5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

2. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the

LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

3. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or B) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.

If the Sell Offer is submitted consistent with the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

(ii) in the subsequent two BRAs, if the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA. If the Resource does not clear, it shall be deemed resubmitted at the highest price per MW at which the Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and it shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer that is entitled to compensation for such first year pursuant to section 5.14(b) of this Attachment. The Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect such resubmission. In such case, the Resource submitted under this provision shall be paid for the entire committed quantity the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer Price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

4) On or before October 1, 2011, PJM shall file with FERC under FPA section 205 revisions to this section 5.14(c) as determined necessary by PJM following a stakeholder process, to address concerns expressed by some parties that this provision in its current form may not provide adequate long-term revenue assurances to support new entry. Any such changes also shall honor concerns expressed by FERC and others that any such revisions must not lead to undue price discrimination between existing and new resources.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located;

and 4) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to

determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2014, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT") and a combined cycle generator ("CC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	138,646	128,226	131,681	128,226	128,340
CC $/MW-yr	175,250	154,870	164,375	154,870	154,870

(2) Beginning with the Delivery Year that begins on June 1, 2015, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.980 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, or submitted in any Base Residual Auction up to and including the second successive Base Residual Auction after the Base Residual Auction in which such resource first clears, in any LDA for which a separate VRR Curve has been established, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry

for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from FERC described in subsection (5) hereof

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted if the Capacity Market Seller submits to FERC a filing under section 206 of the Federal Power Act sufficiently in advance of the Base Residual Auction to obtain a determination from FERC, and in fact obtains a determination from FERC prior to such auction, that such Sell Offer is permissible because it is either (A) consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets, and the resource received no out-of-market payments); or (B) the Sell Offer is based on new entry that is pursuant to a state-mandated requirement that furthers a specific legitimate state objective and that the Sell Offer would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area.

(i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

  - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

  - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures (“CapEx”) for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 16 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources or ILR that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. In addition, for Delivery Years through May 31, 2012, resources qualifying under the criteria set forth below may be certified as ILR on behalf of a Party that has not elected the FRR Alternative for a Delivery Year no later than three months prior to the first day of such Delivery Year; provided, however, that for the 2011-2012 Delivery Year only, the ILR certification deadline shall be no later than two months prior to the first day of such Delivery Year. Qualified Demand Resources and ILR generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section H and the PJM Manuals. Qualified Demand Resources and ILR may be provided by a Demand Resource Provider or ILR Provider (hereinafter, "Provider"), notwithstanding that such Provider is not a Party to this Agreement. Such Providers must satisfy the requirements in section I and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section G of this schedule as applicable, the Office of the Interconnection of the Demand Resource or ILR that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is an ILR resource, a Limited Demand Resource, an Extended Summer Demand Resource or an Annual Demand Resource.

2. A period of no more than 2 hours prior notification must apply to interruptible customers.

3. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

5. An entity offering for sale, designating for self-supply, or including in any FRR Capacity Plan any Planned Demand Resource must demonstrate, in accordance with standards and procedures set forth in the PJM Manuals, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. Providers of Planned Demand Resources must provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to a Base Residual Auction or Incremental Auction. PJM may verify the Provider's adherence to the timetable at any time.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response program and thus available for dispatch during PJM-declared emergency events.

B. The Unforced Capacity value of a Demand Resource and ILR will be determined as:

the product of the Nominated Value of the Demand Resource, or the Nominated Value of the ILR, times the DR Factor, times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections J and K, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR, divided by the total Nominated Value of Demand Resources and ILR in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources and ILR, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. Certified ILR resources shall receive the Final Zonal ILR Price.

E. The Party, Electric Distributor, Demand Resource Provider, or ILR Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in sections C and D for a committed Demand Resource or certified ILR, notwithstanding that such provider is not the customer's energy supplier.

F. Any Party hereto shall demonstrate that its Demand Resources or ILR performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section L and the PJM Manuals. In addition, committed Demand Resources and certified ILR that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

G. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

H. PJM recognizes three types of Demand Resource and ILR:

Direct Load Control (DLC) – Load management that is initiated directly by the Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – Demand Resource or ILR which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

I. Each Provider must satisfy (or contract with another LSE, Provider, or EDC to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- supplemental status reports, detailing Demand Resources and ILR available, as requested by PJM;

- Entry of customer-specific Demand Resource and ILR credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource or ILR event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource or ILR events, prepared in accordance with the PJM Manuals.

J. The Nominated Value of each Demand Resource or ILR shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource or ILR information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections K and L.

K. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource or ILR information, to verify the amount of load management available, and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource, or certification of such resource as ILR. Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. The process establishes potential under/over compliance values for the Provider. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event.

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period. Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent. Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance is checked on an individual customer basis for GLD, by comparing actual load dropped during the event to the nominated amount of load drop. Providers must submit actual loads and comparison loads for the compliance hours. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the full hours of a load management event, for each customer or DLC program dispatched by the Office of the Interconnection. Demand Resource or ILR resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed and ILR Certified by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

M. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption *at the End-Use Customer's retail site* that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine,

upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.