BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18	))))	Case No. 12-2400-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods	)))	Case No. 12-2401-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for the Approval of a Tariff for a New Service	)))	Case No. 12-2402-EL-ATA

NOTICE OF ADDITIONAL AUTHORITY

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Attorneys for Industrial Energy Users-Ohio

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NOTICE OF ADDITIONAL AUTHORITY

In support of its demonstration that the Public Utilities Commission of Ohio ("Commission") does not have jurisdiction to increase the amount of compensation provided to Duke Energy Ohio, Inc. ("Duke") for the provision of wholesale generation-related capacity service ("Capacity Service"), Industrial Energy Users-Ohio ("IEU-Ohio") provides Notice of Additional Authority. Attached is the decision of the United States District Court of Maryland in *PPL Energyplus, LLC, et al., v. Douglas R. M. Nazarian*, *et al.*, Civ. Action No. MJG-12-1286 (decided Sept. 30, 2013) ("*PPL I*"), in which the District Court found that the Maryland Public Service Commission ("Maryland Commission") was preempted from authorizing above-market compensation for the provision of wholesale energy and capacity service. Also attached is the decision of the District Court for the United States District Court of New Jersey in *PPL Energyplus, LLC, et al., v. Robert M. Hanna, et al.*, Civ. Action No. 11-745 (decided Oct. 11, 2013)

("*PPL II*"), in which the District Court found that the New Jersey Long-Term Capacity Pilot Project Act ("LCAPP") was unconstitutional because it violated the Supremacy Clause.

In its Application and supporting testimony, Duke has repeatedly asserted that the Commission has jurisdiction to increase Duke's total compensation for the provision of Capacity Service under Chapters 4905 and 4909, Revised Code, and the Reliability Assurance Agreement ("RAA"), an agreement among members of the PJM Interconnection, LLC ("PJM"), because the service is a wholesale service.[1] In support, it argues that the compensation it receives under the federally-approved Reliability Pricing Model ("RPM-based Price") is inadequate.[2] Neither Ohio law nor the RAA, however, provides authority to approve an increase in compensation for Capacity Service established through the Reliability Pricing Model ("RPM") Duke agreed to in its settlement of its last Electric Security Plan ("ESP") case.[3]

The recent decisions of the District Courts of Maryland and New Jersey provide an additional basis on which the Commission must dismiss Duke's Application. The *PPL* decisions find that the Federal Power Act ("FPA") preempts a state commission from approving an increase in total compensation of a generator for the provision of wholesale energy and capacity above the RPM-based Price.

PPL I

In *PPL I*, the plaintiffs challenged an order of the Maryland Commission directing the local electric distribution companies to compensate generators for the construction

[1] Application at 3; Duke Ex. 1 at 11.

[2] *Id*. at 8.

[3] Initial Brief of Industrial Energy Users-Ohio at 25-44 (June 28, 2013).

and operating costs of a new gas generation plant in an amount in addition to the wholesale compensation they received from PJM for capacity and energy.[4]

Like Ohio, Maryland's legislature enacted legislation in 1999 that restructured the retail electric generation industry and required that the generation business segment be separated from the distribution segment.[5] Also like Ohio, the distribution company was responsible for supplying a default generation alternative, the Standard Offer Service, for those customers that did not contract with a competitive retail electric service provider.[6]

In 2007, the Maryland legislature directed the Maryland Commission to study re-regulation options.[7] In subsequent proceedings, the Maryland Commission questioned the ability of the wholesale market to relieve a potential capacity shortage, and it issued a request for proposals to secure additional capacity resources.[8] Under the request for proposals, the generator would have to offer its capacity and energy to PJM and be compensated by PJM.[9] In addition to the compensation for capacity and energy it received from PJM, the generator would also receive a payment from the local distribution companies under a long term contract that enabled the generator to receive a proposed contract price. As explained by the successful bidder in its response to the request for proposals, the costs it used to calculate the contract price included costs of construction of the generating plant, the fixed operating costs of going forward, such as

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[4] *PPL I* at 50-51 (copy attached).

[5] *Id*. at 49-50.

[6] *Id*. at 50-51.

[7] *Id*. at 52.

[8] *Id*. at 58.

[9] *Id*. at 64.

labor, property taxes, and maintenance, financing costs of construction, and a reasonable rate of return.[10] Electric distribution companies were ordered to enter into contracts to pay the generator the difference between what the generator received for energy and capacity from PJM and the contract-based total compensation.[11] The electric distribution companies that paid the generator amounts in excess of the amounts the generator recovered from PJM for energy and capacity would then be authorized to recover the excess amount from their Standard Offer Service customers.[12]

The District Court determined that the actions of the Maryland Commission approving the compensation structure which permitted the generator to recover revenue in excess of the RPM-based Price were preempted under the Supremacy Clause[13] because the Maryland Commission's pricing of wholesale capacity and energy sales invades a field occupied exclusively by the Federal Energy Regulatory Commission ("FERC") under the FPA.[14] While acknowledging that the Maryland Commission retained jurisdiction over matters such as siting, the Court went on to state that "after a generator physically comes into existence and operation and participates in the wholesale electric energy market, the prices or rates received by that generator in exchange for wholesale energy and capacity sales are within the sole purview of the federal government."[15] The Court continued:

> While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders, the

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[10] *Id*. at 65.

[11] *Id*. at 90-91.

[12] *Id*. at 66.

[13] U.S. Const., Art. VI, cl. 2.

[14] 16 U.S.C. § 201 et seq.

[15] *PPL I* at 85.

> scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices under, *inter alia*, the Supremacy Clause and the field preemption doctrine. Based on this principle, Maryland cannot secure the development of a new power plant by regulating in such a manner as to intrude into the federal field of wholesale electric energy and capacity price-setting.[16]

The intention of the Maryland Commission to fill a potential shortfall in capacity resources did not justify the Commission's actions. "Where a state action falls within a field Congress intended the federal government alone to occupy, the good intentions and importance of the state's objectives are immaterial to the field preemption analysis."[17] The critical fact was whether the state order set the total wholesale compensation received by the generator.[18]

Based on the terms of the contract that allowed recovery of cost-based total compensation, the Court determined that the Maryland Commission's order set a price for wholesale capacity and energy service.[19] Having found that the Maryland Commission had set a price for wholesale capacity and energy service, the District Court concluded that the Commission's actions were preempted: "[U]nder field preemption principles, the [Maryland Commission] is impotent to take regulatory action to establish the price for wholesale energy and capacity sales. FERC has exclusive domain in that field and has fixed the price for wholesale energy and capacity sales in the PJM Markets as the market-based rate produced by the auction processes approved by FERC and utilized by PJM."[20] Further, the Court stated:

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[16] *Id*. at 85-86.

[17] *Id*. at 86.

[18] *Id*. at 87.

[19] *Id*. at 88-93.

[20] *Id*. at 93.

> Because states have no authority, either traditional or otherwise, to set wholesale rates, the compensation received by [the generator] for its wholesale energy and capacity sales is exclusively subject to regulation of FERC. While there exist legitimate ways in which states may secure the development of generation facilities, *states may not do so by dictating the ultimate price received by the generation facility for its actual wholesale energy and capacity sales in the PJM Markets without running afoul of the Supremacy Clause*.[21]

PPL II

In *PPL II*, the District Court's decision finding LCAPP preempted and void again arose in a state in which state law mandates retail electric competition. Like Ohio and Maryland, the New Jersey legislature enacted legislation restructuring the retail electric generation business and its regulation in 1999.[22] The legislation required New Jersey electric distribution companies to divest their generation assets and permitted retail customers to choose a generation supplier.[23] Over the opposition of New Jersey officials, pricing of wholesale capacity resources in New Jersey was governed by PJM under RPM. Beginning in 2006, state leaders opposed the adoption of RPM based on concerns that RPM, transmission constraints, and the effects of environmental regulation would result in insufficient capacity to serve the state.[24]

In response to the concerns regarding sufficient capacity resources, the New Jersey legislature enacted LCAPP in 2011.[25] An express purpose of LCAPP and the contracts approved under the statute was to provide a transaction structure that would result in new power plant construction in the PJM region that would benefit New

[21] *Id* at 110-11 (emphasis added).

[22] *PPL II* at 19.

[23] *Id*. at 19-22.

[24] *Id*. at 30-32.

[25] *Id*. at 32.

Jersey.[26] To effect that purpose, the statute required New Jersey electric distribution companies to enter into long-term contracts with eligible generators selected through a competitive bidding process and pay the generators the difference between the RPM auction price and the "actual development costs" of the generator.[27] (The approved contract for one generator required above-market payments to the generator for fifteen years).[28]

Following analysis similar to that in *PPL I*, the District Court initially determined that LCAPP was preempted under field preemption because LCAPP supplants the FPA.[29] To support that finding, the Court identified various terms of the LCAPP contracts that relied on RPM terminology and related specifically to the determination of a wholesale capacity price.[30] The Court then determined that the field of wholesale electricity pricing was a field within the exclusive authority of FERC[31] and that LCAPP and the New Jersey Board of Public Utilities ("NJ Board") approved contracts sought to supplant the FPA by establishing the price that LCAPP generators would receive for their sales of wholesale capacity. Accordingly, LCAPP was preempted.[32]

The District Court also held that there was a conflict between state and federal law that required the state law to be preempted. Under conflict preemption doctrine, a state law is preempted if it stands as an obstacle to the accomplishment of the purposes

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[26] *Id*.

[27] *Id*. at 33.

[28] *Id*. at 39.

[29] *Id*. at 60.

[30] *Id*. at 54-55.

[31] *Id*. at 58-60.

[32] *Id*. at 60.

and objectives of Congress.[33] If there is a conflict, the state law must yield regardless of the purpose the state seeks to pursue.[34] The District Court held that LCAPP poses an obstacle to FERC's implementation of RPM because the record demonstrated that LCAPP undermined competitors' reliance on the price signals provided by RPM.[35] "The effects … demonstrate that the [Commission-approved contract's] imposition of a government imposed price creates an obstacle to [FERC's] preferred method for the wholesale sale of electricity in interstate commerce."[36]

The FPA Preempts Commission Wholesale Price Setting

In this Application, Duke complains that it is not receiving sufficient revenue because it has agreed to accept only the RPM-based Price.[37] It then seeks a formula-based increase in the total compensation it would receive for Capacity Service.[38] Duke further states that the service for which it is seeking increased compensation is a wholesale service,[39] relying on the Commission's decision in the *AEP-Ohio Capacity Case*.[40]

As demonstrated in the *PPL* decisions, the price setting of wholesale capacity and energy services is within the exclusive federal authority of FERC under the FPA. Based on well-understood principles that a state law or administrative action is

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[33] *Id*. at 61.

[34] *Id*. at 62.

[35] *Id*.

[36] *Id*.

[37] Application at 4.

[38] *Id*. at 4 & 7-8.

[39] Id. at 3.

[40] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* Case No. 10-2929-EL-UNC, Opinion and Order at 13 (July 2, 2012) ("*AEP-Ohio Capacity Case*").

preempted if it falls within a field Congress intended the federal government alone to occupy, the Commission is preempted from increasing the total compensation of Duke for wholesale Capacity Service.

The Commission's motivation for increasing total compensation for Capacity Service does not provide a basis for avoiding the preemptive effect of the FPA. Policy justifications, whether based on the desire to increase available capacity resources as in Maryland and New Jersey or to protect the financial integrity of an electric distribution utility as the Commission has asserted in the *AEP-Ohio Capacity Case*[41] and Duke urges in this case,[42] do not provide any lawful justification. If the Commission order invades the field governed by the FPA, the order is preempted, regardless of the Commission's purpose.

Likewise, an increase in the total compensation cannot be justified because all customers would be required to pay the increase through a nonbypassable "retail" charge. As shown by the decision in *PPL I,* authorization of a retail charge does not save the request for additional wholesale compensation from the preemptive effect of the FPA.

[41] *Id*. at 23.

[42] Application at 3.

Accordingly, the FPA preempts the Commission from authorizing Duke's requested increase in compensation for wholesale Capacity Service even if Ohio law provided the Commission a statutory basis to act (which it does not).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Notice of Additional Authority* was served upon the following parties of record this 18th day of October, 2013, via hand-delivery, electronic transmission, or first class mail, U.S. postage prepaid.

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND

PPL ENERGYPLUS, LLC, et al. *

Plaintiffs *

vs. * CIVIL ACTION NO. MJG-12-1286

DOUGLAS R. M. NAZARIAN, in his official capacity as Chairman of the Maryland Public Service Commission, et al. *

Defendants *

* * * * * * * * *

MEMORANDUM OF DECISION

The Court has heard the evidence, reviewed the exhibits, considered the materials submitted by the parties, and had the benefit of the arguments of counsel.

The Court now issues this Memorandum of Decision as its findings of fact and conclusions of law in compliance with Rule 52(a) of the Federal Rules of Civil Procedure. The Court finds the facts stated herein based upon its evaluation of the evidence, including the credibility of witnesses, and the inferences that the Court has found reasonable to draw from the evidence.

I. INTRODUCTION

Prior to 1999, Maryland utilized a vertically integrated model of electric energy regulation. A single electric utility (such as BGE or Pepco) owned the facilities that produced and delivered electricity to the users in its exclusive territory. Maryland electric power users purchased electricity from the one utility that served the territory in which they were located. The Maryland Public Service Commission ("PSC") ultimately determined whether additional generation resources were needed in Maryland and provided for the financing of those resources through the approval of rate increases.

In 1999, the Maryland General Assembly passed the Electric Customer Choice and Competition Act (the "1999 Act"), which restructured, or deregulated, Maryland's electric energy market. The 1999 Act separated the Maryland "utilities' generating assets from their distribution and transmission functions" by transferring ownership of those generation assets to other companies that owned and operated the power plants. P.391 (2007 PSC Interim Report) at 10.

