COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))	Case No. 2022-00372

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on May 10, 2023 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on May 10, 2023 in this proceeding;

- A written log listing, inter alia, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on May 10, 2023.

A copy of this Notice, the certification of the digital video record, and hearing log have been served upon all persons listed at the end of this Notice. Parties desiring to view the digital video recording of the hearing may do so at https://youtu.be/uhfaXKiFXlE.

Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 19th day of July 2023.

Linda C. Bridwell
Executive Director
Public Service Commission of Kentucky

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CERTIFICATION

I, Candace H. Sacre, hereby certify that:

1. The attached flash drive contains a digital recording of the Formal Hearing conducted in the above-styled proceeding on May 10, 2023. The Formal Hearing Log, Exhibits, and Exhibit List are included with the recording on May 10, 2023;

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the Formal Hearing of May 10, 2023; and

4. The Formal Hearing Log attached to this Certificate accurately and correctly states the events that occurred at the Formal Hearing of May 10, 2023, and the time at which each occurred.

Signed this 30th day of June, 2023.

Candace H. Sacre
Candace H. Sacre
Administrative Specialist III

Stephanie Schweighardt
Stephanie Schweighardt
Kentucky State at Large ID# KYNP 64180
Commission Expires: January 14, 2027

Date:	Type:	Location:	Department:
5/10/2023	Public Hearing\Public Comments	Hearing Room 1	Hearing Room 1 (HR 1)

Witness: Christopher Bauer; Justin Beiber; Jacob Colley; Michael Geers; Jeremy Gibson; Cory Gordon; Paul Halstead; Thomas Heath; Retha Hunsicker; Max McClellan; Dominic Melillo; Paul Normand; Joshua Nowak; John Panizza; Lisa Quilici; Jeffrey Setser; Lisa Steinkuhl; Jacob Stewart; John Swez; Danielle Weatherston; James Ziolkowski
Judge: Kent Chandler; Angie Hatton; Mary Pat Regan
Clerk: Candace Sacre

Event Time	Log Event	
9:08:27 AM	Session Started	
9:08:30 AM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
9:08:48 AM	Chairman Chandler	
	Note: Sacre, Candace	Witness rescheduling. (Click on link for further comments.)
9:09:22 AM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
9:09:27 AM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	John Swez.
9:09:37 AM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
9:09:43 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Examination. Name and address?
9:09:59 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Direct Examination. Position with company?
9:10:09 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Cause to file direct, rebuttal, and responses?
9:10:16 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Adopting any other data requests?
9:10:22 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Which one is that?
9:10:33 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Please identify who sponsored response?
9:10:49 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Changes or corrections?
9:10:54 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Asked same questions, answers be same?
9:11:01 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Intention information be admitted into record?
9:11:11 AM	Chairman Chandler	
	Note: Sacre, Candace	Counsel for AG?
9:11:17 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Cross Examination. Discussed PJM issues with Clark, deferred questions to you, Duke Kentucky advised PJM potential retirement date 2035 for East Bend?
9:11:43 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Planning to advise PJM this year or near future?
9:11:56 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	When say not unless asked, mean if PJM asks?

9:12:21 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Routine for PJM to ask for retirement dates?
9:12:33 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Have response to AG Second, question 15?
9:12:43 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Review it while everyone else has chance to get there?
9:13:11 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	AG asks if PJM requested East Bend stay open past 2035, how impact Duke Kentucky decision keep open or close generating plant?
9:13:29 AM	Chairman Chandler	
	Note: Sacre, Candace	Technical difficulties, recess.
9:16:54 AM	Session Paused	
9:20:19 AM	Session Resumed	
9:20:45 AM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
9:20:54 AM	Chairman Chandler	
	Note: Sacre, Candace	Continue cross examination?
9:21:00 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Cross Examination (cont'd). Looking at response to AG Second Request, question 15, AG asked if PJM requested East Bend stay open past 2035, in response state, in reading (click on link for further comments), when state desired deactivation date is that retirement date?
9:21:54 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Provide three potential outcomes?
9:21:59 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Read into record second outcome?
9:22:37 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Have experience with PJM reliability must-run contracts?
9:22:56 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Know if Duke Kentucky entered into reliability must-run contract with PJM?
9:23:03 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Know if any Duke affiliates or parent company entered into reliability must-run contracts with PJM?
9:23:21 AM	Asst Atty General Goad - witness Swez	
	Note: Sacre, Candace	Any additional information concerning PJM reliability must-run contracts?
9:23:37 AM	Chairman Chandler	
	Note: Sacre, Candace	Sierra Club?
9:23:46 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Cross Examination. PJM coordinates movement wholesale electricity in a multi-state region?
9:23:56 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	PJM operates two energy markets?
9:24:07 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	One is day ahead market?
9:24:11 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Day ahead market, PJM schedules generators meet load on day ahead basis?
9:24:19 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Market balances supply and demand by continuously matching bids with orders buy power?

9:24:37 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	All bids supply stacked from lowest to highest, accepted in order until all demands for power met?
9:25:16 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	At each location called node or buff, market price from minimizing bid production cost is marginal cost provide one more megawatt of energy to that location?
9:25:37 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Market price is known as location marginal price or LMP?
9:25:44 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Every electricity supplier paid price highest accepted bid or offer?
9:26:00 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Not all PJM generators necessary to serve load every hour?
9:26:33 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Generators dispatched according to demand?
9:27:02 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	As with any market, demand increases price increases?
9:27:15 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Periods of high electricity demand LMPs higher?
9:27:50 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Since market matching supply and demand, some generators run full load while other dispatched sporadically?
9:28:03 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	PJM regulates how generators make offers in day ahead market?
9:28:24 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Generators make offers reflect variable cost of production?
9:29:09 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Difference between variable cost of production and revenue is energy margin?
9:29:26 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	When saying better bid in closer to actual cost, make sure have positive margin?
9:30:44 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	They incentivize?
9:30:54 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Fuel primary component variable cost of production?
9:31:02 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Absorbents and reagents considered part variable cost of production?
9:31:15 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Renewable energy not have any absorbents and reagents?
9:31:21 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Renewable energy providers bid generation at zero or negative price?
9:32:03 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Talked how stack offers or bids, renewable energy at lowest end of stack?
9:32:25 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	More renewable energy comes on line places downward pressure on PJM LMP?
9:32:50 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Familiar with STR selective catalytic reduction technology?
9:32:58 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Utilize absorbents and reagents?

9:33:30 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Cost of ammonia variable cost of production?
9:33:54 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Yes?
9:34:13 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	If Duke required utilize STR more frequently, likely increase cost for ammonia use?
9:34:39 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Increases to variable cost of production mean unit move further up stack?
9:35:13 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Duke responsible for bidding energy from East Bend and Woodsdale into PJM marketplace?
9:35:25 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Four general categories to schedule energy into PJM market?
9:35:34 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Those be economic, must run, emergency, and not available?
9:35:40 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	If unit scheduled economic, market operator of PJM has responsibility for commitment?
9:35:53 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Clarify, when unit scheduled economic, means PJM making commitment decision?
9:36:09 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	When unit scheduled economic, might operate some days and not other days?
9:36:21 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	When scheduled economic, might cycle, on and off?
9:36:28 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Unit scheduled as economic, not needed serve load and placed in standby?
9:37:11 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Conversation about what consider bidding in generator incentivizing make sure variable cost of production covered?
9:37:50 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Forecasting process involved?
9:38:00 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Plant bid in as economically offered opposed must run, more likely to cycle?
9:38:40 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Turn to direct, page 10, line 3, Duke Kentucky said, reading (click on link for further comments)?
9:39:12 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Answered yes?
9:39:16 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Lines 7-8, stated, reading (click on link for further comments)?
9:39:29 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Process talking about?
9:39:53 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Reserve shutdown occurs when unit uneconomic to operate?
9:40:01 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Page 9, line 10, state, reading (click on link for further comments)?
9:40:27 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Periods when East Bend not compete successfully?

9:40:47 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Page 16, line 1, explain when unit PJM off line subject to capacity performance penalties time takes restart unit?
9:41:18 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Page 10, line 8, describe company's modeled forecasting more instances of reserve shutdown in future, reading (click on link for further comments)?
9:41:52 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Further state, models showing declining net capacity factor at East Bend?
9:42:00 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Modeling dispatches into PJM energy market show East Bend capacity factor decline and reserve shutdowns continue?
9:42:57 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Lines 13-16, explained reason for expected continuation of reserve shutdown status, state, reading (click on link for further comments)?
9:43:26 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Line 16, refer to future capacity factors as incredibly low?
9:44:17 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Page 15, line 1, Duke Kentucky asks, reading (click on link for further comments), read right?
9:44:42 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Reply, lines 5-8, low capacity factor in late 2020s, reading (click on link for further comments)?
9:45:06 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Go on to explain, lines 10-14, reading (click on link for further comments)?
9:45:36 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Go into that on line 14-16, where state, reading (click on link for further comments)?
9:45:55 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Have responses to data requests?
9:46:00 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	AG request 2-14, adopted subpart A?
9:46:22 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Seen before?
9:46:33 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Second page, person responsible lists two, Kimberly Hughes and John D. Swez?
9:46:43 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	This morning, adopting answer provided previously by Kimberly A. Hughes?
9:46:58 AM	Atty Henry Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Subpart A, correct it says, reading (click on link for further comments)?
9:47:09 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Response talk about transportation issues around barge transportation?
9:47:19 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Duke Kentucky observed declining demand for coal driven barge transportation providers less dependent on coal-related revenues?
9:47:41 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Made barge transportation less available?
9:47:55 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Subpart B, question is, reading (click on link for further comments)?

9:48:11 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	In response, stated, reading (click on link for further comments)?
9:48:22 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Higher forced outage rate increase exposure to PJM capacity performance penalty?
9:48:51 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	In response, talk about PJM performance exposure, what mean by exposure, exposure to penalties?
9:50:01 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Response to AG 2-13, page 4, reading (click on link for further comments)?
9:50:35 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	That's you?
9:50:49 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	In Data Request 2-13, AG question states, reading (click on link for further comments)?
9:51:12 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Subpart B, asks explain in detail coal cost issues?
9:51:25 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	In response, provide reasons why difficult for coal industry respond to variations and increased demand?
9:51:38 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	State because lead times procure coal longer than natural gas?
9:52:04 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	From (b)?
9:52:11 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Also state, reading (click on link for further comments)?
9:52:31 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Also state, reading (click on link for further comments)?
9:52:56 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	PJM and reliability, agree reserve margin measure of resource adequacy but not mechanism to achieve adequacy?
9:53:49 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Not the mechanism?
9:53:55 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Basic idea PJM runs capacity market ensure capacity procured to meet reserve margin?
9:54:25 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Prices rise in auction when close to targeted reserve margin?
9:55:21 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	PJM has 22 percent reserve margin?
9:55:39 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Prices low now so much capacity?
9:56:09 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	PJM holds base residual auction three years ahead?
9:56:26 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	Auction typically three years ahead fourth delivery year?
9:56:35 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	PJM also holds incremental auctions?
9:56:52 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	During incremental auctions, PJM procure additional capacity?
9:57:12 AM	Atty Henry Sierra Club - witness Swez		
		Note: Sacre, Candace	PJM has mechanism if auction not clear enough capacity?

9:57:35 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Familiar with reliability backstop?
9:57:41 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Familiar with PJM Tariff Attachment DD, section 16?
9:57:55 AM	Atty Henry Sierra Club	
	Note: Sacre, Candace	May I mark Sierra Club Exhibit 2 copy of PJM Tariff Attachment D?
9:58:09 AM	Chairman Chandler	
	Note: Sacre, Candace	You may. (Click on link for further comments.)
9:58:10 AM	MARKED - HEARING EXHIBIT SC 2	
	Note: Sacre, Candace	ATTY HENRY SIERRA CLUB - WITNESS SWEZ
	Note: Sacre, Candace	PJM TARIFF ATTACHMENT D
10:00:50 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Seen reliability backstop provision of PJM before?
10:01:08 AM	Atty Henry Sierra Club	
	Note: Sacre, Candace	Take administrative notice of reliability backstop provision? (Click on link for further comments.)
10:02:48 AM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
10:02:57 AM	Staff Atty Tussey PSC - witness Swez	
	Note: Sacre, Candace	Cross Examination. Explain process designate unit for reserve shutdown?
10:07:28 AM	Staff Atty Tussey PSC - witness Swez	
	Note: Sacre, Candace	Mentioned make decision, PJM does not make designation, not have to approve?
10:07:50 AM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
10:08:15 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Examination. Are you all any good at what just described?
10:08:54 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Got people like McClay, market usually well informed, gas prices spiking something coming up, take into account making these decisions?
10:09:55 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Ignoring anomaly, major event days occur more often, three in last nine years, how know good at this, go back and look, what done took over East Bend figure out if good at this and net positive benefit?
10:16:27 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Making decisions whether commit, self-schedule, verse offering East Bend as economic unit based off expectations over time horizon?
10:17:28 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Get below ten days' supply at East Bend?
10:17:39 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Ever point PJM made you change status could not operate or bid into market?
10:18:00 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Taking into account short term what think going to happen, know what input costs are, costs of coal, cost of replacement coal?
10:18:38 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Thought this was going to happen, compare to what actually happen, at end of periods anybody go back and say here's what happened, what need to change next period, what looking at wrong?

10:23:42 AM Chairman Chandler - witness Swez
Note: Sacre, Candace During hours of year East Bend runs, must run status, net positive or net negative profit?
10:26:05 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Only in hours in which utility designated East Bend as self supply or self scheduled?
10:27:26 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Point, never know, way to determine compare marginal cost running unit each hour compared to what load LMP was?
10:28:26 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Could run Monte Carlo, randomized determination of outages?
10:28:50 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Costing consumers a few million a year, not imagine cost a few million dollars have study done?
10:29:15 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Does existence of off-system sharing mechanism impact dispatch decisions?
10:29:40 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Dispatching on own, think for sure made net positive in 2022 given where LMPs were?
10:30:00 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Average LMP in 2022 $82?
10:30:11 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Average LMP during forced outages, table early on eighty-something dollars?
10:30:24 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Average LMP in 2022?
10:30:34 AM Chairman Chandler - witness Swez
Note: Sacre, Candace What marginal cost of running East Bend with prevailing coal prices?
10:31:01 AM Chairman Chandler - witness Swez
Note: Sacre, Candace How compare average LMPs last couple of years?
10:31:47 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Page 4 of rebuttal, cost of replacement power, assume forced outages random, cost of power fairly reflective what average that year be?
10:32:12 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Those are, in rebuttal, $35 in 2019, $21 in 2020, $32 in 2021, $80 in 2022, and $29 seems like to date in 2023?
10:32:27 AM Chairman Chandler - witness Swez
Note: Sacre, Candace East Bend less than in for marginal in ordinary year, value to consumers today an environmentally compliant capacity facility?
10:33:22 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Because CT always capacity value?
10:33:36 AM Chairman Chandler - witness Swez
Note: Sacre, Candace What about East Bend?
10:35:40 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Change by not signing take or pay coal contracts?
10:36:08 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Page 4, rebuttal, replacement power forced outages 2022 close to three times as much as 2023 to date?
10:36:44 AM Chairman Chandler - witness Swez
Note: Sacre, Candace Know amount of replacement power proposed be recovered through rates, test year amounts?

10:37:24 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Experience in markets, information you provided, what know or expect going forward, power prices PJM 2022 representative of power prices going forward?
10:38:41 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Preparing in job for generation act way did and be dispatched and have price signals had in 2023?
10:39:03 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Preparing for power prices look more like 2022 or power prices in 2023 to date?
10:40:26 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	What type of transportation Woodsdale procure?
10:40:48 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Just transportation service, no notice, firm?
10:41:01 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Does change in dispatch of Woodsdale change economics and existence of capacity performance, change economics of transportation service?
10:42:04 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Have to refuel Woodsdale during Elliott with backup fuel delivery?
10:42:56 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Used backup fuel more hours, used backup fuel for 99 hours, rated for less, difference fact ran at something less than max?
10:43:23 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	What status?
10:43:51 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Discussion in rebuttal about Elliott, capacity performance penalties, note been expected for Duke been assigned penalties, seems like very overly simplification, generation share ratio $11 million penalties?
10:44:50 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Comes down to penalties customer pay for capacity products through BRA or through embedded base rates?
10:45:07 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Avoiding having to buy from BRA, have own plan, avoiding having to pay for generation customers already paying for it?
10:45:20 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Penalties transfer of wealth between capacity performance generators that underperformed to noncapacity performance capacity?
10:45:41 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Make up numbers, power plant 500 mW, UCAP is 490, 490 capacity performance capacity for unit?
10:45:56 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Extra ten not capacity performance capacity?
10:46:03 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	If produces at 500, ten megawatts not paid for, procured through BRA as capacity performance product is paid bonuses?
10:46:25 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	From people had obligation who underperformed pursuant to baseline and who paid to people who performed but performed at level otherwise did not have obligation under capacity performance regimen?

10:46:51 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	East Bend perform in excess of obligation during performance assessment intervals related to Elliott?
10:47:33 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	With East Bend, DEK long for FRR plan and able monetize what is long in BRA?
10:48:00 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Up to UCAP, all East Bend capacity performance product?
10:48:13 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Even FRR capacity has to be capacity performance?
10:48:20 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Woodsdale has three units?
10:48:29 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Woodsdale has six units?
10:48:36 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Three had forced outage during performance assessment?
10:48:41 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Know how many hours or intervals unavailable?
10:49:31 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	1, 2, 4, 5, and 6 anticipate being assessed penalties pursuant to performance assessment interval?
10:51:06 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Back to 3, had planned outage, asked extend, denied, once planned outage ended started forced outage?
10:51:22 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Portion planned, PJM agreeing was planned?
10:51:45 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Still out now for turbine rewind?
10:51:55 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Unit referring to still getting overhaul?
10:52:13 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Variable cost based on starts and stops, O&M expense now recoverable through CT bid in energy markets?
10:52:50 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Twenty hours a start, then 2500 hours?
10:53:33 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	RMR, post-hearing provide PJM Manual 14D, generator deactivation notices, transmission planning?
10:53:36 AM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	CHAIRMAN CHANDLER - WITNESS SWEZ
	Note: Sacre, Candace	PJM MANUAL 14D
10:54:00 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Asked earlier data request responses about reliability and market power, remember?
10:54:13 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	With counsel for AG Office that once deactivation notice received by PJM, PJM request unit reliability must run unit if reliability issue or market power concern, remember?
10:54:39 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Know what reliability referring to or reliability analysis referring to in manual?
10:55:07 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Stability issues, thermal issues, voltage issues?

10:55:16 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Know whether manual discusses types of analyses determine whether reliability issue?
10:55:33 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Reliability must run under today's rules, PJM no authority require generator stay on line after generation deactivation notice purposes of resource adequacy?
10:55:57 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Questions asked of Park bilateral transactions as opposed to depending on market, here for questions?
10:56:14 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Agree DEOK zone broken out or separated from rest of RTO and number BRAs past few years?
10:56:32 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Supposed to send price signal?
10:57:02 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	But run internal LDA specific reliability analyses, PJM looks at transfer capabilities into and out of individual LDAs in determining number referring to?
10:57:20 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Experience CETL values related to transfer capabilities?
10:57:37 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Aware LDA clearing at higher price than rest of RTO send signal to generation or transmission be built to increase resources inside the zone or transfer capability?
10:58:02 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Complicate ability of Duke Kentucky enter into bilateral contracts to get capacity performance capacity?
10:59:11 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Not allowed to?
10:59:15 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Price signal, long in last couple of auctions 50 MW?
10:59:40 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Not a lot, Miller talking about economic development efforts, not have 100 MW sitting around?
11:00:54 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Focus on DEK, never said fine to lean on market for resource adequacy, buck stops here, know geography DEK area, given topology, hard put solar in Duke Kentucky territory, agree?
11:01:46 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Land available and not near as flat?
11:02:00 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	How quickly get through PJM generation interconnection queue?
11:02:11 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Before even accept an application to study, if put in application today not be looked at until 2026?
11:02:24 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Year or two to study, couple years build, five-, six-year process?
11:03:07 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Outer end six years, at least four?
11:03:17 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	What do in meantime to meet demand?
11:03:41 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Behind meter?

11:03:48 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	How about energy efficiency/demand response?
11:03:54 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Our toolbox at least next four years meeting increased demand?
11:04:13 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Not response to price signal BRA sending?
11:04:30 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Person responsible making sure DEOK meets FRR plan?
11:04:53 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Bilaterals, what risk sign bilateral contract for capacity outside zone, pricing or performance?
11:05:40 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Energy, part of this case, interest in opportunity hedge through buy market day ahead, risk given transmission constraints entering into contracts outside zone?
11:06:05 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Risk related to congestion, differences in pricing?
11:06:14 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Looked at contracts outside zone?
11:06:39 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Who bears risk of price differences and congestion in agreements?
11:06:52 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Been load, LSE?
11:06:58 AM	Chairman Chandler	
	Note: Sacre, Candace	Recess until 11:20.
11:07:22 AM	Session Paused	
11:25:47 AM	Session Resumed	
11:25:54 AM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
11:26:03 AM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
11:26:11 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Redirect Examination. Recall discussion about start up time for East Bend, what is start up time from cold start to reaching full load?
11:27:18 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Contrast that with Woodsdale CTs, how long take come online?
11:27:44 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Recall questions from AG Office about notices of deactivation or retirements with PJM?
11:28:00 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Requirement member give notice to PJM for deactivation?
11:28:12 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Know what lead time for notice is?
11:28:24 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Familiar with what company stating most likely retirement date East Bend?
11:28:47 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Believe plenty of time for company make decision, give PJM notice?
11:28:54 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Conversations enter into bilateral capacity contracts?
11:29:05 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Know whether company entered into any recently?

11:29:40 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Company address capacity performance risk in relation to bilateral contract?
11:29:58 AM	Atty D'Ascenzo Duke Kentucky - witness Swez	
	Note: Sacre, Candace	Know how addressed?
11:30:09 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Examination. Aware result of $1.8 billion estimated capacity performance penalties related to Elliott lead to bankruptcies?
11:30:28 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Get PJM notifications, emails saying got notice of so-and-so going bankrupt?
11:30:35 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Happening one a week, emails once every other week?
11:30:46 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Without asking counterparty to this agreement going bankrupt, aware conversations between DEOK and counterparty exposure or risk of bankruptcy through Elliott?
11:31:40 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Contract similar to BRA participant less than entire delivery year?
11:32:05 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Need for driven by fact needed to extend planned outage?
11:32:19 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Exclusively for capacity or energy related to agreement?
11:32:27 AM	Chairman Chandler - witness Swez	
	Note: Sacre, Candace	Out one physical hedge on energy prices?
11:32:33 AM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions?
11:32:37 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Recross Examination. Only required give month notice before deactivation?
11:32:53 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Utility can give notice prior, not just six months, could give them few years' notice?
11:33:03 AM	Atty Henry Sierra Club - witness Swez	
	Note: Sacre, Candace	Company willing to do that?
11:33:22 AM	Chairman Chandler	
	Note: Sacre, Candace	Mr. D'Ascenzo?
11:33:34 AM	Chairman Chandler	
	Note: Sacre, Candace	Administrative notice of tariff, federal law, 149-page document include as hearing exhibit, mark as SC 2 and move to introduce or keep out of record. (Click on link for further comments.)
11:35:08 AM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
11:35:11 AM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Michael Geers.
11:35:21 AM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
11:35:26 AM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Examination. Name and address?
11:35:44 AM	Atty D'Ascenzo Duke Kentucky - witness Geers	
	Note: Sacre, Candace	Direct Examination. Cause to file responses?
11:35:57 AM	Atty D'Ascenzo Duke Kentucky - witness Geers	
	Note: Sacre, Candace	Changes or corrections?

11:36:01 AM	Atty D'Ascenzo Duke Kentucky - witness Geers	
	Note: Sacre, Candace	Asked same questions, answers be same?
11:36:06 AM	Atty D'Ascenzo Duke Kentucky - witness Geers	
	Note: Sacre, Candace	Intent responses entered into record?
11:36:16 AM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
11:36:34 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Cross Examination. Heard of Good Neighbor rule?
11:36:55 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Just issued in March?
11:37:03 AM	Atty Huddleston Sierra Club	
	Note: Sacre, Candace	Move for administrative notice of Good Neighbor rule. (Click on link for further comments.)
11:37:04 AM	MARKED - HEARING EXHIBIT SC 3	
	Note: Sacre, Candace	ATTY HUDDLESTON SIERRA CLUB - WITNESS GEERS
	Note: Sacre, Candace	GOOD NEIGHBOR PLAN FOR 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS
11:38:49 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar with what regulates?
11:39:03 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Rule regulates smog-forming nitrogen oxide or NOx pollution from power plants and industrial facilities in 23 states?
11:39:14 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Good Neighbor rule impacts East Bend?
11:39:19 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Good Neighbor rule would impact East Bend plant?
11:39:23 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Good Neighbor rule would require East Bend operate SCR on regular basis?
11:39:44 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Projected East Bend have to cut ozone emissions in half during 2027 ozone season?
11:40:11 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Possibly decrease useful life East Bend?
11:40:36 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Continued declining nature of emissions possibly decrease useful life of East Bend?
11:41:03 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Good Neighbor rule not reflected in 2021 IRP modeling?
11:41:16 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar with steam electric effluent limitations guidelines?
11:41:26 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	As regulatory scheme?
11:41:29 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Aware new ELG rule proposed by EPA in 2023?
11:41:41 AM	Atty Huddleston Sierra Club	
	Note: Sacre, Candace	Mark as SC 4 copy of ELG Rule published Mar 29 2023. (Click on link for further comments.)
11:41:42 AM	MARKED - HEARING EXHIBIT SC 4	
	Note: Sacre, Candace	ATTY HUDDLESTON SIERRA CLUB - WITNESS GEERS
	Note: Sacre, Candace	SUPPLEMENTAL EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

11:43:01 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar with what ELG rule regulates?
11:43:27 AM	Atty Huddleston Sierra Club	
	Note: Sacre, Candace	Have provided prepublication version because has not been published, (click on link for further comments)
11:44:18 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	New ELG rule applies stricter wastewater discharge standards to coal-fired power plants?
11:44:37 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	New proposed rule proposes apply more stringent standards flue gas desulphurization wastewater, bottom ash transport water, and combustion residual leachate?
11:44:56 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	In IRP, page 142, states, reading (click on link for further comments), correct?
11:45:21 AM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Object. (Click on link for further comments.)
11:46:01 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	East Bend subject to new ELG rule if does go forward as proposed?
11:46:25 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Analyzed impact of proposed rule on East Bend?
11:46:58 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Not fully analyzed?
11:47:21 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Proposed new rule possibly decrease useful life of East Bend if goes into effect?
11:48:04 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	New rule not reflected in IRP modeling?
11:48:16 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar National Ambient Air Quality Standards for Fine Particulate Matter?
11:48:25 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Reconsideration of NAAQS proposed by EPA on Jan 27 this year?
11:48:49 AM	Atty Huddleston Sierra Club	
	Note: Sacre, Candace	Like to mark as SC 5 a copy of reconsideration of NAAQS proposed by EPA on Jan 27 2023. (Click on link for further comments.)
11:48:50 AM	MARKED - HEARING EXHIBIT SC 5	
	Note: Sacre, Candace	ATTY HUDDLESTON SIERRA CLUB - WITNESS GEERS
	Note: Sacre, Candace	RECONSIDERATION OF NATIONAL AMBIENT AIR QUALITY STANDARDS FOR PARTICULATE MATTER
11:49:46 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar EPA proposal to reduce primary annual PM2.5 refined particulate matter level?
11:49:59 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	EPA proposes reducing level of PM2.5 from 12 micrograms per cubic meter to nine to ten micrograms?
11:50:17 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Duke analyzed impact on proposed new rule on East Bend?
11:51:04 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Duke Kentucky analyzed impact proposed new rule as just described?
11:51:41 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Proposed new rule affect economics of East Bend negatively?
11:52:00 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Impacts not reflected in IRP modeling?

11:52:17 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Which other environmental compliance regulations see as riskier in terms of costs?
11:52:31 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Climate regulations, what mean?
11:52:40 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	What impact see from climate regulations under 111(d)?
11:53:08 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Analyzed impact of 111(d) on East Bend?
11:53:50 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Clean Power Plan, what impacts on East Bend 2?
11:54:40 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Mentioned and I understood it looking at impact Clean Power Plan on East Bend 2, find any impacts of Clean Power Plan had it gone into effect?
11:55:01 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	What would effect have been?
11:55:35 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	What would have been impact of rule on East Bend?
11:55:39 AM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Object, irrelevant. (Click on link for further comments.)
11:56:03 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Said anticipating regulation on 111(d) any day now, correct?
11:56:25 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Analyzed impact 111(d) on East Bend 2?
11:57:13 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	When say decarbonization, is that a form of carbon regulation?
11:57:39 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Could impact economics of East Bend 2 negatively?
11:57:58 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Mercury and Air Toxic Standards, familiar?
11:58:09 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Aware new mercury and air toxic standards rule proposed by EPA on April 3 this year?
11:58:21 AM	Atty Huddleston Sierra Club	
	Note: Sacre, Candace	Like to have marked SC 6 a copy of EPA NAAQS rule issued on April 3 and move Commission take administrative notice. (Click on link for further comments.)
11:58:22 AM	MARKED - HEARING EXHIBIT SC 6	
	Note: Sacre, Candace	ATTY HUDDLESTON SIERRA CLUB - WITNESS GEERS
	Note: Sacre, Candace	NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW
11:59:13 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar with EPA proposal to strengthen standards for filterable particulate matter?
11:59:21 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Familiar with EPA proposal to require coal-burning plants comply with FPM standard using PM continuous emission monitoring system?
11:59:35 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Analyzed impact of proposed new rule on East Bend 2?
11:59:51 AM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	What found thus far?

12:00:09 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	What else found?
12:00:55 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Could reduction .03 to .01 negatively affect economics of East Bend 2?
12:01:11 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	How filter back in long-term use of unit?
12:01:45 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Could potential physical adjustments incur additional costs?
12:02:36 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	If rules go into effect, replace X unit and X unit costs?
12:02:59 PM	Atty Huddleston Sierra Club - witness Geers	
	Note: Sacre, Candace	Not reflected in IRP modeling?
12:03:16 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
12:03:27 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Examination. Have SC 3, 4, 5, and 6, copies in front of you?
12:03:41 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Good Neighbor final?
12:03:55 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	But comment period and all that is?
12:04:00 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Documents for 3, 4, 5, and 6, expanded ELG, expanded NAAQS, and MATS, all provide for written and oral comments?
12:04:42 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Filed comments on any of these?
12:05:47 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Why EPRI?
12:06:04 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Provide comments costs comply with rules?
12:07:04 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Cost to comply, feasibility to comply or impact on capital costs?
12:07:40 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	MATS big deal, plans filed with Commission?
12:08:01 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Took position on those, related to modeling to mercury and air toxics or concerns around implementation or costs?
12:08:25 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Are comfortable talking about issues other than hypertechnical modeling, why not be what commenting on NAAQS, MATS, and ELG now?
12:09:31 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Avoidance of public health detriments benefit of rule, not expect utility have technical input in that, own assets have to change things own, not intend commenting?
12:12:20 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Expectation if rules require upgrade or retirement issues, concern, here earlier ask Swez?
12:12:51 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Heard conversation how long bring additional capacity online?
12:12:59 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Rule put out costly to comply, concerned make decision implementation date, file those comments no mechanism bring on replacement capacity?

12:14:25 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Duke let Commission know if force retirement not bring on capacity, going to be issue?
12:16:26 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Duke set enterprise-wide goal of retiring coal-fired units by 2035?
12:16:43 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Cannot undue that by decree?
12:17:03 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	If set goal and proposed rules tend to make decision for you, what confidence have will necessarily advocate what best for consumers?
12:18:46 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Why have goal?
12:19:41 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	MATS put out first time prior to merger?
12:20:13 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Duke enterprise-wide different place than were today amount of generation represented by coal?
12:20:43 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Expect given direction take different positions impact rules have on coal?
12:20:59 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Hear term overhang when talk about financial issues?
12:21:12 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Outsized risk of unknown of event, not had certainty regulator recovery undepreciated value of prematurely retired power plants?
12:21:45 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Had a lot of coal, MATS significant impact on Duke?
12:22:55 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Back then significant amount of coal, not have regulatory certainty impact retirement of coal units, took significant role trying to inform EPA what final rule should look like?
12:23:23 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Today have less coal, switching between coal and gas?
12:23:30 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Able shift generation in Florida?
12:23:58 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Lot of solar in Carolinas and in Florida?
12:24:09 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Lot of solar in North Carolina relative to Kentucky?
12:24:23 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Regulatory certainty carbon plan in North Carolina?
12:24:36 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	In that jurisdiction, big part of business North Carolina?
12:24:50 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	System-wide have goal retiring all coal in next 12 years?
12:25:12 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Getting to my point, different position relative dependence on coal today than decade ago with MATS?
12:25:27 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Changes and certainty regarding coal and goals today opposed to ten or fifteen years ago?

12:25:53 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Given have goal and subject to commission approval, not undo federal environmental regulations, given relative impact, expect directed by management provide input into these rules differently than same rules 15 years ago?
12:28:22 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Here yesterday asking Park?
12:28:31 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Reasonableness assuming no going forward environmental compliance 15 years IRP other than scenarios include carbon tax?
12:28:48 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Aware utilities in Kentucky have ability to pass environmental compliance costs through monthly surcharge?
12:29:07 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	If significant investment, aware utility has to request a CPCN build compliance equipment?
12:29:17 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Can be for coal ash or ELG or CCR or SCR or NOx, whatever it is?
12:29:31 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Generally experience with scenario?
12:29:57 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	One-off compliance one or two rules at a time, not necessarily take into account future environmental compliance costs?
12:31:08 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Have SC 3, 4, 5, 6, good amount experience in environmental compliance?
12:31:26 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Reviewing IRPs and considering CPCNs and environmental compliance plans, ignore possibility or risk additional compliance costs beyond review in front of it?
12:32:52 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	In IRP, agree unreasonable assume not going to be additional environmental costs coal and gas?
12:33:27 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	Assuming are none unreasonable?
12:33:40 PM	Chairman Chandler - witness Geers	
	Note: Sacre, Candace	What level assume, what proxy use to consider unknown costs in future?
12:34:02 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
12:34:08 PM	Chairman Chandler	
	Note: Sacre, Candace	Renew Commission take notice of entire rule as Good Neighbor rule, expanded ELG, updated NAAQS, proposed rule MATS? (Click on link for further comments.)
12:37:00 PM	Chairman Chandler	
	Note: Sacre, Candace	Request Geers be excused. (Click on link for further comments.)
12:40:15 PM	Chairman Chandler	
	Note: Sacre, Candace	Beiber first witness when come back? (Click on link for further comments.)
12:40:30 PM	Chairman Chandler	
	Note: Sacre, Candace	Anything else before recess?
12:40:35 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess until 1:30.
12:41:36 PM	Session Paused	
12:44:24 PM	Session Resumed	

12:44:33 PM	Session Paused	
1:35:57 PM	Session Resumed	
1:36:06 PM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in 2022-00372.
1:36:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Only witness?
1:36:29 PM	Chairman Chandler	
	Note: Sacre, Candace	Call your witness?
1:36:31 PM	Atty Boehm Kroger	
	Note: Sacre, Candace	Justin Beiber.
1:36:44 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
1:36:50 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Examination. Name and address?
1:37:10 PM	Atty Boehm Kroger - witness Beiber	
	Note: Sacre, Candace	Direct Examination. Cause to be filed testimony?
1:37:18 PM	Atty Boehm Kroger - witness Beiber	
	Note: Sacre, Candace	Changes?
1:37:22 PM	Atty Boehm Kroger - witness Beiber	
	Note: Sacre, Candace	Asked same questions, answers be same?
1:37:37 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
1:37:52 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Cross Examination. Direct in front of you?
1:38:05 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Page 14, lines 20-21, Kroger multi-site aggregation program with multiple service locations?
1:38:31 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Customers multiple service locations tend to be utilities' larger customers?
1:38:50 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	If multi-site customers allowed to aggregate maximum kilowatt demand, agree conjunctive billing demands lower or equal to sum of individual site demands?
1:39:11 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Under proposed multi-site aggregated demand program, multiple site customers have lower billing demands?
1:39:24 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	In order for Kroger program be revenue neutral, result higher kilowatt charges per dollar higher for single site customers?
1:39:49 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Familiar with billing system Duke Kentucky uses?
1:39:57 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Done study or analysis determine changes required to billing system to implement multi-site aggregated demand program?
1:40:14 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Recommended Duke study program?
1:40:17 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Recommendation not only study program but also implement pilot program?
1:40:43 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	If Duke studies program and determines infeasible, still required propose pilot program?

