



PJM Manual 15:

Cost Development Guidelines

**Revision: 15**

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**Prepared by**

**Cost Development Task Force**

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PJM Manual 15:

Cost Development Guidelines

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 Approval

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Stanley H. Williams, Chairman

Cost Development Task Force

Current Revision

Revision 15 (): Rewrite of entire Manual 15

This revision improves readability and to address changes as a result of FERC Order 719 (Docket Nos. ER09-1063-000 and ER09-1063-001) requirements.

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.](http://www.pjm.com/documents/manuals.aspx)

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 Task Force (CDTF)](http://www.pjm.com/committees-and-groups/task-forces/cdtf.aspx) 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 Task Force Mission

The Cost Development Task Force (CDTF) 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. CDTF responsibilities can be found in the [Task Force’s charter.](http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/cdtf/postings/charter-03312006.ashx)

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 MW 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 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:

1. Start-up cost
2. No-load cost
3. Incremental costs (energy cost per segment)

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

1.7.1 Generator offer curves

Offer curves are used in determining hourly production cost and total production costs. An offer curve can have up to ten points defined. The first point describes the lowest MW amount offered of 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 different periods: 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

**The no-load cost** - is the cost per hour to maintain the generator synchronized at synchronous speed, but not generating any output.

1.7.4 Incremental Cost

**Hourly production costs** -are calculated for a period. It 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 total energy cost per segment.

**The incremental costs or total energy cost per segment** is the cost per hour to produce all of the energy segments above the economic minimum level. 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 ($/hr) cost.

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:

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

It is important to remember that PJM will dispatch generation based on 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 who owns or controls the generating unit(s) (Unit Owner) 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 therefore 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 Unit Owner of its determination of the request no later than fifteen (15) calendar days after the submission of the request to the PJM MMU. If the Unit Owner and the PJM MMU agree on the determination of the request, the request shall be deemed to be approved.

 If the Unit Owner and the PJM MMU cannot agree on the determination of the request, the Unit Owner may submit its request to PJM in writing for consideration and approval. In its written request to PJM, the Unit Owner 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)***](http://www.pjm.com/documents/~/media/documents/manuals/m10.ashx)
* PJM Manual for ***[Scheduling Operations (M-11)](http://www.pjm.com/documents/~/media/documents/manuals/m11.ashx)***
* PJM Manual for [***Generator Operational Requirements (M-14D)***](http://www.pjm.com/documents/~/media/documents/manuals/m14d.ashx)
* PJM Manual for [***Open Access Transmission Tariff Accounting (M-27)***](http://www.pjm.com/documents/~/media/documents/manuals/m27.ashx)
* PJM Manual for ***[Operating Agreement Accounting (M-28)](http://www.pjm.com/documents/~/media/documents/manuals/m28.ashx)***
* PJM Manual for ***[Definitions and Acronyms (M-35)](http://www.pjm.com/documents/~/media/documents/manuals/m35.ashx)***

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

**Total Heat Rate** - equals the MBTU content of the fuel input divided by the MWh of power output. The smaller the heat rate means the greater the efficiency. The total heat rate can also be referred to as the input-output function. Throughout this manual the term “MMBTU” is defined as millions of BTUs.

**The incremental heat rate** is the relationship between an extra MW of output and the fuel 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 total heat rate curve (input fuel versus MW output).

2.1.1 Heat Rate Policy

 All Unit Owners shall develop total heat rates. These curves show input heat or 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.

* Total heat rate curves will be based on design or comparable unit data modified by actual unit test data (when available).
* Data for the total heat rate curve development, ideally, should include minimum and maximum MW points plus at least two intermediate MW points. The total heat rate curve will be fitted from available data.
* This total 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 predicted ratio of actual to theoretical fuel burn for a particular period. Actual burn may vary from standard burn due to factors such as unit age or modification, changes in fuel properties, seasonal ambient conditions, etc.

The performance factor shall be calculated on either the total fuel consumed or a 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 and/or all of:

* As burned test,
* In stock test,
* As received test,
* As shipped test,
* Contract value,
* Seller's invoice,
* Seller's quote, and
* Nominal value based on Industry Standard
* Any value implied by using primary units of fuel (tons, bbl, gal, etc.) throughout the Performance Factor Calculation, an in the development of Costing Data.