The PSC is empowered by the State of Maryland to assure "safe, adequate, reasonable, and proper [electric] service." Md. Code Ann., Pub. Util. § 5-101(a). However, Maryland-based utilities, which now no longer own generating facilities, must purchase energy on federally regulated wholesale markets. Thus, the utilities and, correspondingly, Maryland ratepayers are directly affected by the wholesale prices determined on the federally regulated wholesale markets.

In mid-2000, the PSC and others began to voice concerns over the operations of Maryland's electricity markets, the post-restructuring consumer electricity rates, and the existence of adequate generation resources to serve the energy needs of Maryland ratepayers. In 2007, the PSC filed a report with the General Assembly, stating that the federally regulated wholesale markets had not responded to Maryland's needs and opining that those markets were unlikely to respond in the immediate future to the state's "looming capacity shortage." P.391 (2007 PSC Interim Report) at 1. The PSC concluded that it should require the Maryland utilities to enter into long-term contracts to induce the construction of new electric generation facilities in Maryland.

Ultimately, on April 12, 2012, the PSC issued the Generation Order at issue,[1] directing Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("Delmarva") to enter into a Contract for Differences ("CfD") with CPV Maryland, LLC ("CPV"). In essence, the CfD provided that regardless of the price set by the federally regulated wholesale market, the Maryland utilities would assure that CPV received a guaranteed price fixed by a contractual formula.[2] The result was that CPV had a secure

[1] PSC Order No. 84815. See P.44.
[2] Ultimately, the utilities' customers.

income stream available to finance construction of a generating facility in a designated area within Maryland.[3]

Plaintiffs[4] present claims in three Counts:

Count I	Violation of the Supremacy Clause, U.S. Constitution, art. VI, cl.2;
Count II	Violation of the Commerce Clause, U.S. Constitution, art. I, § 8, cl.3; and
Count III	Violation of 42 U.S.C. § 1983.

As discussed at length herein, the Court holds that Plaintiffs have established their claim that the Generation Order violates the Supremacy Clause of the United States Constitution by virtue of field preemption[5] but does not violate the dormant Commerce Clause.[6]

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[3] As discussed herein, there was a theoretical possibility (but a practical impossibility) that the facility could be constructed in the District of Columbia.

[4] The Plaintiffs are: PPL Energyplus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PSEG Power, LLC; and Essential Power, LLC.

The named Defendants are the Commissioners of the PSC, sued in their official capacities, Douglas R. M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and Kevin Hughes. On January 8, 2013, after Plaintiffs filed the instant suit, Douglas R. M. Nazarian was appointed to the Maryland Court of Special Appeals.

[5] The establishment of Plaintiffs' field preemption claim renders moot the question of whether Plaintiffs also established their Supremacy Clause conflict preemption claim.

[6] The Court also holds that even if not formally abandoned, Plaintiffs' 28 U.S.C. § 1983 claim is not viable.

II. BACKGROUND

A. Electric Power Grids In A Nutshell

As once said in reference to the Rule in Shelley's case, it is one thing to put the subject of electric power grids in a nutshell, but impossible to keep it there.[7] Nevertheless, even an oversimplified, incomplete, and imprecise introduction may be useful to those totally unfamiliar with electric power grids.

To start, think of a power grid as analogous to a network of pipes utilized to transport water from various pumping stations, which take water from natural sources (lake, river, etc.), to reservoirs. The water in the reservoirs is then, as demanded by a local utility, transported by pipes in the grid to the local utility for distribution to the utility's customers.

However, for a closer analogy, think of the same grid without any reservoirs. When an amount of water is placed into the grid by a pumping station, an equal amount must flow out of the grid to a local utility. Thus, the grid operator must insure that, at all times, the supply (water put into the grid

[7] Professor Barton W. Leach wrote that when "Lord Thurlow undertook to put the Rule in Shelley's Case in a nutshell," Lord Macnaghten said, "'it is one thing to put a case like Shelley's in a nutshell and another thing to keep it there.'" W. Barton Leach, Perpetuities in a Nutshell, 51 Harv. L. Rev. 638, 638 n.a1 (1938)(quoting Van Grutten v. Foxwell, [1897] A. C. 658, 671).

by the pumping stations) equals the demand (water sent out of the grid to the local utilities). This balance is maintained by affecting the supply through adjustments of the price paid to pumping station suppliers, payments to local utilities (or customers) to reduce their usage, adjustments to the price paid by the local utilities for the water they demand, etc.

B. Federal Regulation of Electric Energy

1. The Federal Power Act and FERC

In 1927, the United States Supreme Court held that the dormant Commerce Clause prohibited states from regulating the rates for wholesale power sales between utilities in different states. The Court reasoned that, unlike the regulation of the rates charged to local consumers, regulation of interstate rates places "a direct burden upon interstate commerce, from which the state is restrained by the force of the commerce clause." Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).[8]

In response to the Attleboro decision, Congress enacted the Federal Power Act ("FPA") in 1935, which "closed the 'Attleboro gap' by authorizing federal regulation of interstate, wholesale sales of electricity – the precise subject matter beyond the

[8] See Quill Corp. v. N.D. By & Through Heitkamp, 504 U.S. 298 (1992) (recognizing abrogation of Attleboro on other grounds).

jurisdiction of the States in Attleboro."[9] New York v. F.E.R.C., 535 U.S. 1, 20 (2002). Specifically, the FPA gave the Federal Power Commission, the predecessor agency to FERC, jurisdiction over the regulation of interstate wholesale sales of electricity and of interstate transmissions of electric energy. See 16 U.S.C. § 824(a); New York, 535 U.S. at 20-21.

The FPA vested FERC with the responsibility for setting the "rates and charges" of wholesale electric energy and for ensuring that those rates are "just and reasonable." Id. § 824d(a); Entergy La., Inc. v. La. Pub. Serv. Comm'n, 539 U.S. 39, 47-48 (2003). In essence, FERC exercises this authority through an intricate regulatory framework whereby transactions for the wholesale sale of electricity are filed with FERC (on either an individual basis or, more often, under a market-based rate tariff). FERC determines on its own initiative, or in response to a request by some party, whether such rates are "just and reasonable" and not unduly preferential, discriminatory, or disadvantageous to any party.[10] See 16 U.S.C. § 824e; id. § 824d.

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[9] The "'sale of electric energy at wholesale' . . . means a sale of electric energy to any person for resale." 16 U.S.C. § 824(d).

[10] For example, FERC regulations require utilities with market-based rate authority to file an Electronic Quarterly Report ("EQR") every quarter summarizing the contractual terms and conditions in agreements subject to the jurisdiction of FERC, including agreements for the wholesale sales of capacity

As to the physical facilities that generate electric energy, the FPA gave FERC jurisdiction "over all facilities for [the] transmission or sale of electric energy" in interstate commerce. Id. § 824(b)(1). But, "except as specifically provided in this subchapter and subchapter III of this chapter," FERC has no jurisdiction "over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." Id.

The witnesses generally agreed that FERC has no authority or power to order directly the siting, building, or construction of a generation facility generally or in any particular location within a state. Tr. Mar. 5 (PM) at 82:4-21 (Nazarian); Tr. Mar. 6 (AM) at 44:1-21, 46:12-47:7 (Massey); Tr. Mar. 7 (AM) at 32:10-21 (Wodyka). As discussed infra, that authority is retained by the states under the FPA.

The FPA created an exclusive area of federal jurisdiction in the electric energy realm regarding the regulation of interstate wholesale energy sales and transmission, including the entities that engage in such acts. The FPA also retained a sphere of state jurisdiction with respect to interstate retail sales, distribution of electric energy, and the construction of

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and energy. See 18 C.F.R. § 35.10b.

local generation facilities. See New York, 535 U.S. at 22-23 (explaining "the legislative history [of the FPA] is replete with statements describing Congress' intent to preserve state jurisdiction over local facilities").[11] As summarized by the U.S. Court of Appeals for the District of Columbia Circuit:

> Jurisdiction over this sale and delivery of electricity is split between the federal government and the states on the basis of the type of service being provided and the nature of the energy sale . . . . Thus transmission occurs pursuant to FERC-approved tariffs; local distribution occurs under rates set by a state's public service commission.

Niagara Mohawk Power Corp. v. F.E.R.C., 452 F.3d 822, 824 (D.C. Cir. 2006).

2. Development of Wholesale Energy Markets

a. Traditional Vertically Integrated Utilities

"When Congress enacted the FPA, networks of high-voltage, long-distance transmission lines which today crisscross the United States" simply did not exist." See Transmission Access Policy Study Grp. v. F.E.R.C., 225 F.3d 667, 691 (D.C. Cir.

[11] Also recognizing the role of the states, the Energy Policy Act of 2005, which gave FERC jurisdiction over reliability standards for the bulk-power system, states "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard." 16 U.S.C. § 824o(i)(3).

2000), aff'd sub nom. New York v. F.E.R.C., 535 U.S. 1 (2002). The absence of this infrastructure likely was a factor in the development of the vertically integrated structure of electric utilities that generally predominated in the United States until the 1990's. The term "vertically integrated electric utilities" refers to "generation, transmission, and distribution facilities [which are] owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers." Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 60 Fed. Reg. 17,662, 17,668 (Apr. 7, 1995) (hereinafter Open Access). Under the vertically integrated structure:

> Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas.

Id.

A utility operating in the vertically integrated structure typically generates electricity with power plants it owns; transmits the electricity from those power plants to its service territory, usually defined by the state of location;[12] and distributes that electricity to end-use customers within its service territory through local distribution networks, poles, and wires that the utility owns and maintains. See Tr. Mar. 4 (AM) at 121:14-122:21 (Alessandrini); Tr. Mar. 4 (PM) at 8:23-10:20 (Carretta); Tr. Mar. 6 (AM) at 11:8-20 (Massey).

Where utilities operated in a vertical integration structure, states often controlled the fiscal feasibility of a utility's plans to expand its existing generation facilities or to construct new power plants through a regulatory framework. Thus, state regulators could decide whether to allow an increase in the retail rate charged by the utility to end-use customers sufficient to permit the utility to recover the cost of financing the construction of new generation facilities or the development of existing facilities. See Tr. Mar. 4 (AM) at 121:14-122:25 (Alessandrini). If the state approved an adequate increase in retail rates, then the utility acquired a financial

[12] Typically, a utility was granted a franchise by the state government to provide electric service to all consumers located within a defined territory or service territory. See Tr. Mar. 5 (AM) at 42:13-44:11 (Nazarian).

guarantee that assisted the utility in raising capital for its generation projects. See id.

When most electric utilities were vertically integrated one-stop shops with monopolies over designated service territories, the electric energy industry operated predominately as a retail market subject to state regulation without significant intervention from the federal government. See Tr. Mar. 4 (AM) at 121:14-122:26 (Alessandrini). In this scenario, the "wholesale market"[13] regulated by FERC consisted primarily of transactions between vertically integrated utilities whose service territories were physically situated near each other. Tr. Mar. 6 (AM) 13:3-16 (Massey).

b. FERC's Fostering of Wholesale Energy Markets

In the 1970's and 1980's, significant "[t]echnological improvements . . . made feasible the transmission of electric power over long distances at high voltages." See Transmission Access, 225 F.3d at 681 (D.C. Cir. 2000). In response to, among other things, advancements in technology, the wholesale electricity market began to blossom producing, inter alia, independent and non-utility owned power plants capable of providing competitively priced generation to the wholesale

[13] Such as the market was in those days.

market. See id. With a burgeoning wholesale market came more federal legislation and regulation. For instance, in 1978 Congress passed the Public Utility Regulatory Policies Act ("PURPA"), which called for "a program to improve the wholesale distribution of electric energy" and "the reliability of electric service." 16 U.S.C. § 2601(2). However, the traditional vertically integrated utilities that owned transmission lines were inhibiting the development of this wholesale electricity market by "deny[ing] alternative producers access to their transmission lines on competitive terms and conditions." Transmission Access, 225 F.3d at 682.

Congress and FERC took action during the 1990's to facilitate the development of wholesale power markets by "opening up transmission services" and reducing the ability of vertically integrated public utilities to deny customers access to competitively priced electric generation. See Open Access, 60 Fed. Reg. at 17,663-64. "[I]n 1992, Congress enacted the Energy Policy Act, which amended sections 211 and 212 of the FPA to authorize FERC to order utilities to 'wheel' power—i.e., transmit power for wholesale sellers of power over the utilities' transmission lines—on a case-by-case basis." Transmission Access, 225 F.3d at 682 (citing Energy Policy Act of 1992, Pub. L. No. 102-486, §§ 721-22, 106 Stat. 2776 (codified at 16 U.S.C. §§ 824j-k) (giving non-utility generators the right to have FERC order transmission-owning utilities to interconnect and obtain access to the local utilities' delivery systems)).[14] In 1996, FERC issued Order No. 888, which "ordered the national deregulation of electricity transmission services" and required all public utilities that owned or controlled transmission facilities to provide open access to their transmission lines on the same basis on which they provide access to themselves. See Sacramento Mun. Util. Dist. v. F.E.R.C., 616 F.3d 520, 523 (D.C. Cir. 2010) (internal quotation marks omitted).