1:41:05 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Analysis billing program determine changes proposing feasible?
1:41:26 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Not have analysis or study determine cost be implement changes to billing system?
1:41:43 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Know cost of such programs?
1:41:50 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Familiar with energy efficiency programs Duke offers commercial customers?
1:42:03 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Agree be used by commercial customers reduce peak demands?
1:42:23 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Nonresidential customers also have time of day rates?
1:42:35 PM	Atty Herring Duke Kentucky - witness Beiber	
	Note: Sacre, Candace	Allow nonresidential customers ability reduce electric usage off-peak times?
1:42:49 PM	Chairman Chandler	
	Note: Sacre, Candace	Commission Staff?
1:42:51 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Cross Examination. Testified before Kentucky Commission before?
1:43:00 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Familiar with regulatory structure here?
1:43:09 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	In testimony, cite to Michigan as example of providing conjunctive tariff, recall?
1:43:29 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Regulated by Michigan Commission?
1:43:35 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Aware allow for some electric competition for larger customers?
1:43:46 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Affect your opinion benefit of conjunctive tariff for Kroger, the pilot program recommending?
1:44:47 PM	Staff Atty Tussey PSC - witness Beiber	
	Note: Sacre, Candace	Competition not make difference but not know for sure until executed pilot program and did a study?
1:46:00 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
1:46:05 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Examination. Proposal put large multi-site user equal footing with large single-site facility?
1:46:22 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Not think any distinguishing factor between two?
1:46:52 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Assertion around production and transmission costs and related to cost of service, thought heard say not difference expenses between multi-site user and large single-site user?
1:48:02 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	But actual cost?
1:48:41 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Testified in cases Duke before, LG&E, Kentucky Utilities?
1:49:08 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Aware KU service far western to far eastern part of state?

1:49:20 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	If Kroger in Wickliffe and Kroger in Harlan insofar as those two at 2.5 megawatts apiece, drive same expenses as five megawatt facility in Lexington?
1:50:19 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Distinction made cost of service purposes not be any differences?
1:50:29 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Explain why aggregating Kroger facilities in Northern Kentucky reduce total bill using multi-site aggregation?
1:52:32 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Why not what proposing result in slippery slope, want be own subclass, reduce billing, take away bigger picture looking at individual classes since so similar?
1:53:38 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Distinction making that bill goes to single person?
1:54:17 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Effectively the impact, treating one group customers differently, one group owned by corporate entity?
1:54:48 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Different meters, owned by same people consider same customer?
1:55:07 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Treat that customer differently, end result of what proposing?
1:55:52 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Testify across lots of jurisdictions?
1:56:00 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Appeared in front of lot of different jurisdictions, every utility has different rates, commercial customers often difference how apply demand charges?
1:56:27 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	How utilities tariffs applied demand charges differently across jurisdictions?
1:56:35 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Lots of different ways to do that?
1:56:46 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	LG&E/KU remember demand charges, have peak, intermediate, and base demand charge?
1:57:00 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Could propose and Commission approve rachet from one percent to hundred percent?
1:57:16 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Commissions could approve demand charges reset monthly or apply over a year, seen that variation?
1:57:33 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	All come back to fact if demand charge applied differently, not be issue have to aggregate them, have same result Kroger having lower overall bill?
1:58:12 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Cost proposing multi-site customer, cost intending to forego related to demand charge?
1:58:35 PM	Chairman Chandler - witness Beiber	
	Note: Sacre, Candace	Would assume demand charge also be changed be more accurate measuring each site's usage?

1:59:32 PM	Chairman Chandler - witness Beiber		
	Note: Sacre, Candace		Is that not same thing, different way measuring demand amending application of demand charge, what demand charge does, measures and then fills demand?
1:59:55 PM	Chairman Chandler - witness Beiber		
	Note: Sacre, Candace		Trying to understand, what proposing alternative to applying demand charges differently to commercial customers in Duke territory?
2:00:45 PM	Chairman Chandler		
	Note: Sacre, Candace		Redirect?
2:00:49 PM	Chairman Chandler		
	Note: Sacre, Candace		Additional questions?
2:00:51 PM	Chairman Chandler		
	Note: Sacre, Candace		Request Bieber be excused? (Click on link for further comments.)
2:01:33 PM	Chairman Chandler		
	Note: Sacre, Candace		Next witness?
2:01:36 PM	Atty D'Ascenzo Duke Kentucky		
	Note: Sacre, Candace		Lisa Quilici.
2:01:51 PM	Chairman Chandler		
	Note: Sacre, Candace		Witness is sworn.
2:01:56 PM	Chairman Chandler - witness Quilici		
	Note: Sacre, Candace		Examination. Name and address?
2:02:16 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Direct Examination. Company work for and position?
2:02:27 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Cause to file testimony and responses?
2:02:34 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Changes or corrections?
2:02:41 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Walk us through that?
2:03:05 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Only changes?
2:03:08 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Asked same questions, answers be same?
2:03:17 PM	Atty D'Ascenzo Duke Kentucky - witness Quilici		
	Note: Sacre, Candace		Intent information be admitted into record?
2:03:26 PM	Chairman Chandler		
	Note: Sacre, Candace		Will file that in an errata? (Click on link for further comments.)
2:03:55 PM	Chairman Chandler		
	Note: Sacre, Candace		Questions?
2:04:22 PM	Chairman Chandler		
	Note: Sacre, Candace		Next witness?
2:04:28 PM	Atty Brama Duke Kentucky		
	Note: Sacre, Candace		Joshua Nowak.
2:04:37 PM	Chairman Chandler		
	Note: Sacre, Candace		Witness is sworn.
2:04:44 PM	Chairman Chandler - witness Nowak		
	Note: Sacre, Candace		Examination. Name and address?
2:05:04 PM	Atty Brama Duke Kentucky - witness Nowak		
	Note: Sacre, Candace		Direct Examination. Company for whom work and position?
2:05:13 PM	Atty Brama Duke Kentucky - witness Nowak		
	Note: Sacre, Candace		Cause be filed testimony and rebuttal as well as responses?
2:05:20 PM	Atty Brama Duke Kentucky - witness Nowak		
	Note: Sacre, Candace		Corrections?

2:05:25 PM	Atty Brama Duke Kentucky - witness Nowak		
		Note: Sacre, Candace	Asked same questions, have same answers?
2:06:13 PM	Atty Brama Duke Kentucky - witness Nowak		
		Note: Sacre, Candace	Any other corrections or updates to testimony?
2:06:18 PM	Atty Brama Duke Kentucky - witness Nowak		
		Note: Sacre, Candace	Intention testimony and responses be admitted into evidence?
2:06:30 PM	Chairman Chandler		
		Note: Sacre, Candace	Questions?
2:06:35 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Cross Examination. Recommendation company be awarded ROE of 10.53 percent?
2:06:54 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Company's currently authorized ROE 9.25 percent?
2:07:03 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Result of 2020 rate case?
2:07:11 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Attachment JCN-1, direct, pages 4 and 5, looks to be cases provided expert testimony back to 2014?
2:07:41 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	My count four instances in last nine years provided expert testimony on ROE besides this case?
2:08:05 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	In terms what have produced to this, have got four cases?
2:08:14 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Final decisions in any other cases where you filed testimony?
2:08:20 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Most recent case where filed testimony on ROE Aquarion Water case?
2:08:36 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	For which a final order?
2:08:40 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Also proposed an ROE of 10.35 percent?
2:08:50 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Also sound consistent ROE approved 8.70 percent?
2:09:13 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Aware last six months two published opinions for regulated Duke affiliates on ROE?
2:09:28 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Aware Dec 2022 Duke Energy Ohio final order entered company agreed accept ROE of 9.50 percent?
2:09:50 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Aware Mar 2022 Duke Energy Progress settled for ROE 9.60 percent?
2:10:00 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	So are aware of that?
2:10:05 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Going back to Ohio case, aware accepting an ROE 9.50 percent company accepted reduced ROE of 34 basis points from previously authorized return of 9.84 percent?
2:10:28 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Understand Duke Energy Kentucky not publicly traded?
2:10:38 PM	Atty Grundmann Walmart - witness Nowak		
		Note: Sacre, Candace	Competes for capital with other Duke Energy affiliates?

2:10:45 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	March 2023 decision on ROE decided in current inflationary economic climate?
2:11:33 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Last week, did federal jobs report come out with 80,000 more jobs, signals not likely move into a recession?
2:11:58 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Mention Hope and Bluefield decisions, familiar with those?
2:12:03 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Those required this Commission authorize ROE is fair and reasonable and allows utility earn fair rate of return?
2:12:14 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Think fair to Duke Kentucky ratepayers if were to pay 75 basis points more in equity than affiliate sister company?
2:12:54 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Think market proxy group better evidence what appropriate return be than what Duke Energy own sister affiliate agreed is ROE need satisfy shareholders?
2:13:25 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Who corporate parent of Duke Kentucky?
2:13:36 PM	Chairman Chandler	
	Note: Sacre, Candace	Mr. Boehm?
2:13:39 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Cross Examination. Follow up counsel for Walmart asking, mentioned Energy Progress South Carolina settled rate case and approved in March for 9.6?
2:14:05 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Discussing proxy group, Duke Energy Progress South Carolina not in proxy group?
2:14:20 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Mentioned Duke Energy Progress has different risk profile than Duke Kentucky?
2:15:07 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	True of all companies in proxy group, different risk profile than Duke Kentucky?
2:15:35 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Page 10, rebuttal, discussing changes happened in markets since filed direct and made recommendation, discuss three primary changes, reading (click on link for further comments), respect first two, agree your characterization inflation and interest rates moderated?
2:17:00 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Given factors, make recommendation now, be lower than recommended in direct as far as ROE?
2:17:31 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Citing two factors moved in good direction, moderation, and one seems to be same, but recommendation not change?
2:17:46 PM	Atty Boehm Kroger - witness Nowak	
	Note: Sacre, Candace	Say moderated since filed direct, that's positive?
2:18:27 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
2:18:29 PM	Staff Atty Tussey PSC - witness Nowak	
	Note: Sacre, Candace	Cross Examination. When was credit rating changed, update to status?

2:19:11 PM	Staff Atty Tussey PSC - witness Nowak	
	Note: Sacre, Candace	According to release, tied to how this turns out?
2:19:31 PM	Chairman Chandler	
	Note: Sacre, Candace	Commissioner?
2:19:33 PM	Chairman Chandler	
	Note: Sacre, Candace	Post-hearing data request for copy of that.
2:19:34 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	STAFF ATTY TUSSEY PSC - WITNESS NOWAK
	Note: Sacre, Candace	MOODY'S RATING ACTION: MOODY'S AFFIRMS DUKE ENERGY AND SUBSIDIARY RATINGS; CHANGES OUTLOOK OF DUKE KENTUCKY TO NEGATIVE 24 APR 2023
2:19:41 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Examination. Look at Hope and Bluefield, know under what statute or law Hope determined?
2:20:03 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Aware called Federal Power Commission vs. Hope Natural Gas Company?
2:20:08 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Be surprised to know reviewed under Natural Gas Act?
2:20:19 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Cite to note constitutional requirements dictated in Hope and Bluefield?
2:20:38 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Read Hope?
2:20:40 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Refers to determination just and reasonable rates?
2:20:45 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Know legal standard in Kentucky?
2:20:52 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Be surprised if fair, just, and reasonable rates?
2:20:57 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Looked up what constitutional minimums are for fair, just, and reasonable rates?
2:22:24 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Agree Hope and Bluefield looked at what minimal constitutional ROE is?
2:22:50 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Agree Hope and Bluefield look at ROE in context of unconstitutional taking of property without compensation?
2:23:04 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Agree Hope and Bluefield look at just and reasonable and rates and appropriate compensation in context of unconstitutional taking?
2:23:28 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Big picture, falls below this level unconstitutional, if above not unconstitutional, understanding Hope and Bluefield looking at constitutional floor, rate above this floor to not be unconstitutional?
2:24:11 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	At some point where unconstitutional, agree what cases about?
2:24:17 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Some rate, zero, one dollar, unconstitutional, say there is a floor, describe how come up with something that meets requirement, above that floor?
2:24:35 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Not talk about ceiling?

2:24:52 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Asking about your ciations to Hope and Bluefield in relation what those cases stand for in context of your testimony and citation to them that discuss floor, different than appropriate ROE, there is appropriate ROE and then constitutional minimum?
2:26:12 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	In your calculations and determinations, where take into account reasonableness for perspective of consumer?
2:27:04 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Saying took customers' interest in mind when proposing adequate ROE because customers' interest is company's interest?
2:27:35 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	FFO to debt ratios, 12-13 percent ROE make sure FFO to debt ratio over 20, that would reduce borrowing costs?
2:27:58 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Where show in analysis explicitly did balancing?
2:28:35 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
2:28:45 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Redirect Examination. Recall questions ROEs recently established in settlements Duke Energy Ohio and Duke Energy Progress?
2:28:59 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Difference between settled and litigated outcomes?
2:29:42 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Other reasons why one Duke affiliate treated differently establishing ROE than Duke Kentucky?
2:30:15 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Only two things considered?
2:30:51 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Apart from setting ROE, factors other than ROE affect utility's risk?
2:31:13 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Counsel for Kroger interest rates and inflation, affected ROE recommendation?
2:31:29 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Summarize why analysis remains at 10.35 percent?
2:32:27 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Explain why look at average and median results as opposed to very ends of spectrum?
2:33:06 PM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions?
2:33:09 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Recross Examination. Looking for alignment among ratepayers and shareholders, remember?
2:33:25 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Review testimony of Chriss in entirety?
2:33:41 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Recall page 11 produced chart of returns been authorized 2019 through date of filing testimony early March?
2:34:03 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Corrected direct, chart not change?
2:34:14 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Understood chart was authorized ROE 2019 through 2023 vertically integrated utilities?
2:34:40 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Not have reason contest data set forth in figure 1?

2:35:17 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	Dispute results set forth here, reason doubt veracity?
2:35:27 PM	Atty Grundmann Walmart - witness Nowak	
	Note: Sacre, Candace	If approved, agree 10.35 be fourth highest ROE awarded any time 2019 to present across United States, any reason dispute that?
2:36:07 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
2:36:15 PM	Atty Brama Duke Kentucky - witness Nowak	
	Note: Sacre, Candace	Redirect Examination. Context needs to be understood historical ROEs versus modeling for period rates in effect?
2:38:23 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Examination. Over last few years, value of regulated utility firms been in excess of book value?
2:38:39 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Why? From investor perspective, why premium?
2:39:40 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Reflecting more than rate base growth, market values in excess of book value more than expected compound annual growth rate of rate base?
2:40:15 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Easier and easier every day?
2:40:27 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Duke has?
2:40:32 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	That reflect small portion of total revenues?
2:40:40 PM	Chairman Chandler - witness Nowak	
	Note: Sacre, Candace	Market values still in excess of book value even in market conditions been discussing?
2:40:56 PM	Chairman Chandler	
	Note: Sacre, Candace	Anything else?
2:41:15 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
2:41:17 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Christopher Bauer.
2:41:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
2:41:35 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Examination. Name and address?
2:41:48 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Direct Examination. Position with company and for whom work?
2:41:56 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Cause be filed testimony and discovery responses?
2:42:03 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Corrections?
2:42:07 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Asked same questions, have same answers?
2:42:38 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Company has copies if prefer have entered. (Click on link for further comments.)
2:43:45 PM	Atty Grundmann Walmart	
	Note: Sacre, Candace	Clarifying question. (Click on link for further comments.)
2:43:46 PM	MARKED - HEARING EXHIBIT DK 1	
	Note: Sacre, Candace	ATTY BRAMA DUKE KENTUCKY - WITNESS BAUER

	Note: Sacre, Candace	MOODY'S 24 APR 2023 MOODY'S AFFIRMS DUKE ENEGY AND SUBSIDIARY RATINGS; CHANGES OUTLOOK OF DUKE ENERGY KENTUCKY TO NEGATIVE
2:48:31 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Identify what is document premarked as Exhibit DEK 1?
2:49:02 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	What is source of document?
2:49:40 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Moody's cause press release issued?
2:49:45 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	What date?
2:49:49 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	How date relate to direct and rebuttal testimony timing?
2:50:00 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Point to place or places speaks to Duke Energy Kentucky?
2:50:21 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Other than outlook, change any other aspects of testimony?
2:52:30 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Move for admission Exhibit DEK 1. (Click on link for further comments.)
2:52:36 PM	Chairman Chandler	
	Note: Sacre, Candace	So admitted.
2:52:37 PM	HEARING EXHIBIT DK 1	
	Note: Sacre, Candace	ATTY BRAMA DUKE KENTUCKY - WITNESS BAUER
	Note: Sacre, Candace	MOODY'S 24 APR 2023 MOODY'S AFFIRMS DUKE ENEGY AND SUBSIDIARY RATINGS; CHANGES OUTLOOK OF DUKE ENERGY KENTUCKY TO NEGATIVE
2:52:41 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
2:52:50 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Cross Examination. Document published after prefiled testimony?
2:53:09 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	First page says, reading (click on link for further comments), see that sentence?
2:53:28 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Not seen anything in document what unfavorable means, agree?
2:54:03 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	How long take issue one of those longer credit opinions?
2:54:26 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Bottom of page, see begin discussion Duke Energy Carolinas and Duke Energy Progress, no distinction, agree both DEP and DEC multistate in nature?
2:54:50 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Mentions DEP case presently underway?
2:55:05 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	DEC filed, hearing date later this year?
2:55:10 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	When one looks at Duke Energy Progress, looks like all ratings affirmed, no downgrades?
2:55:39 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Appears Moody's not negatively perceive outcome of settlement in DEP rate case, agree?
2:55:51 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Heard questions to Nowak relevance to credit agencies having ROE Duke Kentucky relative ROEs awarded other Duke sister companies?

2:56:06 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Relevant to investor community?
2:56:25 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Nowak engage in communications on behalf of Duke Kentucky with investor community?
2:56:35 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Do you engage in those conversations on behalf of Duke Kentucky?
2:56:39 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Think better positioned to speak to nature of communications than Nowak?
2:56:53 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Direct, page 8, lines 20-23, note that authorized ROE paramount importance, go on to say, reading (click on link for further comments), ever written for Moody's?
2:57:32 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Agree not set forth in testimony what believe be unreasonable ROE?
2:58:32 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Pay attention what going on with other investor utilities?
2:58:55 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	How many times seen 100 basis point swing?
2:59:13 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	In that case see much broader jump but agree had rate case two and a half years ago?
2:59:52 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Page 12, direct, line 6, circumstances have changed?
3:00:11 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Have negative outlook, not know that at time put forward question and answer?
3:00:16 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Looking at line 11, what lead to credit downgrade, among items reduced ROE, expect if Commission award ROE consistent with mid-nines, trigger credit downgrade by ratings agencies?
3:01:22 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	ROE of 9.5 be increase from company's currently authorized ROE?
3:01:33 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	As stand today, increase cash available to company?
3:01:39 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Page 19, direct, lines 12-14, indicate Duke Energy Ohio is Duke Kentucky parent company?
3:02:05 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	In terms of ordering, is it Duke Kentucky, Duke Energy Ohio, Duke Corporation?
3:02:17 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Mean any equity available flow through Duke Kentucky to Duke Energy Ohio?
3:02:41 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Ohio constrained in ability pass along profit to parent by 50-50 cap structure and 9.5 ROE agreed to in company's distribution rate case?
3:03:59 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	In Ohio, cap structure 50-50?
3:04:08 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Here, proposed different cap structure?
3:04:12 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	More heavily weighted on equity side?

3:04:20 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Any other regulated utilities in Duke family where intervening regulated utility in middle?
3:04:39 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Unique structure, impact in sense Duke Kentucky ratepayers funding larger portion of equity because of cap structure that flows up to more limited cap structure 50-50 in Ohio?
3:05:02 PM	Atty Grundmann Walmart - witness Bauer	
	Note: Sacre, Candace	Duke Kentucky would hold 51 percent equity?
3:05:15 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
3:05:21 PM	Staff Atty Tussey PSC - witness Bauer	
	Note: Sacre, Candace	Cross Examination. Effect of parent company, credit rating going down for Duke Kentucky?
3:05:40 PM	Staff Atty Tussey PSC - witness Bauer	
	Note: Sacre, Candace	Affect Duke Ohio?
3:06:07 PM	Staff Atty Tussey PSC - witness Bauer	
	Note: Sacre, Candace	How affect Duke ability raise debt considering banking turmoil?
3:07:35 PM	Staff Atty Tussey PSC - witness Bauer	
	Note: Sacre, Candace	Additional issues going on in banking industry affect that?
3:07:48 PM	Chairman Chandler	
	Note: Sacre, Candace	Commissioner?
3:07:54 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Examination. Duke Kentucky currently rated BAA-1?
3:08:05 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Go with Moody's, as long as not jump places, a downgrade result in BAA-2?
3:08:13 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	BAA-2 is investment grade?
3:08:18 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	BAA-3 is lower?
3:08:23 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Then go to BA-1?
3:08:28 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	At BAA-1?
3:08:31 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Difference in bond yields, Moody's seasoned bond yields, between BAA-1 and BAA-2?
3:10:38 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	For each instrument?
3:10:41 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	When you said a billion dollars, Duke plant in service $3 billion, different scale is what trying to say?
3:10:51 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Effectively what talking about, what cost difference BAA-1 and BAA-2 in event have to issue debt?
3:11:02 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	See something been issuing debt $10 million a year or total debt increasing $10 million a year, reference that in rebuttal?
3:11:40 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	My understanding one of primary benefits of Duke Kentucky and Duke Energy Ohio be opportunity have access greater capital?
3:12:51 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	What additional cost of borrowing verse additional cost to customers having different rate?

3:13:03 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Run analysis determine customers better off, where cost comes in?
3:13:23 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Talking about exchanging higher rates in interim for higher borrowing costs in longer term, analysis determine net impact of being BAA-1 and BAA-2?
3:14:52 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Saying ladder debt effectively?
3:15:47 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	How much driven at corporate level?
3:15:58 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	If increasing pressure, why not throttle back demand on increasing compound annual growth rate of rate base?
3:16:46 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Here when asking questions of Nowak?
3:17:09 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Know cash issue Moody's page 3, reading (click on link for further comments), 2018 not random number in terms of impact, every utility in American had impact to cash in 2018?
3:18:16 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	What was that from?
3:18:25 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	How like extra $4.7 million in cash, what do to FFO to debt ratio?
3:18:38 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Duke Kentucky net income last couple years runs high forties, $48, $51, $52 million, increasing that by 10 percent significant for cash flow?
3:18:50 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Sounds right for unprotected and protected ADIT pass back to consumers every year?
3:19:03 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Looked at test year amounts, approximately $4.7 million, significant driver of impact on cash being flat?
3:19:28 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Other than that, what else primary driver?
3:19:53 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	So that is, to a certain degree, at utility's discretion or result of utility's action, increased depreciation expense not recovered through rates result of incremental investment between rate cases?
3:20:14 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Is what I say incorrect?
3:20:19 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Said in a period of increasing investment?
3:20:26 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Capital expansion, how long in utlity industry?
3:20:33 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Remember time in which Duke not in period capital expansion?
3:20:42 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Time when Duke not been in capital expansion, pretty content with rate base don't need to increase CPS?
3:21:39 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Know Bryan Savoy?
3:21:46 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Publicly-traded DUK?

3:21:54 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Aware earnings call?
3:22:12 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	DUK seeking target FFO to debt ratio of 13 to 14 percent end 2023, over long term 14 percent?
3:22:29 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Why publicly-traded company seeking FFO to debt ratio of 14 percent where you saying target ration DEK needs to be 16, 17, 18 percent?
3:23:16 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	DUK borrow debt?
3:23:24 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	What missing here, problem here DUK looking to be upgraded to BAA-1?
3:23:53 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	This was sale of 19.9 percent of Indiana, ending of coal ash saga?
3:24:02 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Content with BAA-2 with DUK but needs to be BAA-1 for DEK?
3:25:12 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	What be FFO to debt ratio if company approved entirety of rate increase as amended by rebuttal?
3:25:49 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	How much longer have fully amortize unprotected excess ADIT?
3:26:01 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Moody's worried about flat cash since 2018?
3:26:14 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Anybody from DEK told them is temporary because amortizing unprotected excess ADIT and once goes away get extra $3.4 million cash per year?
3:26:42 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	What's 200 basis point hole?
3:27:04 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Throttling of increase in depreciation expense would?
3:27:14 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Reduction in annual compound growth rate of rate base additions?
3:27:23 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	A reduction in investment, annual growth in investment in the utility, what are levers here talking about?
3:28:33 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Has to be balancing, not make sense on paper highest credit rating because incremental benefit to consumers less cost of debt amount additional monies recovered through rates, not make sense on cost of benefit?
3:29:10 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Just want to stay status quo, but where is balance, does A make sense for DEK in terms of cost benefit?
3:30:31 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	ROE and equity layer, sliding scale or one matter more than other?
3:30:43 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Raise one, lower other, compounding impact?
3:31:04 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	To keep follow-through impact equal?

3:31:14 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	More conversation about what ROE used to set rates than do what percentage total capitalization is equity capital, ROE gives more cash, a higher equity ratio reduces debt for FFO to debt, offset each other?
3:32:06 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Internally at DEK, excess capital from DUK, ROE greater consideration than amount of equity level?
3:32:25 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	When Savoy looking who to hand money out to, ROE greater driver in decision making?
3:32:38 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess until 3:50.
3:33:06 PM	Session Paused	
3:58:19 PM	Session Resumed	
3:58:43 PM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
3:58:47 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussion. (Click on link for further comments.)
3:59:06 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
3:59:13 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Redirect Examination. Recall a conversation Walmart counsel not wanting affiliate of Duke Energy Corporation to be outlier?
3:59:25 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Explain what you meant?
3:59:54 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	What is Duke Energy Ohio settled cap structure as currently exists?
4:00:07 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	When say part of settlement, why matter?
4:00:20 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Why Duke Kentucky need or requesting higher cap structure and ROE?
4:00:50 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Third page of DEK 1, some discussion with Commission about paragraph specific to Duke Kentucky, line above, reading (click on link for further comments)?
4:01:20 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	Recall conversation regarding return of ADIT and how affect company?
4:01:29 PM	Atty Brama Duke Kentucky - witness Bauer	
	Note: Sacre, Candace	If company stop returning excess deferred income tax to customers, be ongoing change in company revenue growth?
4:02:13 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	Examination. DUK selling commercial renewables?
4:02:32 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	In order become more pure play, regulated entity?
4:02:40 PM	Chairman Chandler - witness Bauer	
	Note: Sacre, Candace	It's just that, just a fact, get rid of your unregulated, are more regulated?
4:02:45 PM	Chairman Chandler	
	Note: Sacre, Candace	Anything else, counsel?
4:02:48 PM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions?

4:03:16 PM	Chairman Chandler	
	Note: Sacre, Candace	As an aside, DEP case has been going on since 4th. (Click on link for further comments.)
4:04:51 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
4:04:54 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	John Panizza.
4:05:03 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
4:05:09 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Examination. Name and address?
4:05:25 PM	Atty Brama Duke Kentucky - witness Panizza	
	Note: Sacre, Candace	Direct Examination. Identify position within Duke Energy organization?
4:05:36 PM	Atty Brama Duke Kentucky - witness Panizza	
	Note: Sacre, Candace	Cause to file direct and rebuttal and responses?
4:05:45 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Rather than asking if has corrections, draw Commission's attention to motion filed last week with respect to certain corrections. (Click on link for further comments.)
4:06:21 PM	Atty Brama Duke Kentucky - witness Panizza	
	Note: Sacre, Candace	Asked same questions, give same answers?
4:06:33 PM	Atty Brama Duke Kentucky - witness Panizza	
	Note: Sacre, Candace	Intention be admitted into evidence?
4:06:43 PM	Chairman Chandler	
	Note: Sacre, Candace	AG's Office?
4:06:47 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Cross Examination. Accurate rebuttal testimony response to AG witness Futral recommendation reduce projected property tax expense?
4:07:02 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Also accurate Duke Kentucky originally proposing to include $19.741 million in property tax expense in proposed revenue requirement?
4:07:18 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Page 6, revised rebuttal, state revised estimated property tax expense for forecasted test period $18.139 million?
4:07:45 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Revised rebuttal, revised attachment 1, data request sponsored, AG First, question 141, look test period estimated tax expense $18,004,307? (Click on link for further comments.)
4:09:53 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Trying to understand, Duke Kentucky revised estimated property tax expense for forecasted test period $18.13 million state in revised testimony, or is it $18,004,307 in revised attachment?
4:11:24 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	On page 6, revised rebuttal $18.139 million incorrect, should be $18,004,307?
4:11:42 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	Accurate state in revised rebuttal testimony, estimated property tax expense both 2021 and 2202 much closer to per books property tax expense than what previously calculated?
4:12:03 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	What prompted you make these revisions?
4:13:08 PM	Asst Atty General Goad - witness Panizza	
	Note: Sacre, Candace	When discover discrepancies in 2021 base amount?

4:13:22 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:13:30 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Examination. Question deferred to you by Bauer?
4:13:36 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	About excess accumulated deferred income taxes?
4:13:42 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Protected and unprotected?
4:13:44 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Protected, IRS made decision for us?
4:13:51 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Have to unwind way IRS says?
4:14:03 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Unprotected at discretion of regulator for the regulated utility?
4:14:11 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Amounts of taxes customers pay through rates never come due?
4:14:23 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Know how long amortization period Commission approved for regulatory liabilities?
4:14:40 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Still the case, being amortized over ten-year period?
4:14:46 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Three-plus million dollars a year?
4:14:57 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	That's where they get you, federal taxes?
4:15:02 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Got 2018 the entire year?
4:15:09 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	A good portion of 2018?
4:15:14 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Eighty percent, maybe 75?
4:15:18 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Majority of '18, '19, '20, '21, '22, and almost halfway through '23?
4:15:26 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Amortized at least half of excess unprotected ADIT?
4:15:32 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Previously get benefit of having excess cash?
4:15:58 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Difference between book depreciation and taxes?
4:16:20 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Timing differences unrelated to accelerated depreciation?
4:16:32 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	When ten years up, no longer have to hand out three-point-something million dollars cash pursuant to amortization of regulatory liability?
4:17:01 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Cash to hold on to in future time periods were having to hand out in past time periods?
4:17:11 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Consistent with amortization period for unprotected excess ADIT seen in other jurisdictions?
4:17:30 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Thinking averages and medians, where ten years fall on spectrum?

4:17:41 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Whole industry looked at certain way, most regulated utilities in same spot have to pass back excess accumulated deferred income taxes over some time period?
4:18:20 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	If had five-year amortization period?
4:18:26 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Not advocating pass it back the unprotected in five years, agree?
4:18:38 PM	Chairman Chandler - witness Panizza	
	Note: Sacre, Candace	Know regulatory mechanisms not come in for rate case now and when deferred income taxes fully amortized regulatory liability, know whether set up in way just stops passing back?
4:19:21 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
4:19:36 PM	Chairman Chandler	
	Note: Sacre, Candace	Call next witness?
4:19:38 PM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Thomas Heath.
4:19:54 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
4:20:03 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Examination. Name and address?
4:20:21 PM	Atty D'Ascenzo Duke Kentucky - witness Heath	
	Note: Sacre, Candace	Direct Examination. Position with company?
4:20:29 PM	Atty D'Ascenzo Duke Kentucky - witness Heath	
	Note: Sacre, Candace	Cause to file rebuttal?
4:20:34 PM	Atty D'Ascenzo Duke Kentucky - witness Heath	
	Note: Sacre, Candace	Changes or corrections?
4:20:38 PM	Atty D'Ascenzo Duke Kentucky - witness Heath	
	Note: Sacre, Candace	Asked same questions, responses be same?
4:20:44 PM	Atty D'Ascenzo Duke Kentucky - witness Heath	
	Note: Sacre, Candace	Intent testimony admitted into record?
4:20:50 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:21:39 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
4:21:41 PM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Paul Normand.
4:22:12 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
4:22:18 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Examination. Name and address?
4:22:52 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Direct Examination. Position and company?
4:23:12 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Cause to file direct and rebuttal and responses to data requests?
4:23:20 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Changes or corrections?
4:24:07 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Only change?
4:24:10 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Asked same questions, answer be same?
4:24:17 PM	Atty D'Ascenzo Duke Kentucky - witness Normand	
	Note: Sacre, Candace	Intention information admitted into record?

4:24:26 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:24:38 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Cross Examination. Contract with Duke, invoices had name of Michael Morganti?
4:24:53 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	How fits into corporate structure?
4:25:15 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Not sponsor responses?
4:25:24 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Prepared for you?
4:25:33 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Described in direct a little bit about relationship between CRC and Duke?
4:25:44 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Used term factoring of a receivable?
4:25:54 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	They don't factor their receivables?
4:26:00 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	What do they do, what does Duke do or CRC do?
4:26:52 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Based on that, no cash transfer when do this?
4:27:04 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	No cash transferred between Duke and CRC?
4:27:22 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Duke makes interest payments to CRC?
4:27:31 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	What is interest rate charged?
4:27:40 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Have any idea who might ask?
4:27:59 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Any other financing costs associated with exchange?
4:28:22 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Arrangement prolong number of days determined leg days in study?
4:28:50 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	Use the term securitized financing in testimony, recall using that term, page 3 of rebuttal?
4:29:32 PM	Staff Atty Tussey PSC - witness Normand	
	Note: Sacre, Candace	See where used term securitized financing of accounts receivable?
4:30:00 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:30:10 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Examination. Lead/lag studies come up exclusively absence of study, looked at this, what benefit of securitization financing for Duke Kentucky?
4:31:09 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Not do anything with accounts receivable, billed customers and waited for customers to pay, feels like get money from customers faster than 27 days?
4:31:33 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	The 27 days not relate to time period, collection and lag between time send bill and finalizing accounting and sending to CRC?
4:32:34 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Collection lag?

