Proposed Revisions To Incorporate Soak Time Parameter
12/19/2019 Markets and Reliability Committee Meeting

Tariff, Section 1 and Operating Agreement, Section 1 (New Definitions)

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after the generating unit is dispatchable ~~generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero,~~ to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the generating unit is dispatchable to the time of ~~the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and~~ the last generator breaker opening, as measured by PJM's State Estimator.

Cold/~~Warm~~Intermediate/Hot Soak Time

For all generating units that are not combined cycle units, "Cold/Warm/Hot Soak Time" shall mean the minimum number of hours a generating unit must run in its cold/warm/hot temperature state during real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time the unit is dispatchable. For combined cycle units, "Cold/Warm/Hot Soak Time" shall mean the minimum number of hours in its cold/~~warm~~intermediate/hot temperature state from the time immediately after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the time the unit is dispatchable.

Cold/Intermediate/Hot Soak Costs:

"Soak Costs" shall mean the unit costs to bring the boiler, turbine and generator from the point after first breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero to the point when the unit is dispatchable. Soak Costs are determined based on the cost of soak fuel, total fuel-related cost, performance factor, maintenance adder, and operating costs. Soak Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate, and cold.

Soak Output Profile

"Soak Output Profile" shall mean the unit's non-zero MWh per hour that the unit is expected to produce while the unit is operating during the Soak Time. Soak Output Profiles can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate, and cold.

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time, Soak Time, and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources), Soak Costs, and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Tariff, Attachment K-Appendix and Operating Agreement, Schedule 1

1.7.4 General Obligations of the Market Participants.

(j) To the extent as generating facility submits Soak Costs, a Market Participant shall submit a Soak Output Profile in the Day-Ahead and Real-time Energy Market calculated as specified in Schedule 2 of the Operating Agreement and the PJM Manuals.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based Start-up Costs, Soak Costs, and No-load Costs may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit ~~both~~ Start-up Costs, Soak Costs, and No-load Costs on either a market basis or a cost basis and any such election shall be submitted on or before March 31 for the period of April 1 through September 30, and on or before September 30 for the period October 1 through March 31. The election of market-based or cost-based Start-up Costs, Soak Costs, and No-load Costs shall remain in effect without change throughout the applicable periods.

> (i) If a Market Seller chooses to submit market-based Start-up Costs, Soak Costs, and No-load Costs, such Market Seller, in its Offer Data, shall submit the level of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends to request such fees. The Office of the Interconnection shall reject any request for Start-up Costs, Soak Costs, and No-load Costs in a Market Seller's Offer Data that does not conform to the Market Seller's specification on file with the Office of the Interconnection.

(ii) If a Market Seller chooses to submit cost-based Start-up Costs, Soak Costs, and No-load Costs, such fees must be calculated as specified in the PJM Manuals and the Market Seller may change ~~both~~ cost-based fees hourly and must change both fees as the associated costs change, but no more frequently than daily. If a Market Sellers chooses to submit cost-based Soak Costs, the Soak Output Profile for the cost-based and market based offers shall be calculated as specified in Schedule 2 of the Operating Agreement and the PJM Manuals.

1.10 Scheduling.

1.10.1 A Day-ahead Energy Market Scheduling.

(d)

The foregoing offers:

i) i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) Maximum Run Time; (3) Start-up Costs; (4) Soak Costs; (~~4~~5) No-load Costs; (~~5~~6) Incremental Energy Offer; (~~5~~7) Notification Time; (~~7~~8) availability; (~~8~~9) ramp rate; (~~9~~10) Economic Minimum; (~~10~~11) Economic Maximum; (~~11~~12) emergency minimum MW; and (~~12~~13) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour; and

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour; and

x) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

viii) Shall not exceed a Soak Cost of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer Soak Cost is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer Soak Cost must be less than or equal to the cost-based offer Soak Cost; and (2) when a Market Seller's cost-based offer Soak Cost is greater than $2,000/megawatt-hour, then its market-based offer Soak Cost must be less than or equal to $2,000/megawatt-hour.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs, Soak Costs, and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.2 Pool-scheduled Resources.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, Soak Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs, Soak Costs, and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs, Soak Costs, and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

1.10.4 Capacity Resources.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs, Soak Costs, or No-load Costs.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs, Soak Costs, and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, Soak Costs, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9 B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3)cost-based Soak Costs; (~~3~~4) Incremental Energy Offer; (~~4~~5) Economic Minimum and Economic Maximum; (~~5~~6) emergency minimum MW and emergency maximum