In a further effort to facilitate the development of competitive wholesale power markets and to "increase the efficiency of the electric transmission systems," FERC "strongly encouraged the [electric power] industry to organize itself into Regional Transmission Organizations" ("RTOs"). See generally Delmarva Power & Light Co., 106 FERC ¶ 61,290, 62,080 (2004); Tr. Mar. 6 (AM) at 48:7-11 (Massey). RTOs are voluntarily formed independent entities that have "consolidate[ed] control

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[14] Additionally, in 2005 Congress passed the Energy Policy Act of 2005, which made FERC responsible for system reliability standards for the bulk-power system. See Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211(a), 119 Stat. 594, 941 (codified at 16 U.S.C. § 824o); Mandatory Reliability Standards for the Bulk-Power System, 72 Fed. Reg. 16,416 (Apr. 4, 2007). Prior to enactment of the Energy Policy Act, "the nation's bulk-power system depended on participants' voluntary compliance with industry standards." Alcoa Inc. v. F.E.R.C., 564 F.3d 1342, 1344 (D.C. Cir. 2009).

of all transmission services in a particular region" and that provide a platform for regional wholesale power markets. See Braintree Elec. Light Dep't v. F.E.R.C., 550 F.3d 6, 8 (D.C. Cir. 2008); Tr. Mar. 6 (AM) 14:20-15:8, 48:3-11 (Massey); Tr. Mar. 6 (PM) at 5:6-6:1 (Wodyka). FERC explained that such consolidation of control in particular regions was needed because "traditional management of the transmission grid" by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets." Regional Transmission Organizations, 65 Fed. Reg. 810, 811 (Jan. 6, 2000). According to FERC, despite Order No. 888, opportunities still existed "for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own or their affiliates' power marketing activities," which could in turn impede competitive electricity markets. Id. at 817.

In 2000, FERC issued Order No. 2000 requiring "utilities that own, operate, or control interstate transmission facilities either to file a proposal to participate in an RTO or to describe their efforts toward joining one." Me. Pub. Utils. Comm'n v. F.E.R.C., 454 F.3d 278, 280 (D.C. Cir. 2006); 18 C.F.R. § 35.34(a). FERC's stated purpose entailed "promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services." 18 C.F.R. § 35.34(a). FERC defined the required functions of any formed RTO as including, inter alia: (1) "employ[ing] a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities" and (2) "ensur[ing] the development and operation of market mechanisms to manage transmission congestion." Id. § 35.34(k)(1)-(2). An RTO "manage[s] all the accounting for the energy that's put in and taken out" of the transmission system it oversees, "operate[s] all the different pricing and biding mechanisms that fall under those wholesale market structures," and operates and plans the regional transmission system within its area. Tr. Mar. 5 (AM) at 126:20-127:18 (Nazarian).

To constitute an RTO, an entity has to satisfy certain requirements and have its proposal approved by FERC. A FERC-approved RTO operates pursuant to tariffs filed with, and approved by, FERC. See Tr. Mar. 5 (AM) at 126:22-127:6 (Nazarian). Presently, "[RTOs] exist in about two-thirds of the country" and are thus responsible for "about two-thirds of the load" or power consumption in the United States. Tr. Mar. 6 (AM) at 19:21-20:16 (Massey). As relevant hereto, all of Maryland is part of an RTO formed in 2002, operated and administered by PJM Interconnected, LLC[15].

C. PJM Interconnected, LLC ("PJM")

After issuance of Order No. 2000, PJM organized itself into an RTO, receiving full RTO status from FERC in December 2002. Although PJM operates as an RTO under the control of FERC, PJM is a private entity with 750 members or stakeholders, including "parties that own facilities, or buy or sell power in the PJM region." Tr. Mar. 6 (PM) at 11:16-12:3 (Wodyka); see also P.606 (PSC Order No. 81423) at 42. PJM's members include "power generators, transmission owners, distributors, marketers, and large consumers." P.606 (PSC Order No. 81423) at 42. States are not members or stakeholders of PJM. See id.

The PJM area encompasses the District of Columbia and all or parts of 13 states (collectively the "PJM region").[16] The PJM region, i.e., PJM's geographic footprint, consists of about 18 interconnected transmission zones. A transmission zone is the

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[15] PJM (Pennsylvania, Jersey, Maryland) traces its origins back to 1927 when three traditional utilities in Pennsylvania, New Jersey, and Maryland formed a power pool. See Tr. Mar. 6 (PM) at 10:9-23, 17:3-9 (Wodyka).

[16] As part of organizing into an RTO, the transmission resources in the PJM region were unified through the voluntary agreement of the owner-utilities of those resources. Logistically, the owner-utilities "transferred operational control of their transmission lines to the PJM Interconnection," but still retained equity ownership. Tr. Mar. 6 (AM) at 14:24-15:8 (Massey).

area or territory in which a particular utility, such as Baltimore Gas & Electric ("BGE"), owns transmission lines or resources. A transmission zone generally mirrors the utility's historical service territory, discussed supra. See Pls.' Dem. 16. The PJM region has an aggregate population of approximately 60 million people, covers 214,000 square miles, and includes 1,365 electric generators that are connected to PJM's regional transmission system. P.516 (PJM – At a Glance) at 3; Pls.' Dem. 16.

As an RTO:

> PJM is responsible for the coordination and operation of the electric power system across the entire PJM footprint. They also then design and administer competitive markets to support the operations and activities within the, again, PJM RTO region. And finally they do . . . resource adequacy planning to ensure that appropriate generation and transmission resources are available to serve the load requirements across the PJM region. And they do this in a way that they try to ensure the safety and reliability of all the activities that occur in the PJM footprint.

Tr. Mar. 6 (PM) at 10:25-11:10 (Wodyka).

As a FERC-approved RTO, PJM carries out its responsibilities under FERC's jurisdiction and pursuant to FERC-approved tariffs, including the Open Access Transmission Tariff (the "PJM Tariff"), which governs broadly how PJM operates the regional transmission system in the PJM region. P.516 (PJM – At a Glance) at 4. Additionally, PJM executes its duties through agreements with other parties that are filed with, and approved by, FERC, including the Transmission Owners Agreement ("TOA"), the Reliability Assurance Agreement ("RAA"), and the Operating Agreement.[17] Tr. Mar. 6 (PM) at 25:5-19 (Wodyka); P.516 (PJM – At a Glance) at 4.

1. PJM's Operation of the Bulk-Power System and Transmission Planning

One aspect of PJM's duties as an RTO is the day-to-day operation and maintenance of the bulk electric power system "to ensure reliability of electricity delivery across the [PJM] region." Tr. Mar. 4 (AM) at 37:20-38:16 (Alessandrini). Thus, PJM operates and maintains a regional interconnected transmission system and power grid that spans the PJM footprint, enabling electric energy to be dispatched and delivered to various points across the PJM region. See PJM Interconnection, LLC, 132 FERC ¶ 61,173, 61,869-70 (2010); see also Tr. Mar. 5 (AM) at 127:7-18 (Nazarian). PJM can be thought of as analogous

[17] The RAA, which is "signed by all the load-serving entities ['LSEs'] in the PJM region," contains provisions related to the amount of capacity resources that must be procured by each LSE. P.516 (PJM – At a Glance) at 4; see also Tr. Mar. 6 (PM) at 131:2-132:10 (Wodyka). "The Operating Agreement must be signed by organizations to become members of PJM." P.516 (PJM – At a Glance) at 4. It "establish[es] how PJM operates as a regional transmission organization." Id.

to an "air traffic controller[] of the power grid" because it "monitors and coordinates . . . electric generators, . . . high-voltage transmission lines, . . . substations," and the flow of electric energy therein on a day-to-day basis. P.516 (PJM – At a Glance) at 1.

PJM is responsible for planning for the regional transmission system it oversees to ensure resource adequacy and future system reliability. To that end, PJM evaluates whether, and to what extent, new transmission resources or improvements to existing transmission resources "are necessary to meet the requirements of the load in the future." Tr. Mar. 4 (AM) at 38:12-16 (Alessandrini). For example, "PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additional to the grid are needed to ensure reliability and the successful operation of the wholesale markets."[18] P.516 (PJM – At a Glance) at 2; see also Tr. Mar. 6 (AM) at 20:21-24 (Massey). The RTEP includes long-term planning studies that look "into the future as far as 15

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[18] PJM does not "own" the transmission resources within the PJM region. Instead, it manages and operates those resources through an interconnected bulk-power system. See Tr. Mar. 6 (AM) at 15:5-8 (Massey). As a result of the TOA, a FERC-filed agreement, the transmission resource owners who wish to be part of the PJM region are obligated to perform certain transmission projects identified by PJM in its RTEP. All utilities that own transmission resources within the PJM region and wish to be part of the RTO must enter into the TOA. See P.516 (PJM – At a Glance) at 4.

years . . . to evaluate the performance of the transmission as well as the generation system that's going to be able to reliably serve load in the long run." Tr. Mar. 6 (PM) at 22:10-21 (Wodyka).

2. PJM-Administered Wholesale Electricity Markets

In addition to managing the physical flow of electric energy across the interstate transmission system within the PJM region and planning for improvements to ensure infrastructure reliability, PJM administers three wholesale markets[19] in which electric energy products are sold by capacity resources to PJM and then resold by PJM to Load Serving Entities ("LSEs"[20]) according to prices set in each of the respective markets. Only two of these markets, the energy market and the capacity market, are pertinent to the instant case. The third wholesale market,

[19] As explained supra, the FPA charges FERC with the regulation of interstate wholesale sales of electricity. See 16 U.S.C. § 824(a). Pursuant to the FPA, FERC has the power to set and regulate wholesale electric energy "rates and charges," subject to the requirement that "such rates or charges shall be just and reasonable." Id. § 824d(a); Miss. Power & Light Co. v. Miss. ex rel. Moore, 487 U.S. 354, 373 (1988). It is pursuant to this power that FERC authorizes PJM to run the PJM wholesale markets, setting the price for wholesale electricity sales through market-based auctions.

[20] "LSE" refers to an entity that serves an energy demand by purchasing wholesale energy for purposes of resale to end-use customers who are actually using and consuming that energy, such as homes and businesses. Tr. Mar. 5 (AM) at 48:22-51:21 (Nazarian); Tr. Mar. 11 (AM) at 41:1-7 (Roach).

the ancillary services market,[21] is not. Therefore, the term "PJM Markets" as used herein refers to the energy and capacity markets collectively and excludes the ancillary services market.

The PJM Markets are run pursuant to FERC-approved tariffs and are the mechanisms that PJM uses to set or determine the price at which energy and capacity are to be bought and sold within its territory. Transactions on the PJM Markets are not the only permissible FERC-regulated wholesale transactions. Private parties can buy and sell wholesale energy, capacity, and ancillary services outside the PJM Markets and thus outside the prices set by PJM in such markets. See OPC's Post-Trial Br. [Document 140] at 21. For instance, subject to FERC rules, a capacity resource, such as a generation facility, may sell energy and capacity directly to an LSE through a bilateral contract at a price determined by the parties, not set by PJM through its market-based mechanisms. See Tr. Mar. 5 (AM) at 16:21-17:9 (Nazarian).

Irrespective of the transactional means used by an LSE to procure energy for resale to end-use customers, the costs incurred by the LSE for wholesale purchases are passed on to end-use customers through the retail rate charged by the LSE.

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[21] "Ancillary Service Markets are markets for so-called reliability services that are necessary in realtime [sic] to keep the system perfectly in balance." Tr. Mar. 6 (AM) at 18:14-16 (Massey).

See Miss. Power & Light Co. v. Miss. ex rel. Moore, 487 U.S. 354, 372 (1988) ("States may not bar regulated utilities from passing through to retail consumers FERC-mandated wholesale rates."). Thus, an increase in wholesale rates tends to result in a corresponding increase in retail rates.

a. PJM Wholesale Energy Market

The PJM wholesale energy market is a market in which wholesale electric energy generated by power plants is bought and sold to meet present load demand within the PJM region (the "PJM Energy Market"). In the PJM Energy Market, generation resources[22] sell energy to PJM that is generated and delivered into PJM's interconnected power grid by the generator. LSEs then purchase that energy from PJM to deliver and resell it to end-use customers, thereby satisfying load or customer demand for electricity at any point in time. Tr. Mar. 4 (AM) at 23:16-24, 37:20-38:6 (Alessandrini). Because generators sell their energy to PJM, and LSEs purchase that energy from PJM and receive delivery through PJM's interstate grids and transmission systems, there is no direct sale of energy from a generator to a particular LSE. Thus, the PJM Energy Market is composed of two

[22] The term "generation resources" refers to resources or facilities within PJM that generate electric energy such as power plants.

separate sub-markets — day-ahead and real-time. In the day-ahead sub-market, generation facilities bid into an energy market for energy delivery in the next twenty-four hours; in the real-time sub-market, generation resources bid into a market for delivery in the next hour. See Tr. Mar. 6 (AM) at 18:4-19:12 (Massey).

With respect to setting the price of energy in the PJM Energy Market, PJM uses a system called "Locational Marginal Pricing [('LMP')], which is the economic dispatch and price setting of energy." Tr. Mar. 4 (AM) at 24:22-24 (Alessandrini). The concept of LMP is that it "reflects the value of the energy at the specific location and time it is delivered" and "takes into account the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM territory." P.516 (PJM – At a Glance) at 11. LMP may result in different prices for energy in different zones or locations within the PJM region. These "[e]nergy prices vary across the PJM footprint according to a number of factors that differentiate energy prices at different points within the system." P.391 (2007 PSC Interim Report) at 17; see also Tr. Mar. 4 (AM) at 114:11-25 (Alessandrini). LMP for energy is "volatile" because "it depends on the value of that energy, where it's produced, at the time it's produced, and what the weather and other conditions are."[23] Tr. Mar. 5 (PM) at 65:21-66:6 (Nazarian).