4:37:35 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Thrown off by if invoices sold to CRC each day, data request from AG-DR-1-95, your understanding, reading (click on link for further comments), response to H, see that?
4:40:40 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Response reads, (click on link for further comments), see that?
4:41:04 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Seen purchase and sell agreement referenced there?
4:41:12 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Under impression invoices sold to CRC daily?
4:41:20 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	If sold daily, necessarily change your testimony as to appropriate lead and lag days?
4:41:55 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	If sold to CRC daily, Duke not get benefit on daily basis?
4:42:30 PM	Chairman Chandler - witness Normand	
	Note: Sacre, Candace	Says here invoices are sold?
4:42:47 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
4:43:22 PM	Chairman Chandler	
	Note: Sacre, Candace	Recall any witnesses?
4:43:30 PM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	Thomas Heath.
4:43:50 PM	Chairman Chandler	
	Note: Sacre, Candace	Still under oath.
4:44:02 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:44:14 PM	Staff Atty Tussey PSC - witness Heath	
	Note: Sacre, Candace	Recross Examination. Arrangement between CRC and Duke, Normand said no cash exchanged, then Chairman read answer indicated invoices sold daily, explain relationship there?
4:48:31 PM	Staff Atty Tussey PSC - witness Heath	
	Note: Sacre, Candace	Aware provided purchase and sale agreements in responses to any of the data requests?
4:49:06 PM	Staff Atty Tussey PSC - witness Heath	
	Note: Sacre, Candace	Will ask for one relevant, mentioned interest rate, set amount or vary?
4:50:45 PM	Staff Atty Tussey PSC - witness Heath	
	Note: Sacre, Candace	What is benefit to ratepayer using this structure?
4:51:55 PM	Chairman Chandler	
	Note: Sacre, Candace	Commissioner?
4:52:10 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Examination. Not sound like getting money from loan for a number of weeks, are you?
4:54:18 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Most recent agreement 2010, believe when went to $350-million-dollar facility?
4:54:47 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Reference to interest rate, same thing as discount rate, that's different?
4:54:53 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Discount rate Weatherston explained response AG's Office includes variables including net charge-off adjustment, late charge premium, collection charge, discount rate, and three-year average turnover rate?

4:55:17 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Calculation she provided discount rate is LIBOR plus a hundred basis points, be surprised if still LIBOR?
4:55:46 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	If stuck at LIBOR, still be using ABR instead of SOFR?
4:55:56 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	If think been amended, use SOFR?
4:56:02 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Basically, this ship has sailed, borrowed original amount, because of inverted yield curve, paying more for receivables for financing, right?
4:56:39 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	That is rate case, that what setting rate case in today's current environment, here for ROE testimony, all about today's current environment, not six months from now?
4:56:51 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Been serious discussion about exchanging this?
4:57:15 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Just one shot, are done?
4:57:33 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Secured financing?
4:57:37 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Other stuff Bauer putting out there, secured or unsecured?
4:57:45 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Regulated entity significant difference interest rate secured notes and unsecure notes?
4:57:55 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	If Bauer had to market $50 million of this, suspect still be secured note to fund back?
4:58:07 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Not necessarily be different interest rate, what saying is maybe different counterparty?
4:58:18 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Why counterparty diversification matter?
4:58:54 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Saturation concerned about?
4:59:07 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	$45 million not lot considering level of debt Duke Kentucky has?
4:59:30 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Plant in service DEK $2.8 billion, $45 million drop in bucket when talking about size of debt Duke already has on books?
4:59:53 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Internal conversations, still believe value in this exclusively from diversification if interest rate upside down?
5:00:03 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	When last time had internal conversation?
5:00:13 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Since yield curve inverted?
5:00:25 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	That driving those conversations looking at, still make sense?
5:00:32 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Cost now associated with it, an additional cost?
5:01:44 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Get rate case order in this case, go out and pay off with debt two-thirds of the price?

5:02:00 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
5:02:04 PM	Atty D'Ascenzo Duke Kentucky	
	Note: Sacre, Candace	No questions, but for purposes of clarifying record, agreement discussed part of cost allocation manual which was submitted as part of application which is volume 16.
5:02:20 PM	Chairman Chandler	
	Note: Sacre, Candace	Different than agreements provided in response to AG DR-1-93? (Click on link for further comments.)
5:02:43 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Examination. At 1-93 is a receivable sales agreement dated in 2010 Synergy Receivables Company as seller and Duke Energy Ohio, Inc., as initial servicer lots of other entities, then an amended and restated agreement dated Nov 5 among Duke Energy Ohio, Duke Energy Kentucky, and Duke Energy Kentucky as originators and Synergy Receivables Company as SPE?
5:03:15 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Are those back to back effectively?
5:03:23 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Agreement you reference heard might be included in application at volume 16 amends these agreements?
5:03:48 PM	Chairman Chandler - witness Heath	
	Note: Sacre, Candace	Possibly expanding size compared to 2010 amendments?
5:03:52 PM	Chairman Chandler	
	Note: Sacre, Candace	Anything else?
5:03:55 PM	Chairman Chandler	
	Note: Sacre, Candace	Get answers to your questions?
5:04:00 PM	Staff Atty Tussey PSC - witness Heath	
	Note: Sacre, Candace	Recross Examination. Does agreement extend number of lag days?
5:04:40 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
5:04:43 PM	Atty Grama Duke Kentucky	
	Note: Sacre, Candace	Danielle Weatherston.
5:05:03 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:05:11 PM	Chairman Chandler - witness Weatherston	
	Note: Sacre, Candace	Examination. Name and address?
5:05:27 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Direct Examination. Position within Duke organization?
5:05:36 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Cause to file direct and responses?
5:05:42 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Corrections?
5:05:54 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Correct at time filed testimony?
5:06:11 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Asked same questions, otherwise give same answers?
5:06:19 PM	Atty Grama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Same true for responses?
5:06:22 PM	Atty Brama Duke Kentucky - witness Weatherston	
	Note: Sacre, Candace	Intention testimony and responses be admitted into evidence?
5:06:30 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?

5:06:40 PM	Chairman Chandler - witness Weatherston	
	Note: Sacre, Candace	Examination. Sold but don't get money immediately?
5:07:03 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
5:07:05 PM	Atty Grama Duke Kentucky	
	Note: Sacre, Candace	Jeffrey Setser.
5:07:15 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:07:23 PM	Chairman Chandler - witness Setser	
	Note: Sacre, Candace	Examination. Name and address?
5:07:36 PM	Atty Grama Duke Kentucky - witness Setser	
	Note: Sacre, Candace	Direct Examination. Identify position?
5:07:43 PM	Atty Grama Duke Kentucky - witness Setser	
	Note: Sacre, Candace	Cause be filed testimony and responses?
5:07:48 PM	Atty Grama Duke Kentucky - witness Setser	
	Note: Sacre, Candace	Corrections?
5:07:52 PM	Atty Grama Duke Kentucky - witness Setser	
	Note: Sacre, Candace	Asked same questions, give same answers?
5:07:57 PM	Atty Grama Duke Kentucky - witness Setser	
	Note: Sacre, Candace	Intention testimony and discovery admitted into evidence?
5:08:07 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
5:08:59 PM	Chairman Chandler	
	Note: Sacre, Candace	Call next witness?
5:09:00 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	Max McClellan.
5:09:05 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:09:11 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Examination. Name and address?
5:09:23 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Direct Examination. Position with company?
5:09:28 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Cause be filed direct and data requests?
5:09:34 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Changes?
5:09:38 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Asked same questions, answers be same?
5:09:42 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Intent testimony and data requests admitted?
5:09:51 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
5:09:58 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Examination. Provide Park information for IRP?
5:10:13 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	On load forecast, provide that for IRP?
5:10:18 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Do this enterprise wide?
5:10:22 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	What jurisdictions do load forecasting for?
5:10:35 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Post Elliott, anticipate doing job differently, change way do load forecasting in winter?

5:10:46 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Why not?
5:11:01 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	If new heating load increasingly heat pumps backed by resistance heating and given lessons learned from Elliott, not need be taken into account in doing baseline winter load forecasting?
5:11:46 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Previous saturation increase electrification for heating included previous years but missed across Kentucky, Tennessee, North Carolina determining load for Elliott?
5:12:35 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Do Kentucky and Ohio, PJM forecast off for Elliott?
5:12:51 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Couple days ahead load forecast off?
5:13:00 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	If such significant deviation short term, if average in long term, increase risk of missing it for resource adequacy purposes?
5:13:25 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Have to have adequate resources over time meet individual issues?
5:13:40 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Provide long-term forecast, who determine variation from long-term forecast?
5:14:16 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	How come up with long-term forecast for IRP?
5:15:19 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Where getting load shapes?
5:15:29 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Load shapes do not/do take into account variables, double counted or removed?
5:16:03 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Or added outside ordinary load shapes?
5:16:09 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	Not control for weather because normalized using all past weather?
5:16:19 PM	Chairman Chandler - witness McClellan	
	Note: Sacre, Candace	In event increasing variation, only picking whatever up past variations are?
5:17:01 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
5:17:05 PM	Atty Herring Duke Kentucky - witness McClellan	
	Note: Sacre, Candace	Redirect Examination. Fair to say short-term forecast conducted by generation or energy supply sector of company?
5:17:29 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
5:17:31 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	Grady "Tripp" Carpenter.
5:17:48 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:17:57 PM	Chairman Chandler - witness Carpenter	
	Note: Sacre, Candace	Examination. Name and address?
5:18:09 PM	Atty Grama Duke Kentucky - witness Carpenter	
	Note: Sacre, Candace	Direct Examination. Cause be filed testimony and responses?
5:18:15 PM	Atty Grama Duke Kentucky - witness Carpenter	
	Note: Sacre, Candace	Corrections?

5:18:18 PM	Atty Grama Duke Kentucky - witness Carpenter	
	Note: Sacre, Candace	Asked same questions, give same answer?
5:18:25 PM	Atty Grama Duke Kentucky - witness Carpenter	
	Note: Sacre, Candace	Intention testimony and responses be admitted?
5:18:33 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
5:18:41 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Cross Examination. Passed off question to you contracts to mitigate volatility in fuel prices, have contracts would help mitigate variance in fuel expense?
5:19:14 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Who suggest try?
5:19:24 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Application page 70, list of capital projects, second project applied for CPCN, familiar with project?
5:19:52 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Estimated cost $19.4 million?
5:20:20 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Actual application approximate cost $30 million, familiar with discrepancy or why might be discrepancy?
5:21:06 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	In-service date of project, familiar with estimated date?
5:21:23 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Think may have changed, aware what date might be now?
5:21:31 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Have idea who might ask?
5:21:43 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Other two projects, expecting to file for CPCNs or already been approved?
5:22:16 PM	Staff Atty Tussey PSC - witness Carpenter	
	Note: Sacre, Candace	Ms. Steinkuhl have better idea?
5:22:44 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
5:22:50 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess until 5:45.
5:29:28 PM	Session Paused	
5:54:26 PM	Session Resumed	
5:54:53 PM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
5:54:58 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussion. (Click on link for further comments.)
5:55:57 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
5:56:00 PM	Atty Vaysman Duke Kentucky	
	Note: Sacre, Candace	Jacob Stewart.
5:56:08 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:56:14 PM	Chairman Chandler - witness Stewart	
	Note: Sacre, Candace	Examination. Name and address?
5:56:28 PM	Atty Vaysman Duke Kentucky - witness Stewart	
	Note: Sacre, Candace	Direct Examination. Name, title, business address?
5:56:41 PM	Atty Vaysman Duke Kentucky - witness Stewart	
	Note: Sacre, Candace	Cause testimony and responses be filed?

5:56:48 PM	Atty Vaysman Duke Kentucky - witness Stewart	
	Note: Sacre, Candace	Corrections or changes?
5:56:53 PM	Atty Vaysman Duke Kentucky - witness Stewart	
	Note: Sacre, Candace	Same questions asked, responses be same?
5:57:03 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
5:57:19 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
5:57:20 PM	Atty Vaysman Duke Kentucky	
	Note: Sacre, Candace	Retha Hunsicker.
5:57:30 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:57:36 PM	Chairman Chandler - witness Hunsicker	
	Note: Sacre, Candace	Examination. Name and address?
5:57:55 PM	Atty Vaysman Duke Kentucky - witness Hunsicker	
	Note: Sacre, Candace	Direct Examination. Name, title, business address?
5:58:09 PM	Atty Vaysman Duke Kentucky - witness Hunsicker	
	Note: Sacre, Candace	Cause testimony and responses be filed?
5:58:17 PM	Atty Vaysman Duke Kentucky - witness Hunsicker	
	Note: Sacre, Candace	Corrections?
5:58:48 PM	Atty Vaysman Duke Kentucky - witness Hunsicker	
	Note: Sacre, Candace	Any other corrections?
5:58:56 PM	Atty Vaysman Duke Kentucky - witness Hunsicker	
	Note: Sacre, Candace	Same questions asked, responses be same?
5:59:03 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
5:59:25 PM	Atty Vaysman Duke Kentucky	
	Note: Sacre, Candace	Jacob Colley.
5:59:31 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
5:59:38 PM	Chairman Chandler - witness	
	Note: Sacre, Candace	Examination. Name and address?
5:59:51 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Direct Examination. Name, title, business address?
6:00:08 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Cause testimony and responses be filed?
6:00:15 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Corrections?
6:00:19 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Other corrections?
6:00:45 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Is that F-I-S-C-A-L?
6:00:49 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Other corrections?
6:00:53 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Same questions asked, responses be same?
6:01:05 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?
6:01:07 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Cross Examination. Duke Kentucky not have office in Kentucky where customers pay bills or obtain customer service?
6:02:01 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Admitting no office for customer pay bills or obtain customer service in the state?

6:02:18 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Obtain customer service, speak with customer representative?
6:02:52 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Not sponsor response to AG Second, question 4, asked if Duke had office open to pay bills, seen her response?
6:03:19 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	She did confirm Duke confirms not have office in Kentucky open to customers?
6:03:54 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	When talking about payment locations, referencing 70 payment agent locations have at grocery stores, pharmacies, and retailers?
6:04:12 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Response to AG Second, question 9-B, appears in 2022 and 2023 normally over 3,000 customers pay through payment agent?
6:04:40 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Discovery responses, stated $1.50 fee charged customer pays bill through payment agent, indicated some provide free?
6:04:58 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Response, AG Second, question 9-C, read response to subpart (c) into record?
6:05:59 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Clicked on link before, tried to search for free locations in Kentucky?
6:06:14 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Aware when click and narrow down search free locations only one wireless store in Newport shown in all of Kentucky?
6:07:00 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Think normally more than one free location?
6:07:11 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Duke Kentucky not have physical office, attempted work with payment agents expand free payment locations?
6:07:55 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Commit have discussion with Duke Kentucky see if possibility expand locations?
6:08:24 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Just commit to having discussion?
6:08:26 PM	Atty Vaysman Duke Energy	
	Note: Sacre, Candace	Objection, is there a factual question? (Click on link for further comments.)
6:10:16 PM	Asst Atty General Goad - witness Colley	
	Note: Sacre, Candace	Same question, commit to having discussion within Duke Kentucky?
6:11:02 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
6:11:10 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Cross Examination. Fee charged by vendors fee Duke's pass on or one vendor charging?
6:11:46 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Only accepting credit or debit card?
6:11:53 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Do take cash?
6:12:09 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Come in with invoice vendor accept any form of payment?
6:12:21 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Fee charged fee contractually Duke's that Duke chooses pass on or fee vendor charges customer as part of transaction?

6:13:46 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Actual fee goes to vendor?
6:13:47 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	And Duke not receive any part of percentage?
6:13:52 PM	Staff Atty Tussey PSC - witness Colley	
	Note: Sacre, Candace	Not based on amount of bill ever?
6:13:59 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
6:14:10 PM	Commissioner Regan - witness Colley	
	Note: Sacre, Candace	Examination. Said were 2,000 pay bill in person?
6:14:29 PM	Commissioner Regan - witness Colley	
	Note: Sacre, Candace	Percentage of people who could walk to location to pay bill?
6:14:49 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Examination. Of places can pay bill, accept all payment methodologies?
6:15:46 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Dixie Highway, 8 to 7, charge a dollar-fifty, see that cash only?
6:15:55 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Not take check or credit card?
6:16:38 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	See here for Erlanger Warsaw Wireless only location in Kentucky take payment in person not charge a fee?
6:17:14 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Confirms here, basically entire Northern Kentucky\Duke Energy territory in Kentucky that location only free one?
6:17:38 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	If person has $100 bill, go to one of these but Warsaw Wireless to pay bill, actually pay $101?
6:17:58 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Note at bottom of all these says $1.50 nothing to do with Duke Energy, what referring to?
6:18:29 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Provided direct on customer charge, late fee?
6:19:09 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Letter from D'Ascenzo, late payment waivers have occurred since end of Duke gas case, aware existence of waiver?
6:19:28 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Aware Commission stated Duke waive gas, Duke came back waive gas and electric since combined, also gave authority choose to track as regulatory assets?
6:19:49 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Page 2, ever seen data before?
6:20:11 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Gas and electric late payment waivers 2022?
6:20:23 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Specific to people receive third-party assistance help with bill pay?
6:20:37 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Like Community Action Agency?
6:20:52 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Know why amounts Apr May Jun for both nothing?
6:21:18 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Nothing assessed, no late fees assessed to customers?

6:21:25 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Know if Duke came back and asked Commission to have additional waiver for late payment fees for everybody those months?
6:21:43 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Know whether Duke had authority waive late fees, consulted on regulatory side of implementing it?
6:22:12 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Blanket waiver assessing late fees?
6:22:47 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Conversations referring to internal, not necessarily how implemented with regulator?
6:23:42 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Appreciation how community action agencies work?
6:23:55 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	In August, $6,452.02, by waiving that effectively $6,452.02 third-party agencies have additional money put forward other people's bills?
6:24:34 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Not fee assessed if not late?
6:25:14 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Know why increase in dollar amount and count of waivers in Aug 2022?
6:26:41 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Have a post-hearing data request explain that occurrence?
6:26:42 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	CHAIRMAN CHANDLER - WITNESS COLLEY
	Note: Sacre, Candace	EXPLAIN INCREASE IN DOLLAR AMOUNT AND NUMBER OF WAIVERS IN AUGUST 2022
6:26:47 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Witness proposed new cost-based late payment charge?
6:26:56 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Similar to what were explaining with five percent, proposal in this case also percentage of bill amount?
6:27:13 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Only charge late payment fee on amount once?
6:27:25 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Not compound, not charge late fees on late fees?
6:27:52 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Consistent in other territories?
6:28:08 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Attachment JSC-1 lays out late fee factor?
6:28:25 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Tariff proposal instead of five percent, now two-point-three percent?
6:28:41 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Carrying cost of unpaid bills, vary with dollar amount of bill?
6:29:09 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Dollar, two dollars twice carrying charge as dollar?
6:29:20 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Delinquency communications vary based off amount of bill?
6:29:41 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	With each occurrence, varies with occurrence not size of bill?
6:29:58 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Call customer service costs, not cost any more or less if $50 or $500 bill?

6:30:12 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Total of all those $2.42?
6:30:19 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	How calculated cost late-paying customer drives on average per occurrence?
6:30:37 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	A third of amount varies with size of bill, approximately a third?
6:31:10 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Two-thirds of $2.42 not vary on size of bill, related to occurrence?
6:32:08 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Only looking at average current past due balance not cumulative past due balance for termination of cost of 85 cents?
6:33:00 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Average current month charges on late paying accounts, current month billing?
6:33:11 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Average current month past due balance, the cumulative amount owed for average residential customer that month that paid late?
6:33:31 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Two-thirds of cost related to occurrence, one-third carrying charges of cumulative billings are late?
6:33:48 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	If two-thirds of cost drivers occurrence not driven by size of bill, why more reasonable have late payment fee be percentage of bill as opposed to actual per average cost of that incurrence?
6:35:43 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Since two-thirds average amount calculated fixed items, not direct correlation, overpaying for other smaller than average bills delinquency communications and call customer service costs?
6:36:27 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	What hear all the time, paying more than fair share, provide percentage of average bill or late fee percentage of average bill?
6:37:43 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Data use for average bill and average arrearages runs 2021 to 2022?
6:37:57 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Average current monthly past due balance used in carrying cost unpaid bills, include folks have payments plans left over from COVID?
6:38:38 PM	Chairman Chandler	
	Note: Sacre, Candace	Post-hearing data request confirmation of that?
6:38:39 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	CHAIRMAN CHANDLER - WITNESS COLLEY
	Note: Sacre, Candace	AVERAGE MONTHLY PAST DUE BALANCE USED IN CALCULATION OF CARRYING COST INCLUDE PAYMENT PLANS FROM COVID
6:39:01 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Applying percentage of late bill provide revenues in excess of cost?
6:39:28 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Assuming rates go up, bills go up?
6:39:36 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Customer usage stays same, applying 2.3 percent one number and 2.3 percent plus percentage increase times bills expected post this case be higher than bill studied in calculation?
6:40:21 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Increase size of amounts apply carrying charges?

6:40:26 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Agree third of driver of absolute average of $2.42?
6:41:10 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Point making know carrying costs go up because average current month pass-through balance expect go up?
6:41:24 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Your concern may change size relative other two cost drivers?
6:41:37 PM	Chairman Chandler - witness Colley	
	Note: Sacre, Candace	Wage inflation, cost of delinquency, communications, things like that?
6:42:16 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
6:42:20 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Redirect Examination. Customers with higher past due balances utilize call center longer?
6:42:54 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Not performed analysis?
6:43:01 PM	Atty Vaysman Duke Kentucky - witness Colley	
	Note: Sacre, Candace	Know whether size of bill to what extent or not drive estimated call handle time?
6:43:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions?
6:43:42 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions for Halstead?
6:43:51 PM	Chairman Chandler	
	Note: Sacre, Candace	Call next witness?
6:43:54 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	Paul Halstead.
6:44:01 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
6:44:08 PM	Chairman Chandler - witness Halstead	
	Note: Sacre, Candace	Examination. Name and address:
6:44:42 PM	Atty Herring Duke Kentucky - witness Halstead	
	Note: Sacre, Candace	Direct Examination. State position?
6:44:50 PM	Atty Herring Duke Kentucky - witness Halstead	
	Note: Sacre, Candace	Cause be filed testimony and data requests?
6:44:58 PM	Atty Herring Duke Kentucky - witness Halstead	
	Note: Sacre, Candace	Changes?
6:45:03 PM	Atty Herring Duke Kentucky - witness Halstead	
	Note: Sacre, Candace	Asked same questions, answers be same?
6:45:07 PM	Atty Herring Duke Kentucky - witness Halstead	
	Note: Sacre, Candace	Intent testimony and data requests be submitted?
6:45:18 PM	Chairman Chandler	
	Note: Sacre, Candace	Ms. Grundmann?
6:45:28 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Cross Examination. AG witness Kollen opposed Clean Energy Connection?
6:45:44 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Respond his criticism in rebuttal?
6:45:50 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Steps envision would occur, company asked Commission approve Clean Energy Connection concept?
6:46:06 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Need be second proceeding where CPCN sought?

6:46:22 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Able to extent Commission approves Clean Energy Connect market and receive commitments from customers?
6:47:01 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Assuming approval CPCN, then open subscriptions?
6:47:09 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Believe having approval Clean Energy Connection now give ability to put forward evidence to Commission likely be less cost to nonparticipating customers?
6:47:34 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Correct under Clean Energy Connect goal is costs not borne by nonparticipating customers?
6:47:41 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	To extent great deal of interest in process, suggest less likely be impact on nonparticipating customers?
6:48:03 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Implemented in Duke Energy Florida territory?
6:48:13 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Been successful?
6:48:16 PM	Atty Grundmann Walmart - witness Halstead	
	Note: Sacre, Candace	Same format proposing here?
6:48:30 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
6:48:32 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Cross Examination. Clean Energy Connection, method used to calculate fixed and variable benefits, none chosen yet?
6:49:02 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Benefits talking about avoided energy purchases, be used in calculation?
6:49:15 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Walk through calculation?
6:50:05 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Similar program in Florida, proposed in same way?
6:50:44 PM	Staff Atty Tussey PSC - witness Halstead	
	Note: Sacre, Candace	Solar project support project completed as early as 2025, still believe date?
6:51:26 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Be solar project Duke owns and constructs?
6:52:03 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	How program be designed fund renewable facility cost without long-term commitment for participants, explain how work if not fully subscribed to?
6:53:15 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Not propose carbon value for solar project?
6:53:44 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	In Florida up and running, avoided carbon cost included in calculation?
6:54:33 PM	Staff Atty Temple PSC - witness Halstead	
	Note: Sacre, Candace	Assumption what happen with this program as well?
6:55:21 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
6:55:23 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
6:55:40 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussions. (Click on link for further comments.)

6:56:54 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess until 7:50.
6:57:01 PM	Session Paused	
7:44:15 PM	Session Resumed	
7:45:04 PM	Session Paused	
7:57:46 PM	Session Resumed	
7:58:18 PM	Chairman Chandler	
	Note: Sacre, Candace	Back on the record in Case No. 2022-00372.
7:58:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Call another witness?
7:58:26 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	Cory Gordon.
7:58:32 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
7:58:38 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Examination. Name and address?
7:58:54 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Direct Examination. Position?
7:59:03 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Cause be filed testimony and data requests?
7:59:08 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Changes?
7:59:12 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Asked same questions, answers be same?
7:59:17 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Intent testimony and data requests received into proceeding?
7:59:27 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
7:59:39 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Cross Examination. Have direct testimony?
7:59:51 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Page 4, lines 3-20, explain how customers benefit from advancement of EV infrastructure and adoption?
8:00:20 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Significant statewide financial benefits possible increased EV adoption?
8:00:27 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Explained, reading (click on link for further comments)?
8:00:42 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	What mean by broader base?
8:01:00 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Explain, reading (click on link for further comments)?
8:01:27 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Found net benefit to repairs $200 per EV possible in 2030?
8:01:40 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Duke Kentucky forecasts adoption of 20,000 EVs in Duke Energy footprint end of 2030?
8:01:54 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Customer savings $200 roughly per EV of $4 million?
8:02:03 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Savings of $4 million accrue to customers from adoption of EVs and those savings?
8:02:15 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Spread across all customers?

8:02:21 PM	Atty Huddleston Sierra Club - witness Gordon	
	Note: Sacre, Candace	Not just specific savings discussed but savings from adoption electric vehicles accrue all customers?
8:02:56 PM	Chairman Chandler	
	Note: Sacre, Candace	Ms. Grundmann?
8:02:58 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Cross Examination. Following up on rebuttal, revisions to Make Ready credit program, Chriss expressed concerns potential customer confidential information customer usage profile, believe program adequately protects data included in profile?
8:03:46 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	One thing not mentioned context litigated proceeding, what happen party request usage profile in discovery?
8:04:28 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Ever heard phrase can't unring a bell?
8:04:33 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Understand what Chriss requested included language makes clear this completed profile not distributed absent mutual agreement company and customer?
8:05:11 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Anything in tariff reflects agreement?
8:05:38 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	State that explicitly or relying on broad phrase applicable laws and regulations?
8:05:50 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Were reflecting within terms and conditions, set forth reasons data used, otherwise disclosure subject to applicable laws and regulations, catchall means which protect disclosure?
8:06:35 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Company opposed to revising terms and conditions make clear will not disclose data except upon mutual agreement with customer?
8:07:30 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Discovery request, refuse product, motion compel filed, Commission then make decision whether document should/should not be produced?
8:07:53 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	Objection, calls for legal conclusion. (Click on link for further comments.)
8:08:26 PM	Atty Grundmann Walmart - witness Gordon	
	Note: Sacre, Candace	Committing have conversation see whether additional revisions to terms and conditions be appropriate?
8:08:45 PM	Chairman Chandler	
	Note: Sacre, Candace	Anticipate briefing confidentiality issue. (Click on link for further comments.)
8:16:51 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
8:16:56 PM	Staff Atty Temple PSC	
	Note: Sacre, Candace	Technical difficulties. (Click on link for further comments.)
8:18:30 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess.
8:18:39 PM	Session Paused	
8:23:40 PM	Session Resumed	
8:24:13 PM	Chairman Chandler	
	Note: Sacre, Candace	Back on record in Case No. 2022-00372.

8:24:28 PM	Staff Atty Temple PSC - witness Gordon	
	Note: Sacre, Candace	Cross Examination. In direct, stated utilities in Kentucky need some form of managed charging to limit incremental peak capacity costs, how plan do this and when proposed?
8:26:45 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
8:26:55 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Examination. Regulated utilities outside of states implement performance-based regulation have economic incentive maximize capital investments?
8:27:19 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Utilities make profit based on return on capital?
8:27:29 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Talking about how beneficial EVs be increase kilowatt hours sold by company and spread costs over greater number of sales?
8:27:50 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	If those loads EVs not drive more costs than pay for?
8:28:06 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Basis for comments on need to consider managed charging?
8:28:44 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Absent informed consumers understand cost of service, charging at certain times, need to implement rates so EV customers not drive more cost than save the remaining system?
8:29:23 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Time-of-use program single meter taking entire home on meter turning into time of use and allowing homeowner also have EV can move some demand to off-peak times?
8:29:47 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	What referring to earlier?
8:29:55 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Flip side of that, in event EVs drive cost, not managed, expect costs be expenses or capital costs additional EVs can drive but for managed charging?
8:31:34 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Been in hearing last two days?
8:31:42 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Given fact Duke has generation needs serve system, EV use drives additional peak demand, have expectation drive additional capital costs for system?
8:32:56 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Saying answer to question already answered in sense company planning for additional pressure on peak usage due to EV adoption?
8:33:24 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Residential rates, time bearing now?
8:33:35 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Know existence of time-of-use proposal?
8:33:40 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Absent time-of-use proposal, not understanding residential rates are customer charge and volumetric measure charge?
8:33:53 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Not vary with time because proposal to implement time-varying rates, 50 kW demand at noon or midnight no inherent difference under fixed charge and variable charge rate structure?

8:34:18 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Based on convenience, customer provide no price signal driving additional system costs for charging middle of day in summer or 5 am in winter, or any given time of year?
8:34:39 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Run risk that usage just like any usage drive increased system demand over time?
8:35:10 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Have appreciation what intend to do, have to build additional transmission or production or distribution all are capital costs which benefit Duke Energy shareholders?
8:35:40 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	What is internally/externally providing economic incentive to consider and implement managed charging so capital costs not come up?
8:36:50 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Where benefit for EV adoption to Duke?
8:38:06 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	In three years, increased 400 percent just in DEK territory?
8:38:20 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Fleet electrification, work on fleet electrification?
8:38:30 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Less about managed charging relates production, more about incremental infrastructure investment meet demands for fleet electrification, worked on this across Duke territory at Amazon, Amazon gone out and has exclusive deal with Rivian, aware agreement?
8:39:16 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Have to plug in somewhere?
8:39:24 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	DEK in unique position with Amazon?
8:39:32 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	With CVG situation, same with DHL, unique relationship in use of Northern Kentucky Airport?
8:39:44 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Amazon has hub in Northern Kentucky, DEK electric provider, Amazon says entire fleet electric, what doing DEK specifically talk to major fleet customers today what are expectations fleet electrification?
8:43:01 PM	Chairman Chandler - witness Gordon	
	Note: Sacre, Candace	Real risk in terms of cost and time being exclusively reactionary to fleet demands?
8:43:19 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
8:43:22 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Redirect Examination. Recall questions from Chair EV charging impact peak demand drive additional costs for generation and transmission?
8:43:34 PM	Atty Herring Duke Kentucky - witness Gordon	
	Note: Sacre, Candace	Speak to how time-of-use rates proposed in proceeding used manage EV demand and increased load?
8:44:15 PM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions for Gordon?
8:44:26 PM	Chairman Chandler	
	Note: Sacre, Candace	Counsel?

8:44:33 PM	Atty Vaysman Duke Kentucky	
	Note: Sacre, Candace	Dominic Melillo.
8:44:45 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
8:44:50 PM	Chairman Chandler - witness Melillo	
	Note: Sacre, Candace	Examination. Name and address?
8:45:04 PM	Atty Vaysman Duke Kentucky - witness Melillo	
	Note: Sacre, Candace	Direct Examination. Name, position, address?
8:45:22 PM	Atty Vaysman Duke Kentucky - witness Melillo	
	Note: Sacre, Candace	Cause testimony and responses be filed?
8:45:29 PM	Atty Vaysman Duke Kentucky - witness Melillo	
	Note: Sacre, Candace	Corrections?
8:45:33 PM	Atty Vaysman Duke Kentucky - witness Melillo	
	Note: Sacre, Candace	Asked same questions, responses be same?
8:45:42 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
8:46:15 PM	Atty Vaysman Duke Kentucky	
	Note: Sacre, Candace	Jeremy Gibson.
8:46:19 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
8:46:26 PM	Chairman Chandler - witness Gibson	
	Note: Sacre, Candace	Examination. Name and address?
8:46:42 PM	Atty Vaysman Duke Kentucky - witness Gibson	
	Note: Sacre, Candace	Direct Examination. Name, title, and business address?
8:47:00 PM	Atty Vaysman Duke Kentucky - witness Gibson	
	Note: Sacre, Candace	Cause responses be filed?
8:47:04 PM	Atty Vaysman Duke Kentucky - witness Gibson	
	Note: Sacre, Candace	Corrections?
8:47:10 PM	Atty Vaysman Duke Kentucky - witness Gibson	
	Note: Sacre, Candace	Asked same questions, responses be same?
8:47:17 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
8:47:33 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussion. (Click on link for further comments.)
8:51:28 PM	Chairman Chandler	
	Note: Sacre, Candace	Another witness?
8:51:31 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Lisa Steinkuhl.
8:51:35 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
8:51:44 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Examination. Name and address?
8:51:57 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Direct Examination. Position with Duke organization?
8:52:05 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Cause be filed testimony and responses?
8:52:26 PM	Atty Brama Duke Kentucky	
	Note: Sacre, Candace	Filed motion to correct aspects of Steinkuhl testimony. (Click on link for further comments.)
8:52:41 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Corrections to testimony or responses other than contained in motion?
8:52:51 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Asked same questions, provide same answers?

8:53:00 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Intention testimony as corrected and responses admitted?
8:53:08 PM	Chairman Chandler	
	Note: Sacre, Candace	Ms. Goad?
8:53:12 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Cross Examination. Accurate in rebuttal state three adjustments AG's Office witness Futral recommends company willing to accept?
8:53:31 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	First adjustment that Duke Kentucky accepts company's error in calculation forecasted 13-month plant-in-service balances?
8:53:51 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Accepting adjustment reduce requested revenue requirement by .011 million?
8:54:07 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Second adjustment company willing to accept concerns error in lead/lag calculation for collection lag days?
8:54:15 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Correct adjustments to lead/lag calculation reduces cash working capital by $4.919 million?
8:54:25 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Specific adjustment reduce requested revenue requirement by $459,678?
8:54:36 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Third adjustment company willing to accept concerns Duke Kentucky not including amortization for DAB excess income taxes which would reduce proposed revenue requirement by $16,435?
8:54:56 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	In revised testimony, added additional recommendation by Futral that Duke Kentucky partially accepts a reduction to proposed property tax expense?
8:55:36 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Accurate two recommendations by Kollen not oppose, not accept it, don't oppose it?
8:55:52 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Correct Duke Kentucky not oppose Kollen recommendation deny request transfer recovery return projects rider ESM to base revenues?
8:56:07 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	In discovery responses, Duke Kentucky stated recommendation reduce revenue requirement over $12 million?
8:56:18 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Rebuttal correct reduction $9.939 million?
8:56:40 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Revised rebuttal changed reduction to $3.290 million?
8:56:50 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	In revised rebuttal, not explanation why reduced?
8:57:13 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	What response is?
8:57:23 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Explain why Duke Kentucky asserting reduce revenue requirement and now down?
8:59:08 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Based upon first number and then $3 million, certain number is correct?

