$/MWh)} = \text{Real Time LMP (\$/MWh)} * \text{Pumping Power (MWh)}$$

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



7.3.1 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:

$$\text{Pumped Storage Hydro Total Energy Input Related Cost} \\ = \text{Basic Pumped Storage Energy Input Cost} + \text{Maintenance Cost}$$

7.4 Start Cost

See 7.7 Condensing Start Costs.

7.5 No Load

Hydro Units have 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 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.) 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.

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 include the following components:



$$\text{Hydro Costs to Condense (\$/MWh)} =$$
$$\text{Condensing Start Costs} + \left(\frac{\text{VOM}}{\text{Synchronized Reserve MW}} \right) + \text{Margin}$$

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.

In addition (+) identified **variable Operating and Maintenance** cost in \$/Hr. divided by the Synchronized MW provided. These costs shall be totaled over the Maintenance Period and divided by total MWh generated over the maintenance period. These variable Operating and Maintenance costs shall include:

- Maintenance of Electric Plant as derived from FERC Account 544
- Maintenance of Reservoirs as derived from FERC Account 543

In addition (+) **margin** up to \$7.50 per MW of Synchronized Reserve service provided.

Total hydro condensing offers must be expressed in dollars per hour per MW of Synchronized Reserve (\$/MWh) and must specify the total MW of Synchronized Reserve offered.

7.8 Regulation Cost

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



Section 8 : Demand Side Response (DSR)

Demand Side Management – A program designed to provide an incentive to end-use customers or curtailment service providers to enhance the ability and opportunity for reduction of load when PJM LMP is high.

Load Shifting – Demand Side Management programs designed to encourage consumers to move their use of electricity from on-peak times to off-peak times, or daily movement of load between LSEs.

Demand Side Resource – Total contributions provided by demand-side facilities and/or actions.

8.1 Demand Side Response (DSR) Cost to Provide Synchronous Reserves

The cost to provide synchronous reserves from DSR resources shall be equal to the margin up to \$7.50 per MWh of reserves provided.

Demand Side Response shutdown costs shall be zero. Any exceptions to this rule are covered under Section 1.8 Cost Methodology and Approval Process.



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 Rates

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

9.2 Performance Factors

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types. The following additional information only pertains to Wind units.

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

9.3 Fuel Cost

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

"Fuel Cost Policy" will be provided to the MMU annually. The fuel cost policy should include how the generator intends to account for Renewable Energy Credits (RECs) and Production Tax Credits (PTCs).

9.4 Start Cost

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

Start cost for a wind unit is station service cost.

9.5 No Load

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 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: Wind 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 wind units if applicable.

9.8 Regulation Cost

Note: 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 Rates

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

10.2 Performance Factors

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types. The following additional information only pertains to solar units.

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

10.3 Fuel Cost

Note: The information in Section 2.3 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.

10.4 Start Cost

Note: The information in Section 2.3 contains basic Start 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

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: Energy Storage

This section contains information for the development of Battery and Flywheel unit cost offers. Currently energy storage units only participate in the regulation market.

Battery Units – A battery unit consists of electrochemical cells that convert stored chemical energy into electrical energy.

Flywheel Units – Flywheel units store rotational energy in a rotor (flywheel) turning at very high speed in a vacuum.

11.1 Heat Rates

Batteries and Flywheels do not burn fuel so heat rates are not applicable.

11.2 Performance Factors

Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types. The following additional information only pertains to battery and flywheels units.

Battery and Flywheel Units do not burn fuel so Performance Factors are equal to 1.0.

11.3 Fuel Cost

Note: The information in Section 2.3 contains basic Fuel Cost information relevant for all unit types. The following additional information only pertains to battery and flywheel units.

Battery and Flywheel Unit's fuel costs are equal to zero.

11.4 Start Cost

Battery and Flywheel Unit's Start Fuel and Total Fuel Related Costs are equal to zero.

11.5 No Load

Battery and Flywheel Units do not have No Load costs.

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 battery and flywheel units.



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 battery and flywheel units if applicable.

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 battery and flywheels units.

Battery or Flywheel Units 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 Unit Owner wishes to change its method of calculating these losses, the PJM Member shall submit a cost policy to the PJM MMU pursuant to the Cost and Methodology Approval Process. 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 external to a Unit Owner that results in a need for the Unit Owner to change its method of cost calculation, the affected PJM Member may submit a request, or notification as appropriate, to the PJM MMU for evaluation, pursuant to the Cost and Methodology Approval Process.

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:

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



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 of PJM Interconnection, L.L.C. for various products including energy and regulation.
- Requests for recovery of Opportunity Costs not defined in the Operating Agreement of PJM Interconnection, L.L.C. should be submitted to the PJM MMU pursuant to the Cost and Methodology Approval Process.

12.2 Basis for Opportunity Cost to be included in Cost Offers

There two three reasons for 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 generation owner. 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 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

Generators may opt to follow one of the two the following methodologies; the difference between the methodologies being the applicable time period. Generators 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 of PJM Interconnection, L.L.C. should be initially submitted to the PJM MMU for evaluation under the Cost and Methodology Approval Process.

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 M-15, market participants 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. Generation owners 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. Generation owners who include opportunity costs in their cost-based offers must recalculate their short term opportunity cost every day.

12.4 Definitions

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

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 Cost

Unit Dispatch Cost= Cost of Dispatch with Start 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



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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.

Exhibit 16: Three hourly basis differential ratios values for the same hour in each of three historical years:

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

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

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

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.



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

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

Exhibit 17: Monthly Peak Basis Differentials for the three historical periods:

$$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{peak}} = \frac{\sum_{\text{peak hours}} * (\text{Hourly Basis Differential Ratios in June 2007})}{\text{Number of peak hours in June 2007}}$$

$$\text{MonthlyPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{peak}} = \frac{\sum_{\text{peak hours}} * (\text{Hourly Basis Differential Ratios June 2008})}{\text{Number of peak hours in June 2008}}$$

$$\text{MonthlyPeakDifferentialBasisRatio}_{\text{June 2009}}^{\text{peak}} = \frac{\sum_{\text{peak hours}} * (\text{Hourly Basis Differential Ratios June 2009})}{\text{Number of peak hours in June 2009}}$$

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.

$$\text{Forecasted Monthly Bus Price}_{fy,m}^{\text{peak}} = \left[\text{PJMWestern Hub}_{fy,m}^{\text{peak}} * \text{MonthlyPeakBasisRatio}_{y,m}^{\text{peak}} \right]$$



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Exhibit 18: Forecasted monthly bus prices for three historical periods:

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2007}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{OFFpeak}}) \right] \end{aligned}$$

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2008}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{OFFpeak}}) \right] \end{aligned}$$

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2009}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWHFRP}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2009}}^{\text{OFFpeak}}) \right] \end{aligned}$$

Outputs from 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 for STEP 2:

Three years 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.