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 **total fuel approach** is used, the performance factor would represent the ratio:

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 **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:

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

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 eFuel.

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. Each company will be responsible for establishing its own method of calculating delivered fossil-fuel cost, limited to inventoried cost, replacement cost, or combination thereof, that reflect the way fuel is actually 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.

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.

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 as stated in the companies' fuel pricing policy (excluding fixed lease expenses).

**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 or fuel input minus the no-load heat or fuel 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 /NOx 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 /NOx 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 time used for determining the projected SO2 /CO2 /NOx 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 /NOx emitted for each particular fuel or fuel mix.

NOx/ CO2 emissions costs will be included in TFRC only during a NOx/ 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 NOx / 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.

**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.](http://www.pjm.com/committees-and-groups/task-forces/cdtf/starvrts.aspx)

**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

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, to run the generating unit at zero MW output. Since generating units cannot normally be run stable at zero net output, the fuel input may be determined by extrapolating the total fuel input-output curve to zero net output. Therefore, No-load fuel consumed shall be the theoretical value of fuel consumed at zero net output from test data or through extrapolation of the theoretical input-output curve. All PJM Members shall use no-load fuel consumed to value to develop no-load costs for their units.



Exhibit 1: Example of a No Load Cost Curve

No-load fuel value shall be the value used to develop no-load costs. The fuel associated with unit no-load may be a theoretical value extrapolated from other unit operating data, or may be the result of a specific test performed to document the no-load fuel consumed. 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

2.5.2 No Load Calculation

**No-Load Cost ($/Hr)** is the No-Load fuel Cost multiplied by the performance factor, multiplied by the (Total Fuel-Related Cost (TFRC)), plus the No-Load Additional Labor Cost.

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

**No-Load Additional Labor Cost** is the additional labor costs in excess of normal station manning requirements for no-load operations.

2.6 Maintenance Cost

***Maintenance cost*** is the servicing by personnel for maintaining equipment and facilities in satisfactory operating condition.

The PJM MMU will review the Maintenance Adders for all units to 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 history for the defined Maintenance Period (See 2.6.3) regardless of unit ownership. 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”.



Exhibit 2: 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
* 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 CDTF 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.

Estimated Year 2011 Total Maintenance

Estimated Year 2011 Equivalent Service Hours

Exhibit 3: Example Calculation of Maintenance Adder for a 10 year Maintenance Period

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

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

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.

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 MW of Regulation*
* *Sub-critical Steam: $3.50 per MW of Regulation*
* *Combined Cycle: $2.50 per MW of Regulation*
* *Combustion Turbine: $2.00 per MW of Regulation*
* *Hydro: $1.00 per MW of Regulation*

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

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.

Margin/Risk Adder:

Shall not exceed $12.00 per MWh of Regulation service provided.

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

 Annual VOM costs to subtract

 = ($3.50 per Regulation MW \* 5,000 MWh) \* 20 years

 = $17,500 per year \* 20 years

 = $350,000

 20-year balance of historical total VOM accounts

 = $10,000,000 - $350,000

 = $ 9,650,000

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 less than 10 years:

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

|  |  |  |
| --- | --- | --- |
| **Unit Operating Mode**  | **Output**  | **Heat Rate**  |
|  |  |  |
| Steam Unit Highest Regulating Operating Load:  | 100 MW  | 9,000 BTU/kWh  |
| Steam Unit Regulation Band:  | 10 MW  |  |
| Lowest Regulating Operating Load  | 40 MW  | 12,500 BTU/kWh  |