8:59:28 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	After all revisions, willing remove $3,289,776 from revenue requirement rider ESM?
8:59:48 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Duke Kentucky not oppose Kollen recommendation reduce rate base financing for fuel and limestone?
9:00:04 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Reduction reduce rate base $6.459 million?
9:00:20 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Referring reduce rate base?
9:00:35 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Although Duke not agree Baudino recommendation company revised capital structure through rebuttal reduce revenue requirement $369,966?
9:00:58 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Summarize, AG recommendations Duke reduce rate increase $6,355,880?
9:01:17 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Revised rebuttal page 7, new table, number correct?
9:01:51 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	$6,355,880?
9:01:58 PM	Asst Atty General Goad - witness Steinkuhl	
	Note: Sacre, Candace	Produce revised rate increase $68,821,042?
9:02:17 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
9:02:23 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Cross Examination. Here Carpenter testified?
9:02:31 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Expenses Linton substation, Hebron-Oakbrook, post-hearing provide information?
9:03:17 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Staff DR 1-14, rate case expenditures, asked Normand who Morganti, there?
9:03:43 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	What role play?
9:04:08 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	As far as invoices, documentation, additional invoices?
9:04:34 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Five percent professional fee?
9:04:38 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Listed N/A rate case expenses that firm?
9:05:04 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Ask for postage, paper documentation?
9:05:24 PM	Staff Atty Tussey PSC - witness Steinkuhl	
	Note: Sacre, Candace	Other places have N/A, provide additional information?
9:06:01 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	STAFF ATTY TUSSEY PSC - WITNESS STEINKUHL
	Note: Sacre, Candace	PROVIDE DOCUMENTATION FOR RATE CASE EXPENSES LABELED WITH N/A
9:06:05 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
9:06:08 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Examination. Procure services rate case expenses?

9:06:36 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	What about Quilici, Concentric?
9:06:59 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Conduct work other states?
9:07:07 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Similar process recovery rate case expense?
9:07:19 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Going rate $730 expert witness?
9:07:34 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	In line with witnesses experience with?
9:07:57 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	In hearing today asking Swez?
9:08:04 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Replacement power forced outages?
9:08:15 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Test year amount replacement power in COS?
9:08:42 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Deferral accounting related that?
9:08:48 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	What base amount?
9:08:54 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	In base rates?
9:08:56 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Commission gave opportunity defer above and below?
9:09:09 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	What did annual basis since Order?
9:09:13 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	What propose test year COS?
9:09:22 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Proposing same accounting?
9:09:29 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Proposing use same base amount?
9:10:11 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Create regulatory liability offset assets have or deferred for later?
9:10:44 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Why $1.6 million?
9:11:05 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	What benefit normalizing expense and ability track above/below?
9:11:36 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Why need deferral recovery?
9:12:41 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	ESM amount out one pocket, in another?
9:12:51 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Looks better number less but exact same amount?
9:13:03 PM	Chairman Chandler - witness Steinkuhl	
	Note: Sacre, Candace	Different line of bill?
9:13:19 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
9:13:24 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Redirect Examination. Explanation changes in rider ESM?
9:13:41 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	Referred to Staff DR 3-021, provided with rebuttal?
9:13:58 PM	Atty Brama Duke Kentucky - witness Steinkuhl	
	Note: Sacre, Candace	All same time?

9:14:37 PM	Chairman Chandler	
	Note: Sacre, Candace	Next witness?
9:14:40 PM	Atty Herring Duke Kentucky	
	Note: Sacre, Candace	James Ziolkowski.
9:14:50 PM	Chairman Chandler	
	Note: Sacre, Candace	Witness is sworn.
9:14:54 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Examination. Name and address?
9:15:08 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Direct Examination. Position with company?
9:15:17 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Cause be filed testimony and rebuttal?
9:15:23 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Changes?
9:15:33 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Tell what change is?
9:16:16 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Note in data request response changes?
9:16:32 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Asked same questions, responses be same?
9:16:38 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Intent testimony and data requests be received?
9:16:50 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussion. (Click on link for further comments.)
9:17:23 PM	Chairman Chandler	
	Note: Sacre, Candace	Ms. Grundmann?
9:17:32 PM	Atty Grundmann Walmart - witness Ziolkowski	
	Note: Sacre, Candace	Cross Examination. Direct proposes mechanism move all customer classes closer to cost of service, agree?
9:17:54 PM	Atty Grundmann Walmart - witness Ziolkowski	
	Note: Sacre, Candace	Review Chriss' testimony?
9:18:25 PM	Atty Grundmann Walmart - witness Ziolkowski	
	Note: Sacre, Candace	Page 18, Chriss testimony, used information provided by you calculate relative rate of return for rate classes, familiar with calculation?
9:19:05 PM	Atty Grundmann Walmart - witness Ziolkowski	
	Note: Sacre, Candace	Draw attention to page 19, Chriss testimony, starting line 7, position if Commission award company requested revenue requirement, not oppose allocation proposed, at line 13 recommends if lesser increase awarded move classes closer to COS, recall recommendation?
9:19:50 PM	Atty Grundmann Walmart - witness Ziolkowski	
	Note: Sacre, Candace	Presume company agnostic to allocation?
9:20:26 PM	Chairman Chandler	
	Note: Sacre, Candace	Mr. Boehm?
9:20:51 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Cross Examination. Page 4, rebuttal, in room when Bieber testified?
9:21:21 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Generally agree with Beiber generation and transmission cost to serve multi-site customer be same as single-site customer when aggregated no difference in cost for GNT?
9:22:50 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Service territory not quite that large?

9:23:03 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Page 4, rebuttal, line 19, conjunctive billing reallocated across rate classes, direct testimony Duke proposes allocate demand costs using 12 CP method?
9:23:30 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Agree Duke implement conjunctive demand pilot not change coincident peak any class?
9:24:12 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Assume implementing for one rate schedule, agree not change coincident peaks for rate schedule?
9:24:31 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	No change to 12 CP demands, no cost shifting between rate classes?
9:24:56 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Page 5, rebuttal, line 4, reading (click on link for further comments), recall statement?
9:25:25 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Reviewed direct of Duke witness Sailers?
9:25:38 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Read one paragraph, page 10, lines 14-20, reading (click on link for further comments), recall?
9:26:28 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Agree new demand charge rate DT designed recover distribution costs?
9:26:38 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Agree unbundling distribution demand charge facilitate multi-site aggregation demand billing?
9:27:13 PM	Atty Boehm Kroger - witness Ziolkowski	
	Note: Sacre, Candace	Whether would facilitate conjunctive demand billing given statement here?
9:27:35 PM	Chairman Chandler	
	Note: Sacre, Candace	Mr. Werner?
9:27:45 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Cross Examination. Direct, performed cost of service study for allocating costs across different class of customers?
9:28:05 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Classified certain costs?
9:28:17 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Among costs looked at distribution-related costs?
9:28:26 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Performed minimum size cost study?
9:28:33 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Also performed zero intercept analysis?
9:28:39 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Part of zero intercept analysis included cost of zero foot pole?
9:28:48 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Obtained pole cost and quantity data from Duke plant accounting records?
9:28:58 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Duke maintain one set of plant accounting records?
9:29:22 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Not have multiple sets plant accounting books?
9:29:28 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Duke not have multiple sets plant accounting books?
9:29:39 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Believe records accurate?

9:29:45 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Why?
9:30:15 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Used data Duke accounting records determine average cost for each pole size accounting group?
9:30:24 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Have testimony in front of you?
9:30:30 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Have attachments in front of you?
9:30:34 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Pages 1 and 2, JEZ-5, discussed pages 20-25 testimony, recall?
9:30:51 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Page 1 of JEZ-5, category for 35-foot poles?
9:31:09 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Number of poles is 11,980?
9:31:18 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Number derived from Duke plant accounting records?
9:31:25 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Column says minimum size, 11,980 only include 35-foot poles?
9:31:52 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Is 980, or misstating it?
9:31:59 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	890, sorry, just 35-foot poles?
9:32:12 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Personally obtain data?
9:33:10 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Rely on folks plant accounting department provide data?
9:33:30 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	What about when comes to minimum size cost studies?
9:33:38 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Have any reason to doubt ability provide accurate data?
9:33:49 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Look down one row, entry for 40-foot poles?
9:33:58 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Number there 29,114?
9:34:06 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Help me understand this, look back at column indicate 40-foot minimum size poles, correct or just include 40-foot poles?
9:34:42 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	That number 29,114 includes poles minimum size of 40 up to and including 70-foot poles?
9:35:32 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Focus on number, trying to understand what number reflects, understand includes 40-foot poles up to 70 feet?
9:36:04 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Tell you where going with this, if look at page 2, breakdown of poles counts, how numbers page 1 correspond to numbers on page 2?
9:37:31 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Not understanding what say by all of the poles, what is all of the poles?
9:39:35 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Category, entry for 35-foot poles, quantity reflected is quantity of 35 -foot poles?

9:40:23 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Including all poles in minimum size data, why different number for 35-foot poles and for 40-foot poles?
9:40:43 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Quantity and investment numbers used in JEZ-5, include non-unitized poles?
9:41:15 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Numbers in JEZ-5 not include quantity of nonunitized poles as well as investment related those poles?
9:41:49 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Page 2, JEZ-5, that is pole record?
9:42:01 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Nonunitized poles, Duke have document numbers on it how many nonunitized poles out there?
9:42:26 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Heard testify earlier familiar with Sailers testimony?
9:42:37 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Generally familiar, right?
9:42:40 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Look at pole attachment rate analysis?
9:42:48 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Not look at pole counts and investment numbers used to come up with pole attachment rate?
9:43:01 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	If wanted to know why quantities and investment numbers he uses are different from yours, not something could tell me?
9:43:14 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Know what records he used to derive pole quantity investment numbers?
9:43:40 PM	Chairman Chandler	
	Note: Sacre, Candace	Staff?
9:43:55 PM	Staff Atty Tussey PSC - witness Ziolkowski	
	Note: Sacre, Candace	Cross Examination. Direct, page 6, testified chose 12 CP methodology, give examples of studies or measurable factors why eliminated two other methodologies?
9:45:39 PM	Staff Atty Tussey PSC - witness Ziolkowski	
	Note: Sacre, Candace	Really not have any other than this is accepted methodology from past?
9:46:08 PM	Staff Atty Tussey PSC - witness Ziolkowski	
	Note: Sacre, Candace	Turn to page 28 of direct, question about Duke proposing eliminate five percent subsidization of impacted customer classes?
9:46:35 PM	Staff Atty Tussey PSC - witness Ziolkowski	
	Note: Sacre, Candace	How come to determination five percent was appropriate amount?
9:47:32 PM	Staff Atty Tussey PSC - witness Ziolkowski	
	Note: Sacre, Candace	Company determination as to reasonableness but nothing concrete say did this analysis and got this result?
9:47:45 PM	Chairman Chandler	
	Note: Sacre, Candace	Questions?
9:47:48 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Examination. Five percent what proposed in last case?
9:47:55 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	End up being closer to seven-and-a-half, Commission end up approving 15?
9:48:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?

9:48:29 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Redirect Examination. Recall questions about aggregated conjunctive demand billing program Kroger proposed?
9:48:42 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Referencing page 4, line 18, rebuttal, no cost shifting between rate classes, concern raising between rate classes or within rate classes?
9:49:16 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Kentucky Broadband & Cable, minimum system study?
9:49:25 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Page 20, line 10, first step performing minimum system study, tell me what is?
9:50:21 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Turn back to Attachment JEZ-5, column minimize size and pole not just 40-foot pole, other classifications related to minimum size pole?
9:50:56 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Number of qualifications type of 40-foot pole would be minimum size?
9:51:10 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	Know testified not familiar pole calculations performed by Sailers, fair to say data set you used for minimum size pole different than Sailers used?
9:51:57 PM	Atty Herring Duke Kentucky - witness Ziolkowski	
	Note: Sacre, Candace	In developing minimum size study, looked at work orders for poles and decided which provide usable data for both studies?
9:52:36 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Examination. JEZ-5, page 14, two types of poles, account 364 and account 364, see that?
9:52:52 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	All poles fall one of two categories, primary or secondary?
9:52:58 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Records looked at, Duke have 41,004 poles?
9:53:14 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	All you have accounted for?
9:53:32 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Page 2, data wooden poles ten foot up to 70, correct?
9:53:47 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Had data were six 10-foot poles?
9:54:10 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Saying, if added new one, minimum for secondary 35 feet, 40 for primary, what you got in records is there were 41,004 poles?
9:54:44 PM	Chairman Chandler - witness Ziolkowski	
	Note: Sacre, Candace	Why difference between two numbers?
9:55:33 PM	Chairman Chandler	
	Note: Sacre, Candace	Additional questions?
9:55:43 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Recross Examination. If understood testimony, written and today, asked property record folks provide universe of poles?
9:56:06 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Data set all of Duke's poles?
9:56:17 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Asked folks in charge of data where have no basis for doubting abilities track records and provide information for universe of poles, and they provided it, right?
9:56:30 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Went and did some things with it, but what studies all about?

9:56:37 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Just asked questions about what Sailers did, thought you told me not know what Sailers did?
9:56:50 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Where he got information, quantity of poles, and investment in poles, not know?
9:57:00 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Not know if he drawing from same information you were or not?
9:57:09 PM	Atty Werner Kentucky Broadband & Cable - witness Ziolkowski	
	Note: Sacre, Candace	Could be working from same universe of information or different universe of information, not tell me one way or the other?
9:57:24 PM	Chairman Chandler	
	Note: Sacre, Candace	Redirect?
9:57:38 PM	Chairman Chandler	
	Note: Sacre, Candace	Procedural discussions. (Click on link for further comments.)
9:59:08 PM	Chairman Chandler	
	Note: Sacre, Candace	Recess until tomorrow at 9 am.
9:59:23 PM	Session Ended	

Exhibit List Report

2022-00372 10May2023

Duke Energy Kentucky, Inc. (Duke Kentucky)

Name:	Description:
HEARING EXHIBIT DK 1	MOODY'S 24 APR 2023 RATING ACTION: MOODY'S AFFIRMS DUKE ENERGY AND SUBSIDIARY RATINGS; CHANGES OUTLOOK OF DUKE ENERGY KENTUCKY TO NEGATIVE
HEARING EXHIBIT SC 2	PJM TARIFF ATTACHMENT D
HEARING EXHIBIT SC 3	GOOD NEIGHBOR PLAN FOR 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS
HEARING EXHIBIT SC 4	SUPPLEMENTAL EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY
HEARING EXHIBIT SC 5	RECONSIDERATION OF NATIONAL AMBIENT AIR QUALITY STANDARDS FOR PARTICULATE MATTER
HEARING EXHIBIT SC 6	NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW

MOODY'S

Rating Action: Moody's affirms Duke Energy and subsidiary ratings; changes outlook of Duke Energy Kentucky to negative

24 Apr 2023

New York, April 24, 2023 -- Moody's Investors Service (Moody's) affirmed the ratings of Duke Energy Corporation (Duke, Baa2) along with the ratings of its utility subsidiaries: Duke Energy Carolinas, LLC (Duke Energy Carolinas, A2), Duke Energy Progress, LLC (Duke Energy Progress, A2), Duke Energy Florida, LLC. (Duke Energy Florida, A3), Duke Energy Indiana, LLC. (Duke Energy Indiana A2), Duke Energy Ohio, Inc. (Duke Energy Ohio, Baa1), Duke Energy Kentucky, Inc. (Duke Energy Kentucky, Baa1), and Piedmont Natural Gas Company, Inc. (Piedmont, A3). Moody's also affirmed the ratings of Duke's intermediate subsidiary holding company, Progress Energy, Inc. (Progress Energy, Baa1).

At the same time, Moody's changed the rating outlook of Duke Energy Kentucky to negative from stable. The rating outlook for Duke and all of its other subsidiaries is stable.

RATINGS RATIONALE

"The ratings affirmation of Duke and its subsidiaries reflects our expectation that continued credit supportive regulation will help the utilities to maintain their credit quality despite substantial capital investment programs" stated Nana Hamilton, VP- Senior Analyst. "Duke Energy Kentucky's negative outlook reflects the potential that historically weak credit metrics will be sustained going forward should the outcome of the company's pending rate case be unfavorable" added Hamilton.

Over the next two years, we expect Duke's ratio of operating cash flow excluding changes in working capital (CFO pre-WC) to debt ratio to be maintained in the 13%-15% range that we have indicated as appropriate for its current Baa2 rating, albeit at the bottom half of that range, leaving it with little financial flexibility. The company's 2022 credit metrics were materially lower than that range, including a ratio of CFO pre-WC to debt of 11.3% (adjusted for securitization and Duke's proportional ownership of Duke Energy Indiana), primarily due to about $3.9 billion in deferred fuel costs. Adjusting for the cash flow impact of these deferred fuel costs, substantially all which we expect to be recovered by the end of 2024, the CFO pre-WC to debt ratio would have been 12.9%.

With no equity issuances in its financing plan and one of the largest capital expenditure programs in the utilities sector, Duke's credit metrics will remain under pressure. However, we expect continued credit supportive regulation, particularly in Duke's largest service territories in North Carolina, Florida and Indiana, to help the company maintain debt coverage metrics within our expected range for the current rating. Duke is also currently pursuing a sale of its commercial renewables business and proceeds from a successful sale would provide additional funds to supplement debt financing.

The ratings affirmation and stable outlooks at Duke Energy Carolinas and Duke Energy Progress consider what we expect will be credit supportive outcomes of currently pending rate cases at both utilities. Despite generally collaborative regulatory relationships, Duke's Carolina utilities, which combined make up approximately 55% of its earnings base, have historically not benefited from

HEARING EXHIBIT DK 1

tracking mechanisms that could serve to reduce regulatory lag on investments. However, pursuant to legislation passed in October 2021, both utilities are requesting multi-year performance based rate plans for the first time in North Carolina which we view as a positive development toward mitigating this regulatory lag. Both utilities' 2022 credit metrics were depressed by significant under-recovered fuel costs with Duke Energy Carolinas requesting a 12 month recovery of these costs effective September 2023 and Duke Energy Progress expected to request 12 month recovery effective December 2023. A final commission order is expected for Duke Energy Carolinas in August 2023. Over the next two years, we expect both utilities to produce a ratio of CFO pre-WC to debt in the 20%-22% range, excluding the financial impact of storm cost securitization.

The affirmation of Duke Energy Florida's ratings recognizes credit supportive regulation in Florida that allows for timely recovery of costs and investments. This is especially important for Duke Energy Florida whose service territory is highly exposed to hurricanes. The relatively quick restoration of power to about one million customers within three days after Hurricane Ian exited the state in October 2022 demonstrates the success of its infrastructure hardening investments. As of 31 December 2022, Duke Energy Florida had about $353 million of deferred Hurricane Ian costs and has received regulatory approval to recover costs associated with Ian over 12 months and to replenish its storm reserve. Duke Energy Florida's 2022 credit metrics were negatively impacted by the higher debt incurred to fund storm costs and high fuel costs. Over the next two years, we expect the utility will be able to maintain a ratio of CFO pre-WC to debt of around 20%, excluding the financial impact of securitization bonds associated with the retirement of its Crystal River nuclear plant.

The affirmation of intermediate parent company Progress Energy's rating is driven by the affirmation of the ratings of subsidiaries Duke Energy Progress and Duke Energy Florida. The Baa1 rating reflects the structurally subordinate position of its debt vis-à-vis the debt at these two subsidiaries. The percentage of intermediate parent level debt as compared to total consolidated Progress Energy debt has decreased significantly over time and at year-end 2022 was approximately 7%, down from 20% in 2021. This is due to a $450 million maturity in 2022 and higher debt at its subsidiaries to fund higher fuel costs and storm costs. Excluding securitization bonds and associated cash flow impacts, we expect Progress Energy to generate a ratio of CFO pre-WC to debt in the high teens over the next two years.

The affirmation of Duke Energy Indiana's rating acknowledges credit supportive regulation in Indiana including forward looking test years for rate cases and several authorized rider/tracker provisions that permit timely recovery of expenditures. Duke closed the second phase of its minority sale of Duke Energy Indiana to GIC in December 2022, with Duke Energy Indiana issuing an additional 8.85% of its membership interests in exchange for approximately $1 billion, following a sale of 11.05% of its membership interests in September 2021. Our assessment of Duke's credit quality proportionally consolidates the 80.1% of Duke Energy Indiana that it now owns.

We expect Duke Energy Indiana to produce credit metrics in line with our expectations for its rating over the next two years, including a ratio of CFO pre-WC to debt in the low 20% range. However, credit metrics will be pressured beyond 2025 when capital expenditures are forecast to significantly increase to about $1.5 billion annually, up from an already high annual average of around $900 million. The utility's transition away from coal, which represents about 70% of its generation portfolio, is the primary driver of the increase in capital spending. Despite timely cost recovery mechanisms, the sheer size of its capital expenditure program will increase regulatory lag and require more frequent rate case activity.

Duke Energy Ohio's Baa1 rating affirmation reflects a credit supportive regulatory environment that includes a large number of riders and trackers for investments in the company's transmission and distribution system. Credit metrics have been at the weak end of our expectation for the rating over the last three years, including a ratio of CFO pre-WC to debt averaging 15.1%, as the utility has continued to make significant investments in transmission and distribution. With a recently approved electric rate increase effective January 2023 and a pending natural gas rate case, we expect Duke Energy Ohio to maintain a ratio of CFO pre-WC to debt in the 15% - 17% range over the next two years. Longer-term, Duke Energy Ohio's next electric security plan (ESP), which will be effective in 2026, will be important to its future credit quality.

The negative outlook on Duke Energy Kentucky reflects a history of weak credit metrics, including a CFO pre-WC to debt averaging 15.2% in recent years, consistently below our minimum expectation of 17% for its Baa1 rating. These weak metrics may persist depending on the outcome of its currently pending electric rate case. Although Duke Energy Kentucky benefits from several cost recovery mechanisms, including recovery of fuel, purchased power, and environmental compliance costs and the use of a forward test year in rate cases, the company's cash flow has been flat since 2018 relative to a compound annual growth rate in debt of about 10%. In its electric rate case, Duke Energy Kentucky has requested a revenue increase of $75 million based on a 10.35% return on equity and a 52.51% equity layer. A final decision is expected by the end of the second quarter of 2023 and will be important to our assessment of the company's Baa1 credit rating.

The affirmation of Piedmont's A3 rating reflects its low business risk as a regulated natural gas local distribution company operating in supportive regulatory jurisdictions in North Carolina, South Carolina and Tennessee. Substantial capital expenditures, averaging about $870 million annually over the last three years, have kept pressure on debt coverage metrics, with an average CFO pre-WC to debt ratio of 14.3%. Piedmont has not paid a dividend to Duke since 2016, which has helped to support the utility's credit profile through a period of high capital expenditures. The company forecasts annual capital expenditures to be in the $900 million to $950 million range over the next two years as it continues to invest in infrastructure to support customer growth and system integrity. We expect credit metrics to remain pressured over the next two years, with a ratio of CFO pre-WC to debt in the 15%-16% range but see improving debt coverage metrics beyond 2024 when the utility's capital spending is forecast to moderate to a range of $600 million to $700 million annually.

Rating Outlook

The stable outlook for Duke and its subsidiaries, with the exception of Duke Energy Kentucky, reflects our expectation that the companies will maintain supportive regulatory relationships in all of their jurisdictions. The outlook also assumes management will manage its operating, capital and financing plans in a manner that supports credit quality and enables the maintenance of credit metrics that are consistent with our expectations.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that ould Lead to an Upgrade

While unlikely in the near term, upward pressure on the ratings could develop if regulatory environments were to become more supportive, resulting in increased cash flow, or if there were to be reductions in leverage leading to materially stronger credit metrics.

For example, at Duke, an upgrade could be considered if it exhibits a consolidated ratio of CFO pre-WC to debt above 15% on a sustainable basis; at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Indiana, a ratio above 25%; at Duke Energy Florida, a ratio above 22%; at Duke Energy Ohio, a ratio at or above 19% (down from 20% previously); and at Duke Energy Kentucky a ratio above 21% (down from 22% previously). An upgrade of Duke Energy Progress or Duke Energy Florida could put upward pressure on the rating of Progress Energy. At Piedmont, a ratio of CFO pre-

WC to debt above 19% (up from 18% previously) could put upward pressure on the rating.

Factors that Could Lead to a Downgrade

Downward rating action could be considered if there were to be a deterioration in the credit supportiveness of the regulatory relationships at Duke's subsidiaries, that could result in a reduction in cash flow. A material increase in operating or capital expenditures that is not able to be recovered on a timely basis, or an increase in leverage leading to weaker credit metrics could also put downward pressure on the ratings.

For example, at Duke, a downgrade could be considered if the consolidated ratio of CFO pre-WC to debt sustained below 13%; at Duke Energy Carolinas and Duke Energy Progress a ratio maintained below 21% (up from 20% previously); at Duke Energy Indiana a ratio maintained below 22%; at Duke Energy Florida a ratio below 19%; at Duke Energy Ohio a ratio below 15%; and at Duke Energy Kentucky a ratio below 17%. A downgrade of Duke Energy Progress or Duke Energy Florida could put downward pressure on the rating of Progress Energy. At Piedmont, a ratio of CFO pre-WC to debt below 15% (up from 14% previously) could put downward pressure on the rating.

Headquartered in Charlotte, North Carolina, Duke is a large energy holding company with mostly regulated utility operations. Its main business consists of its electric utilities and infrastructure business segment, which serves approximately 8.2 million retail electric customers in six US states and made up about 90% of Duke's 2021 earnings base. Duke's gas utilities and infrastructure businesses provide natural gas to approximately 1.6 million customers located in five states.

Affirmations:

..Issuer: Duke Energy Corporation

.... Issuer Rating, Affirmed Baa2

....Senior Unsecured Conv./Exch. Bond/Debenture, Affirmed Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa2

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa3

....Pref. Stock Preferred Stock, Affirmed Ba1

....Pref. Shelf, Affirmed (P)Ba1

....Senior Unsecured Bank Credit Facility, Affirmed Baa2

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Duke Energy Indiana, LLC.

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Underlying Senior Secured First Mortgage Bonds, Affirmed Aa3

....Backed Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Regular Bond/Debenture, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

..Issuer: Duke Energy Ohio, Inc.

.... Issuer Rating, Affirmed Baa1

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Shelf, Affirmed (P)A2

..Issuer: Duke Energy Kentucky, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Duke Energy Carolinas, LLC

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

..Issuer: Piedmont Natural Gas Company, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Progress Energy, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Duke Energy Progress, LLC

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

..Issuer: Duke Energy Florida, LLC.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Underlying Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Backed Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Underlying Senior Secured First Mortgage Bonds, Affirmed A1

....Backed Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Secured Shelf, Affirmed (P)A1

..Issuer: Boone (County of) KY

....Senior Unsecured Revenue Bonds, Affirmed Baa1

....Underlying Senior Unsecured Revenue Bonds, Affirmed Baa1

....Backed Senior Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: CITRUS (COUNTY OF) FL

....Underlying Senior Secured Revenue Bonds, Affirmed A1

....Backed Senior Secured Revenue Bonds, Affirmed A1

..Issuer: Indiana Finance Authority

....Senior Secured Revenue Bonds, Affirmed Aa3

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

....Backed Senior Unsecured Revenue Bonds, Affirmed A2

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: North Carolina Capital Facilities Fin. Agy.

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

....Backed Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Ohio Air Quality Development Authority

....Senior Unsecured Revenue Bonds, Affirmed Baa1

....Underlying Senior Unsecured Revenue Bonds, Affirmed Baa1

....Backed Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: Ohio Water Development Authority

....Underlying Unsecured Revenue Bonds, Affirmed Baa1

....Backed Senior Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: Public Finance Authority

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

..Issuer: Wake County I.F. & P.C.F.A., NC (The)

....Underlying Senior Secured Revenue Bonds, Affirmed Aa3

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

Outlook Actions:

..Issuer: Duke Energy Corporation

....Outlook, Remains Stable

..Issuer: Duke Energy Indiana, LLC.

....Outlook, Remains Stable

..Issuer: Duke Energy Ohio, Inc.

....Outlook, Remains Stable

..Issuer: Duke Energy Kentucky, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Duke Energy Carolinas, LLC

....Outlook, Remains Stable

..Issuer: Piedmont Natural Gas Company, Inc.

....Outlook, Remains Stable

..Issuer: Progress Energy, Inc.

....Outlook, Remains Stable

..Issuer: Duke Energy Progress, LLC

....Outlook, Remains Stable

..Issuer: Duke Energy Florida, LLC.

....Outlook, Remains Stable

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://ratings.moodys.com/api/rmc-documents/68547. Alternatively, please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

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ATTACHMENT DD

Reliability Pricing Model

References to section numbers in this Attachment DD refer to sections of this Attachment DD, unless otherwise specified.

HEARING EXHIBIT SC 2

1. INTRODUCTION

This Attachment sets forth the terms and conditions governing the Reliability Pricing Model for the PJM Region. In the event of a conflict between this Attachment DD and Attachment M and its Appendix with respect to the responsibilities of the Market Monitoring Unit, the provisions of Attachment M and its Appendix shall control. As more fully set forth in this Attachment and the PJM Manuals, and in conjunction with the Reliability Assurance Agreement, the Reliability Pricing Model provides:

(a) support for LSEs in satisfying Daily Unforced Capacity Obligations for future Delivery Years through Self Supply of Capacity Resources;

(b) a competitive auction mechanism to secure the forward commitment of additional Capacity Resources and Qualifying Transmission Upgrades as necessary to satisfy the portion of LSEs' Unforced Capacity Obligations not satisfied through Self-Supply, in order to ensure the reliability of the PJM Region for future Delivery Years;

(c) long-term pricing signals for the development of Capacity Resources, including demand resources and planned generation resources, to ensure the reliability of the PJM Region;

(d) recognition for the locational benefits of Capacity Resources;

(e) deficiency charges to ensure progress toward, and fulfillment of, forward commitments by demand and generation resources to satisfy capacity requirements;

(f) measures to identify and mitigate capacity market structure deficiencies; and

(g) a Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

2. [Reserved for Future Use]

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;

e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;

f) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

g) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

h) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

i) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

j) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

k) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment, Attachment M, Attachment M - Appendix, the Operating Agreement, and the Reliability Assurance Agreement, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, Reliability Backstop Auction, or Capacity Performance Transition Incremental Auction shall be deemed confidential information for purposes of Section 18.17 of the Operating Agreement, Attachment M and Attachment M -

Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its eRPM tools. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its eRPM tools. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

5. CAPACITY RESOURCE COMMITMENT

5.1 Introduction

In accordance with the Reliability Assurance Agreement, each Load Serving Entity is obligated to pay a Locational Reliability Charge for each Zone in which it serves load based on the Daily Unforced Capacity Obligation of its loads in such Zone. An LSE may offset the Locational Reliability charge for a Delivery Year, in whole or in part, by: (a) Self-Supply of Capacity Resources in the Base Residual Auction or an Incremental Auction; (b) offering and clearing Capacity Resources in the Base Residual Auction or an Incremental Auction (but only to the extent of the additional resources committed to meet Unforced Capacity Obligations through such Incremental Auction); (c) receiving payments from Capacity Transfer Rights; or (d) offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in section 5.14(h). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.3 Commitment of Contractually Purchased Capacity Resources

A Load Serving Entity that has purchased the right to the capacity output of a generation resource and desires to commit such right as a Capacity Resource for a Delivery Year shall be considered a Capacity Market Seller. Such an LSE must submit a Sell Offer in the Base Residual Auction for such Delivery Year, in accordance with the procedure and time schedule set forth in the PJM Manuals. In such Sell Offer, the Capacity Resource offered by the LSE may be submitted as Self-Supply or with an offer price. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP Seller as sold prior to the Third Incremental Auction for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under sections 7, 8, 9, 10, 10A, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction for the purposes set forth in section 2.34. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.5 Eligibility for Participation in RPM Auctions

A Capacity Market Seller may submit a Sell Offer for a Capacity Resource in a Base Residual Auction, Incremental Auction, or Capacity Performance Transition Incremental Auction only if such seller owns or has the contractual authority to control the output or load reduction capability of such resource and has not transferred such authority to another entity prior to submitting such Sell Offer. Capacity Resources must satisfy the capability and deliverability requirements of Schedules 9 and 10 of the PJM Reliability Assurance Agreement, the requirements for Demand Resources or Energy Efficiency Resources in Attachment DD-1 and Schedule 6 of the Reliability Assurance Agreement, as applicable, and, for the 2018/2019 Delivery Year and subsequent Delivery Years, the criteria in section 5.5A.

5.5A Capacity Resource Types

a) Capacity Performance Resources

Capacity Performance Resources are Capacity Resources which, to the extent such resources cleared in a Reliability Pricing Model Auction or are otherwise committed as a Capacity Resource, are obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by the Office of Interconnection during the Performance Assessment Hours. As further detailed in Section 10A of this Attachment, Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Section 10A(d) of this Attachment. Subject to 5.5A(a)(i)-(ii), the following types of Capacity Resources are eligible to submit a Sell Offer as a Capacity Performance Resource: internal or external Generation Capacity Resources; Annual Demand Resources; Capacity Storage Resources; Annual Energy Efficiency Resources; and Qualifying Transmission Upgrades. To the extent the underlying Capacity Resource is an external Generation Capacity Resource, such resource must meet the criteria for obtaining an exception to the Capacity Import Limit as contained in section 1.7A of the Reliability Assurance Agreement.

i). Process for Support and Review of Capacity Performance Resource Offers

A. The Capacity Market Seller shall provide to the Office of the Interconnection and the Market Monitoring Unit, upon their request, all supporting data and information requested by either the Office of the Interconnection or the Market Monitoring Unit to evaluate whether the underlying Capacity Resource can meet the operational and performance requirements of Capacity Performance Resources. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes.

B. The Office of the Interconnection and the Market Monitoring Unit shall review any requested supporting data and information, and the Office of the Interconnection, considering advice and recommendation from the Market Monitoring Unit, shall reject a request for a resource to offer as a Capacity Performance Resource if the Capacity Market Seller does not demonstrate that it can reasonably be expected to meet its Capacity Performance obligations consistent with the resource's offer by the relevant Delivery Year. The Office of Interconnection shall provide its determination to reject eligibility of the resource as a Capacity Performance Resource, and notify the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

b) Base Capacity Resources

For the 2018/2019 and 2019/2020 Delivery Years, following types of Capacity Resources eligible to submit a Sell Offer as a Base Capacity Resource: Generation Capacity Resources, Capacity Storage Resources, Annual Demand Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Each resource that clears a RPM Auction as a Base Capacity Resource must provide energy output to PJM if called during Performance Assessment Hours occurring in the calendar months of June through September, including any necessary recall of such capacity and energy from service to areas outside the PJM Region. As further detailed in Section 10A of this Attachment, Base Capacity Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Section 10A(d) of this section.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources located within the same modeled Locational Deliverability Area may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its eRPM tools. For the 2018/2019 and 2019/2020 Delivery Years, any such offer may be submitted as Capacity Performance Resource, Base Capacity Resource, or as a coupled offer for Capacity Performance Resource and Base Capacity Resource, provided that, for any such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least

$.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer. For the 2020/2021 Delivery Year and subsequent Delivery Years, any such offer must be submitted as a Capacity Performance Resource.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.7 Buy Bids

Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate:

a) The quantity of Unforced Capacity desired, in increments of 0.1 megawatt;

b) The maximum price, in dollars and cents per megawatt per day, that will be paid by the buyer for the megawatt quantity of Unforced Capacity desired;

c) The type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource; and

d) The desired LDA for a replacement Capacity Resource. In the event of delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid shall specify Capacity Resources in the LDA for which such Qualifying Transmission Upgrade was to increase CETL.