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

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

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:

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

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

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

Output from STEP 2:

Three ratio values per hour for each of the historical years used for volatility



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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

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

Exhibit 19: Forecasted bus LMPs for one hour for each of the three historical base years:

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

$$\begin{aligned} &\text{ForecastedBUSLMP}_{\text{June 3,2010 H23,base 2007}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3,2007 H23}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \end{aligned}$$

$$\begin{aligned} &\text{ForecastedBUSLMP}_{\text{June 3,2010 H23,base 2008}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3,2008 H23}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \end{aligned}$$

$$\begin{aligned} &\text{ForecastedBUSLMP}_{\text{June 3,2010 H23,base 2009}} \\ &= \text{HourlyVolatilityScalar}_{\text{June 3,2009 H23}} * \text{ForecastedMonthlyBusPrice}_{\text{June 2010}}^{\text{offpeak}} \end{aligned}$$

Outputs from STEP 3:

Three hourly bus LMP forecasts for each hour remaining in the compliance period



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12.5.4 Step 4: Create a daily fuel volatility scalar

Inputs to STEP 4:

Three years historical delivered daily fuel prices at the generator bus (\$/mBTU)

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:

$$\text{DailyFuelVolatilityScalar}_{y,m,d} = \frac{\text{DeliveredFuelPrice}_{y,m,d}}{\left(\frac{\sum_{n=1}^{N_m} (\text{DeliveredFuelPrice}_{y,m})}{N_m} \right)}$$

Units with Dual Fuel:

$$\text{DailyFuelVolatilityScalar}_{y,m,d} = \frac{\left((\text{DeliveredFuelPriceFuelTypeA}_{y,m,d} * \text{WeightFuelTypeA}) + (\text{DeliveredFuelPriceFuelTypeB}_{y,m,d} * \text{WeightFuelTypeB}) \right)}{\frac{\sum_{n=1}^{N_m} \left((\text{DeliveredFuelPriceA}_{y,m} * \text{WeightA}) + (\text{DeliveredFuelPriceB}_{y,m} * \text{WeightB}) \right)}{N_m}}$$



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Exhibit 20: Three daily fuel volatility scalars values developed for June 3 in each of three historic years for a unit with a single fuel:

$$\text{DailyFuelVolatilityScalar}_{\text{June } 3, 2007} = \frac{\text{DeliveredFuelPrice}_{\text{June } 3, 2007}}{\text{Average June 2007 DeliveredFuelPrice}}$$

$$\text{DailyFuelVolatilityScalar}_{\text{June } 3, 2008} = \frac{\text{DeliveredFuelPrice}_{\text{June } 3, 2008}}{\text{Average June 2008 DeliveredFuelPrice}}$$

$$\text{DailyFuelVolatilityScalar}_{\text{June } 3, 2009} = \frac{\text{DeliveredFuelPrice}_{\text{June } 3, 2009}}{\text{Average June 2009 DeliveredFuelPrice}}$$

If there is no fuel cost record for a given date, use the previous available value.

Output 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 (\$/mBTU) with a daily delivery charge adjustment

Fuel Weights if dual fuel

Fuel contract monthly prices if applicable

Output from STEP 4: Three years historic 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 together 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:

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

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.)

$$\begin{aligned} \text{DailyDeliveredFuel}_{fy,m,d} &= \text{DailyFuelVariabilityScalar}_{y,m,d} \\ &* \left[\text{WeightFuelTypeA}_m \right. \\ &* \left(\text{WeightContractFuelTypeA}_m * \text{ContractPriceFuelTypeA}_m \right. \\ &+ \left. \text{WeightSpotFuelTypeA}_m * (\text{DeliveryAdjustmentFuelTypeA} \right. \\ &+ \left. \text{FuelForwardFuelTypeA}_{fy,m}) \right) + \text{WeightFuelTypeB}_m \\ &* \left(\text{WeightContractFuelTypeB}_m * \text{ContractPriceFuelTypeB}_m \right. \\ &+ \left. \text{WeightSpotFuelTypeB}_m * (\text{DeliveryAdjustmentFuelTypeB} \right. \\ &+ \left. \text{FuelForwardFuelTypeB}_{fy,m}) \right) \left] \text{Where } \text{WeightFuelTypeA}_m \right. \\ &+ \left. \text{WeightFuelTypeB}_m = 1 \end{aligned}$$

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

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

Exhibit 21: Create three daily delivered fuel forecasts from the volatilities of three historic years:

Unit with a single fuel:



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

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

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

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/mBTU)
 (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 M-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 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:

$$\text{UnitCost}_{\text{fy,m,d}}^{\text{base year}} = \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{DailyDeliveredFuelForecast} \left(\frac{\$}{\text{mBTU}} \right)_{\text{Future y,m,d}}^{\text{base year}} \right] + \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitNOxEmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of NOx} \left(\frac{\$}{\text{lb}} \right) \right] + \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitSO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of SO}_2 \left(\frac{\$}{\text{lb}} \right) \right] +$$



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$$\left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitCO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of CO}_2 \left(\frac{\$}{\text{lb}} \right) \right] + \text{VOM} + \left\{ \begin{array}{l} 10\% \text{ margin} \\ \text{FMU adder} \end{array} \right\} \text{OR}$$

Exhibit 22: Daily unit cost:

Unit heat rate=10.35 mBTU/MWh

Unit NOx emission rate =0.328 lbs/mBTU

Unit SO₂ emission rate=1.2 lbs/mBTU

Unit CO₂ emission rate=117 lbs/mBTU

DailyDeliveredFuelForecast=\$5.56/mBTU

Combined NOx Allowance cost=\$1375/ton

SO₂ Allowance cost=\$200/ton

CO₂ emission cost = \$8/ton

VOM & Maintenance Adder=\$2.22/MWh

FMU= \$0.00/MWh

UnitCost =

$$\left[\left(\frac{10.35 \text{mbtu}}{\text{mwh}} \right) * \left(\frac{\$5.56}{\text{mbtu}} \right) \right] + \left[\left(\frac{10.35 \text{mbtu}}{\text{mwh}} \right) * \left(\frac{0.328 \text{ lbs}}{\text{mbtu}} \right) * \left(\frac{\$1375.00}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{ lbs}} \right) \right] + \left[\left(\frac{10.35 \text{mbtu}}{\text{mwh}} \right) * \left(\frac{1.2 \text{ lbs}}{\text{mbtu}} \right) * \left(\frac{\$200}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{ lbs}} \right) \right] + \left[\left(\frac{10.345 \text{mbtu}}{\text{mwh}} \right) * \left(\frac{117 \text{lbs}}{\text{mbtu}} \right) * \left(\frac{\$8}{\text{ton}} \right) * \left(\frac{\text{ton}}{2000 \text{lbs}} \right) \right] + \left(\frac{\$2.22}{\text{MWh}} \right) + \left(\frac{\$0}{\text{MWh}} \right)$$

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

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



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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 startup costs for combined cycle and combustion turbine units and hot startup 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 cost). For units with startup 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 costs. Calculate the total margins for all blocks of hours in the three forecasts.

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

**MRT= minimum run time

***Unit Dispatch cost includes startup when applicable

Where the block ranges from one to [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** 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.

Exhibit 23: 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



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This example uses block # 3788:

$$\begin{aligned}
 & \text{TotalMarginBlock}_{\text{block } 3788}^{2007} \\
 &= \sum_{t=\text{block}}^{t=\text{block}+\text{MRT}-1} \left(\text{ForecastedBusLMP}_{y(t),m(t),d(t),h(t)}^{\text{base year}} - \text{UnitDispatchCost}_{\text{future } y,m,d}^{\text{base year}} \right) \\
 &= \sum_{t=3788}^{t=3788+1-1} \left(\text{ForecastedBusLMP}_{y,m,d,h(t)}^{2007} - \text{UnitDispatchCost}_{y,m,d(t)}^{2007} \right) \\
 &= \text{ForecastedBusLMP}_{y,m,d,h(3788)}^{2007} - \text{UnitDispatchCost}_{y,m,d,h(3788)}^{2007} \\
 &= \text{ForecastedBusLMP}_{\text{June } 3,2010 \text{ H07}}^{2007} - \text{UnitDispatchCost}_{\text{June } 3,2010}^{2007} = \\
 &= \$78.27 - \$69.21 = \$9.06
 \end{aligned}$$

Similarly,

$$\begin{aligned}
 & \text{TotalMarginBlock}_{\text{block } 3788}^{2008} \\
 &= \text{ForecastedBusLMP}_{\text{June } 3,2010 \text{ H07}}^{2008} - \text{UnitDispatchCost}_{\text{June } 3,2010}^{2008} \\
 &= \$58.00 - \$52.41 = 5.59
 \end{aligned}$$

And

$$\begin{aligned}
 & \text{TotalMarginBlock}_{\text{block } 3788}^{2009} \\
 &= \text{ForecastedBusLMP}_{\text{June } 3,2010 \text{ H07}}^{2009} - \text{UnitDispatchCost}_{\text{June } 3,2010}^{2009} \\
 &= \$63.78 - \$76.72 = -\$12.94
 \end{aligned}$$

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

Output from step 7: Three sets of ranked blocks of total margin forecasts including each hour in the compliance period, adjusted to include startup 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

Input 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



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to the generator. If the final opportunity cost component is less than zero then the opportunity cost component will be set to zero.