Concerning the prices received by power plants for energy sold into the PJM Energy Market, generation facilities across the PJM region have the ability to bid electric energy into the PJM Energy Market at a bid price. PJM, as the operator of the power grid, dispatches that energy to meet load demand by taking generation bids in ascending order of cost (i.e., beginning with the lowest cost generation and ending with the highest cost generation) "until the electric load is satisfied." P.391 (2007 PSC Interim Report) at 17. The highest cost generation (that is, the cost at the point at which the load demand is satisfied) "set[s] the clearing price for all [generators] operating in the zone," and the resulting price is the LMP received by those

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[23] FERC describes the LMP as:

> a bid-based, security-constrained economic dispatch and unit commitment model to determine real-time and next-day LMP for electricity, which reflect the value of energy at a specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices differ at the approximately 8,000 pricing nodes on the transmission system by marginal losses only. When transmission congestion prevents the free flow of energy, more expensive electricity is ordered to meet that demand, and the LMP is higher in congested areas.

PJM Interconnection, LLC, 132 FERC ¶ 61173, 61,870 (2010).

generation resources. Id.

> One factor that influences LMPs significantly is the extent, or lack, of transmission capability into a state or region [because w]hen transmission lines are 'congested' or 'constrained,' i.e., they cannot carry the lower cost electricity to meet demand, PJM must dispatch more expensive generation located in the constrained zone, which increases LMPs.

Id. That is, if lower cost generation cannot be dispatched to serve load in a particular zone due to limitations in transporting the energy, PJM "skips" it and dispatches higher cost generation, which results in "congestion costs" and higher LMPs paid by the purchasing LSE and corresponding increases in the retail energy rates for the end-use customers served by the LSE. See id. at 17-18; see also Tr. Mar. 4 (AM) at 116:6-118:1 (Alessandrini); Tr. Mar. 8 (AM) at 93:20-94:19 (Willig). Thus, higher LMPs provide higher revenues to generation facilities.

According to PJM, the LMP pricing model:

> give[s] price signals that encourage new generation sources to locate in areas where they will receive higher prices. It signals large new users to locate where they can buy lower-cost power. It also encourages the construction of new transmission facilities in areas where congestion is common, in order to reduce the financial impact of congestion on electricity prices.

P.516 (PJM – At a Glance) at 11; see also Tr. Mar. 8 (AM) at 94:16-19 (Willig) ("If the LMPs are different at . . . two points, it means there's . . . differential value to resources located at those two points."). The Maryland Public Service Commission ("PSC") has opined that LMPs do not work as intended, in part because they "have not yielded adequate new generation inside Maryland's transmission constraints." P.391 (2007 PSC Interim Report) at 18-19. The PSC noted that as a "result[,] Marylanders have paid and will continue to pay higher prices than others in the PJM region due to our higher LMPs, but no new material generation has been built in recent years." Id. at 19.

b. PJM Wholesale Capacity Market

PJM administers a wholesale capacity market (the "PJM Capacity Market"), which is a forward market where a product called "capacity" is sold by a capacity resource to PJM and then resold by PJM to LSEs. Capacity resources include generators that will increase the energy supply and users that will reduce the energy demand. LSEs purchase capacity to meet their capacity obligations under certain FERC-filed agreements with PJM. As in the PJM Energy Market, capacity resources sell capacity to PJM; there is no direct sale of capacity from a capacity resource to a particular LSE.

PJM sets the price for capacity bought and sold in the PJM Capacity Market through application of the Reliability Pricing Model ("RPM"). The RPM establishes an annual Base Residual

Auction ("BRA") through which PJM procures capacity from capacity resources "for a particular 'power year'" three years after the auction. That is, capacity bid in the 2012 BRA will be made available for the 2015/2016 power year. The BRA determines the market clearing price, which is the price that PJM will pay for all capacity that clears the BRA. P.391 (2007 PSC Interim Report) at 19. Generally speaking, increases in capacity prices lead to increases in the retail rates paid by end-use customers.

(i) "Capacity"

"Capacity," as used herein to refer to a product,[24] is a standby commitment made by a capacity resource to either produce electric energy or to consume less electric energy at a time in the future when called upon by PJM to do so. See Conn. Dep't of Pub. Util. Control v. F.E.R.C., 569 F.3d 477, 479 (D.C. Cir. 2009). "In a capacity market, in contrast to a wholesale energy market, an electricity provider purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n,

[24] Throughout the trial, witnesses referred to capacity as both a product bought and sold in the PJM Capacity Market and, more generally, as the mega-watt capability of existing resources, i.e., how much electric energy an existing generation facility (or facilities) is capable of producing at any point in time. Herein, the Court refers to capacity as the product.

558 U.S. 165, 168 (2010). Accordingly, the purchase of capacity is the purchase of a capacity resource's availability either to supply energy into PJM's interconnected transmission grid or to reduce the demand for electric energy on the transmission system at some defined future time. Tr. Mar. 8 (AM) at 11:11-12:21 (Willig). A purchase of capacity is not a purchase of actual electric energy, but is instead a purchase of a resource capable of producing, or reducing demand for, electric energy in the transmission system when requested.[25] Id.

Capacity resources take various forms. The most typical form is generation capacity, which is a generation resource's commitment to generate actual electric energy into the transmission system operated by PJM that can then be dispatched to serve load at some future point, if and when called upon to do so. See id. at 11:11-18. Any type of power plant (e.g., nuclear, natural gas, coal, wind farm, solar) is a generation resource. Capacity resources can also take the form of demand reduction or energy efficient programs. Unlike generation resources that take place on the energy supply side of the market, "demand response" programs occur on the energy demand side of the market and represent a commitment by an LSE to

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[25] Therefore, a capacity resource that clears the BRA is paid by PJM for that capacity irrespective of whether PJM actually calls upon the resource in the future to generate actual energy into the transmission system or to refrain from doing so.

reduce the demand for energy on the transmission system when called upon to do so. The ability of an LSE to reduce demand generally involves an agreement by end-use customers to reduce demand during peak periods at the request of the LSE in return for compensation. Under the RPM, generation and demand reduction resources bid into the BRA as "capacity."

"Capacity is an important concept in the energy market due to the substantial deviations between maximum energy demand and minimum energy demand." PPL Energyplus, LLC v. Solomon, No. 11-745, 2012 WL 4506528, at *1 (D.N.J. Sept. 28, 2012) (citing U.S. Dep't of Energy, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets, at A.4 (2002), http://www1.eere.energy.gov/femp/pdfs/primer.pdf)). The purchase and sale of capacity ensures that at any given time there are adequate resources capable of supplying energy to serve forecasted load, as well as a reserve margin to meet exigent circumstances, such as an unexpectedly high demand or the failure of a generator. See Tr. Mar. 8 (AM) at 11:4-12:7 (Willig). As explained by Professor Willig:

> If there is capacity in the market, and there is need for the energy, then that capacity is utilized, the physical cast is turned on. However, sometimes capacity is available, but it's not actually used. If the capacity isn't there, then it can't be used, but if it's there, then it could be used if it's needed.

Id. at 12:8-14.

In addition to the general benefits of ensuring an adequate amount of capacity to satisfy load demand, a capacity market benefits capacity resources because capacity sales are a source of revenue. In particular, a generator that clears capacity in the BRA run by PJM in a year (for example, 2012) will have a fixed stream of revenue for one-year period three years in the future (for example, from 2015 to 2016). This fixed stream of revenue is significant because it can enable the generator to obtain current financing essential to its ability to deliver capacity in the future.

(ii) Capacity Obligations Within the PJM Region

Pursuant to the RAA with PJM, each LSE must satisfy certain "Capacity Obligations."[26] See P.76 (PJM RAA Agt.) at 34. The RAA's stated purpose is "to ensure that adequate Capacity Resources . . . will be planned and made available to provide reliable service to loads within the PJM Region." Id. at 23. To effect this purpose, the RAA sets forth a comprehensive process pursuant to which PJM determines the total amount of generating capacity needed within the PJM region and, based on that calculation, creates capacity obligations for each LSE.

[26] The RAA requires any LSE within the PJM region to become and remain a party to the agreement.

See id. at 90-115. To determine the total amount of capacity needed in a future delivery year, PJM calculates the "amount of capacity needed to meet the forecasted load" and adds to it "reserves adequate to provide for the unavailability of Generation Capacity Resources, load forecasting uncertainty, and planned and maintenance outages." See id. at 34. The reserve margin is computed as a percentage and applied to the load forecasts to determine the total amount of capacity required to serve reliably the forecasted load in the PJM region. Tr. Mar. 6 (PM) at 33:7-34:17 (Wodyka).

Once PJM determines the total amount of capacity needed, it divides responsibility for procuring that amount among the LSEs within the PJM region. Id. at 25:24-32:9. Capacity obligations can be satisfied by generation or demand resources, as discussed infra. An LSE can satisfy its capacity obligations by a combination of the following actions:

1. Designating its own generation or demand resources;

2. Entering into a bilateral contract with a capacity resource with the parties to the agreement determining the price for capacity; and/or

3. Being assigned capacity in the BRA, PJM's annual capacity auction, which determines the price for capacity through application of the RPM.

P.516 (PJM – At a Glance) at 9-10.

In lieu of the above actions, an LSE may elect the Fixed

Resource Requirement ("FRR") under the PJM Tariff. Pursuant to the FRR, the LSE, in essence, removes its load or energy demand from PJM. To use the FRR option, the LSE must demonstrate that it can satisfy its share of the total capacity obligation through individual bilateral agreements with capacity resources or through the generation of electricity from its own facilities. Tr. Mar. 4 (AM) at 82:2-20, 124:22-125:15 (Alessandrini); Tr. Mar. 6 (PM) at 16:19-24 (Wodyka).

(iii) PJM’s FERC-approved RPM

In 2006, FERC adopted and approved PJM's RPM for operating a wholesale capacity market and implementing a competitive capacity auction process. The RPM sets forth the terms and conditions governing the sale and delivery of capacity through the annual BRA including the manner by which capacity is offered into the auction, how the clearing price of capacity is determined, how capacity resources are paid for cleared capacity, and the penalties for failure to deliver capacity that clears the auction. Tr. Mar. 4 (AM) at 32:12-13, 37:23-38:2 (Alessandrini); Tr. Mar. 4 (PM) at 8:16-17 (Carretta); Tr. Mar. 4 (PM) at 104:25-106:16 (Cudwadie). Ultimately, the RPM encompasses the method by which PJM sets the price of capacity that is offered into and clears the BRA.[27] In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while also taking into account locational constraints.

PJM is the buyer in the BRA, and the capacity resource is the seller. To sell successfully capacity to PJM in the BRA, a capacity resource must bid or offer an amount of capacity at a price, and the bid must be partially or fully selected in or clear the BRA. When a capacity bid clears the BRA, the seller becomes obligated to sell the cleared amount of capacity to PJM at the market clearing price. The market clearing price is determined in reference to all of the capacity bids (and the corresponding bid prices) submitted in the BRA. See Tr. Mar. 8 (AM) at 16:22-17:5 (Willig). As discussed in more detail infra, the market clearing price is the bid price at which demand, as determined by PJM, is fully supplied. All resources that offer capacity in the BRA at or below the market clearing price generally will clear the BRA and, as a result, receive the market clearing price for the offered capacity. See id. at 16:9-17:5.

[27] As discussed supra, a capacity resource may sell its capacity outside of the BRA, meaning at a price that is not set pursuant to the RPM. Additionally, even if a generation resource does not clear capacity in the BRA, that resource may still sell its electric energy in the PJM Energy Market or in some other FERC-approved manner. See Tr. Mar. 8 (AM) at 13:21-14:2 (Willig).

(1) Bidding in the BRA

To bid into the BRA, a capacity resource must submit an offer consisting of: (1) an amount of capacity the bidder is willing to sell for one year to be delivered beginning three years after the BRA and (2) a bid price for the amount of capacity offered. Id. at 29:9-11. Capacity is measured and offered in megawatt-days ("MW-day"), and the bid price is a dollar amount per MW-day ("$/MW-day"). See id. at 29:9-12. For instance, a power plant that bids 100 MW-days of capacity at $25 into the 2012 BRA, is offering its availability to deliver up to 100 MW of electric energy each day for one year beginning in 2015 (three years after the auction), at a minimum price of $25/MW-day. See generally Tr. Mar. 7 (AM) at 138:19-139:9 (Knight). Hence, if the power plant's bid clears the BRA in its entirety, the power plant will receive that year's clearing price – which may be more than $25/MW-day - for 100 MW-days of capacity during the delivery year beginning in 2015.

A capacity resource generally may select whatever price it wishes in $/MW-day when bidding capacity into the BRA, subject only to the Minimum Offer Price Rule ("MOPR") and a bid ceiling or cap. For example, if a generator is considering an uprate to an existing generation resource that would increase the amount of energy it can output into PJM's interconnected grid, thus increasing its capacity, the generator may price its bid into the BRA at an amount sufficient to recover the uprate costs not gained back through anticipated energy sale revenue. See id. at 129:21-131:5. If the generator clears the BRA at that price, it will go forward with the uprate, but if it does not clear, it will not. See id. at 129:9-130:7; see also Tr. Mar. 8 (AM) at 15:15-17:5 (Willig) (describing a "well-functioning" capacity market as discouraging uneconomic development). However, bidding or bid prices are not necessarily connected directly to an immediate development decision. They may instead be chosen by virtue of the view that getting anything for capacity is better than nothing. That is, an existing capacity resource not subject to the MOPR can bid into the BRA at $0/MW-day. This is referred to as "price taking." See Tr. Mar. 7 (PM) at 68:3-19 (Knight). PJM has reported that in some BRAs, 80% of the participants bid zero. Id. at 68:19. A bid of $0/MW-day ensures that the offered capacity will clear the BRA and will yield a payment more than zero, unless every bidder bids zero. A price taker will accept whatever the market clearing price happens to be in that BRA.[28] See Mar. 7 (AM) at 140:23-41:23 (Knight).