5.8 Submission of Sell Offers and Buy Bids

The Office of the Interconnection shall evaluate and accept or reject Sell Offers and Buy Bids submitted by Capacity Market Sellers on the basis of the following requirements and criteria:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource, shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number specified by the Office of the Interconnection.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under Schedule 8.1 of the Reliability Assurance Agreement.

i) The Office of the Interconnection shall have final authority to determine whether to accept or reject a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

j) A Capacity Market Seller and Capacity Market Buyer may submit any Sell Offer or Buy Bid, respectively, that it chooses or make a decision not to offer a committed resource, provided that the Office of the Interconnection determines that: (i) the Capacity Market Seller has participated in the review process conducted by the Market Monitoring Unit (without regard to whether an agreement is obtained) if required by the Tariff; (ii) the Sell Offer is no higher, in the case of seller market power, or lower, in the case of buyer side market power, than the level to which the Capacity Market Seller has committed or agreed in the course of its participation in such review process; and (iii) the Sell Offer or Buy Bid is compliant with the Tariff and PJM Manuals. Capacity Market Sellers and Capacity Market Buyers assume exclusive responsibility for their Sell Offers and Buy Bids, respectively, and any adverse findings at the Commission related to its Sell Offers and Buy Bids.

5.9 Time Standard

All deadlines for the submission or withdrawal of Sell Offers or Buy Bids, or for other purposes specified in this Attachment, shall be determined by the prevailing time observed in the Eastern Time zone.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)], and for Delivery Years

through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may be greater than, but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, 2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	132,200
BGE, PEPCO (“CONE Area 2”)	130,300
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion (“CONE Area 3”)	128,900
PPL, MetEd, Penelec (“CONE Area 4”)	130,300

B) Beginning with the 2019/2020 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark

CONE values for the 2018/2019 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resourcce Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and

Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement*, and all applicable Capacity Import Limits*;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply Exemption requests under section 5.14(h), all Competitive Entry Exemption requests under section 5.14(h), and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to section 5.14(h).

c) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply and Competitive Entry Exemption categories in the EMAAC, MAAC and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for Self-Supply and Competitive Entry Exemption categories; and the aggregate megawatt quantity of Self-Supply and Competitive Entry Exemptions requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four new generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth business day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh business day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth business day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.11A Backbone Transmission Upgrade Project Development Milestones

A Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan ("Backbone Transmission") shall be included in the system model for an RPM Auction only if it satisfies the project development milestones set forth in this section.

a) Base Residual Auction

Backbone Transmission shall be included in the system model used for a Base Residual Auction only if:

i) No later than 60 days before posting of the planning parameters for the Base Residual Auction, a corporate officer of the project sponsor submits a current critical path project development schedule containing intermediate milestones and showing the project in full commercial operation no later than the start of the Delivery Year corresponding to such Base Residual Auction, and must certify that such schedule is reasonably achievable based on information then known to and reasonably anticipated by the project sponsor. Such notice must identify all states in which such project is subject to the requirement to obtain a certificate of public convenience and necessity, or functional equivalent approval or licensure requirement, and must describe the nature and current status of such approval requirement;

ii) such development schedule additionally must show the scope, schedule, and current status of all other key milestones, including, at a minimum, right-of-way acquisition, engineering design, equipment procurement, construction permitting, and construction activities;

iii) applications for certificates of public convenience and necessity (or for equivalent approval) have been filed in all states applicable to such project that have such requirement.

b) Incremental Auctions

A Backbone Transmission project shall be included in the system models for Incremental Auctions only if the following requirements are satisfied no later than 60 days before each Incremental Auction, as indicated below:

i) a corporate officer submits, and certifies to, an updated project development schedule for the First Incremental Auction that shows, among other things, that 50% of the right-of-way by linear distance has been secured;

ii) a corporate officer submits, and certifies to, an updated project development schedule for the Second Incremental Auction that shows, among other things, that 75% of the right-of-way by linear distance has been secured, and that all certificates of public convenience and necessity (or equivalent approvals) have been issued by the responsible regulatory bodies;

iii) a corporate officer submits, and certifies to, an updated project development schedule for the Third Incremental Auction that shows, among other things, that 100% of the right-of-way by linear distance has been secured.

c) Audit, Removal from System Model, and Reinstatement in System Model

i) for the Backbone Transmission project to remain in the applicable system model, the Office of the Interconnection or independent third party with established expertise in such area must audit the project development schedule and affirm, no later than 30 days before each applicable auction, that the schedule is reasonable and remains on progress to full commercial operation prior to the commencement of the relevant Delivery Year. Audits may include site visits as deemed necessary by the auditor to verify progress.

ii) a Backbone Transmission project that fails to satisfy any of the requirements indicated for the Base Residual Auction shall not be included in the system model for such Base Residual Auction or any Incremental Auction for the relevant Delivery Year. A Backbone Transmission project that fails to satisfy any of the requirements indicated for an Incremental Auction shall not be included in the system model for such Incremental Auction or any subsequent Incremental Auction for the relevant Delivery Year.

iii) a Backbone Transmission project that is excluded from the system model for any RPM Auction for a Delivery Year may be included in the system model for RPM Auctions for a subsequent Delivery Year only if it demonstrates that all deficiencies have been cured and the project is on schedule for full commercial operation prior to such subsequent Delivery Year.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;
- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of

Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the Delivery Years through May 31, 2018, for each LDA, such LDA’s updated Reliability Requirement, less such LDA’s Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA’s updated Reliability Requirement

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 Delivery Year associated with the transition provisions in section 5.14D of this Attachment DD where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR

Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 Delivery Year associated with the transition provisions in section 5.14D of this Attachment DD where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.13 [Reserved]

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 marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, 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. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. 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 committed in the first BRA under section 5.14(c)(1)-(2) 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 that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of 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

(iv) the resource with its Sell Offer submitted 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 satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at 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).

6. 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. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. 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.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

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 and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, 5.14E 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; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, 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); (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); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. 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 calculate and post the Final Zonal Capacity Price for each Delivery Year 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 to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

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 Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, or a Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource’s Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC’s regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,900	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400
IGCC $/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross 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 in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further 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.

ii) 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 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the 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. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the 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 $3,198 per MW-year.

(4) Duration. The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(10) hereof.

(6) Self-Supply Exemption**.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the MOPR Screened Generation Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

vi) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) Competitive Entry Exemption. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity

Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(9) Exemption/Exception Process.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) <u>Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.</u>

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(10) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

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.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource’s RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition 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. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity

Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery

Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.15 Capacity Transfer Rights

(a) To recognize the value of Import Capability and provide a partial offset to potential Locational Price Adders that may be determined for an LDA (as to any Zone that encompasses two or more LDAs, the term "LDA" as used herein shall refer to such Zone, rather than to the LDAs it encompasses), the Office of the Interconnection shall allocate Capacity Transfer Rights to each LSE serving load in such LDA pro rata based on such LSE's Daily Unforced Capacity Obligation in such LDA. The total megawatts of Capacity Transfer Rights available for allocation shall equal the megawatts of Unforced Capacity imported into such LDA determined based on the results of the Base Residual Auction and Incremental Auctions ("Capacity Imported"), less any megawatts of CETL increase into such LDA attributable to Qualifying Transmission Upgrades cleared in an RPM Auction and any Incremental Capacity Transfer Rights into such LDA allocated pursuant to section 5.16 (but not less than zero), and shall be subject to change in subsequent Delivery Years as a result of changes in the quantity of such Capacity Imported into such LDA. Each change in an LSE's Daily Unforced Capacity Obligation during a Delivery Year shall result in a corresponding change in the Capacity Transfer Rights allocated to such LSE.

(b) For LDAs in which the RPM Auctions for the Delivery Year resulted in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of the Capacity Transfer Rights in such LDA shall receive a payment during the Delivery Year equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the megawatt quantity of the Capacity Transfer Right allocated to such LSE in such LDA.

(c) Capacity Transfer Rights shall be transferable. A purchaser of Capacity Transfer Rights from the original party allocated such rights shall receive any payments due under this section or section 5.16, provided the seller and purchaser of such rights timely notify the Office of the Interconnection of such purchase, in accordance with procedures specified in the PJM manuals.

5.16 Incremental Capacity Transfer Rights

(a) The Office of the Interconnection shall allocate Incremental Capacity Transfer Rights to a New Service Customer obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the Import Capability into a Locational Deliverability Area, with respect to any such transmission facility interconnected to or an upgrade of the Transmission System pursuant to Part IV and/or Part VI of this Tariff, including transmission facilities interconnected to or upgrades of the Transmission System pursuant to Part IV and/or Part VI prior to the effective date of this Attachment. Incremental Capacity Transfer Rights shall be available for a facility or upgrade for a Delivery Year only if the Office of the Interconnection certifies the quantity of Import Capability provided by such facility or upgrade at least 45 days prior to the Base Residual Auction for such Delivery Year. The megawatt quantity of Incremental Capacity Transfer Rights allocated to such a New Service Customer shall equal the megawatt quantity of the increase in Import Capability across a locational constraint resulting from such upgrade or facility, provided that the total Incremental Capacity Transfer Rights awarded as to an LDA (including those allocated pursuant to Schedule 12A of the Tariff) may not exceed the total Capacity Transfer Rights determined as to such LDA. A Capacity Market Seller that offers and clears a Qualifying Transmission Upgrade in the Base Residual Auction for a Delivery Year shall not receive Incremental Capacity Transfer Rights with respect to such upgrade for such Delivery Year. Terms and conditions for the allocation of Incremental Capacity Transfer Rights to New Service Customers shall be as further set forth in Part VI of this Tariff, and those for the allocation of Incremental Capacity Transfer Rights to Responsible Customers shall be as further set forth in Schedule 12A of this Tariff.

(b) For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of an Incremental Capacity Transfer Right into such LDA shall receive a payment equal to the average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased Import Capability, multiplied by the megawatt quantity of the Incremental Capacity Transfer Right allocated to such Interconnection Customer.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment Hours in such calendar years) that precede the Base Residual Auction for such Delivery Year), and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market

Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c).

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry for the relevant LDA and Delivery Year or 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) business day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one business (1) day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Section II.F of Attachment M-Appendix, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) business day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Section II.C of Attachment M-Appendix, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Section 5.8 of Attachment DD, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) business days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) business days after receipt of such notification, the Office of the

Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery

Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn’t timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff.

(b) Determinations of EFORd and Unforced Capacity made under section 6.6 hereof as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in section II.G of Attachment M-Appendix. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) business day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal – Large	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame E/Siemens	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83

Technology								
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66
Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to section II.E of Attachment M-Appendix.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

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 + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

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.

- **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **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.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR.

- **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 25 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.

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 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 Plus Alternative 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 *energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agrement and PJM Manuals that are not fuel or environmental costs*.

*T*he 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.

7. GENERATION RESOURCE RATING TEST FAILURE CHARGE

7.1 Generation Resource Rating Test Failure Charges

A Generation Resource Rating Test Failure Charge shall be assessed on any Market Seller that commits a Generation Capacity Resource for a Delivery Year, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, if such resource fails a generation resource capacity test, as provided herein.

a) Generation Resource Fails Capacity Test in Delivery Year

Each Generation Capacity Resource committed for a Delivery Year shall be obligated to complete a generation resource capacity test, as described in the PJM Manuals. The Market Seller that committed the resource, or Locational UCAP Seller that sold the resource, may perform an unlimited number of tests during each such period. If none of the tests during a testing period certify full delivery of the megawatt amount of installed capacity the Market Seller committed, or Locational UCAP Seller sold, for such Delivery Year, the Market Seller or Locational UCAP Seller shall be assessed a daily Generation Resource Rating Test Failure Charge for each day from the first day of the Summer or Winter Season in which such resource failed the rating test through the last day of such Delivery Year, provided, however, that such a seller that fails or is expected to fail a rating test may obtain and commit Unforced Capacity from a replacement Capacity Resource meeting the same locational requirements. Such Unforced Capacity may include uncommitted or uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection, and shall reduce the amount of installed capacity committed from the Generation Capacity Resource, that failed or was expected to fail such rating test, in accordance with the determination prescribed by subsection (b) below.

b) Generation Resource Rating Test Failure Charge

The Generation Resource Rating Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the following megawatt quantity, converted to an Unforced Capacity basis using the Generation Capacity Resource's EFORD for the twelve months ending the September 30 last preceding the Delivery Year: (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period. The Daily Deficiency Rate shall equal the Capacity Resource Clearing Price (weighted as necessary to reflect the clearing prices in all RPM Auctions that resulted in installed capacity commitments from such resource), in $/MW-day, applicable to the Generation Capacity Resource (for purposes of replacement capacity, including Locational UCAP transactions, the applicable Capacity Resource Clearing Price shall be the clearing price for the Locational

Deliverability Area in which such resource is located) plus the greater of (iii) 0.20 times such weighted average Capacity Resource Clearing Price; or (iv) $20/MW-Day, provided, however, if a resource is unavailable during the Delivery Year at less than the level committed in the Market Seller's cleared Sell Offer or Locational UCAP Seller's Locational UCAP sale due to derating, delay, or retirement, then such seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under section 8 for such unavailability; and provided further that a resource that is subject to a charge under this section that is also subject to a charge under Section 10A hereof for a Performance Shortfall during one or more Performance Assessment Hours occurring during the period of resource capacity rating deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Section 10A, but shall not be assessed a charge under both this section and Section 10A for such simultaneous occurrence of a resource capacity rating deficiency and Performance Shortfall. If a single resource is the basis for installed capacity commitments of multiple Capacity Market Sellers or Locational UCAP Sellers, the installed capacity shortfall determined under (i) and (ii) above shall be assessed upon such sellers on a pro-rata basis in accordance with the megawatts of capacity from such resource in their cleared Sell Offers, Locational UCAP sales, or other commitment as replacement capacity.

c) Allocation of Revenue Collected from Generation Resource Rating Test Failure Charges.

The revenue collected from Generation Resource Rating Test Failure Charges shall be distributed on a pro-rata basis to LSEs that were charged a Locational Reliability Charge for the Delivery Year for which the Generation Resource Rating Test Failure Charge was assessed. The charges shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient, provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under Section 10A hereof for a Performance Shortfall during one or more Performance Assessment Hours occurring during the period of resource deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Section 10A, but shall not be assessed a charge under both this section and Section 10A for such simultaneous occurrence of a resource deficiency and Performance Shortfall.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

9. PEAK SEASON MAINTENANCE COMPLIANCE PENALTY CHARGE.

a) Purpose

To preserve and maintain the reliability of the PJM Region and to recognize the impact of planned outages and maintenance outages of Generation Capacity Resources during the Peak Season, each Capacity Market Seller that commits a Generation Capacity Resource for a Delivery Year, and each Locational UCAP Seller that sells Locational UCAP from a Generation Capacity Resource for a Delivery Year, must ensure that such Generation Capacity Resource has available sufficient Unforced Capacity during the Peak Season to satisfy the megawatt amount committed from such resource as a result of all Sell Offers by such seller based on such resource in any RPM Auctions for such Delivery Year the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource. The provisions of this section 9 do not apply to Capacity Performance Resources.

b) Peak Season Requirement

To the extent the Generation Capacity Resource will not be available due to a planned or maintenance outage that occurs during the Peak Season without the approval of the Office of the Interconnection, the Capacity Market Seller or Locational UCAP Seller must obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resources) from a Capacity Resource that is not already committed for such Delivery Year and that meets all characteristics specified in the Sell Offer or Locational UCAP transaction, including the megawatt quantity of Unforced Capacity committed for such Delivery Year (with such Unforced Capacity, in the case of a Generation Capacity Resource, determined on the basis of such Generation Capacity Resource’s EFORD for the twelve months ending on the September 30 last preceding the Delivery Year), or otherwise, for Delivery Years through May 31, 2018, pay a Peak Season Maintenance Compliance Penalty Charge. The Capacity Market Seller or Locational UCAP Seller shall commit such replacement Capacity Resource in accordance with the procedure set forth in the PJM Manuals.

c) Peak Season Planned and Maintenance Outages

The Office of the Interconnection shall adopt and maintain rules and procedures for determining the allowable Peak Season planned and maintenance outages.

d) Peak Season Maintenance Compliance Penalty Charge

The Peak Season Maintenance Compliance Penalty Charge shall equal the Daily Deficiency Rate multiplied by the unforced value of a positive shortfall calculated for the capacity committed for each day during the Peak Season that such resource is out-of-service on a maintenance outage that is not authorized by the Office of the Interconnection. The shortfall shall equal (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the summer net dependable rating minus the amount of capacity out-of-service on unapproved planned or maintenance outage on a peak season day.

e) Allocation of Revenue Collected from Peak Season Maintenance Compliance Penalty Charges

The revenue collected from assessment of a Peak Season Maintenance Compliance Penalty Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

10. PEAK-HOUR-PERIOD AVAILABILITY CHARGES AND CREDITS

(a) To preserve and maintain the reliability of the PJM Region and to encourage Capacity Market Sellers and Locational UCAP Sellers to maintain the availability of Generation Capacity Resources during critical peak hours of the Delivery Year, each Capacity Market Seller that commits a Generation Capacity Resource for the 2017/2018 Delivery Year and any prior Delivery Year, and each Locational UCAP Seller that sells Locational UCAP from a Generation Capacity Resource for the 2017/2018 Delivery Year and any prior Delivery Year, shall be credited or charged to the extent the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short, respectively, of the expected availability of such resources. Charges and credits hereunder shall not apply to wind, solar resources, or Capacity Performance Resources.

(b) Critical peak periods for purposes of this assessment ("Peak-Hour Periods") shall be the hour ending 1500 local prevailing time through the hour ending 1900 local prevailing time on any day during the calendar months of June through August that is not a Saturday, Sunday, or federal holiday, and the hour ending 800 local prevailing time through the hour ending 900 local prevailing time and the hour ending 1900 local prevailing time through the hour ending 2000 local prevailing time on any day during the calendar months of January and February that is not a Saturday, Sunday or federal holiday.

(c) Peak-Period Equivalent Forced Outage Rate and Peak-Period Capacity Calculations

The Peak-Period Equivalent Forced Outage Rate shall be calculated for Peak-Hour Periods based on the following formula:

$EFORP (\%) = (FOH + EFPOH) / (SH + FOH)$

where

FOH = full forced outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below);

EFPOH = equivalent forced partial outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below); and

SH = service hours as defined pursuant to NERC GADS standards.

The Peak-Period Capacity of a Generation Capacity Resource shall be calculated as follows:

$PCAP = ICAP * (1.0 - EFOR_P)$

where

ICAP = the installed capacity rating of such Generation Capacity Resource

(d) Determination of Expected $EFOR_P$ and PCAP for Generation Capacity Resources

For each Delivery Year, the expected $EFOR_P$ and PCAP of each Generation Capacity Resource committed to serve load in such Delivery Year shall be the EFORD and UCAP, respectively, calculated on a rolling-average basis using such resource's service history during the five consecutive annual periods of twelve consecutive months ending September 30 last preceding such Delivery Year. Such $EFOR_D$ and UCAP shall be determined in accordance with Schedule 5 of the Reliability Assurance Agreement, which excludes (for purposes of Capacity Resource UCAP calculations) outages deemed outside management control in accordance with the standards and guidelines of NERC, as defined in the Generating Availability Data System, Data Reporting Instructions in Attachment K or its successor ("Outside Plant Management Control" or "OMC").

(e) For each Delivery Year, the actual $EFOR_P$ and PCAP of each Generation Capacity Resource shall be calculated during the Peak-Hour Periods of such Delivery Year, provided however, that such calculation shall not include any day such a resource was unavailable if such unavailability resulted in a charge or penalty due to delay, cancellation, retirement, de-rating, or rating test failure. The full or partial forced outage hours when called upon shall be those outage hours during which the cost-based offer for energy from the resource would have been less than the applicable Locational Marginal Price for such resource, or when the Office of the Interconnection would have called upon the resource (absent the outage) for Operating Reserves, in both cases as determined by the Office of the Interconnection in accordance with the procedures specified in the PJM Manuals (including, without limitation, respecting such unit's current operating constraints). In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter Peak-Hour Period shall be excused for purposes of this section if the Capacity Market Seller, or Locational UCAP Seller, as applicable, can demonstrate to the Office of the Interconnection that such failure was due to non-availability of gas to supply the unit.

(f) If the calculation under subsection (e) for any Generation Capacity Resource for a Delivery Year results in fewer than fifty total Service Hours during Peak Hours, then the actual EFORP for purposes of such calculation shall be the lower of the resource's $EFOR_D$ (based on Delivery Year outage data) and its $EFOR_P$ and the actual PCAP for purposes of such calculation shall be, respectively, the resource's UCAP or its PCAP.

(g) For each Delivery Year, the excess or shortfall in Peak-Hour Period availability for each Generation Capacity Resource shall be determined by comparing such resource's expected and actual PCAP, subject to the limitation under subsection (i) below. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller and FRR Entity in each Locational Deliverability Area shall be the net of the shortfalls and excesses of all Generation Capacity Resources in such Locational Deliverability Area committed by such Capacity Market Seller or Locational UCAP Seller for such Delivery Year. If there is a net positive Peak Hour Period availability shortfall in the LDA for such committed resources in the LDA, the sum of the excesses of all Generation Capacity Resources in such Locational Deliverability Area owned or controlled by such Capacity Market Seller, available for the

Delivery Year but not committed for such Delivery Year, and satisfying all obligations of a committed Capacity Resource for such Delivery Year shall be used to reduce the net positive Peak Hour Period availability shortfall in the LDA of committed resources by the amount of the sum of the excesses of such available uncommitted resources; however, such reduction shall not result in a net Peak Hour Period availability excess in the LDA.

(h) As to any Generation Capacity Resource experiencing or expected to experience a full or partial outage during any Peak-Hour Period that would or could result in a shortfall under subsection (g) above, a Capacity Market Seller or Locational UCAP Seller may obtain and commit Unforced Capacity from a replacement Capacity Resource (not previously committed) meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resources) as such resource. Such Unforced Capacity shall be recognized for purposes of this section prospectively from the effective date of commitment of such replacement resource, and to the extent such replacement Unforced Capacity thereafter is available during Peak-Hour Periods, any shortfall that otherwise would have been calculated shall be reduced to that extent. Any such commitment of replacement capacity shall be effective upon no less than one day’s notice to the Office of the Interconnection.

(i) The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at either such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

(j) A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller or Locational UCAP Seller with a net shortfall in PCAP in an LDA, where such charge is equal to such shortfall times the Capacity Resource Clearing Price determined for such Locational Deliverability Area for such Delivery Year.

(k) The revenues from such charges shall be distributed to the Capacity Market Sellers, Locational UCAP Sellers, and FRR Entities that committed Generation Capacity Resources, in such Locational Deliverability Area that have net excess PCAP for such Delivery Year, provided however that any such seller shall be paid no more than the product of such seller’s net excess PCAP times the Capacity Clearing Price determined for such Locational Deliverability Area for such Delivery Year. Any excess revenues remaining after such distribution shall be distributed on a pro-rata basis to all LSEs in the Zone that were charged the same Locational Reliability Charge for the Delivery Year for which the Peak Hour Availability Charge was assessed, and to all FRR Entities in the Zone that are LSEs and whose FRR Capacity Plan resources over-performed in the Delivery Year, on a pro-rata basis in accordance with each LSE’s Daily Unforced Capacity Obligation.

(l) The Office of the Interconnection shall provide estimated charges and credits based on the summer Peak-Hour Periods within three calendar months after the end of the summer period. Final charges and credits for the Delivery Year shall be billed within three calendar months following the end of the Delivery Year.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), and each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation or demand response resources that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Hour.

(c) For each Performance Assessment Hour, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

> for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];
>
> > where
> >
> > Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and
> >
> > The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and

Actual Performance =

for each generation resource, the metered output of energy delivered by such resource plus the resource’s real-time reserve or regulation assignment, if any, during the Performance Assessment Hour;

for each storage resource, the metered output of energy delivered by such resource plus the resource’s real-time reserve or regulation assignment, if any, during the Performance Assessment Hour;

for each Demand Resource, the demand response provided by such resource, plus such resource’s real-time reserve or regulation assignment, if any, during the

Performance Assessment Hour, as established through the PJM demand response settlement procedure consistent with the standards specified in Schedule 6 of the RAA;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Hour, and zero if it is not in service during such Performance Assessment Hour.

Such calculation shall encompass all resources located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Hour, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Hour shall not have a Performance Shortfall for such Performance Assessment Hour. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Hour shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Hour to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Hour solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Subject to the foregoing, such resource shall be considered in the calculation of a Performance Shortfall if it would otherwise have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Hour based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (365 / 30) for Delivery Years through and including the 2019/2020 Delivery Year. For the 2020/2021 Delivery Year and any subsequent Delivery Year, the Non-Performance Charge Rate = the highest Resource Clearing Price of the Base Residual Auction for the Delivery Year for which such calaculation is performed * (365 / 30).

and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (365 / 30)

(f) The Non-Performance Charges for each Capacity Performance Resource or (including Locational UCAP from such a resource) for a Delivery Year for Delivery Years through and including the 2019/2020 Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. For the 2020/2021 Delivery Year and any subsequent Delivery Year, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) shall not exceed a Non-Performance Charge Limit equal to, for any calendar month of a Delivery Year, 0.5 times the highest Resource Clearing Price of the Base Residual Auction for the Delivery Year times the megawatts of Unforced Capacity committed by such resource times 365; and for a Delivery Year, an amount equal to 1.5 times the highest Resource Clearing Price of the Base Residual Auction for the Delivery Year times the megawatts of Unforced Capacity committed by such resource times 365. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under section 5.14 of this Attachment DD for such Delivery Year.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Hour shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Hour, that provided energy or load reductions above the levels expected for such resource during such hour. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

And

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Hours; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Hour shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Hour;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Hour occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Hour.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
(ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and
(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017-2018 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;

(ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and

(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Hours within three calendar months after the calendar month that included such Performance Assessment Hours, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year.

For the 2020/2021 Delivery Year and any subsequent Delivery Year, the Office of the Interconnection shall determine the Performance Shortfall and Bonus Performance for each resource for which performance was assessed during Performance Assessment Hours within three calendar months after the calendar month that included such Performance Assessment Hours. After this determination is made but prior to billing for each Performance Assessment Hour, Market Participants will be presented with the performance of each resource for each Performance Assessment Hour and will be given opportunity within a specified time period to transfer Bonus Performance for each specific Performance Assessment Hour to another Market Participant. Once this time period has expired, the Office of the Interconnection shall assess a Non-Performance Charge for each Performance Assessment Hour to any Market Particpant with a net Performance Shortfall for that Performance Assessment Hour, where such charge is equal to such shortfall times the Non-Performance Charge Rate for such Delivery Year specified in subsection (f). Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Hour shall be distributed to each Market Participant with a net Bonus Performance for that Performance Assessment Hour in accordance with the following formula:

Market Participant Performance Payment = (Market Participant Net Bonus Performance / All Market Participants Net Bonus Performance) * Non-Performance Charge Revenues.

11. DEMAND RESOURCE COMPLIANCE PENALTY CHARGE

The provisions of this section 11 do not apply to Demand Resources committed as Capacity Performance Resources. All references to Demand Resources in this section specifically exclude Demand Resources committed as Capacity Performance Resources.

(a) The Office of the Interconnection shall separately evaluate compliance of each Demand Resource committed for a Delivery Year, in accordance with procedures set forth in the PJM ManualsManuals and, for Delivery Years through May 31, 2018, shall assess a Demand Resource Compliance Penalty Charge on Capacity Market Sellers that committed Demand Resources and Locational UCAP Sellers that sold Demand Resources that cannot demonstrate the hourly performance of such resource in real-time. The compliance is evaluated separately by Load Management Event in each CAA for Demand Resources dispatched by the Office of Interconnection. The Demand Resource Compliance Penalty Charges will not be assessed to resources that are dispatched on a subzonal basis for the 2012/2013 and 2013/2014 Delivery Years. For the 2014/2015 Delivery Year, the Demand Resource Compliance Penalty Charge will not be assessed to resources that are dispatched on a subzonal basis unless such subzone is defined and publically posted the day before the Load Management Event as set forth in the PJM Manuals. To the extent a Demand Resource cannot respond, another Demand Resource in the same geographic location defined by the PJM dispatch instruction with the same designated lead time and comparable capacity commitment may be substituted. Any Demand Resource used as a substitute during a Load Management Event will have the same obligation to respond to future Load Management Event(s) as if it did not respond to such Load Management Event. Capacity Market Sellers that committed Demand Resources and Locational UCAP Sellers that sold Demand Resources that cannot demonstrate the hourly performance of such resource in real-time based on the capacity commitment shall be assessed a Demand Resource Compliance Penalty Charge; provided, however, that such under compliance shall be determined on an aggregate basis for all dispatched Demand Resources committed by the same Capacity Market Seller or same Locational UCAP Seller in a CAA.

(b) The Demand Resource Compliance Penalty Charge for a Capacity Market Seller in a CAA for the on-peak period, which includes all hours specified in the Reliability Assurance Agreement definition of the Limited Demand Resource, shall equal the lesser of (1/the number of Load Management Events during the on-peak period for which such Demand Resources were dispatched, or 0.50) times the weighted daily revenue rate for such seller resources dispatched, multiplied by the net under-compliance in such on-peak period, if any, for such seller resulting from all dispatched resources it has committed for such Delivery Year for such CAA for each Load Management Event called by the Office of the Interconnection. Net CAA under compliance for the Load Management Event will be prorated to individual under compliant registrations in the CAA based on performance of each registration in order to determine net under compliance(s). The Demand Resource Compliance Penalty Charge for a Capacity Market Seller in a CAA for the off-peak period, which includes all hours specified in the Reliability Assurance Agreement definitions of Extended Summer Demand Resource or Annual Demand Resource, but does not include all hours in the on-peak period, shall equal 1/52 times the weighted daily revenue rate for resources dispatched for such seller, multiplied by the net undercompliance in such off-peak period, if any, for such seller resulting from all dispatched resources it has committed for such Delivery Year for such CAA for each Load Management Event called by the Office of the Interconnection. If a Load Management Event is comprised of both an on-peak period and an off-peak period then such Demand Resource Compliance Penalty Charge will be the higher of the charges calculated under the prior two sentences. The total Compliance Penalty Charge for the Delivery Year is not to exceed the annual revenue received for such resources. The net CAA undercompliance for each such Load Management Event shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable DR Factor and Forecast Pool Requirement: (i) the megawatts of load reduction capability committed by such seller on the day of the Load Management Event for all dispatched resources minus (ii) the megawatts of load reduction actually provided by all such dispatched Demand Resources during such Load Management Event. A seller's net undercompliance in a CAA shall be reduced by the seller's total amount of Capacity Resource deficiency shortfalls on the day of the Load Management Event, determined pursuant to section 8 of Attachment DD of this Tariff, in a CAA for the seller's committed Demand Resources that are the same product(s) dispatched. The daily revenue rate for a Demand Resource shall be the Resource Clearing Price that the resource received in the auction in which it cleared, including any adjustment pursuant to Attachment DD-1, section C of this Tariff. The weighted daily revenue rate for a Capacity Market Seller shall be the average rate for all cleared Demand Resources, weighted by the megawatts cleared at each price. The total charge per megawatt that may be assessed on a Capacity Market Seller in a Delivery Year shall be capped at the weighted daily revenue rate the Capacity Market Seller would receive in the Delivery Year.

The Demand Resource Compliance Penalty Charges for a Load Management Event for Limited Demand Resources are assessed daily and initially billed by the later of the month of October during such Delivery Year or the third billing month following the Load Management Event that gave rise to such charge. The initial billing for a Load Management Event for Limited Demand Resources will reflect the amounts due from the start of the Delivery Year to the last day that is reflected in the initial billing. The remaining charges for such Load Management Event will be assessed daily and billed monthly through the remainder of the Delivery Year. The Demand Resource Compliance Penalty Charges for a Load Management Event for Annual or Extended Summer Demand Resources are assessed daily and billed by the later of the month of June following such Delivery Year or the third billing month following the Load Management Event that gave rise to such charge. The billing for the Load Management Event for Annual or Extended Summer Demand Resources will be in a lump sum and reflect the accrued charges for the entire Delivery Year.

c) Daily revenues from assessment of a Demand Resource Compliance Penalty Charge shall be distributed on a pro-rata basis to Demand Resource Providers and Locational UCAP Sellers that provided load reductions in excess of the amount such resources were committed to provide. Such revenue distribution, however, shall not exceed for any Capacity Market Seller the quantity of excess megawatts provided by such Capacity Market Seller during a single Load Management Event times 0.20 times the weighted daily revenue rate for such Capacity Market Seller for resources dispatched. To the extent any such revenues remain after such distribution, the remaining revenues shall be distributed to LSEs based on each LSE's Daily Unforced Capacity Obligation.

11A DEMAND RESOURCES TEST FAILURE CHARGE

a) Beginning with the Delivery Year that commences on June 1, 2009, Capacity Market Sellers that commit Demand Resources may be charged to the extent their committed resources fail performance tests, as set forth herein.

b)

(i) For Demand Resources not committed as Capacity Performance Resources for Delivery Years through May 31, 2018:

For Limited Demand Resources: If a registration for a Limited Demand Resource committed by a Capacity Market Seller is not dispatched by the Office of the Interconnection for a Load Management event prior to August 15 of the relevant Delivery Year, then such registration must demonstrate that it was tested as described below in (iii), in a zone for a one-hour period during any hour when a PJM Load Management event may be called between June 1 and September 30, inclusive. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of the Interconnection for a PJM Load Management event in a zone between August 16 and September 30, no test will be required. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of Interconnection for a PJM Load Management event in a subzone between June 1 and September 30 of the 2012/2013 and 2013/2014 Delivery Years, and such registration performs at or above the nominated amount of capacity on the registration, no test will be required and no Demand Resources Test Failure Charges will be assessed for such registrations. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of the Interconnection for a PJM Load Management event in a zone between June 1 and September 30, inclusive, then Demand Resources Test Failure Charges will not be assessed.

For Annual Demand Resources: if an Annual Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then the Annual Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Annual Demand Resource registration committed in a zone was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load

Management event during the Delivery Year, then no test will be required.

For Extended Summer Demand Resources: if an Extended Summer Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event during June through October or the following May, then the Extended Summer Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Extended Summer Demand Resource registration was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year.

(ii) For Demand Resources committed as Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years and for all Demand Resources for the 2018/2019 Delivery Year and subsequent Delivery Years:

For Base Capacity Demand Resources: if an Base Capacity Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event during June through September, then the Base Capacity Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Base Capacity Demand Resource registration was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through September of the relevant Delivery Year.

For Demand Resources that commit as Capacity Performance Resources: if a Demand Resource that is a Capacity Performance Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then that Demand Resource registration committed by a Capacity Market Seller must demonstrate that that Demand Resource registration committed in a zone was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, then no test will be required.