|  |  |  |
| --- | --- | --- |
|  |  |  |
| **Base Prices**  |  |  |
|  |  |  |
| Fuel Cost (TFRC):  |  | $1.50/MBTU  |
|  |  |  |
| **Heat Rate Adjustment (Operating Range)** |  |
|  |  |  |
| Unit Base Load Heat Rate Fuel Input =  |  | 9,000 \* 40 / 1000 = 360.0 MBTU/Hr  |
| Unit Reduced Load Heat Rate Fuel Input = |  | 12,500 \* 40 / 1000 = 500.0 MBTU/Hr  |
| Difference =  |  | 140.0 MBTU/Hr  |
|  |  |  |
| **Heat Rate Adjustment (Non Steady-State Operation)** |
| Top Operating Point Heat Rate = |  | 9,000 Btu/kWh |
| Heat Rate Loss Factor =  |  | 0.35% |
| Heat Rate Loss = |  | (9,000\*0.35%) \* 100 MW / (1000 kW/MW) |
|  |  | = 3.15 MBTU/Hr |
|  |  |  |
| **Total Regulation Cost:**  |
|  |  |  |
| (a) Heat Rate Adjustment (Operating Range) |  |
| Fuel Cost Adder – Operating Range = |  | 140.0 MBTU/Hr \* $1.50/MBTU / 60 MW Operation Band  |
|  |  | = $3.50/Hr/MW of Regulation  |
|  |  |  |
| (b)Heat Rate Adjustment (Non Steady-State Operation) |
| Fuel Cost Adder–Non Steady-State Operation  | = 3.15 MBTU/Hr \* $1.50 MBTU / 10 MW Regulation Band |
|  |  | = $0.47/Hr/MW of Regulation |
|  |  |  |
| (c) VOM Adder  |  |  |
| Regulation VOM Adder  |  | $3.50/Hr/MW of Regulation (for a Steam Unit) |
|  |  |  |
| (d) Margin/Risk Adder  |  |  |
| Margin/Risk Adder =  |  | $12.00/Hr/MW of Regulation  |
|  |  |  |
| **Total Regulation Cost**  |  |  |
| Total Regulation Cost =  |  | (a) Fuel Cost Adder (Operating Range) + (b) Fuel Cost Adder (Non Steady-State Operation) + (c) VOM Adder + (d) Margin/Risk Adder  |
| Total Regulation Cost =  |  | $3.50 + $0.47 +3.50+ $12.00  |
| Total Regulation Cost =  |  | $19.47/Hr/MW of Regulation  |

Exhibit 6: Regulation Maximum AllowableCost Adder Example

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](http://en.wikipedia.org/wiki/Nuclear_reaction) to heat pressurized water to produce steam that drives steam turbines generators.

**Nuclear Units** are units within a nuclear plant with similar ratings and conditions at the same site location.

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.

3.3.2 Total Fuel-Related Costs for Nuclear Units

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 nor 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 512 and 513 for fossil steam units and FERC Accounts 530 and 531 for nuclear steam units.

3.6.1Configuration 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 NOx burner).

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
* Upgrade of turbines
* Turbine Inlet Air Cooling

Turbine overhauls or inspections, testing, and nuclear re-fueling

* 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.

Calculate total fuel cost for the maintenance period.

These allow for the calculation of the maintenance adder: 

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.

…

This formula calculates the total number of starts:

These allow for the calculation of the start maintenance adder:

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.

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

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.

**Fossil Steam Units** are units with similar ratings and steam conditions at the same site location.

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](#_Hlk260219247) plus incremental expenses for fuel treatment and pollution control (excluding SO2 and NOX 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 NOX emission allowance costs.

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.

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 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 derivedfrom FERC Accounts 512 and 513 for fossil steam units and FERC Accounts 530 and 531 for nuclear steam units.

**Notes:**

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

Units with less than 7 years of history are considered immature. Such units can be assigned their calculated Maintenance Adder and/or Start Cost Maintenance Adder, or a forecast values, subject to evaluation pursuant to the Cost and Methodology Approval Process.

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.

Calculate total fuel cost for the maintenance period.

These allow for the calculation of the maintenance adder:

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.

This formula calculates the total number of starts:

These allow for the calculation of the start maintenance adder:

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 NOx burner).

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

* Installation of Flue Gas Desulfurization (FGD or scrubber) systems
* Activated Carbon Injection (ACI) or other sorbent injection systems
* Installation of SCR or SNCR NOx removal systems
* Conversion from open loop to closed loop circulation water systems
* Bag House addition
* Water injection for NOx control
* Turbine Inlet Air Cooling
* The specific system or unit configuration system change needs to be reviewed by 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.