[28] Professor Willig explained that a capacity bid of zero by an existing generation facility may well reflect its costs on the capacity side for keeping the generation facility going during the future delivery year because once the plant is built and does not need new investment "the forward-looking incremental cost of the capital is not high, it could be zero." Tr. Mar. 8 (AM) at 21:9-18 (Willig).

New capacity resources bidding into the BRA are subject to the MOPR, found in the PJM Tariff. The MOPR has been in place since establishment of the RPM in 2006, but its form has varied. See id. at 91:20-22. In essence, the MOPR subjects new generation resources to a minimum bid amount "to ensure that . . . new plant generating resources . . . bid[] their competitive cost-based fixed nominal net cost of new entry if it was to rely purely on PJM market revenues alone," and thereby precludes new generators from acting as price takers. Id. at 92:1-4.

(2) Determining the Market Clearing Price and Clearing Capacity in the BRA

After all capacity offers are submitted into the BRA, PJM must determine: (1) which offers will successfully sell into, or clear, the BRA and (2)the single price that PJM will pay for the cleared capacity (the "market clearing price"). Broadly speaking, PJM makes these determinations by taking the capacity bids, in ascending price order, until a pre-determined capacity demand amount is fulfilled. The price of the bid that fulfills the demand amount sets the market clearing price for everyone. Every bid at, or below, the market clearing price clears the BRA, and every bid above the market clearing price does not.[29]

[29] If there happens to be too much capacity bid at the market

Explanation of the RPM framework and establishment of a market clearing price in any given BRA can be illustrated by the simplified hypothetical provided by Plaintiffs' witnesses:

1. In a BRA, PJM receives a number of capacity bids at a variety of prices and amounts. The bids are submitted in a sealed fashion so that initially, only PJM knows what each capacity resource bid into the BRA.

2. Every capacity bid submitted is stacked in ascending order of price, lowest priced bid at the bottom and highest priced bid at the top. Once the bids are stacked in price order, one can tell the total MW-Days available at each bid price by adding up the MW-day amount of each bid preceding any particular price:

Generator	MW-Day Bid	Price Bid	Total MW-Days Available at Each Price
L	500	$0	500
G	700	$0	1,200
J	800	$0	2,000
F	500	$10	2,500
M	500	$25	3,000
Etc.			

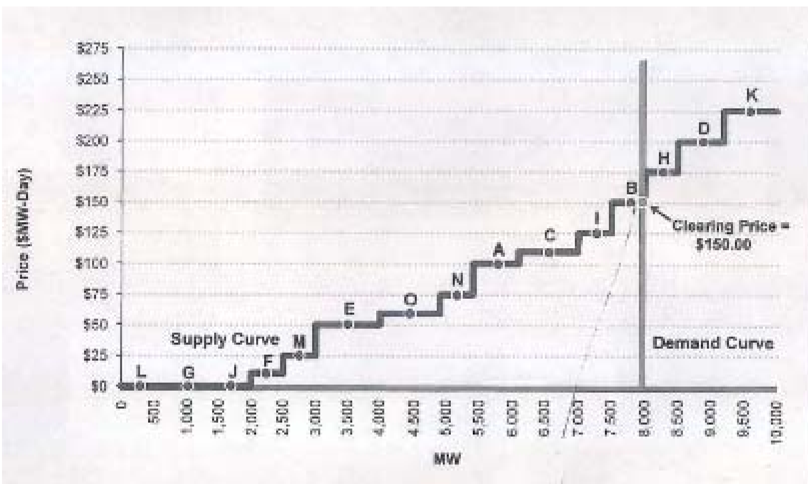
3. A graph can be created in which, in ascending order, the x-axis is MW and the y-axis is Price ($MW-Day). PJM uses the bids stacked in price order to create a "supply curve" and plots that supply curve on the graph. With just the supply curve plotted, one can see that at the price of $25/MW-day on the y-axis, the BRA generated bids totaling 3,000 MW, represented on the x-axis. Stated differently, there are 3,000 MW of capacity bid into the BRA willing to accept $25/MW-day or less for the capacity.

4. Next, PJM configures a Variable Resource

clearing price, a bid at that price may not entirely, or even at all, clear the BRA.

Requirement curve ("VRR Curve" or "demand curve"), representing the total amount of capacity in MW that PJM has determined must be procured through the BRA to adequately supply forecasted load within the PJM region for the one-year period three years following the BRA.

5. The demand curve, generally a vertical line, is plotted on the graph at the appropriate amount of MW on the x-axis. The demand curve then intersects with the supply curve of stacked bids when the aggregate amount of capacity offered is equal to the demand in MW established by PJM. The point at which the supply curve intersects with the demand curve is the market clearing price and the market clearing amount of capacity. This is illustrated by the demonstrative submitted by Plaintiffs:



6. As illustrated above, if the demand is determined to be 8,000 MW, the market clearing price would be $150/MW-day. This means that all capacity offered at or below that price clears the BRA. Every bidder whose capacity cleared the BRA will be paid the clearing price of $150/MW-day. As a result, even the generators that bid $0 for their capacity will receive $150/MW-day.

Tr. Mar. 8 (AM) at 28:24-38:24 (Willig). If a generation resource successfully clears capacity in the BRA, PJM rules require the generator to offer the electric energy generated in the PJM Energy Market.

Since the market clearing price in any BRA is entirely dependent on the bid prices received by PJM from capacity resources (again, which for existing resources can be $0), the price is volatile and difficult – if not impossible - to predict with a reasonable degree of reliability. See Tr. Mar. 8 (AM) at 76:19-22 (Willig); Tr. Mar. 11 (AM) at 32:8-12 (Roach); Tr. Mar. 11 (PM) at 101:20-102:1 (Kahal). The following reflects six years of BRA clearing prices:

Delivery Year	Market Clearing Price		
	PJM (charted as "RTO")	SWMAAC Southwest Mid-Atlantic Area Council	MAAC Mid-Atlantic Area Council
2007/2008	$40.80	$188.54	$40.80
2008/2009	$111.92	$210.11	$111.92
2009/2010	$102.04	$237.33	$191.32
2010/2011	$174.29	$174.29	$174.29
2011/2012	$110.00	$110.00	$110.00
2012/2013	$16.46	$133.37	$133.37

See D.34 (2015/2016 RPM BRA Results).

(3) Locational Deliverability Areas ("LDAs") and Price Separation in the BRA

In theory, the BRA could establish one uniform market clearing price based on one model supply and demand curve for the entire PJM region. However, in practice the process is significantly more complicated. When procuring capacity through the BRA, PJM recognizes that not all locations are equally situated. Transmission constraints exist that make importing energy and capacity into certain areas within the PJM region more difficult than importing into other areas. A "transmission constraint" is a limitation on the ability of the transmission system or infrastructure effectively and reliably to transport electric energy from one point to another point within the PJM region. See Tr. Mar. 8 (AM) at 94:6-95:8 (Willig). PJM employs several indicators and standards to alert whether and where transmission constraints exist and the consequences, affects, and severity of any such constraints.

In the context of the PJM Capacity Market, to take locational transmission constraints into account, PJM models certain areas as Locational Deliverability Areas ("LDAs") for purposes of the BRA.[30] An area or zone is modeled as an LDA if "the amount of transmission import capability into [that] area" from the rest of the RTO (the Capacity Emergency Transport Limit ("CETL")) falls below a target ratio with the level of capacity needed to import power to meet reliability requirements under

[30] There can be transmission constraints between any two points within the PJM region for a variety of reasons not just with respect to energy being dispatched into an LDA.

the Capacity Emergency Transfer Objective ("CETO").[31] P.42 (2011 Boston Pacific Evaluation of Draft RFP) at 16. "The lower the ratio, the 'tighter' supply line into the area. If the CETL/CETO ratio is less than 1.15, then the area must be modeled as a separate zone in RPM." Id. Being modeled as an LDA neither precludes generators outside the LDA from supplying electric energy into the LDA, nor necessarily affects the ability of generators outside the LDA to enter into bilateral agreements for energy and/or capacity with LSEs within an LDA. See Tr. Mar. 4 (PM) at 115:16-117:6 (Cudwadie).

Once an area or zone is modeled as an LDA, it functions as a separate capacity market with a separate supply and demand curve and a separate market clearing price from the balance of the PJM footprint. That is, there are "separate supply stacks and separate reliability needs . . . considered by the PJM" in the BRA process for an LDA. See Tr. Mar. 8 (AM) at 93:15-19 (Willig). Since LDAs function as a separate capacity market for purposes of the BRA, the market clearing price for an LDA may be different from the price for the rest of the RTO. When the market clearing price for an LDA is different from the balance of the PJM footprint the phenomenon is referred to as "price separation." See Tr. Mar. 4 (PM) at 113:23-114:1 (Cudwadie).

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[31] The CETO is an import capability required by an area to comply with a Transmission Risk of Loss of Load Event of 1 in 25 years.

Price separation occurs because each LDA has a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA. See id. at 114:1-115:15, 119:2-122:23. As a result of the import limitation, a lower-priced capacity resource located outside the LDA may be "skipped" or excluded from the stack of bids used by PJM to create the supply curve. This occurs because the LDA has reached its import limit so that even though the outside resource is the next bid in price order PJM will not select it to meet the capacity needs within the LDA. See Tr. Mar. 8 (AM) at 94:2-22 (Willig). Where lower-cost capacity resources outside of the LDA are excluded due to the import limitation, PJM must then select more expensive capacity resources located within the LDA to fulfill the LDA's capacity target level. See Tr. Mar. 4 (PM) at 113:23-115:15, 119:8-122:15 (Cudwadie). When an LDA reaches its import limitation before the LDA's capacity needs are met and PJM is forced to select more expensive capacity bids from within the LDA, the LDA's market clearing price will separate from the rest of PJM because the last capacity bid selected – a more expensive resource within the LDA - sets the LDA price at a level higher than the RTO clearing price. See id.

Within the PJM region, the Mid-Atlantic Area Council ("MAAC") is modeled as an LDA. The Southwest Mid-Atlantic Area

Council ("SWMAAC") is a sub-LDA within MAAC. See Tr. Mar. 4 (PM) at 27:6-10 (Carretta). SWMAAC includes part of Maryland and the District of Columbia; about 98% of SWMAAC is within Maryland. Tr. Mar. 6 (AM) at 37:15-18 (Massey). SWMAAC includes the transmission systems of BGE and Pepco. The portions of Maryland not in SWMAAC are in the Eastern Mid-Atlantic Area Council ("EMAAC"), a sub-LDA that includes parts of Delaware, Pennsylvania, and New Jersey. Tr. Mar. 5, 2013 (AM) at 106:15-18 (Nazarian). In the BRA conducted for the 2015/2016 delivery year, the market clearing price in all of MAAC (including EMAAC and SWMAAC) was $167.46/MW-day, and the market clearing price in the rest of PJM was $136.00/MW-day. D.34 (2015/2016 RPM BRA Results). For the 2010/2011, 2011/2012, 2012/2013, and 2015/2016 delivery years, the market clearing price for SWMAAC did not separate from the rest of MAAC, even in years when MAAC separated from the balance of the PJM footprint. Id.

(iv) Price Signals

FERC has described the PJM Capacity Market as "provid[ing] long-term price signals to attract needed investment in the PJM region through a competitive auction process three years in advance." PJM Interconnection, LLC, 132 FERC ¶ 61,173, 61,870

(2010). PJM identifies the RPM system as a means of providing "incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – not just generating plants, but demand response and energy efficiency programs as well." P.516 (PJM – At a Glance) at 8. Plaintiffs submitted expert testimony to explain in an economic sense how the capacity prices set in the PJM Capacity Market through the RPM send price signals to market participants capable of inducing investment in generation development. Plaintiff's expert, Professor Willig, opined that higher capacity prices in an LDA encourage projects to be developed in that area because the RPM[32] "reflect[s] the locational impact on need and on cost" of electric energy. Tr. Mar. 8 (AM) at 95:9-24, 99:5-20 (Willig). According to Professor Willig, because the RPM is configured to create a positive correlation between transmission constraint and price, higher prices indicate greater difficulties in importing energy into an LDA, which signals to the market a need for capacity development and/or signals to PJM a need for transmission planning. Id. at 98:6-99:20. This is because constraint on the transmission system can be eased by additional

[32] According to Professor Willig, the same principles apply to the LMP in the PJM Energy Market because the LMP increases to the extent there is "congestion" or some other constraint as to the transmission system in dispatching electric energy to a particular location.

capacity resources in the right location and/or new or expanded transmission lines to that location. Id. As Professor Willig concluded, a decrease in constraint, either by additional capacity or by a transmission-related solution, "will tend to bring pricing closer, because when prices are closer, it's because there's less constraints between their areas." Id. at 99:5-9.

The PSC has stated that the RPM "ha[s] failed to attract new generation in [Maryland] to mitigate these longer-term reliability concerns," and that "RPM's signal remains unable to anchor the financing new generation development requires." P.2 (2011 RFP) at 3.

D. Maryland’s Regulation of Electric Energy

Maryland has, as have various other states, abandoned the vertical integration model of electric energy regulation.

1. Pre-Restructuring Vertical Integration

Before the restructuring of 1999, Maryland's electric utilities (such as BGE and Pepco) were vertically integrated and predominately regulated by the Maryland PSC, except insofar as the utilities engaged in wholesale transactions, which were regulated by FERC. Tr. Mar. 5 (AM) at 40:23-41:18 (Nazarian). Even then, however, Maryland's utilities imported approximately

30% of the electric energy resold to end-use customers from generation resources outside the state in wholesale transactions. Id. at 50:6-51:24.