(iii) All registrations in a zone required to test must be tested simultaneously for each product except that, when less than 25 percent (by megawatts) of a provider’s total resources in a zone fail a test, the provider may conduct a re-test limited to all registrations that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registrations must test simultaneously, where affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. If less than 25 percent of resources fail the test and the provider chooses to conduct a retest, the provider may elect to maintain the performance compliance result for registration(s) achieved during the test if provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the provider retests affiliated registrations under this election as set forth in the PJM Manual.

c) a Capacity Market Seller that committed Demand Resources shall be assessed a Demand Resources Test Failure Charge equal to the net capability testing shortfall for such products tested in a Zone during such test in the aggregate of all of such Seller's Demand Resources tested in such Zone times the Demand Resources Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable DR Factor and Forecast Pool Requirement: (i) the summer daily average of the megawatts of load reduction capability committed by such seller in such Zone for such product(s) tested minus (ii) the megawatts of load reduction actually provided by all such Demand Resources in such Zone during such test. The net capability testing shortfall in such Zone for such product(s) tested shall be reduced by the provider's summer daily average of the Capacity Resource deficiency shortfalls, determined pursuant to section 8 of Attachment DD of this Tariff, in such Zone for all of the provider's committed Demand Resources that are of the same product(s) tested.

d) the Demand Resources Test Failure Charge Rate shall equal such Seller's Weighted Daily Revenue Rate in such Zone for the product(s) tested plus the greater of (0.20 times the Weighted Daily Revenue Rate in such Zone for the product(s) tested or $20/MW-day). The Daily Demand Resources Test Failure Charge in a zone for the product(s) tested shall be equal to the net capability testing shortfall in such Zone for such product(s) tested times the Demand Resources Test Failure Charge Rate. Such charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

e) revenues collected from assessment of Demand Resources Test Failure Charges shall be distributed to Load Serving Entities that were charged a Locational Reliability Charge for the Delivery Year for which the Demand Resources Test Failure Charge was assessed, pro-rata based on such Load Serving Entities' Daily Unforced Capacity Obligations.

12. QUALIFYING TRANSMISSION UPGRADE COMPLIANCE PENALTY CHARGE

If a Qualifying Transmission Upgrade forming the basis of a Sell Offer that cleared in the Base Residual Auction for a Delivery Year is not in service at the commencement of such Delivery Year, and the Capacity Market Seller does not obtain replacement Capacity Resources in the LDA for which such upgrade was to increase CETL, such seller shall pay a compliance penalty charge for each day such upgrade is delayed during such Delivery Year equal to the megawatt quantity of Import Capability cleared in the Base Residual Auction based on such upgrade, multiplied by the greater of: (i) 1.2 times the Capacity Resource Clearing Price of the LDA into which the Qualifying Transmission Upgrade is cleared, in $/MW-day; or (ii) the Net Cost of New Entry; provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under Section 10A hereof for a Performance Shortfall during one or more Performance Assessment Hours occurring during the period of resource delay addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Section 10A, but shall not be assessed a charge under both this section and Section 10A for such simultaneous occurrence of a resource delay and Performance Shortfall. The revenue collected from the assessment of Qualifying Transmission Upgrade Compliance Penalty Charges shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

13. EMERGENCY PROCEDURE CHARGE

13.1 Application of the Emergency Procedure Charge

Following an Emergency, the compliance during the period of such Emergency with the instructions of the Office of the Interconnection of each Capacity Market Seller that committed Capacity Resources and each Locational UCAP Seller that sold Locational UCAP for such period shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Capacity Market Seller or Locational UCAP Seller refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, then such Capacity Market Seller or Locational UCAP Seller shall pay an Emergency Procedure Charge.

13.2 Emergency Procedure Charge

The Emergency Procedure Charge shall equal the number of days in the Delivery Year multiplied by the Daily Deficiency Rate for such Delivery Year times each megawatt of a Demand Resource that was not implemented as directed, and each megawatt of a Generation Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Region in the case of a Generation Capacity Resource located outside the PJM Region.

13.3 Allocation of Revenue from Emergency Procedure Charges

The revenue collected from assessment of an Emergency Procedure Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Emergency Procedure Charge was assessed. The charges shall be allocated on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

14. CONVERSION OF CAPACITY CREDITS FROM PRIOR CAPACITY ADEQUACY REGIME

14.1 Purpose

Capacity Credits shall not be accepted as satisfaction of the Daily Unforced Capacity Obligation of any LSE. Parties to Capacity Credit transactions may agree bilaterally to convert such transactions on a basis that permits them to clear in a Reliability Pricing Model Auction, or may settle such transactions financially as described in section 14.2.

14.2 Settlement

For the 2007/2008 Delivery Year, only Capacity Credits confirmed by the Office of the Interconnection to have been entered into prior to April 1, 2006 will be settled based on the marginal value of system capacity ($/MW-day) as determined under section 5.14(a) in the Base Residual Auction for such Delivery Year, plus any Locational Price Adder determined in such auction for the Locational Deliverability Area that corresponds to the Mid-Atlantic Region plus the Allegheny Power System Zone. The party that purchased such Capacity Credit shall receive this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of such transaction. The party that sold such Capacity Credit shall be assessed this value, multiplied by the megawatt quantity of the Capacity Credit, for the duration of such transaction. For the 2008/2009 Delivery Year, and thereafter, Capacity Credits will be settled based on the marginal value of system capacity ($/MW-day) as determined under section 5.14(a) in the Base Residual Auction for such Delivery Year. The party that purchased such Capacity Credit shall receive this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of the transaction. The party that sold such Capacity Credit will be assessed this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of the transaction.

15. COORDINATION WITH ECONOMIC PLANNING PROCESS

Prior to the posting of the planning parameters for each Base Residual Auction, if the Office of the Interconnection determines that the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective for any LDA, the Office of the Interconnection will include a transmission upgrade in the RTEP as soon as practicable, if all of the following criteria is satisfied:

- The transmission upgrade(s) will result in a Capacity Emergency Transfer Limit that exceeds 1.15 times the Capacity Emergency Transfer Objective for the LDA; and
- The transmission upgrade(s) is/are expected to be in-service prior to June 1 of the Delivery Year for which the Base Residual Auction is being conducted; and
- The transmission upgrade cost is expected to be less than $5 million; and
- There are no Merchant Network Upgrades that have or are expected to have an executed Facilities Study Agreement by 45 days prior to the Base Residual Auction that are designed to resolve the same constraint for which the RTEP upgrade is designed to resolve.

The annual costs of such upgrade shall be allocated as specified in Schedule 12 of the Tariff.

The Office of the Interconnection shall include in its planning period parameters report, posted on its website in February of each year, the following information for the transmission upgrades it identifies to address easily resolvable constraints under this Section 15, if any: (1) a description of each easily resolvable constraint; (2) the limiting transmission elements responsible for each such easily resolvable constraint; (3) an explanation of why the transmission elements responsible for each such easily resolvable constraint identified are limiting; (4) a list of the easily resolvable constraint transmission upgrades undertaken as well as the cost, location, and the entity(ies) undertaking each such upgrade; and (5) the impact of these projects on that Delivery Year's planning parameters.

Following each Base Residual Auction, the Office of the Interconnection shall review each LDA that has a Locational Price Adder to determine if Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades submitted Sell Offers that cleared in such auction. If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, and no such planned resources or upgrades clear in such auctions for such LDA, then the Office of the Interconnection shall evaluate in the RTEP process the costs and benefits of a transmission upgrade that would reduce to zero the Locational Price Adder for such LDA. Such evaluation will compare the cost of the upgrade over ten years against the value of elimination of the Locational Price Adder over such period. If such upgrade is found to be feasible and beneficial, it shall be included in the RTEP as soon as practicable. The annual costs of such upgrade shall be allocated as specified in Schedule 6 of the Operating Agreement.

16. RELIABILITY BACKSTOP

16.1. Purpose

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by: (a) lack of sufficient capacity committed through the Reliability Pricing Model Auctions; or (b) near-term transmission deliverability violations identified after the Base Residual Auction is conducted. These backstop mechanisms are intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The backstop mechanisms are based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources through Self-Supply or the Reliability Pricing Model Auctions.

16.2 Investigation of Capacity Shortfall

If the total Unforced Capacity of Capacity Resources committed for a Delivery Year following the Base Residual Auction equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection shall investigate the cause for the shortage, and recommend corrective action, including, without limitation, adjusting the Cost of New Entry to the extent determined necessary by such investigation, or addressing other barriers to entry identified by such investigation. No Reliability Backstop Auction will be conducted to address such a shortfall unless it occurs in the Base Residual Auctions for three consecutive Delivery Years.

16.3 Triggering Conditions

a) Either of the following two conditions will trigger reliability backstop measures provided in this section, as described below:

i) If the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years, equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection will declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

ii) If the total Unforced Capacity of all Base Load Generation Resources committed in a Base Residual Auction for a Delivery Year is less than the forecasted minimum hourly load calculated by the Office of the Interconnection for such Delivery Year, the Office of the Interconnection will investigate the cause of shortfall. If such a shortfall occurs in the Base Residual Auctions for three consecutive Delivery Years, the Office of the Interconnection shall declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

b) In addition to the foregoing events that trigger reliability backstop measures, if a near-term, i.e., later in time than the conduct of the Base Residual Auction for a Delivery Year, transmission criteria violation caused by an announced generation resource deactivation is identified by the regional transmission reliability planning analysis performed by the Office of the Interconnection in accordance with Part V of this Tariff, the Office of the Interconnection will identify the necessary transmission upgrade. In accordance with such rules, such generation resource may remain in service until the transmission upgrade is installed. No Reliability Backstop Auction will be conducted.

16.4. Reliability Backstop Auction

a) Scope of Auction

The Office of the Interconnection shall conduct each Reliability Backstop Auction to commit additional Generation Capacity Resources, or in the case of an auction triggered by section 16.3(a)(ii), additional Base Load Generation Resources to the PJM Region to resolve the system-wide reliability criteria violation that triggered the need for such auction. Capacity Resources committed in a Reliability Backstop Auction for a Delivery Year shall not include any Planned Generation Capacity Resources previously committed in the Base Residual Auction for such Delivery Year. The Reliability Backstop Auction shall obtain commitments of additional Generation Capacity Resources (or, as applicable, additional Base Load Generation Resources) for a term of up to fifteen (15) Delivery Years. If a Reliability Backstop Auction is required, the offer period for such auction shall commence, subject to FERC approval as specified above, no later than four months after the Base Residual Auction in which the third consecutive Capacity Resource shortfall occurs. Upon verification and notification by the PJM Board of Managers that a Reliability Backstop Auction is required, the Office of the Interconnection shall post notification that a Reliability Backstop Auction is to be held. Upon such notification, the offer period shall commence, and shall remain open for six (6) months. PJMSettlement shall be the Counterparty to the capacity transaction resulting from committed Capacity Resources clearing the Reliability Backstop Auction.

b) Sell Offers

Each Sell Offer shall specify the following information, as further specified in the PJM Manuals:

- the minimum price in $/MW-day required by the Capacity Market Seller to provide additional Unforced Capacity from a Generation Capacity Resource (or from a Base Load Generation Resource, in the case of an auction triggered by section 16.3(a)(ii));
- the megawatts of Unforced Capacity to be provided by such resource;
- the specific location of the proposed plant;
- all information required from a Generation Interconnection Customer by Part IV of this Tariff and the PJM Manuals;

- general plant technical specifications, as specified in the PJM Manuals;

- the term of cost recovery ("Backstop Period") requested, not to exceed 15 years; and

- the first full Delivery Year for which such resource shall be available, which shall also be the first year of the Backstop Period.

Each Generation Capacity Resource (or Base Load Generation Resource) accepted in a Reliability Backstop Auction shall comply with the procedures for new generation interconnection in Part IV of this Tariff, and each such resource shall be responsible for satisfying all capability and deliverability requirements for Capacity Resources, pursuant to the Reliability Assurance Agreement.

c) Submission of Sell Offers

The Sell Offer period shall begin at 00:01 Eastern Prevailing Time on the date specified by the Office of the Interconnection in the notification posting and shall end at 23:59 Eastern Prevailing Time six calendar months after such date. Sell offers shall be submitted during such period in writing to the Office of the Interconnection, and shall conform to the submission procedures as specified in the PJM Manuals. The Office of the Interconnection shall confirm in writing the receipt of each Sell Offer, within two weeks after receipt of each such offer.

d) Posting of Information by the Office of the Interconnection

Upon notification by the PJM Board of Managers that a Reliability Backstop Auction will be conducted, the Office of the Interconnection shall post the following information:

- System condition that necessitates a Reliability Backstop Auction;

- Megawatt quantity of Unforced Capacity required from additional Generation Capacity Resources, or from additional Base Load Generation Resources;

- Date by which the resources must be capable of delivering Unforced Capacity;

- Any other required specifications for the additional Unforced Capacity sought through such auction.

e) Conduct of the Reliability Backstop Auction

i) Auction Clearing Procedure

The Reliability Backstop Auction shall select the Sell Offer or combination of Sell Offers that that satisfies the requirements posted by the Office of the Interconnection at the lowest offer price(s). If more than one Sell Offer must be selected to satisfy the specified requirements, the Sell Offers shall be selected in rank order from lowest offer price to highest offer price until the requirement is satisfied. In the event two or more Sell Offers specify the same offer price, and fewer than all of such offers are needed to satisfy the specified requirements, the Office of the Interconnection shall select the Sell Offer(s) proposing Generation Capacity Resource(s), or, as applicable, Base Load Generation Resource(s) that will best satisfy overall reliability requirements for the PJM Region, as determined by the Office of the Interconnection using transmission reliability analysis.

ii) Market Settlement

Pursuant to the agreement specified below, each Capacity Market Seller submitting a Sell Offer that is accepted in a Reliability Backstop Auction shall be paid by PJMSettlement the offer price in such Sell Offer for each MW-day in the Backstop Period, less any payments the Capacity Market Seller is entitled to receive pursuant to section 5 of this Attachment as a result of Sell Offers submitted with respect to such Generation Capacity Resource in any Base Residual Auction or Incremental Auction, including, without limitation, payments of Capacity Resource Clearing Prices (including for Self-Supply) and Resource Make-Whole Payments; and less any payments the Capacity Market Seller is entitled to receive for energy or ancillary services pursuant to Schedule 1 of the Operating Agreement with respect to services provided by such resource, net of the Variable Operations and Maintenance costs of such resource, as determined in accordance with the PJM Manuals.

PJM shall recover the costs of any such payments to Capacity Market Sellers for such resources through a charge, in addition to the Locational Reliability Charge, assessed on all LSEs in the PJM Region, pro rata based on each such LSE's Daily Unforced Capacity Obligations in all LDAs in which such LSE serves load. PJMSettlement shall be the Counterparty to the LSE's obligation to pay, and payment of, such charges.

iii) Standard Contract Provisions

PJMSettlement, will enter into an agreement with each Capacity Market Seller that submitted an accepted Sell Offer in any Reliability Backstop Auction providing for the payments specified above. Such agreement shall include the provisions and address the standards set forth in Section 16.4(b), and shall include such other terms and conditions as are customary in the industry, as specified in the PJM Manuals.

f) FERC Approval

Any such agreement shall provide that it shall be filed with FERC as a rate schedule pursuant to section 205 of the Federal Power Act, and that the effectiveness of such agreement shall be conditioned on receipt of FERC acceptance or approval of such agreement.

16.5 Must Offer into Base Residual Auction

All Capacity Market Sellers submitting a Sell Offer that is selected in a Reliability Backstop Auction must offer all Unforced Capacity of the Generation Capacity Resource underlying such Sell Offer into the Base Residual Auctions conducted subsequent to the Reliability Backstop Auction for all Delivery Years in the Backstop Period. The Market Seller shall offer the

Unforced Capacity of such resources into each such auction at zero price, and shall receive the Capacity Resource Clearing Price as determined in each such auction.

16.6 Reliability Backstop Resource Deficiency Charges

(a) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that is not able to deliver in a Delivery Year all megawatts of Unforced Capacity specified in the selected Sell Offer, shall not receive any payments that such Capacity Market Seller otherwise would have been eligible to receive for such Delivery Year pursuant to the Reliability Backstop Auction.

(b) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that fails to deliver all megawatts of Unforced Capacity specified in the selected Sell Offer at any time during the Backstop Period specified in such Sell Offer must refund all payments received by such Market Seller pursuant to section 16.4(b).

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 AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources 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. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource 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 a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, 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 a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, 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. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

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 and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

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

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, 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. 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, divided by the total Nominated Value of Demand Resources 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, 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 Curtailment Service 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. The Party, Electric Distributor, or Curtailment Service 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 section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources 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 K hereof and the PJM Manuals. In addition, committed Demand Resources 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.

F. 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.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service 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. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

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

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service 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.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company 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 available, as requested by PJM;

- Entry of customer-specific Demand Resource 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 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 events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource 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 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 Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy 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 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 J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource 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 Curtailment Service 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, 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. Curtailment Service 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 Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources 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. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand 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 LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed 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.

L. 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 summer and winter 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, 2011. 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.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value 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;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource 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; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

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. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, 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. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020

Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times 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.

The EPA Administrator, Michael S. Regan, signed the following notice on 3/15/2023, and EPA is submitting it for publication in the *Federal Register* (FR). While we have taken steps to ensure the accuracy of this Internet version of the rule, it is not the official version of the rule for purposes of compliance. Please refer to the official version in a forthcoming FR publication, which will appear on the Government Printing Office's govinfo website (https://www.govinfo.gov/app/collection/fr) and on Regulations.gov (https://www.regulations.gov) in Docket No. EPA-HQ-OAR-2021-0668. Once the official version of this document is published in the FR, this version will be removed from the Internet and replaced with a link to the official version.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78 and 97

[EPA-HQ-OAR-2021-0668; FRL 8670-02-OAR]

RIN 2060-AV51

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes Federal Implementation Plan (FIP) requirements to address 23 states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is taking this action under the "good neighbor" or "interstate transport" provision of the Clean Air Act (CAA or Act). The Agency is defining the amount of ozone-precursor emissions (specifically, nitrogen oxides) that constitute significant contribution to nonattainment and interference with maintenance from these 23 states. With respect to fossil fuel-fired power plants in 22 states, this action will prohibit those emissions by implementing an allowance-based trading program beginning in the 2023 ozone season. With respect to certain other industrial stationary sources in 20 states, this action will prohibit those emissions through emissions limitations and associated requirements beginning in the 2026 ozone season. These industrial source types are: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product

HEARING EXHIBIT SC 3

Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

DATES: This final rule is effective on **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021-0668. All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at *http:// www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA Docket Center, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539-01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (919)-541-3918; email address: *selbst.elizabeth@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1	2016 Version 1 Emissions Modeling Platform
2016v2	2016 Version 2 Emissions Modeling Platform
4-Step Framework	4-Step Interstate Transport Framework
ABC	Associated Builders and Contractors
ACS	American Community Survey
ACT	Alternative Control Techniques
AEO	Annual Energy Outlook
AQAT	Air Quality Assessment Tool
AQS	Air Quality System
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOF	Basic Oxygen Furnace
BPT	Benefit Per Ton
C1C2	Category 1 and Category 2
C3	Category 3
CAA or Act	Clean Air Act
CAIR	Clean Air Interstate Rule
CBI	Confidential Business Information
CCR	Coal Combustion Residual
CDC	Centers for Disease Control and Prevention
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	Continuous Emissions Monitoring Systems
CES	Clean Energy Standards
CFB	Circulating Fluidized Bed Units
CHP	Combined Heat and Power
CMDB	Control Measures Database

CMV	Commercial Marine Vehicle
CoST	Control Strategy Tool
CPT	Cost Per Ton
CRA	Congressional Review Act
CSAPR	Cross-State Air Pollution Rule
DAHS	Data Acquisition and Handling System
DOE	Department of Energy
EAF	Electric Arc Furnace
EGU	Electric Generating Unit
EIA	U.S. Energy Information Agency
EIS	Emissions Inventory System
EISA	Energy Independence and Security Act
ELG	Effluent Limitation Guidelines
EO	Executive Order
EPA or the Agency	United States Environmental Protection Agency
ERT	Electronic Reporting Tool
FERC	Federal Energy Regulatory Commission
FFS	Findings of Failure to Submit
FIP	Federal Implementation Plan
GIS	Geographic Information System
g/hp-hr	grams per horsepower per hour
HDGHG	Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD	High Electricity Demand Days
ICI	Industrial, Commercial, and Institutional
I/M	Inspection and Maintenance
IPM	Integrated Planning Model
IRA	Inflation Reduction Act
LAER	Lowest Achievable Emission Rate
LDC	Local Distribution Company
LME	Low Mass Emissions

LNB	Low-NOx Burners
MATS	Mercury and Air Toxics Standards
MCM	Menu of Control Measures
MDA8	Maximum Daily Average 8-Hour
MJO	Multi-Jurisdictional Organization
MOU	Memorandum of Understanding
MOVES	Motor Vehicle Emissions Simulator
MSAT2	Mobile Source Air Toxics Rule
MWC	Municipal Waste Combustor
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NAICS	North American Industry Classification System
NEEDS	National Electric Energy Data System
NEI	National Emissions Inventory
NERC	North American Electric Reliability Corporation
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NMB	Normalized Mean Bias
NME	Normalized Mean Error
No SISNOSE	No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU	Non-Electric Generating Unit
NODA	Notice of Data Availability
NOx	Nitrogen Oxides
NREL	National Renewable Energy Lab
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
OFA	Over-Fire Air
OMB	United States Office of Management and Budget
OSAT/APCA	Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis

OTC	Ozone Transport Commission
OTR	Ozone Transport Region
OTSA	Oklahoma Tribal Statistical Area
PDF	Portable Document Format
PEMS	Predictive Emissions Monitoring Systems
$PM_{2.5}$	Fine Particulate Matter
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million by volume, dry
PRA	Paperwork Reduction Act
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RCF	Relative Contribution Factor
RFA	Regulatory Flexibility Act
RICE	Reciprocating Internal Combustion Engines
ROP	Rate of Progress
RPS	Renewable Portfolio Standards
RRF	Relative Response Factor
RTC	Response to Comments
RTO	Regional Transmission Organization
SAFETEA	Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SIL	Significant Impact Level
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide

tpd	ton per day
TAS	Treatment as State
TSD	Technical Support Document
UMRA	Unfunded Mandates Reform Act
VMT	Vehicle Miles Traveled
VOCs	Volatile Organic Compounds
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting

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I. Executive Summary

This final rule resolves the interstate transport obligations of 23 states under CAA section 110(a)(2)(D)(i)(I), referred to as the "good neighbor provision" or the "interstate transport provision" of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to submit to EPA ozone infrastructure State Implementation Plan (SIP) revisions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018. The EPA proposed the subject rule to address outstanding interstate ozone transport obligations for the 2015 ozone NAAQS in the *Federal Register* on April 6, 2022 (87 FR 20036).

The EPA is making a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in

[1] *See* 80 FR 65291 (October 26, 2015).

downwind states, based on projected ozone precursor emissions in the 2023 ozone season. The EPA is issuing FIP requirements to eliminate interstate transport of ozone precursor emissions from these 23 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in downwind states. The EPA is not finalizing its proposed error correction for Delaware's ozone transport SIP, and we are deferring final action at this time on the proposed FIPs for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action. As discussed in section III of this document, the EPA's updated analysis of 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico may be significantly contributing to one or more nonattainment or maintenance receptors. The EPA is not making any final determinations with respect to these states in this action but intends to address these states, along with Tennessee and Wyoming, in a subsequent action or actions.

The EPA is finalizing FIP requirements for 21 states for which the Agency has, in a separate action, disapproved (or partially disapproved) ozone transport SIP revisions that were submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Texas, Utah, West Virginia, and Wisconsin. *See* 88 FR 9336. In this final rule, the EPA is issuing FIPs for two states – Pennsylvania and Virginia – for which the EPA issued Findings of Failure to Submit for 2015 ozone NAAQS transport SIPs. *See* 84 FR 66612 (December 5, 2019). Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2]

This final rule defines ozone season nitrogen oxides (NOx) emissions performance obligations for Electric Generating Unit (EGU) sources and fulfills those obligations by implementing an allowance-based ozone season trading program beginning in 2023. This rule also establishes emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as "non-Electric Generating Units" (non-EGUs)). Taken together, these regulatory requirements will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone NAAQS.

This final rule implements the necessary emissions reductions as follows. Under the FIP requirements, EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) are required to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NOx Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] In addition to reflecting emissions reductions based on the Agency's determination of the necessary control stringency in this rule, the revised trading program includes several enhancements to the program's design to better ensure achievement of the selected control stringency on all days of the ozone season and over time. For 12 states already required to

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[2] In general, specific tribal names or reservations are not identified separately in this final rule except as needed. *See* section III.C.2 of this document for further discussion about the application of this rule in Indian Country.

[3] As explained in section V.C.1 of this document, the EPA is making a finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

participate in the CSAPR NOx Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) under the Revised CSAPR Update (with respect to the 2008 ozone NAAQS), the FIPs are amended by the revisions to the Group 3 trading program regulations. For seven states currently covered by the CSAPR NOx Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. The EPA is issuing new FIPs for three states not currently covered by any CSAPR NOx ozone season trading program: Minnesota, Nevada, and Utah.

This rulemaking requires emissions reductions in the selected control stringency to be achieved as expeditiously as practicable and, to the extent possible, by the next applicable nonattainment dates for downwind areas for the 2015 ozone NAAQS. Thus, initial emissions reductions from EGUs will be required beginning in the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.

The remaining emissions reduction obligations will be phased in as soon as possible thereafter. Substantial additional reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs, also referred to in this action as industrial sources, will phase in beginning in the 2026 ozone season, associated with the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. The EPA had proposed to require all emissions reductions to eliminate significant contribution to be in place by the 2026 ozone season. While we continue to view 2026 as the appropriate analytic year for purposes of applying the 4-step interstate transport framework, as discussed in section V.D.4 and VI.A.2 of this document, the final rule will allow individual facilities limited additional time to fully implement the required emissions reductions where the owner or operator demonstrates to the EPA's satisfaction that more rapid compliance is not possible. For EGUs, the emissions trading program budget stringency associated with retrofit of post-combustion controls will be phased in over two ozone seasons (2026-2027). For industrial sources, this final rule provides a process for individual facilities to seek a one year extension, with the possibility of up to two additional years, based on a specific showing of necessity.

The EGU emissions reductions are based on the feasibility of control installation for EGUs in 19 states that remain linked to downwind nonattainment and maintenance receptors in 2026. These 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The emissions reductions required for EGUs in these states are based primarily on the potential retrofit of additional post-combustion controls for NO_x on most coal-fired EGUs and a portion of oil/gas-fired EGUs that are currently lacking such controls.

The EPA is finalizing, with some modifications from proposal in response to comments, certain additional features in the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets and recalibration of the allowance bank over time as well as backstop daily emissions rate limits for large coal-fired units. The purpose of these enhancements is to better ensure that the emissions control stringency the EPA found necessary to eliminate significant contribution at Step 3 of the 4-step interstate transport framework is maintained over time in Step 4 implementation and is durable to changes in the power sector. These enhancements ensure the elimination of significant contribution is maintained both in terms of geographical distribution (by limiting the degree to which individual sources can avoid making emissions reductions) and in terms of temporal distribution (by better ensuring emissions reductions are maintained throughout each ozone season, year over year). As we further discuss in section V.D of this document, these changes do not alter the stringency of the emissions trading program over time. Rather, they ensure that the trading program (as the method of implementation at Step 4) remains aligned with the determinations made at Step 3. These enhancements are further discussed in section VI.B of this document.

The EPA is making a finding that NOx emissions from certain non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NOx emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA is establishing emissions limitations beginning in 2026 for non-EGU sources located within 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The final rule establishes NOx emissions limitations during the ozone season for the following unit types for sources in non-EGU industries:[4] reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and

[4] We use the terms "emissions limitation" and "emissions limit" to refer to both numeric emissions limitations and control technology requirements that specify levels of emissions reductions to be achieved.

Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in downwind states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section III of this document provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[5,6] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[7]

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[5] Bergin, M.S. et. al. (2007) Regional air quality: local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677-4689.

[6] Liao, K. et. al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100-112.

[7] *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[8] Within 3 years of the EPA promulgating a new or revised NAAQS, all states are required to provide SIP submittals, often referred to as "infrastructure SIPs," addressing certain requirements, including the good neighbor provision. *See* CAA section 110(a)(1) and (2). The EPA must either approve or disapprove such submittals or make a finding that a state has failed to submit a complete SIP revision. As with any other type of SIP under the Act, when the EPA disapproves an interstate transport SIP or finds that a state failed to submit an interstate transport SIP, the CAA requires the EPA to issue a FIP to directly implement the measures necessary to eliminate significant contribution under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this rule, the EPA is finalizing requirements to fully address good neighbor obligations for the covered states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c). By eliminating significant contribution from these upwind states, this rule will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country. At any time after the effective date of this rule, states may submit a Good Neighbor SIP to replace the FIP requirements contained in this rule, subject to EPA approval under CAA section 110(a).

The EPA conducted air quality modeling for the 2023 and 2026 analytic years to identify (1) the downwind areas identified as "receptors" (which are associated with monitoring sites) that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality

[8] 42 U.S.C. 7410(a)(2)(D)(i)(I).

problems. We use the term "downwind" to describe those states or areas where a receptor is located, and we use the term "upwind" to describe states whose emissions are linked to one or more receptors. States may be both downwind and upwind depending on the receptor or linkage in question. Section IV of this document provides a full description of the results of the EPA's updated air quality modeling and relevant analyses for the rulemaking, including a discussion of how updates to the modeling and air quality analysis following the proposed rule have resulted in some modest changes in the overall geography of the final rule. Based on the EPA's air quality analysis, the 23 upwind states covered in this action are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in downwind states. The EPA intends to expeditiously review the updated air quality modeling and related analyses to address potential good neighbor requirements of six additional states—Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming—in a subsequent action. The EPA had previously approved 2015 ozone transport SIPs submitted by Oregon and Delaware, but in the proposed FIP action the EPA found these states potentially to be linked in the modeling supporting our proposal. We proposed to issue an error correction for our prior approval of Delaware's 2015 ozone transport SIP; however, in this final rule, the EPA is withdrawing the proposed error correction and the proposed FIP for Delaware, because our updated modeling for this final rule confirms that Delaware is not linked above the 1 percent of NAAQS threshold (*see* section III.C.1 of this document for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

1. Emissions Limitations for EGUs Established by the Final Rule

In this rule, the EPA is issuing FIP requirements that apply the provisions of the CSAPR NOx Ozone Season Group 3 Trading Program as revised in the rule to EGU sources within the borders of the following 22 states: Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. Implementation of the revised trading program provisions begins in the 2023 ozone season.

The EPA is expanding the CSAPR NO_x Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require power plants within the borders of the 22 states listed in the previous paragraph to participate in an expanded and revised version of the CSAPR NO_x Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program under existing FIPs remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs also require affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_x Ozone Season Group 2 Trading Program (the "Group 2 trading program") under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.[9] Finally, the EPA is issuing new FIPs for EGUs within the borders of three states not currently covered by any existing CSAPR trading program for seasonal NO_x emissions: Minnesota, Nevada, and

[9] Five of these seven states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) currently participate in the federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update. The FIPs required under this rule amend the existing FIPs for these states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the federal Group 2 trading program, so the FIPs required in this action constitute new FIPs for these states. The EPA will cease implementation of the state Group 2 trading programs included in the two states' SIPs on the effective date of this rule.

Utah. Sources in these states will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[10] Refer to section VI.B of this document for details on EGU regulatory requirements.

2. Emissions Limitations for Industrial Stationary Point Sources Established by the Final Rule

The EPA is issuing FIP requirements that include new NOx emissions limitations for industrial or non-EGU sources in 20 states, with sources expected to demonstrate compliance no later than 2026. The EPA is requiring emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia and West Virginia.

The EPA is establishing emissions limitations for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. Refer to Table II.A-1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this proposed rule.

B. Summary of the Regulatory Framework of the Rule

[10] Three states, Kansas, Iowa, and Tennessee, will remain in the Group 2 Trading Program.

The EPA is applying the 4-step interstate transport framework developed and used in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to define and implement good neighbor obligations for the 2015 ozone NAAQS. The four steps are as follows: (Step 1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (Step 2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems (*i.e.*, in this rule as in prior transport rules beginning with CSAPR in 2011, above a contribution threshold of 1 percent of the NAAQS); (Step 3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS through a multifactor analysis; and (Step 4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to the provisions of the rule; additional details regarding the EPA's approach are found in section III of this document.

To apply the first step of the 4-step framework to the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023 and 2026.[11] The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to

[11] These 2 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, and August 3, 2027, for areas classified as Serious nonattainment. *See* 83 FR 25776.

identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis of projected ozone concentrations was then repeated for 2026.

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (i.e., 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the 4-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

Based on the EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA finds that the following 23 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

There are locations in California to which Oregon contributes greater than 1 percent of

[12] The EPA performed air quality modeling for 2032 in the proposed rulemaking, but did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3. The modeling of 2032 done at proposal using the 2016v2 platform does not constitute or represent any final agency determinations respecting air quality conditions or regulatory judgments with respect to good neighbor obligations or any other CAA requirements.

[13] *See* section IV.F of this document for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

the NAAQS; the EPA proposed that downwind areas represented by these monitoring sites in California should not be considered interstate ozone transport receptors at Step 1. However, the EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

Based on the air quality analysis presented in section IV of this document, the EPA finds that, with the exception of Alabama, Minnesota, and Wisconsin, the states found linked in 2023 will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season. As a result, the EPA's evaluation of significantly contributing emissions at Step 3 for Alabama, Minnesota, and Wisconsin is limited to emissions reductions achievable by the 2023 and 2024 ozone seasons.

At the third step of the 4-step framework, the EPA applied a multifactor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that "significantly" contribute to downwind nonattainment or maintenance receptors. The EPA is applying the multifactor test described in section V.A of this document to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,[14] as well as in intervening and later years to determine the emissions reductions required to eliminate

[14] The EPA included emissions reductions from the potential installation of SCRs at all affected large coal-fired EGUs in the 2026 analytic year for the purposes of assessing significant contribution to nonattainment and interference with maintenance, which is consistent with the associated attainment date. However, in response to comments identifying potential supply chain and outage scheduling challenges if the full breadth of these assumed SCR installations were to occur, the EPA is implementing half of this emissions reduction potential in 2026 ozone-season NOx budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NOx budgets for those states.

significant contribution in 2023 and future years where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NOx emissions control technologies: (1) fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NOx removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NOx combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NOx removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in section V of this document and supported by the "Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA-HQ-OAR-2021-0668, EGU NOX Mitigation Strategies Final Rule TSD" (Mar. 2023), hereinafter referred to as the EGU NOx Mitigation Strategies Final Rule TSD, included in the docket for this action, the EPA determines that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NOx emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NOx combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. *See* section V.B.1 of this document for a full discussion of EPA's analysis of NOx emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NOx emissions reduction potential from EGUs – among the uniform mitigation measures assessed for the covered region – and the most corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA is making a finding that the required controls provide cost-effective reductions of NOx emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in the EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NOx SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[15] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

Furthermore, the CSAPR Update provided only a partial remedy for eliminating significant contribution for the 2008 ozone NAAQS, as needed to obtain available reductions by the 2017 ozone season. In that rule, the EPA made no determination regarding the appropriateness of more stringent EGU NOx controls that would be required for a *full* remedy for interstate transport for the 2008 ozone NAAQS. Following the remand of the CSAPR Update in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*), the EPA again declined to require the retrofit of new post-combustion controls on EGUs in the Revised CSAPR Update, but that determination was based on a specific timing consideration: downwind air quality problems

[15] *See, e.g.*, 70 FR 25162, 25205-06 (May 12, 2005).

under the 2008 ozone NAAQS were projected to resolve before post-combustion control retrofits could be accomplished on a fleetwide, regional scale. *See* 86 FR 23054, 23110 (April 30, 2021).