Exhibit 24: A unit with 700 run hours:

The average value of the block which includes the **700th hour**_{base 2007} = **\$7.99/MWh**

The average value of the block which includes the **700th hour**_{base 2008} = **\$ - 2.54/MWh** The

average value of the block which includes the **700th hour**_{base 2009} = **\$10.59/MWh**

$$\text{700th hour opportunity cost component} = \frac{\$7.99 + (-\$2.54) + 10.59}{3} = \$5.33/\text{MWh}$$

Output 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 generators to recalculate opportunity costs everyday 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 Daily Forward Price 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



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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

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

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.

Exhibit 25: Three hourly basis differential ratios values for the same hour in each of three historical years:

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

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

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

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.



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

$$\begin{aligned} & \text{MonthlyOffPeakBasisDifferentialRatio}_{y,m}^{\text{peak}} \\ = & \frac{\sum_{\text{off-peak hours}} \left(\text{HourlyBasisDifferentialRatios}_{y,m,d,h}^{\text{off-peak}} \right)}{\text{Number of Off – Peak Hours in month } m} \end{aligned}$$

Exhibit 26: Monthly Peak Basis Differentials for the three historical periods:

$$\begin{aligned} & \text{MonthlyPeakBasisDifferentialRatio}_{\text{June } 2007}^{\text{peak}} \\ = & \frac{\sum_{\text{peak hours}} \left(\text{Hourly Basis Differential Ratios in June 2007} \right)}{\text{Number of peak hours in June 2007}} \end{aligned}$$

$$\begin{aligned} & \text{MonthlyPeakBasisDifferentialRatio}_{\text{June } 2008}^{\text{peak}} \\ = & \frac{\sum_{\text{peak hours}} \left(\text{Hourly Basis Differential Ratios June 2008} \right)}{\text{Number of peak hours in June 2008}} \end{aligned}$$

$$\begin{aligned} & \text{MonthlyPeakDifferentialBasisRatio}_{\text{June } 2009}^{\text{peak}} \\ = & \frac{\sum_{\text{peak hours}} \left(\text{Hourly Basis Differential Ratios June 2009} \right)}{\text{Number of peak hours in June 2009}} \end{aligned}$$

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.

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{fy,m}^{\text{peak}} \\ = & \left[\left(\text{PJMWestern Hub}_{fy,m}^{\text{peak}} \right) * \left(\text{MonthlyPeakBasisRatio}_{y,m}^{\text{peak}} \right) \right] \end{aligned}$$

Exhibit 27: Forecasted monthly bus prices for three historical periods:



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$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2007}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2007}}^{\text{OFFpeak}}) \right] \end{aligned}$$

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2008}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2008}}^{\text{OFFpeak}}) \right] \end{aligned}$$

$$\begin{aligned} & \text{Forecasted Monthly Bus Price}_{\text{June 2010,base 2009}}^{\text{OFFpeak}} \\ = & \left[(\text{PJMWH}_{\text{for delivery June 2010}}^{\text{OFFpeak}}) * (\text{MonthlyOffPeakBasisDifferentialRatio}_{\text{June 2009}}^{\text{OFFpeak}}) \right] \end{aligned}$$

Outputs from 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 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.



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

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

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

$$\text{HourlyVolatilityScalar}_{\text{June } 3, 2007 \text{ H } 23} = \frac{\text{BUSLMP}_{\text{June } 3, 2007 \text{ H } 23}}{\text{Average Offpeak June 2007 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June } 3, 2008 \text{ H } 23} = \frac{\text{BUSLMP}_{\text{June } 3, 2008 \text{ H } 23}}{\text{Average Offpeak June 2008 BUSLMP}}$$

$$\text{HourlyVolatilityScalar}_{\text{June } 3, 2009 \text{ H } 23} = \frac{\text{BUSLMP}_{\text{June } 3, 2009 \text{ H } 23}}{\text{Average Offpeak June 2009 BUSLMP}}$$

Output 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



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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

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

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:

$$\begin{aligned} & \text{ForecastedBUSLMP}_{\text{June } 3, 2010 \text{ H}00, \text{base } 2007} \\ & = \text{HourlyVolatilityScalar}_{\text{June } 3, 2007 \text{ H}00} * \text{ForecastedMonthlyBusPrice}_{\text{June } 2010}^{\text{offpeak}} \end{aligned}$$

$$\begin{aligned} & \text{ForecastedBUSLMP}_{\text{June } 3, 2010 \text{ H}00, \text{base } 2008} \\ & = \text{HourlyVolatilityScalar}_{\text{June } 3, 2008 \text{ H}00} * \text{ForecastedMonthlyBusPrice}_{\text{June } 2010}^{\text{offpeak}} \end{aligned}$$

$$\begin{aligned} & \text{ForecastedBUSLMP}_{\text{June } 3, 2010 \text{ H}00, \text{base } 2009} \\ & = \text{HourlyVolatilityScalar}_{\text{June } 3, 2009 \text{ H}00} * \text{ForecastedMonthlyBusPrice}_{\text{June } 2010}^{\text{offpeak}} \end{aligned}$$

Outputs from Step 3:

Three hourly bus LMP forecasts for each hour remaining in the compliance period

12.6.4 Step 4: Fuel Price



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Fuel Weights if dual fuel
 Contract Fuel Prices in 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:

$$\text{Daily Delivered Fuel}_{y,m,d} = \text{WeightSpot}_m * (\text{Day Ahead Fuel Price} + \text{Delivery Adjustment}) + (\text{Weight Contract}_m * \text{Contract Price}_m)$$

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

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.

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

$$\text{Where Weight Fuel Type A}_m + \text{WeightFuel Type B}_m = 1$$

$$\text{Where Weight Contract Type A}_m + \text{WeightSpot Type A}_m = 1$$

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



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Outputs 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 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/MBTU)
 (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 M-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 costs, start 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:

$$\begin{aligned}
 \text{UnitCost}_{fy,m,d}^{\text{base year}} = & \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{DailyDeliveredFuelForecast} \left(\frac{\$}{\text{mBTU}} \right)_{\text{Future } y,m,d}^{\text{base year}} \right] + \\
 & \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitNOxEmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of NOx} \left(\frac{\$}{\text{lb}} \right) \right] + \\
 & \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitSO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of SO}_2 \left(\frac{\$}{\text{lb}} \right) \right] + \\
 & \left[\text{UnitHeatRate} \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \text{UnitCO}_2\text{EmissionRate} \left(\frac{\text{lbs}}{\text{mBTU}} \right) * \text{Cost of CO}_2 \left(\frac{\$}{\text{lb}} \right) + \text{VOM} + \right\} \\
 & + \text{either a } \left\{ \begin{array}{l} 10\% \text{ margin} \\ \text{FMU adder} \end{array} \right. \text{ OR}
 \end{aligned}$$

Exhibit 28: Daily unit cost:

Unit heat rate=10.345 MBTU/MWh
 Unit NOx emission rate =0.328 lbs/MBTU
 Unit SO₂ emission rate=1.2 lbs/MBTU
 Unit CO₂ emission rate=117 lbs/MBTU
 DailyDeliveredFuelForecast=\$3.01/MBTU



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Combined NOx Allowance cost=\$1375/ton