Under the vertically integrated structure, the PSC generally retained authority to "regulate[] the distribution, transmission and generation rates" that Maryland utilities charged to rate payers. P.606 (PSC Order No. 81423) at 33. The rates charged by Maryland utilities to end-use customers were determined by the PSC through cost-of-service principles. That is, the PSC set rates that "w[ould] result in an operating income to the [utility] that yields, after reasonable deduction for . . . expenses and reserves, a reasonable return on the fair value of the [utility]'s property used and useful in providing service to the public." Id. at 33-34; P.391 (2007 PSC Interim Report) at 10. Because the Maryland utilities primarily sold electric energy generated by their own power plants to users in retail transactions, the PSC effectively determined - through its rate making authority - whether new or additional generation resources would be built in Maryland. Generation development by a Maryland utility would be financed through rate increases, which required approval by the PSC. See P.162 (2009 Nazarian Presentation) at slide 10. Additionally, in pre-restructured Maryland, ratepayers had no choice as to their electric utility supplier; they purchased electricity from whichever utility's service territory in which they were located. See Tr. Mar. 5 (AM) at 43:12-23, 44:21-24 (Nazarian).

2. 1999 Maryland Restructures

In 1999, the Maryland General Assembly passed the Electric Customer Choice and Competition Act (the "1999 Act"), which restructured, or deregulated, Maryland's electric energy market. See Md. Code Ann., Pub. Util. § 7-504, et seq. "The premise of the 1999 Act was that electric consumers would benefit more from a competitive market for their electricity rather than being captive to a single utility that had a monopoly on their electricity service." P.606 (PSC Order No. 81423) at 36. The 1999 Act put this premise into effect by removing generating assets from the control and ownership of the Maryland utilities and requiring the utilities to provide Standard Offer Service, discussed in more detail infra, to their customers.

Post-restructuring, the PSC remains an agency empowered by the State of Maryland to assure "safe, adequate, reasonable, and proper [electric] service." Md. Code Ann., Pub. Util. § 5-101(a). In addition to regulating the procurement of electric energy by the Maryland Electric Distribution Companies (the "EDCs" or "Maryland EDCs") for Maryland residents, the PSC administers a streamlined "process by which transmission and generating facilities are sited and . . . approve[d]" for construction in Maryland. P.606 (PSC Order No. 81423) at 42. However, the PSC does not evaluate the need for new generation stations in Maryland. Rather, that need is determined by the marketplace. Tr. Mar. 5 (AM) at 58:18-59:5 (Nazarian) (noting the "residual authority [of the PSC] to order new generation in anticipation of a long-term demand in the state").

a. Separation of Generation Assets

The 1999 Act separated the Maryland "utilities' [Maryland-located] generating assets from their distribution and transmission functions" by transferring ownership of those generation assets to other companies that owned and operated the power plants. P.391 (2007 PSC Interim Report) at 10; see also Md. Code Ann., Pub. Util. § 7-504(3); Tr. Mar. 5 (AM) at 42:13-18 (Nazarian). This separation effectively forced Maryland utilities, now referred to as EDCs, to purchase electric energy at wholesale, thereby engaging in federally regulated energy transactions. Since the EDCs no longer owned generation assets or power plants,[33] "electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be

[33] Post-restructuring, Maryland's EDCs still own their transmission and distribution systems. See Tr. Mar. 5 (AM) at 42:13-43:15 (Nazarian).

purchased by local [EDCs] in the federally regulated wholesale electricity market" for purposes of re-selling that electricity to end-use customers. P.391 (2007 PSC Interim Report) at 10. Consequently, Maryland EDCs now rely on the wholesale energy market regulated by FERC to purchase the electric energy that they ultimately sell to end-use customers. See P.606 (PSC Order No. 81423) at 37. By virtue of having to purchase energy at wholesale, the Maryland EDCs (and correspondingly Maryland ratepayers) are financially affected by wholesale prices set by the PJM Markets.

b. Standard Offer Service

Maryland's restructuring not only required local utilities to divest themselves of ownership of power-generating facilities, but also allowed Maryland electricity consumers to choose their electric energy supplier. Electricity customers in Maryland have a choice to buy electric service from the default local utility or from an alternative supplier. Tr. Mar. 5 (AM) at 45:3-47:19 (Nazarian). The sale of electricity supplied by the default local utility is called Standard Offer Service ("SOS"). The PSC regulates the SOS procurement process, which is conducted by the Maryland EDCs, and the rate the EDCs may charge customers for SOS. See id. at 44:2-45:23. If a Maryland customer chooses an alternative supplier, that transaction is a matter of contract and is not regulated by the PSC. See id. at 46:16-24, 48:10-18. Since Maryland's energy market is deregulated, the EDCs purchase the electric energy for SOS from the wholesale market. This procurement of electric energy takes place through contractual agreements as well as through the use of "PJM spot energy markets."[34] OPC's Post Trial Br. [Document 140] at 15-16. According to the Maryland Office of People's Counsel, only 15% of all wholesale electricity sales in the PJM region occur through "PJM spot energy markets." Id. at 15.

E. The Path to the PSC Order

In mid-2000, the Maryland General Assembly and the PSC began to voice concerns over the operations of Maryland's electricity markets, the post-restructuring consumer electricity rates, and the existence of adequate generation resources to serve the energy needs of Maryland ratepayers. For instance, in "the summer of 2006, the General Assembly convened a special session to pass legislation that would mitigate a proposed 72% rate increase on residential ratepayers [in the] BGE" territory, the largest utility territory in Maryland. P.391 (2007 PSC

[34] "[I]f [the EDCs'] customers use more energy in a particular hour than they have bought ahead of time for that hour, then they buy the residual through the PJM spot energy market." OPC's Post Trial Br. [Document 140] at 15.

Interim Report) at 5.

These concerns, which took the form of several legislative and regulatory actions, eventually culminated in the issuance of the Generation Order at issue.

1. Maryland General Assembly Orders the PSC to Study Re-Regulatory Options for Maryland

In May 2007, the Maryland General Assembly signed into law Senate Bill 400, calling for the PSC to study re-regulatory options and the availability of adequate generation and transmission assets in the state and to also provide the General Assembly with interim and final reports[35] containing the results of the PSC's evaluations. See P.391 (2007 PSC Interim Report) at 1; see also EmPOWER Maryland Energy Efficiency Act of 2008, Md. Code Ann., Pub. Util. § 7-211.

In December 2007, the PSC filed its interim report with the General Assembly that "offer[ed its] recommendations and analysis regarding options for 're-regulating' Maryland's electricity markets and for obtaining new generation and transmission resources" in Maryland. P.391 (2007 PSC Interim Report) at 1. In the interim report, the PSC explained that

[35] The reports provided to the Maryland General Assembly consisted of reports authored by the PSC and by two groups of consultants, the law firm Kaye Scholer LLP and the economic consulting firm Levitan & Associates, Inc.

"Maryland faces a critical shortage of electricity capacity . . . because Maryland sits in a highly congested portion of the regional electric transmission system (which makes it difficult to bring more power in) and because we use more electricity than is generated here." Id. To respond to this problem, the PSC advised that Maryland could "add more capacity, either through new generation or transmission, or . . . reduce the amount of electricity [it] use[s]." Id.

Describing the wholesale and retail markets as "structured ostensibly to create price incentives for new generation or transmission," the PSC noted that the wholesale markets had not responded to Maryland's needs and opined that those markets were unlikely to respond in the immediate future to the state’s "looming capacity shortage." Id. According to the PSC, "capacity shortages and transmission constraints" in Maryland caused consumers to "pay much higher than average prices for wholesale (and thus retail) electricity." Id. The PSC reasoned that this situation provided no incentive for existing generators to build more capacity and increase the supply, since such actions would decrease the price received by the generators for energy and capacity on the wholesale market. See id.

Ultimately, after reviewing reports presented by two groups of consultants, the PSC concluded that "[t]he analyses by [the consultants] combine to create a compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a 're-regulation' option that we believe should be pursued and that we intend to pursue." Id. at 41. The PSC believed this option would maintain the reliability of the transmission grid and obtain the best possible prices for Maryland ratepayers. Tr. Mar. 5 (AM) at 64:5-11 (Nazarian).

2. PSC Initiates the "Gap RFP Proceeding"

In the summer of 2007, PJM began warning the PSC about a potential capacity shortfall in Maryland for the following year. In November 2008, the PSC issued an order in Case No. 9149, referred to as the "Gap RFP Proceeding," to address "a ['potential'] gap between the anticipated need [for electricity] in the summers going forward based on load forecasts and the known resources available to serve that need" in response to PJM's representation of a "potential delay in a transmission line project" known as the TrAIL Line. Tr. Mar. 5 (AM) at 74:10-76:19 (Nazarian). Seeking new demand response resources that would bid as capacity resources into the BRA, the PSC ordered the four Maryland EDCs to issue Requests for Proposals ("Gap RFPs"). P.345 (PSC Order in Case No. 9149) at 7. In exchange for the demand response resources bidding into the BRA, the PSC offered the EDCs contracts for differences that apparently guaranteed the suppliers a fixed revenue stream for the demand response, irrespective of the market clearing price in the BRA. The Gap RFPs yielded 600 MW of demand response.[36]

3. PSC Provides Final Report to General Assembly

On December 10, 2008, the PSC provided its final report to the Maryland General Assembly. See generally P.582 (2008 PSC Final Report). In the report, the PSC stated that in addition to reliability measures already underway, the PSC would "undertake a new investigation in 2009 to determine whether[,] and on what terms[,] to direct or solicit the construction of one or more new power plants in Maryland." Id. at 2. Former PSC Chairman Nazarian testified that although the PSC had intended to open a proceeding for the particular purpose of addressing that issue, it never opened such a case. Trial Tr. Mar. 5, 2013 (AM) at 78:22-81:-23 (Nazarian). Instead, the PSC commenced a proceeding related to inducing new generation in Maryland — Case No. 9214. It is this proceeding that led to the PSC's issuing the Generation Order.

[36] Demand response capacity in the amount of 600 MW means a commitment to decrease the demand for electric energy up to 600 MW if and when called upon by PJM to do so.

4. CPV Requests a Long-Term Contract from the PSC in an Unrelated Matter

In PSC Case No. 9117, a case unrelated to the Generation Order, CPV filed a motion to intervene and "strongly urge[d] the [PSC] to encourage policies that promote and direct long-term (10 to 15 years) PPAs [Purchase Power Agreements] from in-state generation to serve Maryland's load." P.31 (CPV Motion to Intervene) at 3. In July 2009, CPV made a specific request that the PSC "order one or more [Maryland EDCs] to enter into 20-year long-term contract(s)" providing a fixed revenue stream to CPV for purposes of financing CPV's development of new generation in Charles County, Maryland.[37] P.14 (2009 CPV Motion) at 1; Tr. Mar. 5, 2013 (AM) at 86:21-87:16 (Nazarian).

In its filings in Case No. 9117, CPV asserted its belief in the necessity of having state-sponsored long-term financing to move forward with its Charles County project because "traditional commercial banks no longer are willing to finance the types of risks they might once have undertaken; nor will they be willing to rely on third party consultant reports estimating a project's potential revenue stream in a particular wholesale market." P.14 (2009 CPV Motion) at 22. CPV explained that "RPM's conditional three-year commitment period is simply

[37] Former PSC Chairman Nazarian reflected that in 2008-2009, CPV advocated heavily and strongly for the PSC to order the long-term contract, but the PSC never gave CPV the contract. Tr. Mar. 5 (AM) at 85:13-86:3 (Nazarian).

insufficient to allow new baseload [sic] generation to be financed [because] the RPM is too short-term, too volatile, and too fraught with continued regulatory uncertainty to provide lenders with anything close to the certainty of a fixed revenue stream required for financing." Id. at 24. CPV went on to note that "given RPM's purpose to provide an accurate price signal to new generation, the FERC rejected" proposed changes to RPM that would extend the commitment period. See id. at 24-25.

Instead of granting CPV's request for a state-sponsored financing contract specifically for CPV's Charles County project, in September 2009 the PSC opened a separate proceeding, Case No. 9214, which implemented the competitive bid process that eventually resulted in the Generation Order, and eventually awarded the contract for differences to CPV for its Charles County project. Tr. Mar. 5 (AM) at 85:13-86:20 (Nazarian).

5. PSC Opens Case No. 9214 for "New Maryland-Located Electric Generating Facilities"

On September 29, 2009, the PSC initiated Case No. 9214 and directed "[t]hat any proposals for new Maryland-located electric generating facilities . . . be filed by December 11, 2009." P.35 (PSC Order No.82936) at 3-4.

a. The Draft RFP and Engagement of Boston Pacific

On December 29, 2010, the PSC issued for comment a draft Request for Proposals for Generation Capacity Resources Under Long-Term Contract (the "Draft RFP"). See generally P.13 (2010 Draft RFP). The Draft RFP solicited up to 1,800 MW of capacity, energy, and ancillary services from generation resources. The PSC invited all interested parties to review the Draft RFP and provide comments.

The Draft RFP differed in several respects from the RFP ultimately issued by the PSC. For example, the Draft RFP solicited proposals from all types of generation resources and permitted bids from existing facilities that would uprate, or expand, their existing generation capacity. With respect to locational requirements, the Draft RFP required "[t]he proposed Generation Capacity Resource [to] be interconnected to the System such that the [resource's] output may be infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion." Id. at 15. Using this locational definition, it was possible for a generation facility in Pennsylvania to submit a proposal to the PSC in response to the Draft RFP. See Tr. Mar. 5 (AM) at 99:6-100:6 (Nazarian).