In this rulemaking, the EPA is addressing good neighbor obligations for the more protective 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in downwind states under that NAAQS. As further discussed in section V of this document, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. In this rule, the EPA is requiring emissions performance levels for EGU NOx control strategies commensurate with those determined to be necessary in the NOx SIP Call and CAIR.

Based on the Step 3 analysis described in section V of this document, the EPA finds that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 22 states linked to downwind nonattainment or maintenance in 2023 (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin). For 19 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100

MW capacity and on CFBs of any capacity size, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NOx per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NOx emissions reductions that would result in meaningful air quality improvements in downwind areas, for the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact in providing ozone air quality improvements in affected downwind states. Once the EPA identified the industries, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[16,17] This information helped shape the proposal and final rule. To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved SIPs, consent decrees,

[16] The memorandum is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.*

[17] This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that had emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

and permit limits. That evaluation is detailed in the "Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, Non-EGU Sectors TSD" (Dec. 2021), hereinafter referred to as the Proposed Non-EGU Sectors TSD, prepared for the proposed FIP.[18]

In this final rule, the EPA is retaining the industries and many of the emissions unit types included in the proposal in its findings of significant contribution at Step 3, as discussed in section V of this document. As discussed in the memorandum titled, "*Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs*," for the final rule the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the Control Measures Database,[19] to estimate NO_X emissions reductions and costs for the year 2026. In this final rule, the EPA made changes to the applicability criteria and emissions limits following consideration of comments on the proposal and reassessed the overall non-EGU emissions reduction strategy based on the factors at Step 3 to render a judgment as to whether the level of emissions control that would be achievable from these units meets the criteria for "significant contribution." In the final rule, we affirm our proposed determinations of which industries and emissions units are potentially impactful and warrant further analysis at Step 3, and we find that the available emissions reductions are cost-effective and make meaningful improvements at the identified downwind receptors. For a

[18] The TSD is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

[19] More information about the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution*.

detailed discussion of the changes, between the proposal and this final rule, in emissions unit types included and in emissions limits, see section VI.C. of this document.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to evaluate the air quality improvements anticipated to result from the implementation of the selected EGU and non-EGU emissions reduction strategies. See section V.D of this document.[20] We also used AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an "over-control" scenario. As in prior transport rules following the holdings in *EME Homer City*, overcontrol would be established if the record indicated that, for any given state, there is a less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (i.e., 1 percent of the NAAQS or 0.70 ppb) to all of linked receptors. The EPA's over-control analysis, discussed in section V.D.4 of this document, shows that the control stringencies for EGU and non-EGU sources in this final rule do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for

[20] The use of AQAT and other simplified modeling tools to generate "appropriately reliable projections of air quality conditions and contributions" when there is limited time to conduct full-scale photochemical grid modeling was upheld by the D.C. Circuit in *MOG v. EPA*, No. 21-1146 (D.C. Cir. March 3, 2023). The EPA has used AQAT for the purpose of air quality and overcontrol assessments at Step 3 in the prior CSAPR rulemakings, and we continue to find it reliable for such purposes. We discuss the calibration of AQAT for this action and the multiple sensitivity checks we performed to ensure its reliability in the Ozone Transport Policy Analysis Final Rule TSD in the docket. Because we were able to conduct a photochemical grid modeling run of the 2026 final rule policy scenario, these results are also included in the docket and confirm the regulatory conclusions reached with AQAT. *See* Section VIII of this document and Appendix 3A of the Final Rule RIA for more information.

any linked upwind state.

Based on the multi-factor test applied to both EGU and non-EGU sources and our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 23 upwind states subject to EGU and non-EGU emissions reductions requirements under the rule. For additional details about the multi-factor test and the over-control analysis, *see* the document titled, "Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA-HQ-OAR-2021-0668, Ozone Transport Policy Analysis Proposed Rule TSD" (Mar. 2023), hereinafter referred to as Ozone Transport Policy Analysis Final Rule TSD, included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA is including enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 23 states. Specifically, the FIPs require covered power plants within the borders of 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) to participate in the CSAPR NOx Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program will remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of the following seven states currently covered by the CSAPR NOx Ozone Season Group 2 Trading Program (the "Group 2 trading program") – Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin – will transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[21] and affected EGUs within the borders of three states not currently covered by any CSAPR trading program for seasonal NOx emissions – Minnesota, Nevada, and Utah – will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA is revising other aspects of the Group 3 trading program to better ensure that this method of implementation at Step 4 provides a durable remedy for the elimination of the amount of emissions deemed to constitute significant contribution at Step 3 of the interstate transport framework. These enhancements, summarized later in this section, are designed to operate together to maintain that degree of control stringency over time, thus improving emissions performance at individual units and offering a necessary measure of assurance that NOx pollution controls will be operated throughout each ozone season, as described in section VI.B of this document. This rulemaking does not revise the budget stringency and geography of the existing CSAPR NOx Ozone Season Group 1 trading program. Aside from the seven states moving from the Group 2 trading program to the Group 3 trading program under the final rule, this rule otherwise leaves unchanged the budget stringency of the existing CSAPR NOx Ozone Season Group 2 trading program.

The EPA is establishing preset ozone season NOx emissions budgets for each ozone season from 2023 through 2029, using generally the same Group 3 trading program budget-setting methodology used in the Revised CSAPR Update, as explained in section VI.B of this

[21] The EPA will deem participation in the Group 3 trading program by the EGUs in these seven states as also addressing the respective states' good neighbor obligations with respect to the 2008 ozone NAAQS (for all seven states), the 1997 ozone NAAQS (for all the states except Texas), and the 1979 ozone NAAQS (for Alabama and Missouri) to the same extent that those obligations are currently being addressed by participation of the states' EGUs in the Group 2 trading program.

document and as shown in Table I.B-1. The preset budgets for the 2026 through 2029 ozone seasons incorporate EGU emissions reductions to eliminate significant contribution and also take into account a substantial number of known retirements over that period to ensure the elimination of significant contribution is maintained as intended by this rule. These budgets serve as floors and may be supplanted by a budget that the EPA calculates for that control period using more recent information (a "dynamic budget") if that dynamic budget yields a higher level of allowable emissions—still consistent with the Step 3 level of emissions control stringency—than the preset budget. As reflected in Table I.B-1, and accounting for both the stringency of the rule and known fleet change, the 2026 preset budget is 23 percent lower than the 2025 preset budget; the 2027 preset budget is 20 percent lower than the 2026 preset budget; the 2028 preset budget is 4 percent lower than the 2027 preset budget; and the 2029 preset budget is 8 percent lower than the 2028 preset budget.

While it is possible that additional EGUs may seek to retire in this 2026-2029 period than are currently scheduled and captured in the preset emissions budgets, it is also possible that EGUs with currently scheduled retirements may adjust their retirement timing to accommodate the timing of replacement generation and/or transmission upgrades necessitated by their retirement. While the EPA designed this final rule to provide preset budgets through 2029 to incorporate known retirement-related emissions reductions to ensure the elimination of significant contribution as identified at Step 3 is maintained over time, the use of these floors also provides generators and grid operators enhanced certainty regarding the minimum amount of allowable NOx emissions for reliability planning through the 2020s. By providing the opportunity for dynamic budgets to subsequently calibrate budgets to any unforeseen increases in fleet demand, it also ensures this rule will not interfere with ongoing retirement scheduling or adjustments and thus is robust to future uncertainty during a transition period.

The EPA also believes the likelihood and magnitude of a scenario in which a state's preset emissions budgets during this period would authorize more emissions than the corresponding dynamic budget is low. As described elsewhere, dynamic budgets are incorporated to best calibrate the rule's stringency to future unknown changes to the fleet. The circumstances in which a dynamic budget would produce a level of allowable emissions less than preset budgets is most pronounced for future periods in which there is a high degree of unknown retirements (increasing the risk that budgets are not appropriately calibrated to the reduced fossil fuel heat input post retirement). However, the 2026-2029 period presents a case where retirement planning has been announced with greater lead time than normal due to a combination of utility 2030 decarbonization commitments, and Effluent Limitation Guideline (ELG) and Coal Combustion Residual (CCR) alternative compliance pathways available to units planning to cease combustion of coal by December 31, 2028. For each of these existing rules, facilities that are planning to retire have already conveyed that intention to EPA in order to take advantage of the alternative compliance pathways available to such facilities.[22] Therefore, the likelihood of unknown retirements—leading to lower dynamic budgets—is much lower than typical for this time horizon. This makes EPA's balanced use of preset emissions budgets or dynamic budgets if they exceed preset levels a reasonable mechanism to accommodate planning and fleet transition dynamics during this period. The need and reasoning for the limited-period preset budget floor is further discussed in section VI.B.4.

[22] Notices of Planned Participation for the ELG Reconsideration Rule were due October 31, 2021 (85 FR 64708, 64679). For the CCR Action, facilities had to indicate their future plans to cease receipt of waste by April 11, 2021 (85 FR 53517).

For control periods in 2030 and thereafter, the emissions budgets will be the amounts calculated for each state and noticed to the public roughly one year before the control period, using the dynamic budget-setting methodology. In this manner, the stringency of the program will be secured and sustained in the dynamic budgets of this program, regardless of whatever EGU transition activities ultimately occur in this 2026-2029 transition period.

Table I.B-1: Preset CSAPR NO_X Ozone Season Group 3 State Emissions Budgets (tons) for 2023 through 2029 Control Periods*

State	2023 State Budget	2024 State Budget	2025 State Budget	2026 State Budget**	2027 State Budget**	2028 State Budget**	2029 State Budget**
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416
Total	**208,119**	**198,014**	**195,259**	**151,329**	**119,663**	**115,193**	**105,201**

* Further information on the state-level emissions budget calculations pertaining to Table I.B-1 is provided in

section VI.B.4 of this document as well as the Ozone Transport Policy Analysis Final Rule TSD. Further information on the approach for allocating a portion of Utah's emissions budget for each control period to the existing EGU in the Uintah and Ouray Reservation within Utah's borders is provided in section VI.B.9 of this document.

** As described in section VI of this document, the budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

The budget-setting methodology that the EPA will use to determine dynamic budgets for each control period starting with 2026 is an extension of the methodology used to determine the preset budgets and will be used routinely to determine emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined. The stringency of the dynamic emissions budgets will simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. As already noted, for the control periods in which both preset budgets and dynamic budgets are determined for a state (i.e., 2026 through 2029), the state's dynamic budget will apply only if it is higher than the state's preset budget. *See* section VI.B of this document for additional discussion of the EPA's method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

In conjunction with the levels of the emissions budgets, the carryover of unused allowances for use in future control periods as banked allowances affects the ability of a trading program to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time. Unrestricted banking of allowances allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. To prevent this outcome, the EPA is also revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances using a target percentage of 21 percent for the 2024-2029 control periods and 10.5 percent for control periods in 2030 and later years.

As an enhancement to the structure of the trading program originally promulgated in the Revised CSAPR Update, the EPA is also establishing backstop daily emissions rates for coal steam EGUs greater than or equal to 100 MW in covered states. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NOx emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period.

The backstop daily emissions rates work in tandem with the ozone season emissions budgets to ensure the elimination of significant contribution as determined at Step 3 is maintained over time and more consistently throughout each ozone season. They will offer downwind receptor areas a necessary measure of assurance that they will be protected on a daily basis during the ozone season by more continuous and consistent operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[23] In addition to maintaining a mass-based seasonal requirement, this rule will achieve a much more consistent level of emissions control in line with

[23] *See* 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NOx emission rate between 2017 and 2019.

our Step 3 determination of significant contribution while maintaining compliance flexibility consistent with that determination. These trading program improvements will promote consistent emissions control performance across the power sector in the linked upwind states, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA is including enforceable emissions control requirements that will apply during the ozone season (annually from May to September) for nine non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 20 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states that meet the relevant applicability criteria. Thus, the emissions limitations for non-EGU sources and associated compliance requirements would apply in all 20 states listed in this paragraph, even if some of these states do not currently have any existing emissions units meeting the applicability criteria for the identified industries.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this rule, the EPA has identified the 2026 ozone season as a reasonable compliance date for industrial sources. The EPA is therefore finalizing control requirements for non-EGU sources that take effect in 2026. However, in recognition of comments and additional information indicating that not all facilities may be capable of meeting the control requirements by that time, the final rule provides a process by which the EPA may grant compliance extensions of up to 1 year, which if approved by the EPA, would require compliance no later than the 2027 ozone season, followed by an additional possible extension of up to 2 more years, where specific criteria are met. For sources located in the 20 states listed in the previous paragraph, the EPA is finalizing the NOx emissions limits listed in Table I.B-2 for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the NOx emissions limits listed in Table I.B-3 for kilns in Cement and Cement Product Manufacturing; the NOx emissions limits listed in Table I.B-4 for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the NOx emissions limits listed in Table I.B-5 for furnaces in Glass and Glass Product Manufacturing; the NOx emissions limits listed in Table I.B-6 for boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and the NOx emissions limits listed in Table I.B-7 for combustors and incinerators in Solid Waste Combustors or Incinerators.

Table I.B-2: Summary of NOx Emissions Limits for Pipeline Transportation of Natural Gas

Engine Type and Fuel	**NOx Emissions Limit**
Natural Gas Fired Four Stroke Rich Burn	1.0 g/hp-hr
Natural Gas Fired Four Stroke Lean Burn	1.5 g/hp-hr
Natural Gas Fired Two Stroke Lean Burn	3.0 g/hp-hr

Table I.B-3: Summary of NOx Emissions Limits for Kiln Types in Cement and Concrete Product Manufacturing

Kiln Type	**NOx Emissions Limit (lb/ton of clinker)**
Long Wet	4.0
Long Dry	3.0
Preheater	3.8

Kiln Type	NO_X Emissions Limit (lb/ton of clinker)
Precalciner	2.3
Preheater/Precalciner	2.8

Based on evaluation of comments received, the EPA is not, at this time, finalizing the source cap limit as proposed at 87 FR 20046 (*see* section VII.C.2 of the April 6, 2022, Proposal).

Table I.B-4: Summary of NO_X Control Requirements for Iron and Steel and Ferroalloy Emissions Units

Emissions Unit	NO_X Emissions Standard or Requirement (lb/mmBtu)
Reheat furnace	Test and set limit based on installation of Low-NOx Burners

Table I.B-5: Summary of NO_X Emissions Limits for Furnace Unit Types in Glass and Glass Product Manufacturing

Furnace Type	NO_X Emissions Limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

Table I.B-6: Summary of NO_X Emissions Limits for Boilers in Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills

Unit type	Emissions limit (lbs NOx/mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

Table I.B-7: Summary of NO_X Emissions Limits for Combustors and Incinerators in Solid Waste Combustors or Incinerators

Combustor or Incinerator, Averaging Period	NO_X Emissions Limit
ppmvd on a 24-hour block averaging period	110 ppmvd
ppmvd on a 30-day rolling averaging period	105 ppmvd

Section V.C of this document provides an overview of the applicability criteria, compliance assurance requirements, and the EPA's rationale in proposing these emissions limits and control requirements for each of the non-EGU industries covered by the rule.

The remainder of this preamble is organized as follows: section II of this document outlines general applicability criteria and describes the EPA's legal authority for this rule and the relationship of the rule to previous interstate ozone transport rulemakings. Section III of this document describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as the EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this rule. Section IV of this document describes the Agency's analyses of air quality data to inform this proposed rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the rule, as well as the EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states. Section V of this document describes the EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits. Section VI of this document describes key elements of the implementation schedule for EGU and non-EGU emissions reductions requirements, including details regarding the revised aspects of the CSAPR NOx Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources. Section VII of this document discusses the environmental justice analysis of the rule, as well as outreach and engagement efforts. Section VIII of this document describes the expected costs, benefits, and other impacts of this rule. Section IX of this document provides a summary of proposed changes to the existing regulatory text applicable to the EGUs covered by this rule; and section X of this document discusses the statutory and executive orders affecting this rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this final rule is presented in Table I.C-1. Table I.C-1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A-4, of the health and climate benefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2023. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the final rule. These results present an incomplete overview of the effects of the rule because important categories of benefits—including benefits from reducing other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than this table reflects.

Table I.C-1. Estimated Monetized Health and Climate Benefits, Compliance Costs, and Net Benefits of the Final Rule, 2023 Through 2042 (Millions 2016$, Discounted to 2023)[a]

		3% Discount Rate	7% Discount Rate
Present Value	Health Benefits[b]	$200,000	$130,000

	Climate Benefits[c]	$15,000	$15,000
	Compliance Costs[d]	$14,000	$9,400
	Net Benefits	**$200,000**	**$140,000**
Equivalent Annualized Value	Health Benefits	$13,000	$12,000
	Climate Benefits	$970	$970
	Compliance Costs	$910	$770
	Net Benefits	**$13,000**	**$12,000**

[a] Rows may not appear to add correctly due to rounding.
[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in ozone and $PM_{2.5}$ concentrations. The health benefits are associated with two point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table.
[c] Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC-CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.
[d] The costs presented in this table are consistent with the costs presented in Chapter 4 of the *Regulatory Impact Analysis (RIA)*. To estimate these annualized costs for EGUs, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8 in the RIA.

As shown in Table I.C-1, the PV of the monetized health benefits, associated with reductions in ozone and $PM_{2.5}$ concentrations, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits, associated with reductions in GHG emissions, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819; FRL–8794–01–OW]

RIN 2040–AG23

Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule; notification of public hearing.

SUMMARY: The Environmental Protection Agency (EPA or the Agency) is proposing a regulation to revise the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category applicable to flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) at existing sources. EPA is also soliciting comment on ELGs for legacy wastewater. This proposal is estimated to cost $200 million dollars annually in social costs and reduce pollutant discharges by approximately 584 million pounds per year.

DATES:

Comments: Comments on this proposal must be received on or before May 30, 2023. Comments intended for the associated direct final rule published elsewhere in this issue of the **Federal Register**, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Initial Notification Date Extension,* must be received on or before April 28, 2023.

Public hearing: EPA will conduct two online public hearings about this proposed rule on April 20, 2023, and April 25, 2023. After a brief presentation by EPA personnel, the Agency will accept oral comments that will be limited to three (3) minutes per commenter. The hearing will be recorded and transcribed, and EPA will consider all the oral comments provided, along with the written public comments submitted via the docket for this rulemaking. To register for the hearing, please visit EPA's website at *www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2023-proposed-rule.*

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OW–2009–0819 at *www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *www.regulations.gov.* EPA may publish any comment received to its public docket. Do not electronically submit any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (*e.g.*, audio, video) must be accompanied by a written comment. The written comment is considered the official comment and should include all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI and multimedia submissions, and general guidance on making effective comments, please visit *www.epa.gov/dockets/commenting-epa-dockets.* All documents in the docket are listed on the *www.regulations.gov* website. Although listed in the index, some information is not publicly available, such as CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Electronically available docket materials are available through *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For technical information, contact Richard Benware, Engineering and Analysis Division, telephone: 202–566–1369; email: *benware.richard@epa.gov.* For economic information, contact James Covington, Water Economics Center, telephone: 202–566–1034; email: *covington.james@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Acronyms and Abbreviations. EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, EPA defines terms and acronyms used in Appendix A of this preamble.

Supporting Documentation. The proposed rule is supported by a number of documents, including:

- Technical Development Document for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD), Document No. 821R23005. This report summarizes the technical and engineering analyses supporting the proposed rule. The TDD presents EPA's updated analyses supporting the proposed revisions to FGD wastewater, BA transport water, CRL, and legacy wastewater. The TDD includes additional data that has been collected since the publication of the 2015 and 2020 rules, updates to the industry (*e.g.*, retirements, updates to wastewater handling), cost methodologies, pollutant removal estimates, corresponding non-water quality environmental impacts associated with updated FGD and BA methodologies, and calculation of the proposed effluent limitations. In addition to the TDD, the Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (2015 TDD, Document No. EPA–821–R–15–007) and the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (2020 Supplemental TDD, Document No. EPA–821–R–20–001) provide a more complete summary of EPA's data collection, description of the industry, and underlying analyses supporting the 2015 and 2020 rules.
- Supplemental Environmental Assessment for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA), Document No. 821R23004. This report summarizes the potential environmental and human health impacts estimated to result from implementation of the proposed revisions to the 2015 and 2020 rules.
- Benefit and Cost Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA Report), Document No. 821R23003. This report summarizes the societal benefits and costs estimated to result from implementation of the proposed revisions to the 2015 and 2020 rules.
- Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. 821R23002. This report presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with the proposed revisions to the 2015 and 2020 rules, and an assessment of the potential impacts on employment and small businesses.
- Environmental Justice Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating

HEARING EXHIBIT SC 4

Point Source Category (EJA), Document No. 821R23001. This report presents a profile of the communities and populations potentially impacted by this proposal, analysis of the distribution of impacts in the baseline and proposed changes, and a summary of inputs from potentially impacted communities that EPA met with prior to the proposal.

• Docket Index for the Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. This document provides a list of the additional memoranda, references, and other information EPA relied on for the proposed revisions to the ELGs.

Organization of this Document. The information in this preamble is organized as follows:

I. Executive Summary

A. Purpose of Rule

EPA is proposing new regulations that apply to wastewater discharges from steam electric power plants, particularly coal-fired power plants. These plants are increasingly aging and uncompetitive sources of electric power in many portions of the United States and are subject to several environmental regulations designed to control (and in some cases eliminate) air, water, and land pollution over time. One of these regulations, the Steam Electric Power Generating Effluent Limitations Guidelines—or steam electric ELGs—was promulgated in 2015 (80 FR 67838; November 3, 2015) and revised in 2020 (85 FR 64650; October 13, 2020). The 2015 and 2020 rules apply to the subset of the electric power industry where "generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium" (40 CFR 423.10). The 2015 rule addressed discharges from FGD wastewater, fly ash (FA) transport water, BA transport water, flue gas mercury control (FGMC) wastewater, gasification wastewater, CRL, legacy wastewater, and nonchemical metal cleaning wastes. The 2020 rule modified the 2015 requirements for FGD wastewater and BA transport water for existing sources only. The 2015 limitations for CRL from existing sources and legacy wastewater were vacated by the United States (U.S.) Court of Appeals for the Fifth Circuit in *Southwestern Electric Power Co., et al.* v. *EPA,* 920 F.3d 999 (5th Cir. 2019).

In the years since EPA revised the steam electric ELGs in 2015 and 2020, pilot testing and full-scale use of various, more stringent compliance technologies have continued to expand. This proposal, if finalized, would revise requirements for discharges associated with the two wastestreams addressed in the 2020 rule: BA transport water and FGD wastewater at existing sources. The proposal would also address the 2015 rule CRL requirements that were vacated. Finally, while EPA is proposing technology-based limitations determined by permitting authorities on a site-specific basis using their best professional judgment (BPJ), an option discussed by the Court in *Southwestern Electric Power Co.* v. *EPA.*

B. Summary of Proposed Rule

For existing sources that discharge directly to surface water, with the exception of the subcategories discussed below, the proposed rule would establish the following effluent limitations based on Best Available Technology Economically Achievable (BAT):

- A zero-discharge limitation for all pollutants in FGD wastewater and BA transport water.
- Numeric (non-zero) discharge limitations for mercury and arsenic in CRL.

The proposed rule would eliminate the separate, less stringent BAT requirements for two subcategories: high flow facilities and low utilization electric generating units (LUEGUs). The proposed rule does not seek to change the existing subcategories for oil-fired EGUs and small generating units (50 MW or less) established in the 2015 rule. The proposed rule also does not seek to change the existing subcategory for electric generating units (EGUs) permanently ceasing the combustion of coal by 2028, which was established in the 2020 rule (although the Agency does solicit comment on possible changes to this subcategory). Finally, the proposed rule would create separate requirements for a new subcategory of facilities that have already complied with either the 2015 or 2020 rule's requirements (hereafter referred to as "early adopters") where such facilities would retire by 2032. For both the existing and new subcategory referenced immediately above, EPA proposes additional requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

For the one known high flow facility (TVA Cumberland Fossil Plant) and the two known facilities with LUEGUs (GSP Merrimack LLC and Indiana Municipal Power Agency (IMPA) Whitewater Valley Station), the proposed rule would eliminate these two subcategories for FGD wastewater and BA transport water, subjecting those wastestreams to the otherwise applicable requirements for the rest of the industry. For early adopters retiring by 2032, the rule would retain the 2020 rule requirements for FGD wastewater and BA transport water rather than require the new, more stringent zero-discharge requirements for these wastestreams.

Where BAT limitations in this proposed rule are more stringent than previously established BPT and BAT limitations, EPA is proposing that any new limitations would not apply until a date determined by the permitting authority that is as soon as possible on or after [Final Rule Publication Date + 60 days], but no later than December 31, 2029.

For indirect discharges (*i.e.,* discharges to publicly owned treatment works (POTWs)), the proposed rule would establish pretreatment standards for existing sources that are the same as the BAT limitations.

C. Summary of Costs and Benefits

EPA estimates that the proposed rule will cost $200 million per year in social costs and result in $1,557 million per year in monetized benefits using a three percent discount rate and will cost $216 million per year in social costs and result in $1,290 million per year in monetized benefits using a seven percent discount rate.[1] Not all costs and benefits can be fully quantified and monetized, and in particular EPA anticipates the proposed rule would also generate important unquantified benefits (*e.g.,* improved habitat conditions for plants, invertebrates, fish, amphibians, and the wildlife that prey on aquatic organisms). Furthermore, while some health benefits and willingness to pay for water quality

[1] As discussed in Section XII of this preamble, not all benefits could be fully quantified and monetized at this time.

improvements have been quantified and monetized, those estimates may not fully capture all important water quality-related benefits.

Table I–1 of this preamble summarizes the monetized benefits and social costs for the four regulatory options EPA analyzed at a three percent discount rate. EPA's analysis reflects the Agency's understanding of the actions steam electric power plants are expected to take to meet the limitations and standards in the proposed rule. EPA based its analysis on a modeled baseline that reflects the full implementation of the 2020 rule, the expected effects of announced retirements and fuel conversions, and the impacts of relevant final rules affecting the power sector. Although the baseline does not reflect anticipated impacts on the industry because of the recently passed Inflation Reduction Act (IRA), EPA solicits comment on means by which the Agency could model the impacts of the IRA for the final rule. Because the primary effect of the IRA in the context of this rule would be to increase the number of facilities that permanently cease coal combustion in the baseline, EPA expects that it would proportionally reduce the benefits and costs estimated in this proposal.[2] EPA understands that these modeled results are uncertain and that the actual costs for individual plants could be higher or lower than estimated. The current estimate reflects the best data and analysis currently available. For additional information on costs and benefits, see Sections VIII and XII of this preamble, respectively.

TABLE I–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF FOUR REGULATORY OPTIONS

[Millions of 2021$, three percent discount rate]

Regulatory option	Total social costs	Total monetized benefits [a b]	Total monetized net benefits [a b]
Option 1	$88.4	$696	$608
Option 2	167.0	1,336	1,169
Option 3 (Preferred)	200.3	1,557	1,357
Option 4	207.2	1,670	1,463

[a] EPA estimated the air-related benefits for Option 3 using the Integrated Planning Model (IPM). EPA did not analyze Options 1, 2, and 4 using IPM. Instead, EPA extrapolated estimates for Options 1, 2, and 4 air-related benefits from the estimate for Option 3 in proportion to total social costs.

[b] Includes benefits of changes in CO_2 air emissions monetized using the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) SC–CO_2 at 3% (average). See Section XII.B.3 of this preamble for benefits monetized using other SC–CO_2 values.

II. Public Participation

Submit your comments, identified by Docket ID No. EPA–HQ–OW–2009–0819, at *www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute. Multimedia submissions (*e.g.,* audio, video) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *www.epa.gov/dockets/commenting-epa-dockets.*

III. General Information

A. Does this action apply to me?

Entities potentially regulated by any final rule following this action include:

Category	Example of regulated entity	North American Industry Classification System (NAICS) Code
Industry	Electric Power Generation Facilities—Electric Power Generation	22111
	Electric Power Generation Facilities—Fossil Fuel Electric Power Generation	221112

This section is not intended to be exhaustive, but rather provides a guide regarding entities likely to be regulated by any final rule following this action. Other types of entities that do not meet the above criteria could also be regulated. To determine whether your facility is regulated by any final rule following this action, carefully examine the applicability criteria listed in 40 CFR 423.10 and the definitions in 40 CFR 423.11. If you still have questions regarding the applicability of any final rule following this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What action is EPA taking?

The Agency is proposing to revise, and is soliciting comment on possible revision to certain BAT effluent limitations guidelines and pretreatment standards for existing sources in the steam electric power generating point source category that apply to FGD wastewater, BA transport water, CRL, and legacy wastewater.

[2] Furthermore, because the cessation of coal combustion would occur in the baseline, EPA expects that the rule would continue to be economically achievable even after accounting for the IRA.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 50, 53, and 58

[EPA–HQ–OAR–2015–0072; FRL–8635–01–OAR]

RIN 2060–AV52

Reconsideration of the National Ambient Air Quality Standards for Particulate Matter

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Based on the Environmental Protection Agency's (EPA's) reconsideration of the air quality criteria and the national ambient air quality standards (NAAQS) for particulate matter (PM), the EPA proposes to revise the primary annual $PM_{2.5}$ standard by lowering the level. The Agency proposes to retain the current primary 24-hour $PM_{2.5}$ standard and the primary 24-hour PM_{10} standard. The Agency also proposes not to change the secondary 24-hour $PM_{2.5}$ standard, secondary annual $PM_{2.5}$ standard, and secondary 24-hour PM_{10} standard at this time. The EPA also proposes revisions to other key aspects related to the PM NAAQS, including revisions to the Air Quality Index (AQI) and monitoring requirements for the PM NAAQS.

DATES: Comments must be received on or before March 28, 2023.

Public Hearings: The EPA will hold a virtual public hearing on this proposed rule. This hearing will be announced in a separate **Federal Register** document that provides details, including specific dates, times, and contact information for these hearings.

ADDRESSES: You may submit comments, identified by Docket ID No. EPA–HQ–OAR–2015–0072, by any of the following means:

- *Federal eRulemaking Portal: https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-Docket@epa.gov.* Include the Docket ID No. EPA–HQ–OAR–2015–0072 in the subject line of the message.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand Delivery or Courier (by scheduled appointment only):* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

Instructions: All submissions received must include the Docket ID No. for this document. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Dr. Lars Perlmutt, Health and Environmental Impacts Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Mail Code C539–04, Research Triangle Park, NC 27711; telephone: (919) 541–3037; fax: (919) 541–5315; email: *perlmutt.lars@epa.gov.*

SUPPLEMENTARY INFORMATION:

General Information

Preparing Comments for the EPA

Follow the online instructions for submitting comments. Once submitted to the Federal eRulemaking Portal, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written submission. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, the cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

When submitting comments, remember to:

- Identify the action by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Explain why you agree or disagree, suggest alternatives, and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- Provide specific examples to illustrate your concerns and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

Availability of Information Related to This Action

All documents in the dockets pertaining to this action are listed on the *www.regulations.gov* website. This includes documents in the docket for the proposed decision (Docket ID No. EPA–HQ–OAR–2015–0072) and a separate docket, established for the Integrated Science Assessment (ISA) (Docket ID No. EPA–HQ–ORD–2014–0859) that has been adopted by reference into the docket for this proposed decision. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and may be viewed with prior arrangement with the EPA Docket Center. Additionally, a number of the documents that are relevant to this proposed decision are available through the EPA's website at *https://www.epa.gov/naaqs/particulate-matter-pm-air-quality-standards.* These documents include the Integrated Science Assessment for Particulate Matter (U.S. EPA, 2019a), available at *https://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=347534,* the Supplement to the 2019 Integrated Science Assessment for Particulate Matter (U.S. EPA, 2022a), available at *https://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=354490,* and the Policy Assessment for the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter (U.S. EPA, 2022b), available at *https://www.epa.gov/naaqs/particulate-matter-pm-standards-integrated-science-assessments-current-review.*

Table of Contents

The following topics are discussed in this preamble:

HEARING EXHIBIT SC 5

Executive Summary

This document presents the Administrator's proposed decisions for the reconsideration of the 2020 final decision on the primary (health-based) and secondary (welfare-based) National Ambient Air Quality Standards (NAAQS) for Particulate Matter (PM). More specifically this document summarizes the background and rationale for the Administrator's proposed decisions to revise the primary annual $PM_{2.5}$ standard by lowering the level from 12.0 µg/m³ to within the range of 9.0 to 10.0 µg/m³ while taking comment on alternative annual standard levels down to 8.0 µg/m³ and up to 11.0 µg/m³; to retain the current primary 24-hour $PM_{2.5}$ standard (at a level of 35 µg/m³) while taking comment on revising the level as low as 25 µg/m³; to retain the primary 24-hour PM_{10} standard, without revision; and, not to change the secondary PM standards at this time, while taking comment on revising the level of the secondary 24-hour $PM_{2.5}$ standard as low as 25 µg/m³. In reaching his proposed decisions, the Administrator has considered the currently available scientific evidence in the 2019 Integrated Science Assessment (2019 ISA) and the Supplement to the 2019 ISA (ISA Supplement), quantitative and policy analyses presented in the Policy Assessment (PA), and advice from the Clean Air Scientific Advisory Committee (CASAC). The EPA solicits comment on the proposed decisions described here and on the array of issues associated with the reconsideration of these standards, including the judgments of public health, public welfare and science policy inherent in the proposed decisions, and requests commenters also provide the rationales upon which views articulated in submitted comments are based.

The EPA has established primary and secondary standards for $PM_{2.5}$, which includes particles with diameters generally less than or equal to 2.5 µm, and PM_{10}, which includes particles with diameters generally less than or equal to 10 µm. The standards include two primary $PM_{2.5}$ standards, an annual average standard, averaged over three years, with a level of 12.0 µg/m³ and a 24-hour standard with a 98th percentile form, averaged over three years, and a level of 35 µg/m³. It also includes a primary PM_{10} standard with a 24-hour averaging time, and a level of 150 µg/m³, not to be exceeded more than once per year on average over three years. Secondary PM standards are set equal to the primary standards, except that the level of the secondary annual $PM_{2.5}$ standard is 15.0 µg/m³.

The last review of the PM NAAQS was completed in December 2020. In that review, the EPA retained the primary and secondary NAAQS, without revision (85 FR 82684, December 18, 2020). Following publication of the 2020 final action, several parties filed petitions for review and petitions for reconsideration of the EPA's final decision.

In June 2021, the Agency announced its decision to reconsider the 2020 PM NAAQS final action.[1] The EPA is reconsidering the December 2020 decision because the available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the Clean Air Act. The EPA noted that the 2020 PA concluded that the scientific evidence and information called into question the adequacy of the primary $PM_{2.5}$ standards and supported consideration of revising the level of the primary annual $PM_{2.5}$ standard to below the current level of 12.0 µg/m³ while retaining the primary 24-hour $PM_{2.5}$ standard (U.S. EPA, 2020a). The EPA also noted that the 2020 PA concluded that the available scientific evidence and information did not call into question the adequacy of the primary PM_{10} or secondary PM standards and supported consideration of retaining the primary PM_{10} standard and secondary PM standards without revision (U.S. EPA, 2020a).