SO₂ Allowance cost=\$200/ton

CO₂ emission cost = \$8/ton

VOM & Maintenance Adder=\$2.22/MWh

FMU= \$0.00/MWh

Unit Cost =

$$\left\{ \left[10.345 \left(\frac{\text{mBTU}}{\text{mwh}} \right) * \$3.01 \left(\frac{\$}{\text{mBTU}} \right) \right] + \left[10.345 \left(\frac{\text{mBTU}}{\text{mwh}} \right) * 0.328 \left(\frac{\text{lbs}}{\text{mBTU}} \right) * 0.6875 \left(\frac{\$}{\text{lb}} \right) \right] + \left[10.35 \left(\frac{\text{mBTU}}{\text{mwh}} \right) * 1.2 \left(\frac{\text{lbs}}{\text{mBTU}} \right) * 0.1 \left(\frac{\$}{\text{lb}} \right) \right] + \left[10.345 \left(\frac{\text{mBTU}}{\text{mwh}} \right) * 117 \left(\frac{\text{lbs}}{\text{mBTU}} \right) * 0.004 \left(\frac{\$}{\text{lb}} \right) \right] + \$2.22 + \right\}$$

Unit Cost =

$$\left\{ \left[\left(\frac{\$31.14}{\text{mwh}} \right) \right] + \left[\left(\frac{2.33}{\text{mwh}} \right) \right] + \left[\left(\frac{\$1.24}{\text{mwh}} \right) \right] + \left[\left(\frac{\$4.84}{\text{mwh}} \right) \right] + \$2.22 + \right\} = \frac{\$41.77}{\text{MWh}}$$

Outputs for 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 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 startup costs for combined cycle and combustion turbine units and hot startup 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



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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 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 costs. Calculate the total margins for all blocks of hours in the three forecasts:

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

**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.

Exhibit 29: 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

This example uses block # 3679:

$$\begin{aligned} \text{TotalMarginBlock}_{\text{block } 3679}^{2007} &= \sum_{t=\text{block}}^{t=\text{block}+\text{MRT}-1} \left(\text{ForecastedBusLMP}_{y(t),m(t),d(t),h(t)}^{\text{base year}} - \text{UnitDispatchCost}_{\text{future } y,m,d}^{\text{base year}} \right) \\ &= \sum_{t=3679}^{t=3679+1-1} \left(\text{ForecastedBusLMP}_{y(t),m(t),d(t),h(t)}^{2007} - \text{UnitDispatchCost}_{\text{future } y,m,d}^{2007} \right) \\ &= \text{ForecastedBusLMP}_{y,m,d,h(3679)}^{2007} - \text{UnitDispatchCost}_{y,m,d,h(3679)}^{2007} \\ &= \text{ForecastedBusLMP}_{\text{June } 3, 2010 \text{ H}07}^{2007} - \text{UnitDispatchCost}_{\text{June } 3, 2010}^{2007} = \\ &= \$53.23 - \$41.77 = \$11.46 \end{aligned}$$

Similarly



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$$\text{TotalMarginBlock}_{\text{block } 3679}^{2008}$$

$$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H07}}^{2008} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2008}$$

$$= \$55.44 - \$57.88 = -\$2.44$$

And

$$\text{TotalMarginBlock}_{\text{block } 3679}^{2009}$$

$$= \text{ForecastedBusLMP}_{\text{June 3, 2010 H07}}^{2009} - \text{UnitDispatchCost}_{\text{June 3, 2010}}^{2009}$$

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

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

[Output 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

[Input 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.

Exhibit 30: A unit with 700 run hours left:

The average value of the block which includes the **700th hour**_{base 2007} = **\$18.33/MWh**

The average value of the block which includes the **700th hour**_{base 2008} = **\$ - 2.50/MWh**

The average value of the block which includes the **700th hour**_{base 2009} = **\$1.59/MWh**

$$\text{700th hour opportunity cost adder} = \frac{\$18.33 + (-2.50) + \$1.59}{3} = \$5.81/\text{MWh}$$



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

Output from step 7:

Maximum Opportunity Cost Component that can be added to an environmentally run limited generator's cost offer.



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 PJM Market Monitoring Unit (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, BTU content and cost of each type of fuel used.



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Attachment A: Applicable FERC System of Accounts

- 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



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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.



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- 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 PJM members 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 Original Equipment Manufacturer and performing a regression analysis,

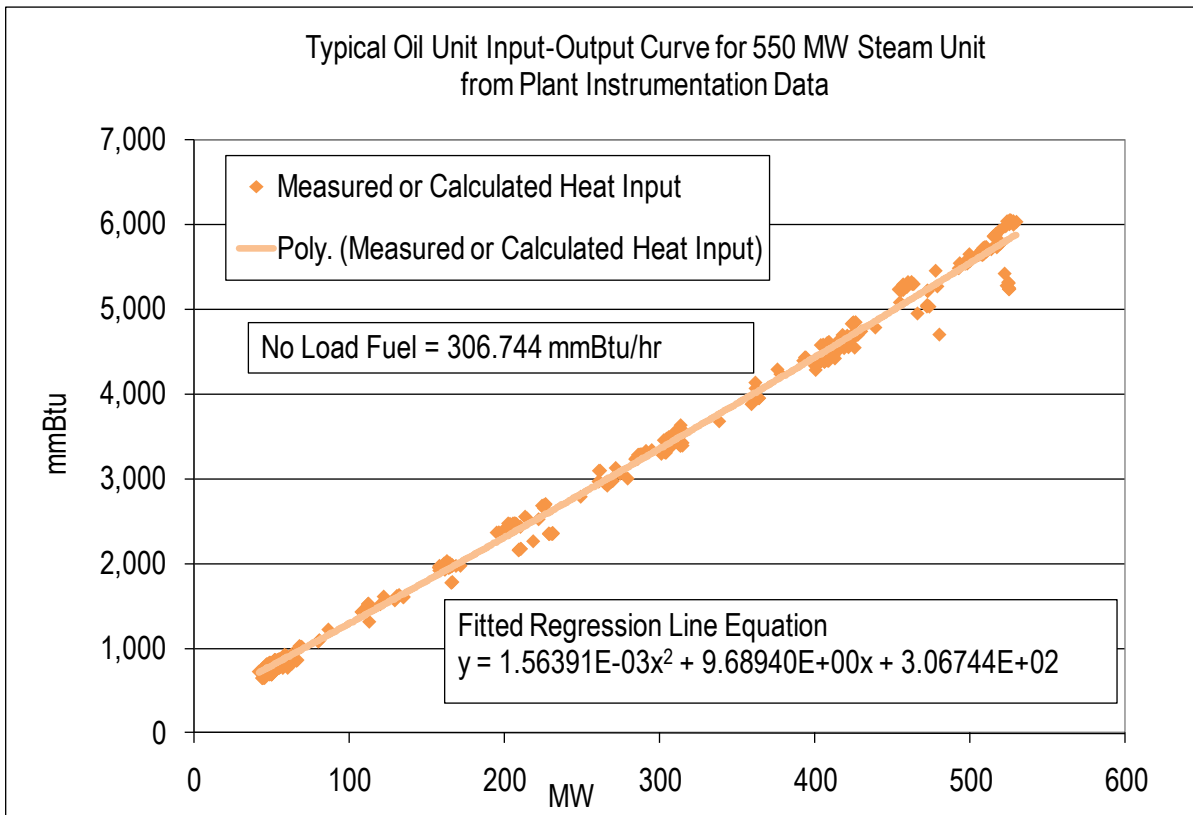
Using the initial design heat input curve for an immature unit and performing a regression analysis