In the summer of 2011, the PSC engaged Boston Pacific

Company, Inc. ("Boston Pacific") to perform consultation work in connection with the Draft RFP. Tr. Mar. 5 (AM) at 100:20-102:1 (Nazarian). On August 12, 2011,[38] Boston Pacific provided the PSC with its (1) "review [of] the factual basis for the reliability concern that motivated the [PSC] to issue the Draft RFP," (2) view of possible paths forward for the PSC, and (3) "suggested edits to the Draft RFP." P.42 (Boston Pacific Evaluation of Draft RFP) at 1.

Regarding the reliability concern in Maryland, Boston Pacific observed that conditions had improved since 2008 when the PSC provided its final report to the Maryland General Assembly illustrating scenarios in which there could be a generation shortfall in Maryland. For example, many of the scenarios posited to the General Assembly in 2008 related to a failure on the part of PJM to secure the construction of the Trans-Allegheny Interstate Line ("TrAIL Line"). Id. at 1-2, 15. But, as Boston Pacific pointed out, PJM had come through and the TrAIL Line had gone into service in May 2011 "providing more transmission support for the [Maryland] region." Id.

Boston Pacific also explained that load growth in Maryland had declined, reducing pressure on the transmission system, and that demand response resources had materially increased, due in

[38] Boston Pacific filed its report in Case No. 9214 on January 23, 2012.

part to the Gap RFPs. Id. However, Boston Pacific identified "several key risk factors that could rapidly change Maryland's future [energy] supply needs." Id. at 2. Specifically, Boston Pacific noted:

> (1) "[L]oad growth could be higher than expected;"
>
> (2) "[R]etirements of existing generation facilities could be greater than expected [where] coal-fired generation makes up about 60% of all electricity produced in [Maryland, and] sources anticipate new EPA regulations will force shutdowns and increase costs as coal-fired generators modify their plants," which would leave Maryland more reliant on importing power; and
>
> (3) Certain PJM transmission projects, such as the MAPP line, may not be completed on time, which is of concern since "Maryland imports roughly 30% of its power" and relies on transmission to bring power into the state.

Id. at 2, 17-27.

Boston Pacific identified two alternatives for the PSC to respond to reliability concerns: (1) take more time to evaluate the risks identified by Boston Pacific or (2) issue a request for proposals "targeted to address and mitigate the key risks" identified by the company. Id. at 3, 27. Boston Pacific advised the second option if the PSC "believes . . . that the current risks to reliability are great enough to justify immediate action, and that RPM will not bring new generation to the State." Id. at 3. If the PSC decided on the second option to issue a request for proposals, Boston Pacific suggested several modifications to the Draft RFP "[t]o effectively mitigate the [reliability] risks" faced by Maryland. See id. at 3-5. Boston Pacific advised:

> [T]he RFP should specifically solicit only new, in-State, natural gas-fired combined-cycle generation located in SWMAAC or Eastern MAAC (EMAAC) . . . because [those] zones, due to their constrained nature, have seen the highest RPM prices, the least development of generation and are most at risk for reliability problems caused by load swings, generator retirements, and transmission issues.

Id. at 4; see id. at 30-31.

b. The PSC Issues the RFP Seeking Proposals to Construct and Operate a New Generation Resource in SWMAAC in Exchange for the Contract for Differences

On December 8, 2011, the PSC issued the Amended Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies (the "RFP"), which ordered each Maryland EDC to issue an attached request for proposals.[39] See generally P.2 (2011 RFP).

[39] The PSC issued the first RFP on September 29, 2011, but after holding a pre-bid conference concerning the RFP, it issued the amended RFP on December 8, 2011. Among other things, the amended RFP extended the proposal due date to January 20, 2012. See P.2 (2011 RFP) at 12.

According to the PSC, the RFP's purpose was "to ensure the continued, long-term reliability of the electricity supply to Maryland customers by mitigating key risks faced by the State." Id. at 1. Such risks, as listed in the RFP, included the risks identified by Boston Pacific, as well as "the risk that RPM will not attract enough new capacity to address these risks effectively, whatever the level of need turns out to be." See id. at 2-3. According to the PSC, "RPM has failed to attract new generation in the State to mitigate these longer-term reliability concerns, and RPM's signal remains unable to anchor the financing new generation development requires." Id. at 3. Consequently, the PSC concluded that, "[a]lthough [it] appreciates PJM's role in planning regional transmission solutions, . . . [b]ecause market forces have not produced new generation in our region," the PSC may need to order the construction of new generation to "satisfy the long-term anticipated demand in Maryland" for electric supply. Id. at 3-4.

The PSC set a deadline of January 20, 2012 for proposals from interested parties for the construction and operation of new generation resource(s) to be submitted pursuant to the requirements detailed in the RFP. In exchange for building and operating the generation resource, the PSC offered the selected supplier a long-term contract for differences with three

Maryland EDCs, which would provide the supplier with a guaranteed revenue stream based upon the supplier's wholesale energy and capacity sales into the PJM Markets. The PSC stated that it would select "the bid(s) that produces the lowest-cost solution for ratepayers when accounting for risk." Id. at 16. The PSC explicitly reserved the right to reject all proposals submitted in response to the RFP.

(i) Requested Generation Resource(s) Requirements

In the RFP, the PSC sought proposals to build and operate a particular type of generation resource in a particular location. Specifically, the PSC only solicited proposals for:

- "[N]ew, natural gas-fired" generation capacity resources;
- Physically located inside the SWMAAC zone of the PJM region;
- Capable of producing energy and capacity products "not to exceed, a total installed capacity of 1,500 MW;"
- "[F]or an initial term of up to twenty years beginning no earlier than June 1, 2015 and no later than June 1, 2017."

Id. at 4-5. Hence, an existing generation resource or a resource physically located outside of SWMAAC was ineligible to submit a proposal to the PSC and to compete for the long-term financial benefits to be awarded to any selected submission.

Pursuant to the structure employed by the RFP,[40] the selected supplier would construct, operate, and own the new generation resource. As to the physical delivery of energy and capacity, the supplier would be obligated to offer the generator's output to PJM in the PJM Markets. See id. at 5. The PSC described the selected supplier's relationship with the Maryland EDCs as a "financial arrangement . . . in which the physical delivery to the EDC of Capacity, Energy and Ancillary Services is not required. . . . Hence, the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy." Id.

(ii) The Contract for Differences

As outlined in the RFP, the compensation structure for any supplier chosen by the PSC to construct and operate a new generation resource in SWMAAC would be governed by a long-term contract for differences ("CfD"). The RFP provided that, after selecting a supplier, the PSC would direct or order one or more

[40] The PSC attached to the RFP a draft contract for differences "to be executed as a result of th[e] RFP." Id. at 6. The PSC explained that the contract for differences "is meant to memorialize the terms and conditions described in this RFP; to the extent there is any conflict, this RFP controls and the final Agreement will be revised to comply with it. The Agreement contains the parties' rights and obligations for providing and receiving Capacity and Energy." Id.

of the Maryland EDCs to enter into the CfD with the supplier. The CfD contained compensation provisions that enabled the selected supplier to receive its proposed "contract price" for each unit of energy and capacity sold to PJM in the PJM Markets up to a ceiling amount. See generally id.; id., Attachment 1 (CfD Settlement Example); id., Attachment 8 (Sample CfD).

The terms of the RFP required each submitted proposal to contain "the total pricing provisions for the Capacity and Energy produced by the Generation Capacity Resource over the contract term." See P.2 (2011 RFP) at 10-11. The RFP and its attachments contained detailed explanations of the parameters for submission of the contract price.

At trial, CPV explained its "method" for reaching the proposed contract price. CPV assessed the costs of all of its obligations surrounding its proposed project, including: construction of its facility; fixed operating costs going forward, such as labor, property taxes, and maintenance; raising capital to finance the construction; and a reasonable rate of return to CPV. CPV then applied those assessments to a financial model to determine the annual revenue requirements necessary to construct and operate its proposed generation resource. Tr. Mar. 7 (AM) at 122:15-123:19 (Knight). That annual revenue requirement served as the basis for CPV's requested contract price presented in $/MW-day of unforced capacity and $/MWh.

As discussed in detail infra, under the CfD the actual revenue received by the supplier for its sale of energy and capacity in the PJM Markets is compared to what the supplier would have received for those sales had the contract prices been controlling, and any difference is settled between the supplier and the EDC(s). If the contract prices are higher than the market prices, the EDC(s) pays the difference to the supplier. If the market prices are higher than the contract prices, the supplier pays the difference to the EDC(s). In the event the EDC(s) have to make payments to the supplier, the EDCs would able to recoup their losses through increases in the rates paid by Maryland SOS customers. Correspondingly, the EDC(s) would be required to pass on any gains to the SOS ratepayers.

c. The Generation Order and Selection of CPV's Charles County Proposal

In response to the RFP, the PSC received seven bids, including a proposal from CPV for the construction and operation of a power plant in Charles County, Maryland. On April 12, 2012, after evaluation of the bids, the PSC issued the Generation Order directing BGE, Pepco and Delmarva (the "Maryland EDCs") "to enter into a Contract for Differences with CPV . . . under which CPV will construct a 661 megawatt (MW) natural gas-fired combined-cycle generation plant in Waldorf in Charles County, Maryland, with a commercial operation date of June 1, 2015. P.44 (Generation Order) at 7.

The PSC determined that CPV's bid provided "the best price for [Maryland] SOS ratepayers, with the average impact to residential SOS ratepayers projected to be a credit of $0.49/month over the entire life of the contract." Id. at 26. The PSC also ordered that the Maryland EDCs required to enter into the CfD with CPV should recover their costs from all Maryland SOS ratepayers, not just those ratepayers in the SWMAAC zone. Id. at 26-27.

In the Generation Order, the PSC provided a summary of the comments it received from various interested parties with respect to moving forward with the RFP. Specifically, the Maryland EDCs opposed proceeding with the RFP on the grounds "that customers would be 'burdened' with additional costs for unneeded and uneconomic generation." See id. at 10-12. With respect to the Plaintiffs, PPL opposed the RFP on the grounds that "it is not necessary because the competitive market is working to create reserve margins above 20% through 2015, and trends indicate demand is declining." Id. at 13-14. Similarly, PSEG "assert[ed] that proceeding with the RFP will interfere with the proper functioning of the wholesale competitive market." Id. at 14. The PSC rejected these concerns along with the contention that demand needs could be satisfied by the RPM and the BRA, stating:

> [O]f critical importance, we cannot rely on PJM's Reliability Pricing Model to deliver new generation to Maryland. . . . Since its inception in 2007, RPM has brought no new generation to Maryland, in spite of the fact that clearing prices for capacity in SWMAAC have averaged almost double those of the non-constrained portions of PJM. . . . Despite these exorbitant capacity charges, which have increased energy costs to Maryland ratepayers by hundreds of millions of dollars, no new base load generation was bid into the BRA during the 2012-2014 delivery period. Zero. The simple fact is that the one year signal, three years into the future has not provided sufficient certainty for prospective generation suppliers to secure financing in the current economic climate. And we do not find it reasonable to require us . . . . to entrust the reliability of our State's electricity supply entirely to the operation of a capacity market that, by design, seeks to incent long-term assets solely through short-term price signals.

Id. at 22-23.

F. Commercial Power Ventures Maryland

Commercial Power Ventures Maryland ("CPV") and its affiliates develop natural gas-fired and renewable energy generation facilities and manage generation assets on behalf of other owners, usually financial institutions that have taken control of the asset as collateral. Tr. Mar. 7 (AM) at 87:7-25.

(Knight). CPV is located in Charles County, Maryland, which is part of the SWMAAC LDA.

In 2006, CPV began planning the project to build its Charles County Facility (the "Facility"). Tr. Mar. 7 (PM) at 87:3-10 (Egan). As discussed supra, CPV was of the opinion that it needed a long-term price contract, or its equivalent, to finance the construction and development of the Facility. Id. at 89:6-18. In about 2008, after exploring options in the open market to no avail, CPV began pursuing the procurement of a long-term contract from the State of Maryland, and in 2009 it formally requested such a contract from the PSC. Id. at 88:9-15. As discussed herein, on April 12, 2012, the PSC issued the Generation Order selecting CPV's generation proposal and awarding CPV the CfD. As of the time of bench trial, CPV has stated that it would not move forward with construction of the Facility without the CfD. Id. at 89:15-18, 93:21-94:1.

In the spring of 2012, CPV bid 661 MW-days of capacity from its yet-to-be-built Facility into the BRA. Tr. Mar. 7 (AM) at 104:19-107:22 (Knight). Because it involved a new generation resource, CPV's bid was subject to the MOPR, which FERC had recently modified in 2011. The MOPR, as it existed in 2012, placed a floor on CPV's bid into the BRA that precluded CPV from bidding zero and acting as a price taker. Pursuant to the MOPR, CPV could not bid less than 90% of Net CONE (Cost of New Entry)[41] or its unit specific cost once it received a unit-specific MOPR exception from PJM. As described by FERC, the MOPR:

> is the mechanism that seeks to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Pricing Model (RPM) on a competitive basis. The MOPR imposes a minimum offer screen to determine whether an offer from a new resource is competitive. We continue to conclude that the MOPR serves a critical function to ensure that wholesale prices are just and reasonable and should elicit new entry when new capacity is needed. The long-term viability of the PJM market demands an assurance of competitive offers from new entrants.

PJM Interconnection, L.L.C., 137 FERC ¶ 61,145, at *4 (2011).

On March 7, 2012, CPV filed a unit-specific MOPR exception proposing a bid floor of $13.95/MW-day. See generally D.173 (CPV MOPR Exception Request). Pursuant to PJM's tariff, PJM must review a submitted unit-specific exception "to determine if it's consistent with competitive cost-based fixed nominal levelized [CONE]." Tr. Mar. 7 (AM) at 96:12-97:23 (Knight). PJM's independent market monitor made the initial determination that CPV's unit-specific costs precluded it from bidding below

[41] CONE is a PJM-determined analysis as to the generic cost of a new power plant to enter the market. The Net CONE is the amount of annual revenue requirements from the capacity market that a new generic generator would need, assuming the plant will earn money from energy and ancillary service markets. See Tr. Mar. 7 (AM) at 92:9-93:23 (Knight).