The proposed decisions presented in this document on the primary $PM_{2.5}$ standards have been informed by key aspects of the available health effects evidence and conclusions contained in the 2019 ISA and ISA Supplement, quantitative exposure/risk analyses and policy evaluations presented in the PA, advice from the CASAC[2] and public comment received as part of this reconsideration.[3] The health effects evidence available in this reconsideration, in conjunction with the full body of evidence critically evaluated in the 2019 ISA, supports a causal relationship between long- and

[1] The press release for this announcement is available at: *https://www.epa.gov/newsreleases/epa-reexamine-health-standards-harmful-soot-previous-administration-left-unchanged.*

[2] In 2021, the Administrator announced his decision to reestablish the membership of the CASAC. The Administrator selected seven members to serve on the chartered CASAC, and appointed a PM CASAC panel to support the chartered CASAC's review of the draft ISA Supplement and the draft PA as a part of this reconsideration (see section I.C.6.b below for more information).

[3] More information regarding the CASAC review of the draft ISA Supplement and the draft PA, including opportunities for public comment, can be found in the following **Federal Register** notices: 86 FR 54186, September 30, 2021; 86 FR 52673, September 22, 2021; 86 FR 56263, October 8, 2021; 87 FR 958, January 7, 2022.

short-term exposures and mortality and cardiovascular effects, and the evidence supports a likely to be a causal relationship between long-term exposures and respiratory effects, nervous system effects, and cancer. The longstanding evidence base, including animal toxicological studies, controlled human exposure studies, and epidemiologic studies, reaffirms, and in some cases strengthens, the conclusions from past reviews regarding the health effects of $PM_{2.5}$ exposures. Epidemiologic studies available in this reconsideration demonstrate generally positive, and often statistically significant, $PM_{2.5}$ health effect associations. Such studies report associations between estimated $PM_{2.5}$ exposures and non-accidental, cardiovascular, or respiratory mortality; cardiovascular or respiratory hospitalizations or emergency room visits; and other mortality/morbidity outcomes (e.g., lung cancer mortality or incidence, asthma development). The scientific evidence available in this reconsideration, as evaluated in the 2019 ISA and ISA Supplement, includes a number of epidemiologic studies that use various methods to characterize exposure to $PM_{2.5}$ (e.g., ground-based monitors and hybrid modeling approaches) and to evaluate associations between health effects and lower ambient $PM_{2.5}$ concentrations. There are a number of recent epidemiologic studies that use varying study designs that reduce uncertainties related to confounding and exposure measurement error. The results of these analyses provide further support for the robustness of associations between $PM_{2.5}$ exposures and mortality and morbidity. Moreover, the Administrator notes that recent epidemiologic studies strengthen support for health effect associations at lower $PM_{2.5}$ concentrations, with these new studies finding positive and significant associations when assessing exposure in locations and time periods with lower mean and 25th percentile concentrations than those evaluated in epidemiologic studies available at the time of previous reviews. Additionally, the experimental evidence (*i.e.*, animal toxicological and controlled human exposure studies) strengthens the coherence of effects across scientific disciplines and provides additional support for potential biological pathways through which $PM_{2.5}$ exposures could lead to the overt population-level outcomes reported in epidemiologic studies for the health effect categories for which a causal relationship (*i.e.*, short- and long-term $PM_{2.5}$ exposure and mortality and cardiovascular effects) or likely to be causal relationship (*i.e.*, short- and long-term $PM_{2.5}$ exposure and respiratory effects; and long-term $PM_{2.5}$ exposure and nervous system effects and cancer) was concluded.

The available evidence in the 2019 ISA continues to provide support for factors that may contribute to increased risk of $PM_{2.5}$-related health effects including lifestage (children and older adults), pre-existing diseases (cardiovascular disease and respiratory disease), race/ethnicity, and socioeconomic status. For example, the 2019 ISA and ISA Supplement conclude that there is strong evidence that Black and Hispanic populations, on average, experience higher $PM_{2.5}$ exposures and $PM_{2.5}$-related health risk than non-Hispanic White populations. In addition, studies evaluated in the 2019 ISA and ISA Supplement also provide evidence indicating that communities with lower socioeconomic status (SES), as assessed in epidemiologic studies using indicators of SES including income and educational attainment are, on average, exposed to higher concentrations of $PM_{2.5}$ compared to higher SES communities.

The quantitative risk assessment, as well as policy considerations in the PA, also inform the proposed decisions on the primary $PM_{2.5}$ standards. The risk assessment in this consideration focuses on all-cause or nonaccidental mortality associated with long- and short-term $PM_{2.5}$ exposures. The primary analyses focus on exposure and risk associated with air quality that might occur in an area under air quality conditions that just meet the current and potential alternative standards. The risk assessment estimates that the current primary $PM_{2.5}$ standards could allow a substantial number of $PM_{2.5}$-associated premature deaths in the United States, and that public health improvements would be associated with just meeting all of the alternative (more stringent) annual and 24-hour standard levels modeled. Additionally, the results of the risk assessment suggest that for most of the U.S., the annual standard is the controlling standard and that revision to that standard has the most potential to reduce $PM_{2.5}$ exposure related risk. Further analyses comparing the reductions in average national $PM_{2.5}$ concentrations and risk rates within each demographic population estimate that the average percent $PM_{2.5}$ concentrations and risk reductions are slightly greater in the Black population than in the White population when meeting a revised annual standard with a lower level. The analyses are summarized in this document and described in detail in the PA.

In its advice to the Administrator, the CASAC concurred with the draft PA that the currently available health effects evidence calls into question the adequacy of the primary annual $PM_{2.5}$ standard. With regard to the primary annual $PM_{2.5}$ standard, the majority of the CASAC concluded that the level of the standard should be revised within the range of 8.0 to 10.0 μg/m³, while the minority of the CASAC concluded that the primary annual $PM_{2.5}$ standard should be revised to a level of 10.0 to 11.0 μg/m³. With regard to the primary 24-hour $PM_{2.5}$ standard, the majority of the CASAC concluded that the primary 24-hour $PM_{2.5}$ was not adequate and that the level of the standard should be revised to within the range of 25 to 30 μg/m³, while the minority of the CASAC concluded that the primary 24-hour $PM_{2.5}$ standard was adequate and should be retained, without revision.

In considering how to revise the suite of standards to provide the requisite degree of protection, the Administrator recognizes that the current annual standard and 24-hour standard, together, are intended to provide public health protection against the full distribution of short- and long-term $PM_{2.5}$ exposures. Further, he recognizes that changes in $PM_{2.5}$ air quality designed to meet either the annual or the 24-hour standard would likely result in changes to both long-term average and short-term peak $PM_{2.5}$ concentrations. Based on the current evidence and quantitative information, as well as consideration of CASAC advice and public comment thus far in this reconsideration, the Administrator proposes to conclude that the current primary $PM_{2.5}$ standards are not adequate to protect public health with an adequate margin of safety.

The Administrator also notes that the CASAC was unanimous in its advice regarding the need to revise the annual standard. In considering the appropriate level for a revised annual standard, the Administrator provisionally concludes that a standard set within the range of 9.0 to 10.0 μg/m³ would reflect his placing the most weight on the strongest available evidence while appropriately weighing the uncertainties. In addition, the Administrator recognizes that some members of CASAC advised, and the PA concluded, that the available scientific information provides support for considering a range that extends up to 11.0 μg/m³ and down to 8.0 μg/m³.

With regard to the primary 24-hour $PM_{2.5}$ standard, the Administrator finds it is less clear whether the available scientific evidence and quantitative information calls into question the adequacy of the public health protection afforded by the current 24-hour standard. He notes that a more stringent annual standard is expected to reduce both average (annual) concentrations and peak (daily) concentrations. Furthermore, he notes that the CASAC did not reach consensus on whether revisions to the primary 24-hour $PM_{2.5}$ standard were warranted at this time. The majority of the CASAC recommended that the level of the current primary 24-hour $PM_{2.5}$ should be revised to within the range of 25 to 30 μg/m³, while the minority of the CASAC recommended retaining the current standard. The Administrator proposes to conclude that the 24-hour standard should be retained, particularly when considered in conjunction with the protection provided by the suite of standards and the proposed decision to revise the annual standard to a level of 9.0 to 10.0 μg/m³.

The EPA solicits comment on the Administrator's proposed conclusions, and on the proposed decision to revise the primary annual $PM_{2.5}$ standard and retain the primary 24-hour $PM_{2.5}$ standard, without revision. The Administrator is conscious of his obligation to set primary standards with an adequate margin of safety and preliminarily determines that the proposed decision balances the need to provide protection against uncertain risks with the obligation to not set standards that are more stringent than necessary. The requirement to provide an adequate margin of safety was intended to address uncertainties associated with inconclusive scientific and technical information and to provide a reasonable degree of protection against hazards that research has not yet identified. Reaching decisions on what standards are appropriate necessarily requires judgments of the Administrator about how to consider the information available from the epidemiologic studies and other relevant evidence. In the Administrator's judgment, the proposed suite of primary $PM_{2.5}$ standards reflects the appropriate consideration of the strength of the available evidence and other information and their associated uncertainties and the advice of the CASAC. The final rulemaking will reflect the Administrator's ultimate judgments as to the suite of primary $PM_{2.5}$ standards that are requisite to protect the public health with an adequate margin of safety. Consistent with these principles, the EPA also solicits public comment on alternative annual standard levels down to 8.0 μg/m³ and up to 11.0 μg/m³, on an alternative 24-hour standard level as low as 25 μg/m³ and on the combination of annual and 24-hour standards that commenters may believe is appropriate, along with the approaches and scientific rationales used to support such levels. For example, the EPA solicits comments on the uncertainties in the reported associations between daily or annual average $PM_{2.5}$ exposures and mortality or morbidity in the epidemiologic studies, the significance of the 25th percentile of ambient concentrations reported in studies, the relevance and limitations of international studies, and other topics discussed in section II.D.3.b.

The primary PM_{10} standard is intended to provide public health protection against health effects related to exposures to $PM_{10-2.5}$, which are particles with a diameter between 10 μm and 2.5 μm. The proposed decision to retain the current 24-hour PM_{10} standard has been informed by key aspects of the available health effects evidence and conclusions contained in the 2019 ISA, the policy evaluations presented in the PA, advice from the CASAC and public comment received as part of this reconsideration. Specifically, the health effects evidence for $PM_{10-2.5}$ exposures is somewhat strengthened since past reviews, although the strongest evidence still only provides support for a suggestive of, but not sufficient to infer, causal relationship with long- and short-term exposures and mortality and cardiovascular effects, short-term exposures and respiratory effects, and long-term exposures and cancer, nervous system effects, and metabolic effects. In reaching his proposed decision, the Administrator recognizes that, while the available health effects evidence has expanded, recent studies are subjected to the same types of uncertainties that were judged to be important in previous reviews. He also recognizes that the CASAC generally agreed with the draft PA that it was reasonable to retain the primary 24-hour PM_{10} standard given the available scientific evidence, including PM_{10} as an appropriate indicator. He proposes to conclude that the newly available evidence does not call into question the adequacy of the current primary PM_{10} standard, and he proposes to retain that standard, without revision.

This reconsideration of the secondary PM standards focuses on visibility, climate, and materials effects.[4] The Administrator's proposed decision to not change the current secondary standards at this time has been informed by key aspects of the currently available welfare effects evidence as well as the conclusions contained in the 2019 ISA and ISA Supplement; quantitative analyses of visibility impairment; policy evaluations presented in the PA; advice from the CASAC; and public comment received as part of this reconsideration. Specifically, the welfare effects evidence available in this reconsideration is consistent with the evidence available in previous reviews and supports a causal relationship between PM and visibility, climate, and materials effects. With regard to climate and materials effects, while the evidence has expanded since previous reviews, uncertainties remain in the evidence and there are still significant limitations in quantifying potential adverse effects from PM on climate and materials for purposes of setting a standard. With regard to visibility effects, the results of quantitative analyses of visibility impairment are similar to those in previous reviews, and suggest that in areas that meet the current secondary 24-hour $PM_{2.5}$ standard that estimated light extinction in terms of a 3-year visibility metric would be at or well below the upper end of the range for the target level of protection (*i.e.*, 30 deciviews (dv)). The CASAC generally agreed with the draft PA that substantial uncertainties remain in the scientific evidence for climate and materials effects. In considering the available scientific evidence for climate and materials effects, along with CASAC advice, the Administrator proposes to conclude that it is appropriate to retain the existing secondary standards and that it is not appropriate to establish any distinct secondary PM standards to address non-visibility PM-related welfare effects. With regard to visibility effects, while the Administrator notes that the CASAC did not recommend revising either the target level of protection for the visibility index or the level of the current secondary 24-hour $PM_{2.5}$ standard, the Administrator

[4] Consistent with the 2016 Integrated Review Plan (U.S. EPA, 2016), other welfare effects of PM, such as ecological effects, are being considered in the separate, on-going review of the secondary NAAQS for oxides of nitrogen, oxides of sulfur and PM. Accordingly, the public welfare protection provided by the secondary PM standards against ecological effects such as those related to deposition of nitrogen- and sulfur-containing compounds in vulnerable ecosystems is being considered in that separate review. Thus, the Administrator's conclusion in this reconsideration of the 2020 final decision will be focused only and specifically on the adequacy of public welfare protection provided by the secondary PM standards from effects related to visibility, climate, and materials and hereafter "welfare effects" refers to those welfare effects.

recognizes that, should an alternative level be considered for the visibility index, that the CASAC recommends also considering revisions to the secondary 24-hour $PM_{2.5}$ standard. In considering the available evidence and quantitative information, with its inherent uncertainties and limitations, the Administrator proposes not to change the secondary PM standards at this time, and solicits comment on this proposed decision. In addition, the Administrator additionally solicits comment on the appropriateness of a target level of protection for visibility below 30 dv and down as low as 25 dv, and of revising the level of the current secondary 24-hour $PM_{2.5}$ standard to a level as low as 25 µg/m³.

Any proposed revisions to the PM NAAQS, if finalized, would trigger a process under which states (and tribes, if they choose) make recommendations to the Administrator regarding designations, identifying areas of the country that either meet or do not meet the new or revised PM NAAQS. Those areas that do not meet the PM NAAQS will need to develop plans that demonstrate how they will meet the standards. As part of these plans, states have the opportunity to use tools to advance environmental justice, in this case for overburdened communities in areas with high PM concentrations above the NAAQS, as provided in current PM NAAQS implementation guidance to meet requirements (80 FR 58010, 58136, August 25, 2016). The EPA is not proposing changes to any of the current PM NAAQS implementation programs in this proposed rulemaking, and therefore is not requesting comment on any specific proposals related to implementation or designations.

On other topics, the EPA proposes to make two sets of changes to the $PM_{2.5}$ sub-index of the AQI. First, the EPA proposes to continue to use the approach used in the revisions to the AQI in 2012 (77 FR 38890, June 29, 2012) of setting the lower breakpoints (50, 100 and 150) to be consistent with the levels of the primary $PM_{2.5}$ annual and 24-hour standards and proposes to revise the lower breakpoints to be consistent with any changes to the primary $PM_{2.5}$ standards that are part of this reconsideration. In so doing, the EPA proposes to revise the AQI value of 50 within the range of 9.0 and 10.0 µg/m³ and proposes to retain the AQI values of 100 and 150 at 35.4 µg/m³ and 55.4 µg/m³, respectively. Second, the EPA proposes to revise the upper AQI breakpoints (200 and above) and to replace the linear-relationship approach used in 1999 (64 FR 42530, August 4, 1999) to set these breakpoints, with an approach that more fully considers the $PM_{2.5}$ health effects evidence from controlled human exposure and epidemiologic studies that has become available in the last 20 years. The EPA also proposes to revise the AQI values of 200, 300 and 500 to 125.4 µg/m³, 225.4 µg/m³, and 325.4 µg/m³, respectively. The EPA proposes to finalize these changes to the $PM_{2.5}$ AQI in conjunction with the Agency's final decisions on the primary annual and 24-hour $PM_{2.5}$ standards, if proposed revisions to such standards are promulgated. The EPA is soliciting comment on the proposed revisions to the AQI. In addition, the EPA also proposes to revise the daily reporting requirement from 5 days per week to 7 days per week, while also reformatting appendix G and providing clarifications.

With regard to monitoring-related activities, the EPA proposes revisions to data calculations and ambient air monitoring requirements for PM to improve the usefulness of and appropriateness of data used in regulatory decision making and to better characterize air quality in communities that are at increased risk of $PM_{2.5}$ exposure and health risk. These proposed changes are found in 40 CFR part 50 (appendices K, L, and N), part 53, and part 58 with associated appendices (A, B, C, D, and E). These proposed changes include addressing updates in data calculations, approval of reference and equivalent methods, updates in quality assurance statistical calculations to account for lower concentration measurements, updates to support improvements in PM methods, a revision to the $PM_{2.5}$ network design to account for at-risk populations, and updates to the Probe and Monitoring Path Siting Criteria for NAAQS pollutants.

In setting the NAAQS, the EPA may not consider the costs of implementing the standards. This was confirmed by the Supreme Court in *Whitman* v. *American Trucking Associations*, 531 U.S. 457, 465–472, 475–76 (2001), as discussed in section II.A of this document. As has traditionally been done in NAAQS rulemaking, the EPA prepared a Regulatory Impact Analysis (RIA) to provide the public with information on the potential costs and benefits of attaining several alternative $PM_{2.5}$ standard levels. In NAAQS rulemaking, the RIA is done for informational purposes only, and the proposed decisions on the NAAQS in this rulemaking are not based on consideration of the information or analyses in the RIA. The RIA fulfills the requirements of Executive Orders 13563 and 12866. The RIA estimates the costs and monetized human health benefits of attaining three alternative annual $PM_{2.5}$ standard levels and one alternative 24-hour $PM_{2.5}$ standard level. Specifically, the RIA examines the proposed annual and 24-hour alternative standard levels of 10/35 µg/m³ and 9/35 µg/m³, as well as the following two more stringent alternative standard levels: (1) An alternative annual standard level of 8 µg/m³ in combination with the current 24-hour standard (*i.e.,* 8/35 µg/m³), and (2) an alternative 24-hour standard level of 30 µg/m³ in combination with the proposed annual standard level of 10 µg/m³ (*i.e.,* 10/30 µg/m³). The RIA presents estimates of the costs and benefits of applying illustrative national control strategies in 2032 after implementing existing and expected regulations and assessing emissions reductions to meet the current annual and 24-hour particulate matter NAAQS (12/35 µg/m³).

I. Background

A. Legislative Requirements

Two sections of the Clean Air Act (CAA) govern the establishment and revision of the NAAQS. Section 108 (42 U.S.C. 7408) directs the Administrator to identify and list certain air pollutants and then to issue air quality criteria for those pollutants. The Administrator is to list those pollutants "emissions of which, in his judgment, cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare"; "the presence of which in the ambient air results from numerous or diverse mobile or stationary sources"; and for which he "plans to issue air quality criteria. . . ." (42 U.S.C. 7408(a)(1)). Air quality criteria are intended to "accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of [a] pollutant in the ambient air. . . ." (42 U.S.C. 7408(a)(2)).

Section 109 [42 U.S.C. 7409] directs the Administrator to propose and promulgate "primary" and "secondary" NAAQS for pollutants for which air quality criteria are issued [42 U.S.C. 7409(a)]. Section 109(b)(1) defines primary standards as ones "the attainment and maintenance of which in the judgment of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health." [5] Under

[5] The legislative history of section 109 indicates that a primary standard is to be set at "the maximum permissible ambient air level . . . which

Continued

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–01–OAR]

RIN 2060–AV53

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as the Mercury and Air Toxics Standards (MATS). Specifically, the EPA is proposing to amend the surrogate standard for non-mercury (Hg) metal HAP (filterable particulate matter (fPM)) for existing coal-fired EGUs; the fPM compliance demonstration requirements; the Hg standard for lignite-fired EGUs; and the definition of startup. These proposed amendments are the result of the EPA's review of the May 22, 2020 residual risk and technology review (RTR) of MATS.

DATES:

Comments. Comments must be received on or before June 23, 2023. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before May 24, 2023.

Public hearing. The EPA will hold a virtual public hearing on May 9, 2023. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2018–0794, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2018–0794 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2018–0794.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2018–0794, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on May 9, 2023 and will convene at 11 a.m. Eastern Time (ET) and conclude at 7 p.m. ET. If the EPA receives a high volume of registrations for the public hearing, we may continue the public hearing on May 10, 2023. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be May 8, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/stationary-air-pollution/mercury-and-air-toxics-standards.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony by submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of an interpreter or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by May 1, 2023. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2018–0794.[1] All documents in the docket are listed in *https://www.regulations.gov/.* Although listed, some information is not publicly available, *e.g.,* Confidential Business

[1] As explained in a memorandum to the docket, the docket for this action includes the documents and information, in whatever form, in Docket ID Nos. EPA–HQ–OAR–2009–0234 (National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units), EPA–HQ–OAR–2002–0056 (National Emission Standards for Hazardous Air Pollutants for Utility Air Toxics; Clean Air Mercury Rule (CAMR)), and Legacy Docket ID No. A–92–55 (Electric Utility Hazardous Air Pollutant Emission Study). See memorandum titled *Incorporation by reference of Docket Number EPA–HQ–OAR–2009–0234, Docket Number EPA–HQ–OAR–2002–0056, and Docket Number A–92–55 into Docket Number EPA–HQ–OAR–2018–0794* (Docket ID Item No.

HEARING EXHIBIT SC 6

Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov*.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2018–0794. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov/*, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit electronically to *https://www.regulations.gov/* any information that you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets*.

The *https://www.regulations.gov/* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov/*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets*.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/*. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the Docket ID No., mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the Docket ID No. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.*, Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described above, should include clear CBI markings and note the Docket ID No. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, or if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2018–0794. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

Btu British Thermal Units
CAA Clean Air Act
CBI Confidential Business Information
CEMS continuous emissions monitoring systems
CFR Code of Federal Regulations
CO_2 carbon dioxide
CPMS continuous parameter monitoring system
EAV equivalent annualized value
ECMPS Emissions Collection and Monitoring Plan System
EGU electric utility steam generating unit
EIA Energy Information Administration
EJ environmental justice
EPA Environmental Protection Agency
ESP electrostatic precipitator
FF fabric filter
FGD flue gas desulfurization
fPM filterable particulate matter
GWh gigawatt-hour
HAP hazardous air pollutant(s)
HCl hydrogen chloride
HF hydrogen fluoride
Hg mercury
Hg^0 elemental Hg vapor
HQ hazard quotient
IGCC integrated gasification combined cycle
IPM Integrated Planning Model
lb Pounds
LEE low emitting EGU
MACT maximum achievable control technology
MATS Mercury and Air Toxics Standards
MM million
MW megawatt
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NESHAP National Emission Standards for Hazardous Air Pollutants
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF Portable Document Format
PM particulate matter
ppm parts per million
PV present value
RIA regulatory impact analysis
RTR residual risk and technology review
SC–CO_2 social cost of carbon
SO_2 sulfur dioxide
tpy tons per year
TBtu trillion British thermal units
WebFIRE Web Factor Information Retrieval System

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary

A. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollution ("HAP," sometimes known as toxic air pollution, including Hg, chromium, arsenic, and lead) can cause a range of adverse health effects including harming people's central nervous system; damage to their kidneys; and cancer. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the EPA is required to set standards (known as "MACT" (maximum achievable control technology) standards) for major sources of HAP that "require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable." 42 U.S.C. 7412(d)(2). To ensure a minimum level (or "floor") of emissions reductions, Congress required that MACT standards for existing sources "shall not be less stringent than . . . the average emission limitation achieved by the best performing 12 percent of existing sources"; and MACT standards for new sources "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source[.]" 42 U.S.C. 7412(d)(3). These requirements effectively obligated all sources to reduce emissions as well as the best sources in their category. Congress did not stop there, however. First, it required the EPA, 8 years after setting the standard, to address any residual risks posed by the source category (called the "residual risk review"). Second, and as explained in more detail below, it required the EPA, at least every 8 years on an ongoing basis, to review and revise as necessary the MACT standard taking into account developments in practices, processes and control technologies (called the "technology review"). For EGUs, Congress also required the EPA to make a one-time determination of whether it is "appropriate and necessary" to regulate this source category under CAA section 112. The EPA found regulation of EGUs "appropriate and necessary" in 2000 and reaffirmed that finding in 2012 and 2016. MACT standards were originally set for EGUs in 2012, and those standards remain in place today. In 2020, the EPA conducted the 8-year residual risk and technology review and determined not to update the MACT standard.

On January 20, 2021, President Biden signed Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" (86 FR 7037; January 25, 2021). The Executive order, among other things, instructed the EPA to review the 2020 final rule titled, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review" (85 FR 31286; May 22, 2020) (2020 Final Action) and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action. The 2020 Final Action included a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 as well as the RTR for the MATS rule. The results of the EPA's review of the 2020 appropriate and necessary finding were proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, the EPA also solicited information on the performance and cost of new or improved technologies that control hazardous air pollutant (HAP) emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the 2020 MATS RTR. This action presents the proposed results of the EPA's review of the MATS RTR.

In particular, with respect to the standard for fPM (as a surrogate for non-Hg metals), and the standard for Hg from EGUs that burn lignite coal, the EPA proposes to conclude that developments since 2012—and in particular the fact that the majority of sources are vastly outperforming the MACT standards with control technologies that are cheaper and more effective than the EPA forecast while a smaller number of sources' performance lags behind—warrant strengthening these standards. While the 2012 MATS drove critical HAP reductions at much lower cost than estimated, coal-fired EGUs still emit a substantial amount of HAP and developments since 2012 provide opportunities to address these emissions and ensure that all coal-fired EGUs are performing at levels achievable by the fleet. These proposed revisions would ensure that the EPA's standards continue to fulfill Congress's direction to require the maximum degree of reduction of HAP while taking into account the statutory factors.

B. Summary of the Major Provisions of the Regulatory Action

The 2012 MATS Final Rule established emission standards to limit emissions of HAP from coal- and oil-fired EGUs. The rule required that affected sources limit emissions of Hg, of non-Hg metal HAP (*e.g.*, chromium, nickel, arsenic, lead), acid gas HAP (*e.g.*, hydrogen chloride (HCl), hydrogen fluoride (HF), selenium dioxide (SeO_2)), and organic HAP (*e.g.*, formaldehyde, dioxins/furans). Since MATS was promulgated in 2012, power sector emissions of Hg, acid gas HAP, and non-Hg metal HAP have decreased by about 86 percent, 96 percent, and 81 percent, respectively, as compared to 2010 emissions levels (See Table 4 at 84 FR 2689, February 7, 2019). Still, coal- and oil-fired EGUs remain the largest domestic emitter of Hg and many other HAP, including many of the non-Hg HAP metals and HCl. Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. These adverse health effects may include irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; alimentary effects such as nausea and vomiting; and cancer.[2] See 77 FR 9310 for a fuller discussion of the health effects associated with these pollutants. Three of the key metal HAP emitted by EGUs (inorganic arsenic (As), hexavalent chromium (Cr), and nickel compounds (Ni)) have been classified as human carcinogens, while two others (cadmium (Cd) and selenium (Se)) are classified as probable human carcinogens.[3]

To address emissions of these non-Hg metal HAP, MATS sets individual emission limits for each of the 10 non-Hg metals emitted from coal- and oil-fired EGUs. Alternatively, affected sources may meet an emission standard for "total non-Hg metals" by summing the emission rates of each of the non-Hg metals. The MATS rule also allows affected sources to meet a filterable PM (fPM)[4] emission standard as a surrogate for the non-Hg metals. For existing coal-fired EGUs, most units have chosen to demonstrate compliance with the non-Hg metal HAP surrogate fPM emission standard of 3.0E–02 pounds of fPM per million British thermal units of heat input (lb/MMBtu).

CAA section 112(d)(2) directs the EPA to require the maximum degree of HAP emission reductions achievable, taking into account certain considerations, and CAA section 112(d)(3) sets the floor for emission standards based on the reductions achieved by the best performing sources. The MATS was based upon the EPA's analysis under CAA sections 112(d)(2) and (d)(3) in 2012. CAA section 112(d)(6) further requires the EPA, at least every 8 years, to review and revise standards taking into account developments in practices, processes and control technologies. After reviewing developments in the current emission levels of fPM from existing coal-fired EGUs, the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a standard that is more stringent than 3.0E–02 lb/MMBtu and the other statutory factors, the EPA is proposing to revise the non-Hg metal surrogate fPM emission standard for all existing coal-fired EGUs to a more stringent fPM emission standard of 1.0E–02 lb/MMBtu, which is comparable to the MATS new source standard for fPM.[5] The EPA is also soliciting comment on opportunities to revise the MATS fPM emission standard to an even more stringent level of 6.0E–03 lb/MMBtu.

The EPA is also proposing a revision to the requirements for demonstrating compliance with the fPM emission standard. Currently, EGUs that do not qualify for the low emitting EGU (LEE) program can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.*, quarterly stack testing) or by using PM continuous emission monitoring systems (PM CEMS). After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and on the measurement capabilities of PM CEMS, as well as other benefits of using PM CEMS, which include increased transparency and accelerated identification of anomalous emissions, the EPA is proposing to require that all coal-fired EGUs demonstrate compliance with the fPM emission standard by using PM CEMS. Accordingly, because almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard and because of the benefits of PM CEMS use for demonstrating compliance, the EPA is proposing to remove the total and individual non-Hg metals emission limits from MATS. Requiring the use of PM CEMS, if finalized, would also render the current compliance method for the LEE program superfluous, since LEE is an optional stack testing program and the considered fPM limits are both below the current fPM LEE program limit of 1.5E–02 lb/MMBtu (*i.e.*, 50 percent of the current fPM standard). Therefore, the EPA also proposes to remove fPM, as well as the total and individual non-Hg HAP metals, from the LEE program.

The EPA is also proposing to establish a more protective Hg emission standard for existing lignite-fired EGUs. Currently, existing lignite-fired EGUs must meet a Hg emission standard of 4.0E–06 lb/MMBtu[6] or an alternative output-based emission standard of 4.0E–02 pounds of Hg per gigawatt-hour output (lb/GWh). The EPA recently collected information on current Hg emission levels and controls for lignite-fired EGUs from information provided routinely to the EPA and to the Energy Information Administration (EIA) and by using the information collection authority provided under CAA section 114. That information showed developments that demonstrate that lignite-fired EGUs can achieve a Hg emission rate that is much lower than the current standard, and that there are cost-effective control technologies and methods of operation that are available to achieve a more stringent standard. Accordingly, the EPA is proposing that lignite-fired EGUs must meet the same Hg emission standard as EGUs firing other types of coal (*i.e.*, bituminous, and subbituminous) which is 1.2 lb/TBtu or an alternative output-based standard of 1.3E–02 lb/GWh. The EPA is not proposing to revise the current Hg emission standard for existing EGUs firing non-lignite coal.

Finally, the EPA is proposing to remove one of the two options for defining the startup period for MATS-affected EGUs. The first option defines

[2] 77 FR 9310.

[3] U.S. EPA. Table 1. Prioritized Chronic Dose-Response Values for Screening Risk Assessments. Available at: ***https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants.***

[4] Total PM is composed of the filterable PM fraction (fPM) and the condensible PM fraction. In establishing fPM as a surrogate for the non-Hg metal HAP, the EPA explained that most of the non-Hg metal HAP are present overwhelmingly in the fPM fraction. Selenium may be present in both the fPM fraction and/or as the acid gas, SeO_2, in the condensible PM fraction. SeO_2 is an acid gas HAP and is well controlled by the emission limit for acid gas HAP. In addition, using fPM as the surrogate will allow the use of continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

[5] The fPM standard for new coal-fired EGU is 9.0E–02 lb/MWh, which is an output-based emission standard. See 78 FR 24073. This emission is equivalent for a new coal-fired EGU with a heat rate of 9.0 MMBtu/MWh (9,000 Btu/kWh).

[6] The emission standard of 4.0E–06 lb/MMBtu is more often written as 4.0 lb/TBtu (pounds of Hg per trillion British thermal units).

startup as either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Under the first option, startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose, and startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Under the second option, startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. The EPA is proposing to remove the second option, which is currently being used by fewer than 10 EGUs as discussed in section V.D.1 of this preamble.

The EPA is not proposing to modify the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, HF, SeO_2) for existing coal-fired EGUs. An evaluation of recent compliance data for HCl and/or SO_2 emissions revealed that approximately two-thirds of coal-fired EGUs operate at or below the alternative SO_2 emission standard of 2.0E–01 lb SO_2/MMBtu (SO_2 may be used as an alternative surrogate for acid gas HAP at coal-fired EGUs with operational flue gas desulfurization (FGD) systems and SO_2 CEMS). Approximately one-third of coal-fired EGUs have a SO_2 emission rate above the current SO_2 standard, but instead operate in compliance with the primary acid gas HAP limit for HCl of 2.0E–03 lb HCl/MMBtu, with most using an FGD system and/or by firing coal with low chlorine content and high alkalinity. The EPA did not identify any new technologies or developments in existing technologies that would achieve additional emission reductions. Based on this review, the EPA is not proposing revisions to the acid gas HAP emission standards for coal-fired EGUs.

The EPA is unaware of any new coal- or oil-fired EGUs in development and has not projected any new coal- or oil-fired EGUs in EPA modeling to support various power sector-related rulemakings. For that reason, the EPA has not reviewed and is not proposing any revisions to the MATS new source emission standards. In some cases, however, proposed revisions to existing source emission standards may be more stringent than the corresponding new source emission standard. In those instances, the EPA has addressed that illogical outcome by proposing to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard.

The EPA is also not proposing to revise MATS emission standards for existing Integrated Gasification Combined Cycle (IGCC) EGUs, nor to the MATS emission standards for any of the subcategories of existing oil-fired EGUs.

In addition to generally soliciting comments on all aspects of this proposed action, the EPA has identified several aspects of the proposal on which comments are specifically requested.

In selecting a proposed standard, as discussed in detail below, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to E.O. 12866, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, "Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Ref. EPA–452/R–23–002), is available in the docket, and is briefly summarized here and in section VI of this preamble.

II. General Information

A. Does this action apply to me?

The source category that is the subject of this proposal is coal- and oil-fired EGUs regulated under 40 CFR part 63, subpart UUUUU. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150. This list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 63, subpart UUUUU would be affected by this proposed action. The coal- and oil-fired EGU source category was added to the list of categories of major and area sources of HAP published under section 112(c) of the CAA on December 20, 2000 (65 FR 79825). CAA section 112(a)(8) defines an EGU as any fossil fuel-fired combustion unit of more than 25 megawatts (MW) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale is also considered an EGU.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A memorandum showing the rule edits that would be necessary to incorporate the changes proposed in this action to 40 CFR part 63, subpart UUUUU is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2018–0794). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

III. Background

A. What is the authority for this action?

1. Statutory Authority

The statutory authority for this action is provided by sections 112 and 301 of the CAA, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, during the first stage Congress directed the EPA to establish technology-based standards to ensure that all sources control pollution at the level achieved by the best-performing sources, referred to as the maximum achievable control technology (MACT). After the first stage, Congress directed the EPA to review those standards periodically to determine whether they should be strengthened. Within 8 years after promulgation of the standards, the EPA must evaluate the MACT standards to determine whether additional standards are needed to address any

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