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 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 Output with oil as a fuel:

$$\text{Heat Input (mmBTU/Hr)} = 0.00156391 * MW^2 + 9.6894 * MW + 306.744$$

Then the No-Load Fuel at zero output is

$$\text{No - Load Fuel} = 306.744 \text{ mmBtu/hr}$$



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 Attachment B: No Load Calculation Examples

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is:

Performance Factor = 1.02

Total Fuel related Cost (TFRC) = \$14.00 MBTU

$$\begin{aligned} \text{No Load Cost}(\$/\text{Hour}) &= \\ &(\text{No Load Fuel} * \text{Performance Factor} * \text{TFRC}) \\ &= 306.744 \text{ mmBtu/hr} * 1.02 * \$14.00/\text{mmBtu} \\ &= \$4,380/\text{hr} \end{aligned}$$

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 outputs. Total Operating Cost is calculated by:

VOM = \$0.15/MBTU

Total Operating Cost (\$/hr)

$$= \text{Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Heat Input (MBTU/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:

$$\text{Incremental Cost}(\$/\text{MWh}) =$$



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Attachment B: No Load Calculation Examples

Total Operating Cost MW2 – Total Operating Cost MW1/(MW2 – 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 outputs can also be determined by using the derivative of the Heat Input Curve:

$$\text{Incremental Cost (\$/MWh)} = (2 * 0.00156391 * \text{MW} + 9.6894) * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Incremental Cost (\$/MWh)
50	142.10
160	147.07
310	153.84
410	158.36
525	163.55
550	164.68



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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.

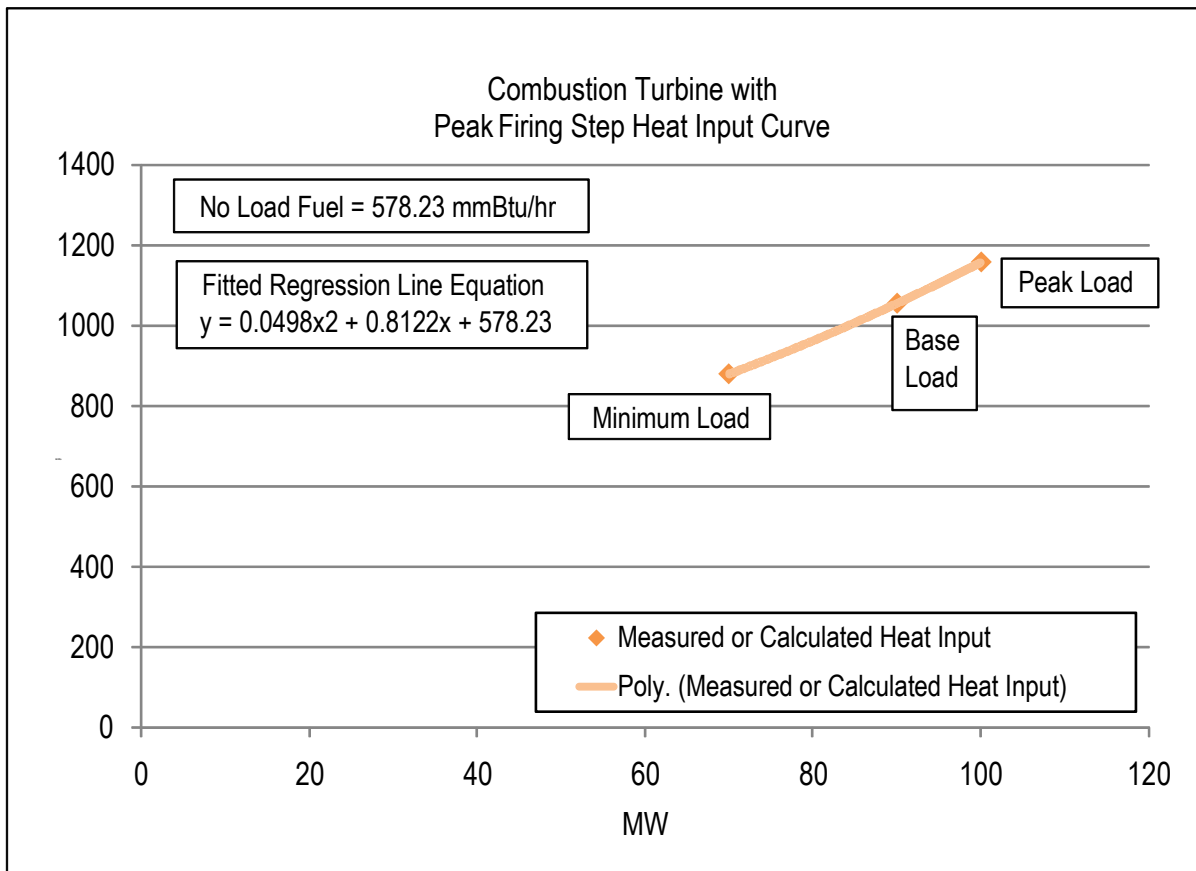
$$\begin{aligned} \text{No - Load Cost (\$/hr)} &= \\ &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * (\text{TRFC} + \text{VOM})) \\ &\quad - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\ &= (795.12\text{mmBtu/hr} * 1.02 * (\$14.00/\text{mmBtu} + \$0.15/\text{mmBtu})) - (\$142.10/\text{MWh} * 50 \text{ MW}) \\ &= \$4,370.97/\text{hr} \end{aligned}$$

Differences in the calculated No-Load 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 eMKT.



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 combustion turbine 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 Output with natural gas as a fuel:

$$\text{Heat Input (mmBTU/Hr)} = 0.0498 * MW^2 + 0.8122 * MW + 578.23$$

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:



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 Attachment B: No Load Calculation Examples

Performance Factor = 1.02

Total Fuel related Cost (TFRC) = \$4.00 MBTU

$$\begin{aligned} \text{No Load Cost}(\$/\text{Hour}) &= \\ &= (\text{No Load Fuel} * \text{Performance Factor} * \text{TFRC}) \\ &= 578.23\text{mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu} \\ &= \$2,359/\text{hr} \end{aligned}$$

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 outputs. Total Operating Cost is calculated by:

Maintenance Factor = 1.0 for Minimum & Base (=4.0 for Peak)

VOM = \$75.00/ESH

Total Operating Cost (\$/hr)

$$= \text{Heat Input} * \text{Performance Factor} * \text{TFRC} + \text{Maintenance Factor} * \text{VOM}$$

Output (MW)	Heat Input (MBTU/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 outputs can be determined arithmetically by the following equation:

$$\begin{aligned} \text{Incremental Cost}(\$/\text{MWh}) &= \\ &= \frac{\text{Total Operating Cost MW2} - \text{Total Operating Cost MW1}}{\text{MW2} - \text{MW1}} \end{aligned}$$



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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 outputs can also be determined by using the derivative of the Heat Input Curve:

$$\text{Incremental Cost (\$/MWh)} = ((2 * 0.0498 * \text{MW} + 0.8122) * \text{Performance Factor} * \text{TFRC}) + \Delta\text{VOM}/\Delta\text{MW}$$

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)
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.

$$\begin{aligned} \text{No - Load Cost (\$/hr)} &= \\ &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * \text{TFRC}) + \text{VOM} \\ &\quad - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\ &= (879.02\text{mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu}) + (\$75.00/\text{ESH}) - (\$32.83/\text{MWh} * 70 \text{ MW}) \end{aligned}$$



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Attachment B: No Load Calculation Examples