MW; and (~~6~~7) for Real-time Offers only, (i) notification time, and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable Start-up Costs, Soak Costs, ~~or~~ No-load Costs or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit Start-up Costs, Soak Costs, and No-load ~~values~~ Costs of a generating unit for consideration in calculation of the Operating Reserve Credit shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.
(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit Start-up Costs, Soak Costs, and No-load ~~values~~ Costs of a generating unit for consideration in calculation of the Operating Reserve Credit shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

3.2.3 Operating Reserves

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following *S*egments: 1) the greater of their day-ahead schedules or scheduled Soak Time plus ~~minimum~~ Minimum ~~run~~ Run ~~time~~ Time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or scheduled Soak time plus M~~m~~inimum ~~run~~ Run ~~time~~ Time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two *S*egments for each resource. Segment 1 will be the greater of the day-ahead schedule and scheduled Soak Time plus ~~minimum~~ Minimum ~~run~~ Run ~~time~~ Time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

. . . .

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for Start-up Costs, Soak Costs, and No-load ~~fees~~Costs. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh *and greater than the Market Seller's lowest available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the scheduled Soak Time and ~~minimum~~ Minimum ~~run~~ Run ~~time~~ Time or other operating constraint of the unit, and (iii) for any unit with a scheduled Soak Time plus ~~minimum~~ Minimum ~~run~~ Run ~~time~~ Time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) sum of the Soak Time and the Minimum Run Time hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(r) Market Sellers that incur Incremental Energy or Soak Costs ~~operating costs~~ for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of Incremental Energy or Soak Costs ~~cost~~ greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

(o) Units that choose the cost-based option for Soak Costs per section 1.7.4 will be considered following dispatch during their submitted Soak Time. Units that choose the price-based option for Soak Costs per section 1.7.4 will be considered to be not following dispatch when both(i) their price-based soak MW profile is not equal to the cost-based soak MW profile and (ii) their total Real Time soak MWh are greater than 110% of the submitted total soak MWH or less than 90% of the submitted total soak MWh and will be subject to balancing Operating Reserve Deviation charges. Deviations will be charged on a five minute interval basis based on Real Time settlement interval MW minus Day Ahead MW profile.

6.4 Offer Price Caps - 6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest overall system production cost. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost, Soak Costs, or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(g) In the Real-time Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at the time of commitment, where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Startup Cost [$] + Soak Cost [$/MWh] * Soak Output Profile [MWh]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or the sum of the Soak Time plus the Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

6.4 Offer Price Caps - 6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(ii) For offers of $2,000/MWh or less, the incremental Offer and Soak Cost ~~operating costs~~ of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus up to the lesser of 10% of such costs or $100 MWh, the sum of which shall not exceed $2,000/MWh; and, for offers greater than $2,000/MWh, the Incremental Offer and Soak c~~C~~ost of the generation resource;

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(c) If a Market Seller submits a cost-based energy offer for a generation resource that includes a Soak Cost greater than $1,000/megawatt-hour, then, the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Soak Cost component of such cost-based offer. The Office of the Interconnection shall evaluate whether such offer exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Soak Cost in accordance with the following formula:

Maximum Allowable Soak Cost ($/MWh) = Soak Heat Rate x Performance Factor x Fuel Cost x (1+A)

Where:

Soak Heat Rate = Ration of the amount of fuel needed in MMBtu during the Soak Time divided by the amount of energy produced in MWh during the Soak Time.

Performance Factor = A scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost in dollars per MMBtu as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(b) For the 2014/2015 through 2017/2018 Delivery Years, parameter limited schedules shall be defined for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts~~.~~;

(vi) Soak Time.

For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources during Hot Weather Alerts, Emergency Actions during hot weather operations, and when the resource is offer capped to maintain system reliability as a result of limits on transmission capability per Section 6.4 hereof, and for the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources during Hot Weather Alerts, Cold Weather Alerts, Emergency Actions, and when the resource is offer capped to maintain system reliability as a result of limits on transmission capability per Section 6.4 hereof, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual resource on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; ~~and~~

(viii) Notification Time and

(ix) Soak Time.