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

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.

4.6.3 Reductions in Total Maintenance Costs:

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

4.7 Synchronized Reserve

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

Total costs to provide Tier 2 Synchronized reserve from a steam unit shall include the following components:

**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/MBTU |
| Steam Unit Reduced Load Heat Input = | 9,500 \* 70 /1000 = 665 MBTU/Hr |
| Heat Rate VOM Penalty = | ($0.5278/MBTU - $0.50/MBTU) \* 665 MBTU/Hr = $18.487/Hr |
| Synchronized Reserve VOM Adder = | $18.487/Hr / (100 MW – 70 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 has a steam-to-heat 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:

TFRC = Total Fuel Related Cost



**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** rate 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).

Combustion Turbine and Combined Cycle Plant major inspection and overhaul costs categories include but are not limited to the following:

* Combustion Turbine Generator Inlet Air System
* Inlet Air Filter Replacement
* Evaporative cooling system media replacement
* Mechanical inlet air cooling chiller and pump inspection and overhaul
* Fuel System
* Fuel Gas Compressors Inspection and Overhaul
* Distillate Fuel Pumps Inspection and Overhaul
* Water Treatment
* Resin Replacement
* RO Cartridges Replacement
* Environmental
* SCR and/or CO Reduction Catalyst Replacement
* Combustion Turbine Generator ("CTG")
* Combustion Inspections including Parts, Labor, Rentals and Specialized technical expertise and support
* Hot Gas Path Inspection including Parts, Labor, Rentals and Specialized technical expertise and support
* Major Overhauls including Parts, Labor, Rentals and Specialized technical expertise and support
* Electric Generator Inspection and Overhaul including Parts, Labor, Rentals and Specialized technical expertise and support
* Heat Recovery Steam Generator ("HRSG")
* Chemical Cleaning or Hydro-Blasting of Heat Transfer Surfaces
* BFW Pump Inspection and Overhaul
* Heat Transfer Surface Replacements
* Casing Repair and Replacements
* Steam Turbine Generator ("STG") Major Overhaul including Parts, Labor, Rentals and Specialized technical expertise and support
* Surface Condenser
* Chemical Cleaning or Hydro-Blasting of Heat Transfer Surfaces
* Condensate Pump Inspection and Overhaul
* Heat Transfer Surface Replacements
* Cooling Tower
* Circulation Pump Inspection and Overhaul
* Cooling Tower Fan Motor and Gearbox Inspection and Overhaul
* Replacement of Cooling Tower Fill and Drift Eliminators

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** - Combustion Turbine and Combined Cycle Plant major inspection and overhaul expenses may be included in variable maintenance expenses regardless of accounting methodology if they meet specific criteria.

In order to be included in variable maintenance expenses, these costs must represent actual expenditures that are due to incremental degradation of generating equipment directly related to generation, starts or a combination of both. Expenditures that are not directly related to such operation may not be included in variable maintenance expense. It must be clear that these costs would have been included in the appropriate FERC Accounts as described in this section. A detailed listing of all proposed long-term maintenance costs must be submitted to the PJM MMU for evaluation and final approval pursuant to the Cost and Methodology Approval Process.

Long Term Maintenance Expenses cannot be counted if they are included elsewhere in VOM.

Combustion Turbine and Combined Cycle Plant major inspection and overhaul costs categories include but are not limited to the following:

* Combustion Turbine Generator Inlet Air System
* Inlet Air Filter Replacement
* Evaporative cooling system media replacement
* Mechanical inlet air cooling chiller and pump inspection and overhaul
* Fuel System
* Fuel Gas Compressors Inspection and Overhaul
* Distillate Fuel Pumps Inspection and Overhaul
* Water Treatment
* Resin Replacement
* RO Cartridges Replacement
* Environmental
* SCR and/or CO Reduction Catalyst Replacement
* Combustion Turbine Generator ("CTG")
* Combustion Inspections including Parts, Labor, Rentals and Specialized technical expertise and support
* Hot Gas Path Inspection
* Major Overhaul
* Electric Generator Inspection and Overhaul
* Heat Recovery Steam Generator ("HRSG")
* Chemical Cleaning or Hydro-Blasting of Heat Transfer Surfaces
* BFW Pump Inspection and Overhaul
* Heat Transfer Surface Replacements
* Casing Repair and Replacements
* Steam Turbine Generator ("STG")
* Surface Condenser
* Condensate Pump Inspection and Overhaul
* Cooling Tower
* Circulation Pump Inspection and Overhaul
* Cooling Tower Fan Motor and Gearbox Inspection and Overhaul
* Replacement of Cooling Tower Fill and Drift Eliminators