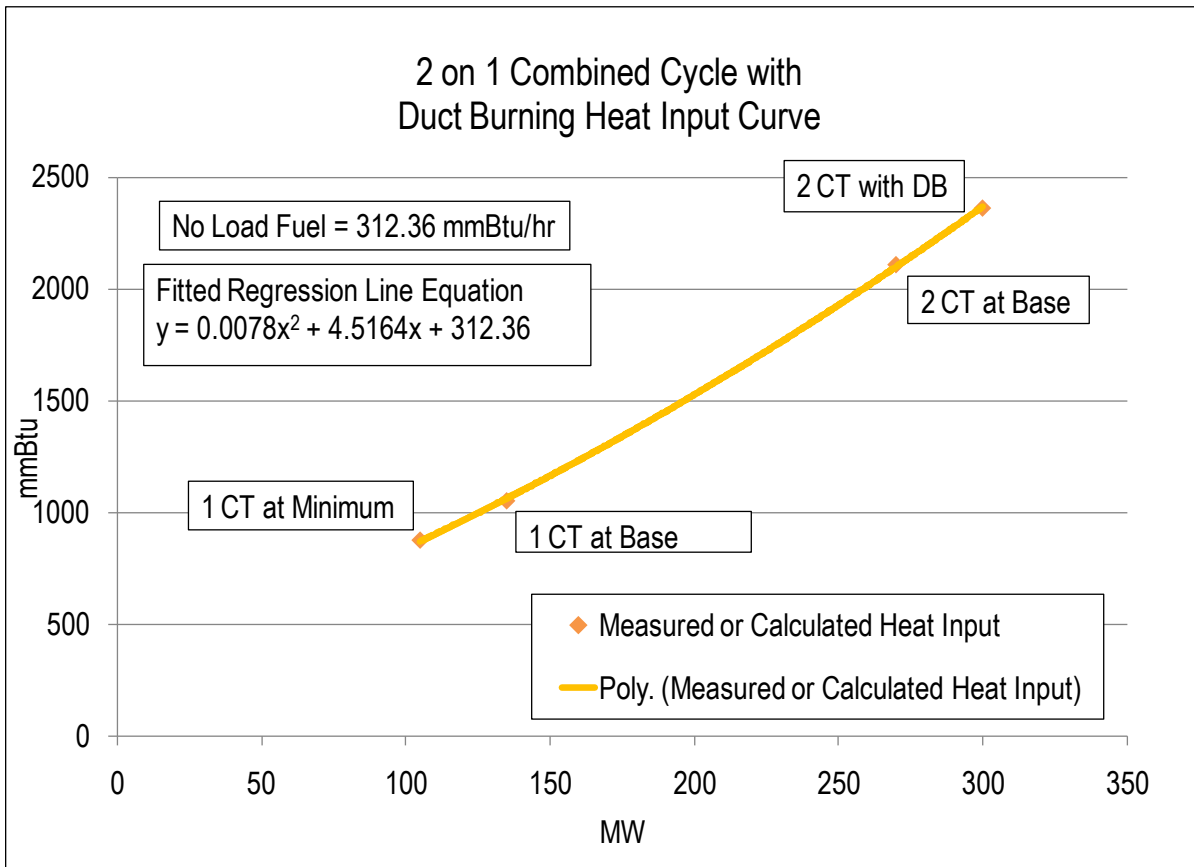
= \$1,363.30/hr

Differences in the calculated No-Load 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 eMKT.



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 combined cycle with duct burners 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 Output with natural gas as a fuel:

Heat Input (mmBTU/Hr) =

$$0.0078 * MW^2 + 4.5164 * MW + 312.36$$

$$0.0078 * MW^2 + 4.5164 * MW + 312.36$$



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 Attachment B: No Load Calculation Examples

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:

$$\text{Performance Factor} = 1.02$$

$$\text{Total Fuel related Cost (TFRC)} = \$4.00 \text{ MBTU}$$

$$\begin{aligned} \text{No Load Cost}(\$/ \text{ Hour}) &= \\ &= (\text{No Load Fuel} * \text{Performance Factor} * \text{TFRC}) \\ &= 312.36 \text{ mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu} \\ &= \$1,274/\text{hr} \end{aligned}$$

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 outputs. Total Operating Cost is calculated by:

$$\text{Maintenance Factor} = 1.0$$

$$\text{VOM} = \$75.00/\text{ESH}$$

Total Operating Cost (\$/hr)

$$= \text{Heat Input} * \text{Performance Factor} * \text{TFRC} + \text{Maintenance Factor} * \text{VOM}$$

Output (MW)	Heat Input (MBTU/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 outputs can be determined arithmetically by the following equation:

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 Attachment B: No Load Calculation Examples

$$\text{Incremental Cost (\$/MWh)} = \frac{\text{Total Operating Cost MW2} - \text{Total Operating Cost MW1}}{\text{MW2} - \text{MW1}}$$

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 outputs can also be determined by using the derivative of the Heat Input Curve:

$$\text{Incremental Cost (\$/MWh)} = ((2 * 0.0078 * \text{MW} + 4.5164) * \text{Performance Factor} * \text{TFRC}) + \Delta\text{VOM}/\Delta\text{MW}$$

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.



$$\begin{aligned} \text{No - Load Cost (\$/hr)} &= \\ &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * \text{TFRC}) + \text{VOM} \\ &\quad - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\ &= (872.58\text{mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu}) + (\$75.00/\text{ESH}) - (\$25.82/\text{MWh} * 105 \text{ MW}) \\ &= \$924.03/\text{hr} \end{aligned}$$

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 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 eMKT.

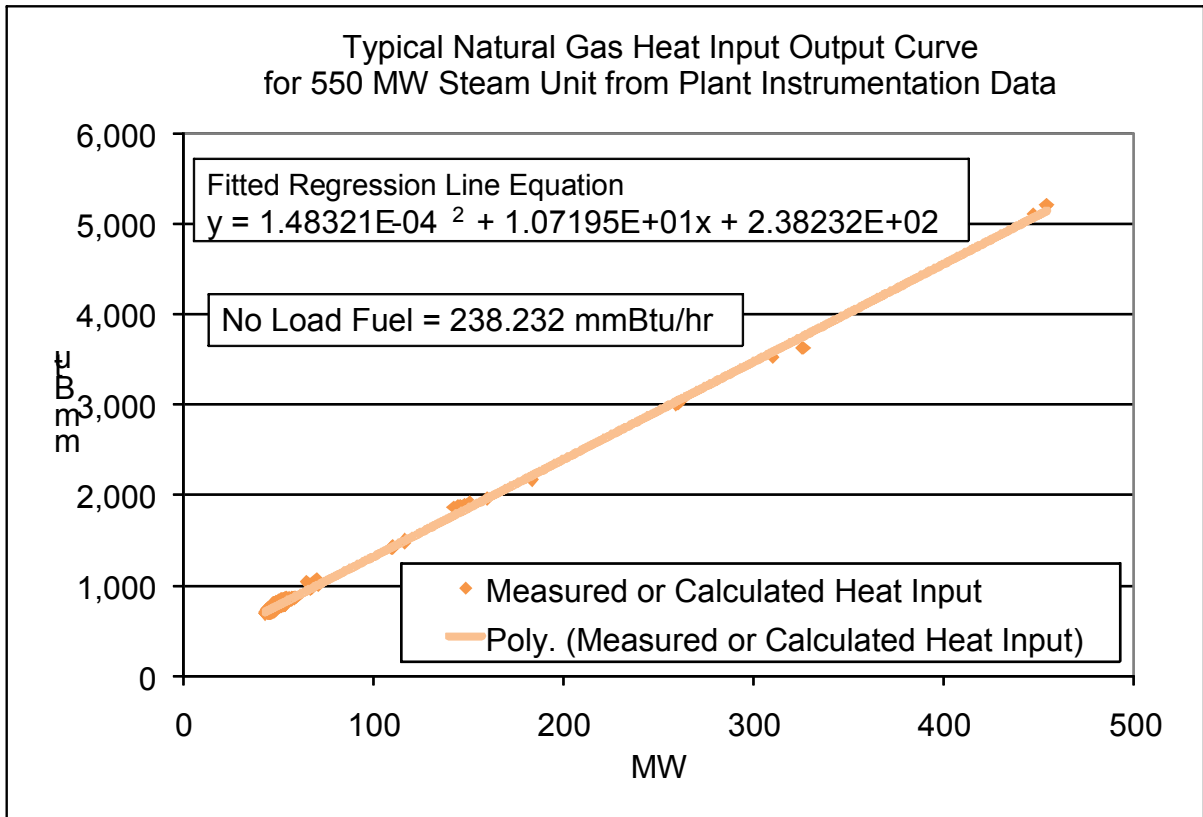
B.5 No-Load Cost Adjustments

The calculated no-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 follows. Heat input values as a function of output was collected for a typical fossil steam and a regression analysis was performed to obtain the no-load.