(c) For the 2014/2015 through 2017/2018 Delivery Years, the following table specifies default parameter limited schedule values, by technology type, for generating units, no portion of which is committed as a Capacity Performance Resource:

Parameter Limited Schedule Matrix

Parameter	Minimum Down Time (Hrs)	Minimum Run plus Soak Time (Hrs)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio = Economic Maximum MW / Economic Minimum MW
Small Frame CT and Aero CT Units - Up to 29 MW ICAP	2.0 or Less	2.0 or Less	2 or More	14 or More	1.0 or More
Medium Frame CT and Aero CT Units - 30 MW to 65 MW ICAP	2.0 or Less	3.0 or Less	2 or More	14 or More	1.0 or More
Medium-Large Frame CT Units - 65 MW to 135 MW ICAP	3.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Large Frame CT Units - 135 MW to 180 MW ICAP	4.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Combined Cycle Units	4.0 or Less	6.0 or Less	2 or More	11 or More	1.5 or More
Petroleum and Natural Gas Steam Units - Pre-1985	7.0 or Less	8.0 or Less	1 or More	7 or More	3.0 or More
Petroleum and Natural Gas Steam Units - Post-1985	3.5 or Less	5.5 or Less	2 or More	11 or More	2.0 or More
Sub-Critical Coal Units	9.0 or Less	15.0 or Less	1 or More	5 or More	2.0 or More
Super-Critical Coal Units	84.0	24.0 or Less	1 or More	2 or More	1.5 or More

Tariff, Schedule 6A

Testing

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13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's Soak Time (if applicable) and M~~m~~inimum R~~r~~un T~~t~~ime at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

Operating Agreement, Schedule 2

1.3 Application of Cost Components to Three-Part Cost-based Offers.

A cost-based offer, as defined in Operating Agreement, Schedule 1, section 1.2, is a ~~three~~four-part offer consisting of Start-up Costs, Soak Costs, No-load Costs, and the Incremental Energy Offer. These terms are as defined in Operating Agreement, section 1.

The following lists the categories of cost that may be applicable to a Market Participant's four part cost-based offer:

(a) For Start-up Costs

Fuel cost

Emission allowances/adders

Maintenance Adders

Operating Costs

Labor costs

(b) For Soak Costs

Fuel cost

Emission allowances/adders

Maintenance Adders

Operating Costs

(~~b~~c) For No-load Costs

Fuel cost

Emission allowances/adders

Maintenance Adders

Operating Costs

(~~c~~d) Incremental Costs in Incremental Energy Offers

Fuel cost

Emission allowances/adders

Maintenance Adders

Operating Costs

Opportunity Costs

2.5 Information Required To Be Included In Fuel Cost Policies.

(a) Each Market Seller shall include in its Fuel Cost Policy the following information, as further described in the applicable provisions of PJM Manual 15:

(i) For all Fuel Cost Policies, regardless of fuel type, the Market Seller shall provide a detailed explanation of the Market Seller's established method of calculating fuel costs, indicating whether fuel purchases are subject to a contract price and/or spot pricing, and specifying how it is determined which of the contract prices and/or spot market prices to use. The Market Seller shall include its method for determining commodity, handling and transportation costs.

(ii) For Fuel Cost Policies applicable to generation resources using a fuel source other than natural gas, the Market Seller shall adhere to the following guidelines:

1. Fuel costs for solar, Energy Storage Resources and run-of-river hydro resources shall be zero.

2. Fuel costs for nuclear resources shall not include in-service interest charges whether related to fuel that is leased or capitalized.

3. For Pumped Storage Hydro resources, fuel cost shall be determined based on the amount of energy necessary to pump from the lower reservoir to the upper reservoir.

4. For wind resources, the Market Seller shall identify how it accounts for renewable energy credits and production tax credits.

5. For solid waste, bio-mass and landfill gas resources, the Market Seller shall include the costs of such fuels even when the cost is negative.

(iii) Market Sellers shall report, for all of the generation resource's operating modes, fuels, and at various operating temperatures, the incremental, no load, soak, and start heat requirements, the method of developing heat inputs, and the frequency of updating heat inputs.

(iv) A Fuel Cost Policy shall include any applicable unit specific performance factors, and the method used to determine them, which may be modified seasonally to reflect ambient conditions.

(v) A Fuel Cost Policy shall include the cost-based Start Cost calculation for the generation resource, and identify for each temperature state the starting fuel (MMBtu), station service (MWh), start Maintenance Adder, and any Start Additional Labor Cost.

vi) A Fuel Cost Policy shall include any other incremental operating costs included in a Market Seller's cost-based offer for a resource, including but not limited to the consumables used for operation and the marginal value of costs in terms of dollars per MWh or dollars per unit of fuel, along with all applicable descriptions, calculation methodologies associated with such costs, and frequency of updating such costs.

vii) A Fuel Cost Policy shall include the cost-based Soak Cost calculation for the generation resource, and identify for each temperature state the soaking fuel (MMBtu) and Soak Output Profile (MWh).