5.6.3 Equivalent service hours (ESH)

The estimated hours the unit will run based on history.

Where:

A =Cyclic starting factor (A = 5.0 for aircraft - type CT's; A = 10.0 for industrial - type CT's)

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.

B = Cyclic peaking factor (B = 3.0 for all CT's)

This 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.

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.

**Note:**

1. Units with less than seven years of history are considered immature. Such units can be assigned either their calculated Equivalent Hourly Maintenance Cost, or a forecast value, subject to evaluation pursuant to the Cost and Methodology Approval Process.
2. If any unit in a block is at least seven years old, then all like units on the block may be considered mature.

5.7 Synchronized Reserve

**Note:** The information in Section 2.7 contains basic Synchronized Reserve information relevant for all unit types including combined cycle units.

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. It is typically used for peak shaving operations due to quick response capability.

**Diesel Engine -** A generating unit in which a natural gas or oil fired diesel reciprocating engine is the prime mover for an electrical generator. It is typically used for peak shaving operations due to quick response capability. It does not include station service costs in its operating costs.

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 MMBTU/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.

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 NOX 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



**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 non-regenerative combustion turbines and diesel units shall include only the following components:

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.

Starting Maintenance Cost, please see section 2.6

**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** - A device in which air is compressed and a gaseous or liquid fuel is ignited. The combustion products expand directly through the blades in a turbine to drive an electric generator.

**Aircraft - Type Combustion Turbine** - A generator is driven by a free turbine. Hot exhaust gases from one or more engines are used to Synchronized Reserve the free turbine.

**Diesel - Maintenance Adder** - The total dollars from FERC Account 553 divided by total fuel burned (in MBTUs or other unit of fuel).

**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 and Combined Cycle Plant major inspection and overhaul expenses may be included in variable maintenance expenses regardless of accounting methodology if they meet specific criteria.

In order to be included in variable maintenance expenses, these costs must represent actual expenditures that are due to incremental degradation of generating equipment directly related to generation, starts or a combination of both. Expenditures that are not directly related to such operation may not be included in variable maintenance expense. It must be clear that these costs would have been included in the appropriate FERC Accounts as described in this section. A detailed listing of all proposed long-term maintenance costs must be submitted to the PJM MMU for evaluation and final approval pursuant to the Cost and Methodology Approval Process.

Combustion Turbine and Combined Cycle Plant major inspection and overhaul costs categories include but are not limited to the following:

* Combustion Turbine Generator Inlet Air System
* Inlet Air Filter Replacement
* Evaporative cooling system media replacement
* Mechanical inlet air cooling chiller and pump inspection and overhaul
* Fuel System
* Fuel Gas Compressors Inspection and Overhaul
* Distillate Fuel Pumps Inspection and Overhaul
* Water Treatment
* Resin Replacement
* RO Cartridges Replacement
* Environmental
* SCR and/or CO Reduction Catalyst Replacement
* Combustion Turbine Generator ("CTG")
* Combustion Inspections including Parts, Labor, Rentals and Specialized technical expertise and support
* Hot Gas Path Inspection
* Major Overhaul
* Electric Generator Inspection and Overhaul
* Cooling Tower
* Circulation Pump Inspection and Overhaul
* Cooling Tower Fan Motor and Gearbox Inspection and Overhaul
* Replacement of Cooling Tower Fill and Drift Eliminators

 (Industrial Unit)

|  |  |
| --- | --- |
| Peak Hours y = 200 Hrs. |  |
| Service Hours Z = 2000 Hrs. (Total Base Peak Hours) |
| No. of Starts = 300Peak Pickup = 5 MW |

Calculation

TMD = $100,000 (Actual historical maintenance data escalated to present value).