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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 Output with oil as a fuel:

Heat Input (mmBTU/Hr) =

$$0.000148321 * MW^2 + 10.7195 * MW + 238.232$$

$$0.000148321 * MW^2 + 10.7195 * MW + 238.232$$

Then the No-Load Fuel at zero output is

$$\text{No - Load Fuel} = 238.232 \text{ mmBtu/hr}$$

The initial estimate of a unit's **No-Load Cost (\$/Hr)** is:

$$\text{Performance Factor} = 1.02$$

$$\text{Total Fuel related Cost (TFRC)} = \$4.00 \text{ MBTU}$$

$$\text{No Load Cost}(\$ / \text{ Hour}) =$$



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$$\begin{aligned}
 & \text{(No Load Fuel * Performance Factor * TFRC)} \\
 & = 238.232 \text{ mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu} \\
 & = \$972/\text{hr}
 \end{aligned}$$

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 outputs. Total Operating Cost is calculated by:

$$\text{VOM} = \$0.15/\text{MBTU}$$

Total Operating Cost (\$/hr)

$$= \text{Heat Input} * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Heat Input (MBTU/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 outputs can be determined arithmetically by the following equation:

$$\begin{aligned}
 & \text{Incremental Cost (\$/MWh)} = \\
 & \text{Total Operating Cost MW2} - \text{Total Operating Cost MW1} / (\text{MW2} - \text{MW1})
 \end{aligned}$$

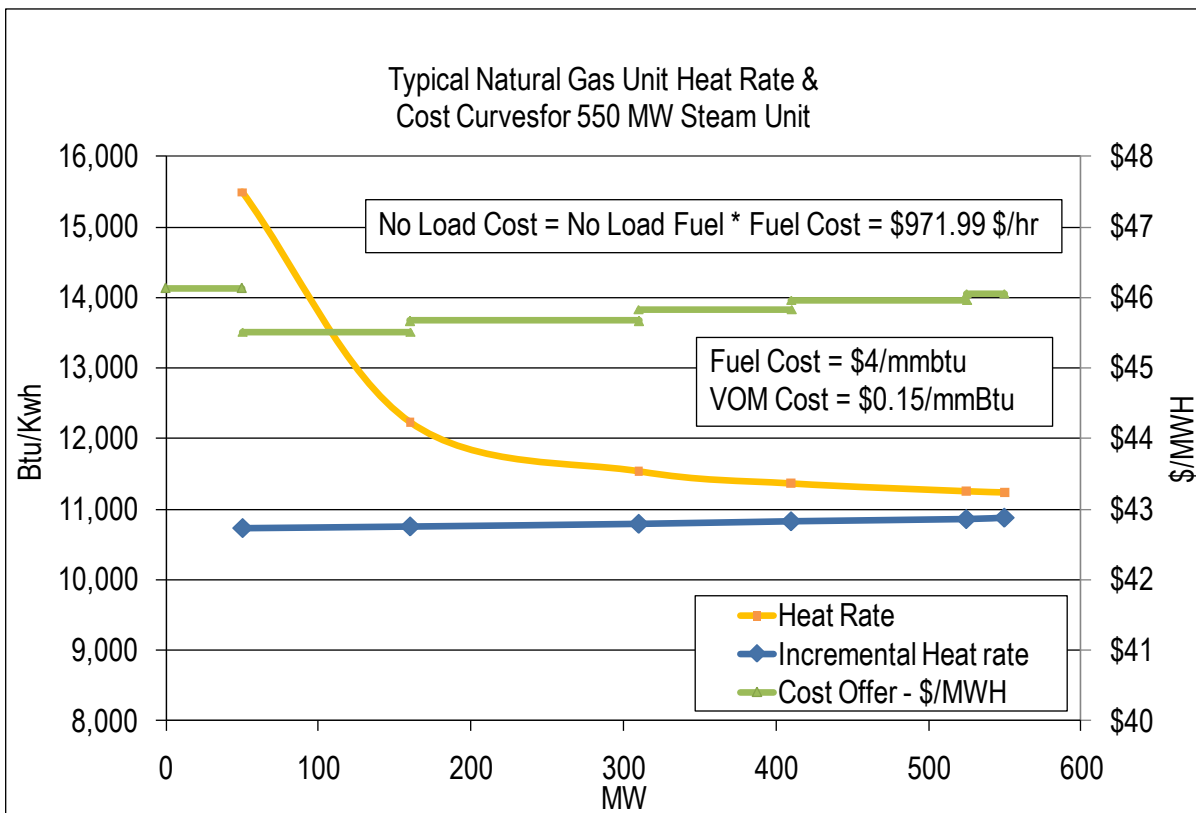
Output (MW)	Incremental Cost (\$/MWh)
50	46.14
160	45.51



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 Attachment B: No Load Calculation Examples

310	45.67
410	45.83
525	45.96
550	46.05

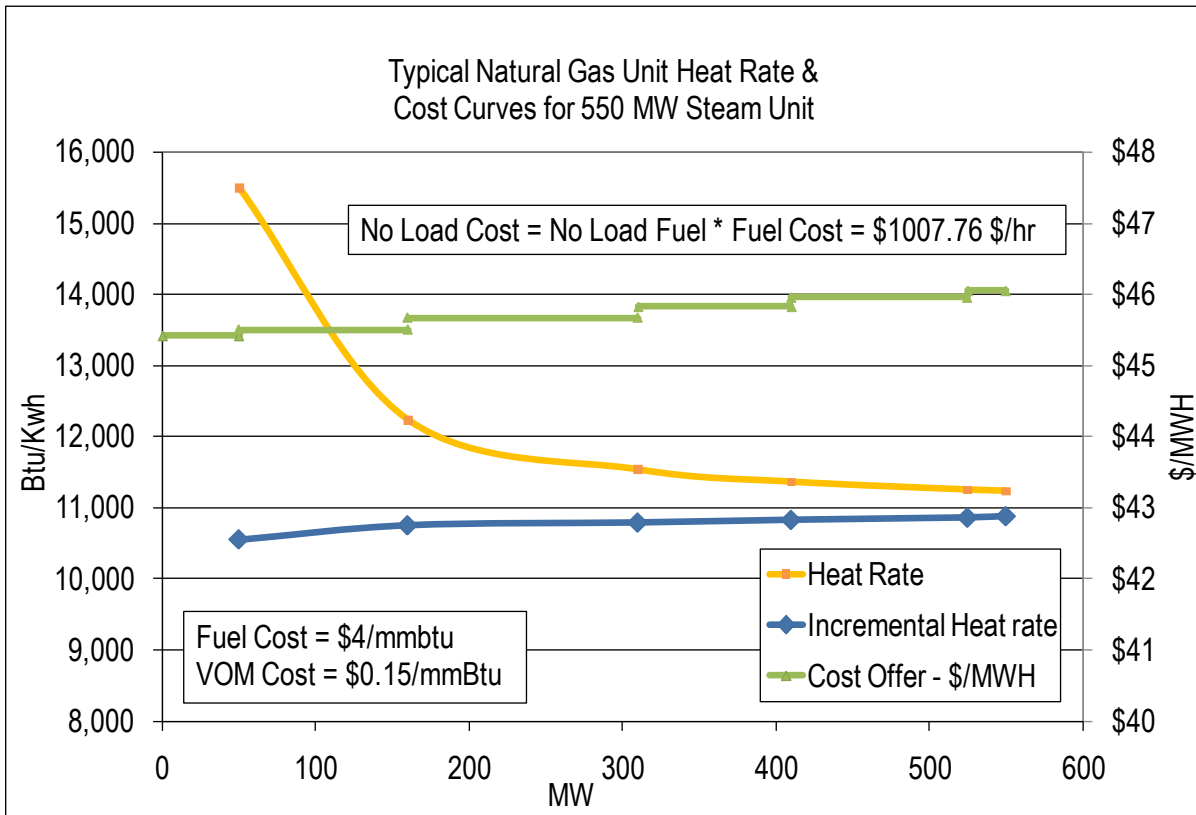
When calculating the first increment, MW1 is zero and the Total Operating Cost MW1 is the No-Load Cost. However due to the quality of the heat input data, the first increment of the cost offer was greater than the second increment. This is shown in the graph below:



The No-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:



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To avoid making adjustments to the No-Load, first calculate the unit's Incremental Cost (\$/MWh) at various outputs using the derivative of the Heat Input Curve:

$$\text{Incremental Cost (\$/MWh)} = (2 * 0.000148321 * \text{MW} + 10.7195) * \text{Performance Factor} * (\text{TFRC} + \text{VOM})$$

Output (MW)	Incremental Cost (\$/MWh)
50	45.43
160	45.58
310	45.76
410	45.89
525	46.03



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550	46.06
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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.

$$\begin{aligned}
 \text{No - Load Cost (\$/hr)} &= \\
 &= (\text{Economic Minimum Heat Input} * \text{Performance Factor} * (\text{TRFC} + \text{VOM})) \\
 &\quad - (\text{Economic Minimum Incremental Cost} * \text{Economic Minimum MW}) \\
 &= (774.58\text{mmBtu/hr} * 1.02 * (\$4.00/\text{mmBtu} + \$0.15/\text{mmBtu})) - (\$45.43/\text{MWh} * 50 \text{ MW}) \\
 &= \$1007.3/\text{hr}
 \end{aligned}$$

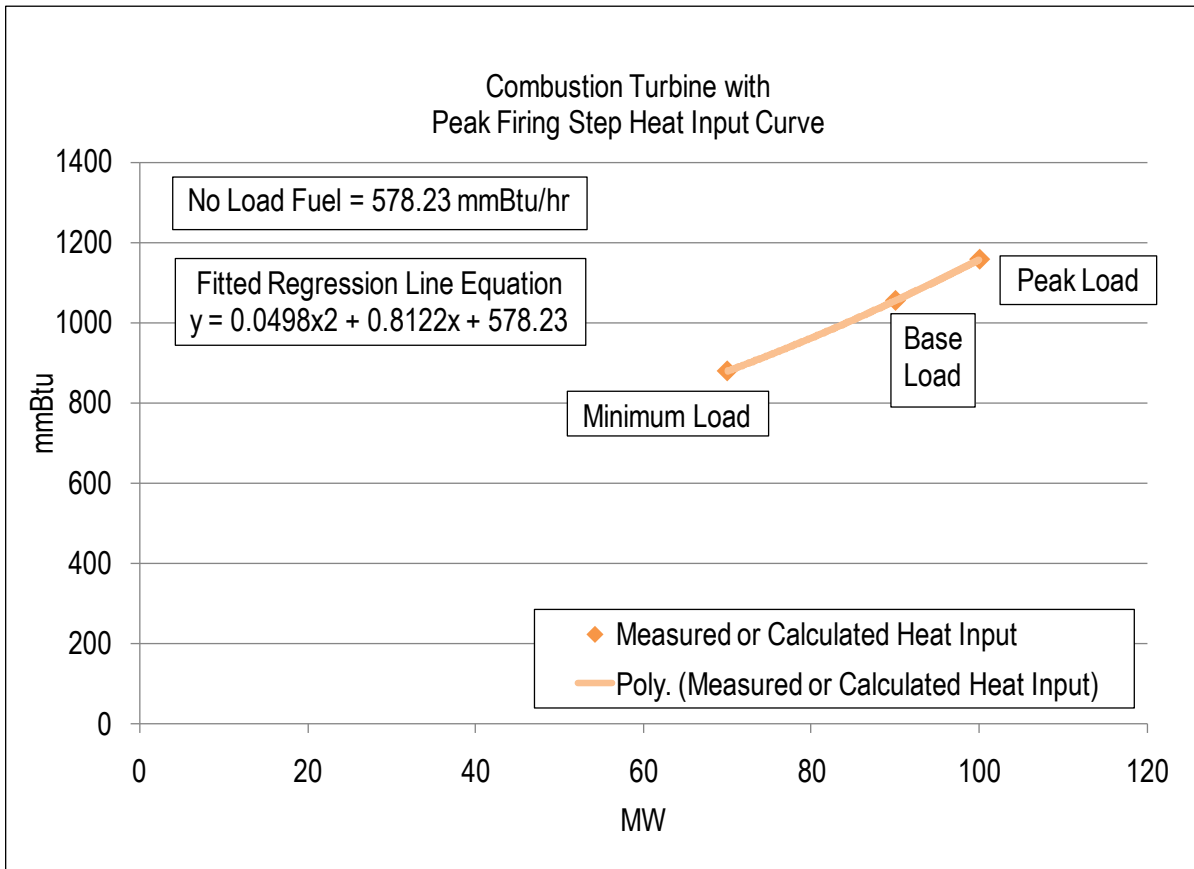
Differences in the calculated No-Load between the two methods are due to the differences in using a block average cost offer method versus a sloped derivative cost offer. When using the derivative method, user must select "Use Sloped Offer" when entering cost information into eMKT.

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:



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 Attachment B: No Load Calculation Examples



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 Output with natural gas as a fuel:

Heat Input (mmBTU/Hr) =

$$0.0498 * MW^2 + 0.8122 * MW + 578.23$$

$$0.0498 * MW^2 + 0.8122 * MW + 578.23$$

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.**

$$\text{No Load Cost}(\$ / \text{ Hour}) =$$

$$= \$0/\text{hr}$$



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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).

Heat Input (mmBTU/Hr) =

$$0.0498 * 100^2 + 0.8122 * 100 + 578.23 \quad 0.0498 * MW^2 + 0.8122 * MW + 578.23$$

$$= 1157.28 \text{ mmBtu/hr}$$

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)

$$= \text{Heat Input} * \text{Performance Factor} * \text{TFRC} + \text{Maintenance Factor} * \text{VOM}$$

$$= 1157.28 \text{ mmBtu/hr} * 1.02 * \$4.00/\text{mmBtu} + 4.0 * \$75/\text{hr}$$

$$= \$5,022/\text{hr}$$

The unit's Incremental Cost (\$/MWh) at maximum output with a zero No-Load Cost is calculated by:

$$\text{Incremental Cost (\$/MWh)} =$$

$$\frac{\text{Total Operating Cost Maximum Output}}{\text{Maximum Output}}$$

$$\frac{(\$5,022)}{(100\text{MW})}$$

$$= \$50.22 /\text{MWh}$$



Revision History

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 (03/02/06):

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 (08/18/05):

Updated Exhibit 1 to include new PJM Manuals.

Updated Exhibit 2, Chronology of Maintenance Adder Escalation Index Numbers, for the year 2005.

Revision 04 (09/01/04):

Insert new section nine into the CDS Manual

Revision 03 (06/01/04):

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 (06/01/03):

Revised table in Section 5.6, “Chronology of Maintenance Adder Escalation Index Numbers”, for the year 2003

Revision 01 (12/01/02):

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 (12/01/02):

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.