A = 10, B = 3 (Note: A = 5 for aircraft engine CT's).



Calculation of maintenance rates







Exhibit 14: Combustion Turbine Maintenance Cost Adder Example

6.6.1 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.

6.6.2 Equivalent service hours (ESH)

The estimated hours the unit will run based on history.

Where:

A =Cyclic starting factor (A = 5.0 for aircraft - type CT's; A = 10.0 for industrial - type CT's)

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.

B = Cyclic peaking factor (B = 3.0 for all CT's)

This 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.

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.

**Note:**

1. Units with less than seven years of history are considered immature. Such units can be assigned either their calculated Equivalent Hourly Maintenance Cost, or a forecast value, subject to evaluation pursuant to the Cost and Methodology Approval Process.
2. If any unit in a block is at least seven years old, then all like units on the block may be considered mature.

6.6.3 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.

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 two MWh of pumping load to pump 1,000 ft3 of water from the sink to the pond. The resultant efficiency is:

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

**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:

7.3.1Total Fuel-Related Costs for Pumped Storage Hydro Plant Generation

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

7.4 Start Cost

Hydro Units have no 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:

**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 supply-side and demand-side facilities and/or actions.

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

Currently there are no cost rules for DSR cost except for the DSR margin adders. The cost to provide synchronous reserves from DSR resources shall equal the margin up to $7.50 per MWh of reserves provided.

Section 9: Opportunity Cost Guidelines

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

Specific business rules for Opportunity Costs have been defined in the PJM Operating Agreement for various products including energy and Regulation.

Attachment A: Applicable FERC System of Accounts

The information included in this Attachment B 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

1. Invoice price of fuel less any cash or other discounts.
2. Freight, switching, demurrage and other transportation charges, not including, however, any charges for unloading from the shipping medium.
3. Excise taxes, purchasing agents’ commissions, insurance and other expenses directly assignable to cost of fuel.
4. 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.
5. 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

1. 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.
2. 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 on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.

Items

Labor:

1. Supervising purchasing and handling of fuel.
2. All routine fuel analysis.
3. Unloading from shipping facility and putting in storage.
4. Moving of fuel in storage and transferring fuel from one station to another.
5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler-house structure.
6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.

Materials and expenses:

1. 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).
2. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).
3. Cost of fuel including freight, switching, demurrage and other transportation charges.
4. Excise taxes, insurance, purchasing commissions and similar items.
5. Stores expense to extent applicable to fuel.
6. Transportation and other expenses in moving fuel in storage.
7. Tools, lubricants and other supplies.
8. Operating supplies for mechanical equipment.
9. 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)

1. 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)
2. 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:
	1. Inlet flange of throttle valve on prime mover.
	2. Flange of all steam extraction lines on prime mover.
	3. Hotwell pump outlet on condensate lines.
	4. Inlet flange of all turbine-room auxiliaries.
	5. 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.3.1and 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)

1. 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.
2. This account shall also include the costs involved when fuel is leased.
3. This account shall also include the cost of other fuels, used for ancillary steam facilities, including superheat.
4. 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

1. 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.
2. Materials recovered in connection with the maintenance of property shall be credited to the same account to which the maintenance cost was charged.
3. If the book cost of any property is carried in Account 102, Electric Plant Purchased or Sold, the cost of maintaining such property shall be charged to the accounts for maintenance of property of the same class and use, the book cost of which is carried in other electric plant in service accounts. Maintenance of property leased from others shall be treated as provided in operating expense instruction 3.

Items

1. Direct field supervision of maintenance.
2. 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 which have been made.
3. Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life of plant.
4. Rearranging and changing the location of plant not retired.
5. Repairing for reuse materials recovered from plant.
6. Testing for locating and clearing trouble.
7. Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in service.
8. 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

1. 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.
2. 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.
3. 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.
4. 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

Revision History

Revision 14 (6/1/2010):

Section 5: Updated Chronology of Maintenance Adder Escalation Index Numbers for the year 2010.

Revision 13 (5/7/2010):

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 5 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 CDTF 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.