$136.87/MW-day. See id. at 98:15-103:23. On April 10, 2012, CPV requested a separate determination from PJM. One month later, on April 20, 2012, PJM approved a bid floor of $96.13/MW-day for CPV because the offer was "'consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely on solely on revenues from PJM-administered markets' as required by [the] PJM Tariff." D.265 (PJM Decision).

In accordance with PJM's unit-specific determination, CPV submitted a bid into the 2012 BRA of $96.13/MW-day for the amount of 661 MW for the delivery year 2015/2016. In SWMAAC and MAAC, the market clearing price for the 2012 BRA was $167.46/MW-day. Hence, CPV cleared the BRA. After the 2012 BRA results were released, PJM performed a sensitivity analysis. See Tr. Mar. 4 (PM) at 22:23-24, 24:23-24 (Carretta). In the sensitivity analysis, PJM calculated that if the offered supply of capacity had been decreased in SWMAAC by 750 MW from the bottom of the supply stack or curve, the resulting clearing price for capacity in SWMAAC would have been $195.00/MW-day instead of $167.46/MW-day. See id. at 24:23-25:6; Tr. Mar. 5 (PM) at 135:13-140:6 (Cudwadie).

III. DISCUSSION

A. Supremacy Clause (Count I)

1. Legal Principles

The Supremacy Clause of the United States Constitution renders federal law "the supreme Law of the Land." U.S. Const. art. VI, cl. 2. "The Supremacy Clause is grounded in the allocation of power between federal and state governments . . . ." Md. Pest Control Ass'n v. Montgomery Cnty., Md., 884 F.2d 160, 162 (4th Cir. 1989) (per curiam). Rooted in the Supremacy Clause and its recognition of a hierarchy of federal and state power is the doctrine of preemption. See Gade v. Nat'l Solid Wastes Mgmt. Ass'n, 505 U.S. 88, 108 (1992). Pursuant to the doctrine of preemption, "[i]t is a familiar and well-established principle that the Supremacy Clause invalidates state laws that 'interfere with, or are contrary to,' federal law." Hillsborough Cnty., Fla. v. Automated Med. Labs., Inc., 471 U.S. 707, 712-13 (1985) (internal citation omitted) (quoting Gibbons v. Ogden, 22 U.S. 1, 211 (1824)). Accordingly, the doctrine of preemption is a limitation on state power stemming from the recognition in the U.S. Constitution of a dual system of government where the national government reigns supreme. See Anderson v. Sara Lee Corp., 508 F.3d 181, 191 (4th Cir. 2007) (explaining that "'federal statutes and regulations properly enacted and promulgated can nullify conflicting state or local actions'") (citation omitted).

Preemption of state action through federal law can occur as the result of: (1) "the Constitution itself," (2) "a valid act of Congress," and/or (3) "regulations duly promulgated by a federal agency." City of Charleston, S.C. v. A Fisherman's Best, Inc., 310 F.3d 155, 168-69 (4th Cir. 2002). "Yet '[c]onsideration under the Supremacy Clause starts with the basic assumption that Congress did not intend to displace state law.'" S. Blasting Servs., Inc. v. Wilkes Cnty., N.C., 288 F.3d 584, 589-90 (4th Cir. 2002) (quoting Maryland v. Louisiana, 451 U.S. 725, 746 (1981)). This presumption (of a lack of congressional intent to displace state law) is strongest when "Congress has 'legislate[d] . . . in a field which the States have traditionally occupied.'" Medtronic, Inc. v. Lohr, 518 U.S. 470, 485 (1996) (alteration in original) (citation omitted). "[A]n 'assumption' of nonpre-emption is not triggered when [a] State regulates in an area where there has been a history of significant federal presence." United States v. Locke, 529 U.S. 89, 108 (2000).

However, even in a traditionally state-occupied realm, the Supremacy Clause empowers Congress to preempt or supersede state or local law, either expressly through explicit statutory language or impliedly through field or conflict preemption. See Hillsborough Cnty., 471 U.S. at 713; Shaw v. Delta Air Lines, Inc., 463 U.S. 85, 95 (1983) ("'Pre-emption may be either express or implied, and 'is compelled whether Congress' command is explicitly stated in the statute's language or implicitly contained in its structure and purpose. '") (citation omitted); Anderson, 508 F.3d at 191-92. "Accordingly, '[t]he purpose of Congress is the ultimate touchstone' of pre-emption analysis." Cipollone v. Liggett Grp., Inc., 505 U.S. 504, 516 (1992) (alteration in original) (citations omitted).

2. Field Preemption

Plaintiffs contend that the Generation Order impermissibly invades a field occupied exclusively by FERC – the regulation of wholesale energy and capacity sales, including the price at which such sales are made – because the Generation Order sets the wholesale price received by CPV for its capacity and energy sales into the PJM Markets. Defendants assert that the Generation Order falls within the area of electric energy regulation not only traditionally occupied by the states, but also explicitly reserved to the states in the Federal Power Act ("FPA").

As discussed supra, preemption of state law may be express, i.e., explicitly provided for by the federal statue in question, or implied. See Morales v. Trans World Airlines, Inc., 504 U.S.

374, 383 (1992). One type of implied preemption is field preemption. Field preemption occurs "where Congress has legislated comprehensively, thus occupying an entire field of regulation." La. Pub. Serv. Comm'n v. F.C.C., 476 U.S. 355, 368 (1986). Thus, "state law is [field] pre-empted where it regulates conduct in a field that Congress intended the Federal Government to occupy exclusively." English v. Gen. Elec. Co., 496 U.S. 72, 79 (1990).

The congressional intent essential for a field preemption claim can be found in

> [A] "scheme of federal regulation . . . so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it," or where an Act of Congress "touch[es] a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject."

English, 496 U.S. at 79 (alterations in original) (quoting Rice v. Santa Fe Elevator Corp., 331 U.S. 218, 230, 67 (1947)). Generally speaking, "if Congress evidences an intent to occupy a given field, any state law falling within that field is preempted." Silkwood v. Kerr-McGee Corp., 464 U.S. 238, 248 (1984); Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n, 461 U.S. 190, 212 (1983).

Accordingly, assessment of Plaintiffs' field preemption claim requires a determination of whether Congress intended the federal government to regulate exclusively the field of wholesale energy and capacity sales and, if so, whether the Generation Order can be said to have regulated in that field.

Plaintiffs assert that through the FPA, "Congress has made plain its intention" for FERC to occupy exclusively "the field of wholesale sales of electric power, including the prices at which those sales occur." Pls.' Post-Trial Br. [Document 144] at 12-13. Though not necessarily disputing that Congress intended FERC to regulate exclusively some of the field of wholesale energy and capacity sales, Defendants maintain that the Maryland PSC acted within the jurisdiction reserved to the states by Congress under the FPA, and that therefore, the PSC could not have invaded any field occupied by FERC.

By enacting the FPA and other related laws, Congress created a division between federal and state authority within the broad field of electric energy regulation. As discussed supra, this division was somewhat necessitated by the Supreme Court's holding in Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927)[42] that the dormant Commerce Clause prohibited states from regulating the rates for wholesale power sales between utilities in different states. Cf. First Iowa Hydro-Elec. Co-op. v. Fed. Power Comm'n, 328 U.S. 152, 167-

[42] See Quill Corp. v. N.D. By & Through Heitkamp, 504 U.S. 298 (1992) (recognizing abrogation of Attleboro on other grounds).

68, 171 (1946) (interpreting the FPA as mandating divided powers and "a dual system involving the close integration of these powers rather than a dual system of futile duplication of two authorities over the same subject matter").

In the FPA, Congress declared:

> Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States

16 U.S.C. § 824(a).

In line with this dual federal/state regulatory regime, pursuant to the FPA, FERC has jurisdiction over "the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce,"[43] but <u>not</u> over "any other sale of electric energy." <u>Id.</u> § 824(b)(1). Additionally, the FPA grants FERC jurisdiction over all facilities for the transmission and wholesale sales of electric energy in interstate commerce, but not "over facilities used for the generation of electric energy." <u>Id.</u> § 824(b)(1).

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[43] The "'sale of electric energy at wholesale' . . . means a sale of electric energy to any person for resale." 16 U.S.C. § 824(d).

Though it creates a federal role, the FPA explicitly "preserve[d] state jurisdiction" over certain areas of the electric energy regulation field, including, but not limited to, regulation concerning the siting and construction of physical facilities used for the generation of electric energy.[44] See New York v. F.E.R.C., 535 U.S. 1, 22-24 (2002). Where Congress has explicitly recognized a role for the states, there can be no serious assertion that the structure and framework of the FPA expresses a clear and manifest intent on the part of Congress to displace completely state authority vis-à-vis physical generation facilities (distinct from those facilities' wholesale energy sales and transmissions) and the construction thereof. Of course, given the dual federal/state regulatory regime, the division of power regulation labor may not always be clear, because, for example, FERC's regulatory actions relating to wholesale energy sales are surely capable of seeping into issues that surround the emergence of generation facilities. See, e.g., Miss. Power & Light Co. v. Miss. ex rel. Moore, 487 U.S. 354, 355-56 (1988) (finding that FERC's order requiring a power company to purchase 33% of the output of a newly constructed power plant at a rate determined by FERC to be just and reasonable preempted the state PSC from "examining the prudence"

[44] However, FERC obviously has jurisdiction over a facility's market actions to the extent the facility engages in wholesale energy and capacity transmission and sales.

of the construction of the power plant in calculating rates chargeable to a retail customer by the power company to recover the cost of its purchases from the new power plant). In any event, Plaintiffs do not contend that an act of the Maryland General Assembly or PSC related to the siting or building of a physical generation facility, the direct financing of the construction of a power plant, or the encouragement of or limitations on certain types of power plants within its borders (such as environmental-related regulation) would be field preempted by the FPA.[45] Rather, Plaintiffs take the more narrow position that the field of wholesale electric energy sales and price setting is exclusive to FERC and that the regulatory means by which the PSC sought to bring about the construction of a new power plant in Maryland invaded this field.

The preservation of state authority in a carved-out area within a broader federal regulatory field does not eliminate the exclusive federal jurisdiction over the balance of the field. See generally Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n, 461 U.S. 190, 212 (1983) (explaining that "the federal government has occupied the entire field of nuclear safety concerns, except the limited powers expressly ceded to the states"). Indeed, structuring a statutory scheme

[45] Of course, Plaintiffs would likely argue that there could be circumstances in which such action would be conflict preempted and/or violate the dormant Commerce Clause.

so as to divide state and federal authority within one regulatory realm could be viewed as indicating that Congress intended the "federal side" of the field to be regulated exclusively by the federal government.

In regard to electric energy regulation, through the FPA Congress vested FERC with authority over wholesale electric energy prices. The FPA provides that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

16 U.S.C. § 824d(a). A "public utility" is defined as "any person who owns or operates facilities subject to the jurisdiction of the Commission." Id. § 824(e). A power plant that engages in wholesale electric energy sales and interstate transmission would fall within the definition of a public utility.

To ensure the just and reasonableness of wholesale electric energy rates, the FPA implements a regulatory framework that vests FERC with authority to determine the lawfulness of wholesale energy rates or prices. See NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n, 558 U.S. 165, 172 (2010). Under the present regulatory scheme, wholesale energy prices are generally established in the first instance by public utilities, either unilaterally through tariffs or through contracts between wholesale sellers and buyers. Id. Such rates or prices must be filed with FERC and are lawful only if "'just and reasonable.'" Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash., 554 U.S. 527, 531 (2008). "Rates may be examined by [FERC], upon complaint or on its own initiative, when a new or altered tariff or contract is filed or after a rate goes into effect." NRG Power Mktg., 558 U.S. at 171 (citing §§ 824d(e), 824e(a)). "Following a hearing, [FERC] may set aside any rate found 'unjust, unreasonable, unduly discriminatory or preferential,' and replace it with a just and reasonable rate." NRG Power Mktg., 558 U.S. at 171 (quoting § 824e(a)).

Wholesale electric energy rates include energy prices as well as capacity prices, which "are a large component of wholesale rates." See Miss. Indus. v. F.E.R.C., 808 F.2d 1525, 1541 (D.C. Cir. 1987), vacated in part on other grounds, 822 F.2d 1104 (D.C. Cir. 1987); see also Entergy La., Inc. v. La. Pub. Serv. Comm'n, 539 U.S. 39, 43, n.1 (2003) ("Where, as here public utilities share capacity, the allocation of costs of maintaining capacity and generating power constitutes 'the sale of electric energy at wholesale in interstate commerce.'" (quoting § 824(b)(1))).

As stated by the Supreme Court:

> FERC has exclusive authority to determine the reasonableness of wholesale rates. It is now settled that "'the right to a reasonable rate is the right to the rate which the Commission files or fixes, and, ... except for review of the Commission's orders, [a] court can assume no right to a different one on the ground that, in its opinion, it is the only or the more reasonable one.'"
>
> . . . .
>
> Congress has drawn a bright line between state and federal authority in the setting of wholesale rates and in the regulation of agreements that affect wholesale rates. States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that agreements affecting wholesale rates are reasonable.

Miss. Power & Light, 487 U.S. at 371, 374 (alteration in original) (quoting Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 960, 957 (1986) (noting that FERC "has exclusive jurisdiction over wholesale power rates")); Ark. La. Gas Co. v. Hall, 453 U.S. 571, 580-82 (1981) (finding that state breach-of-contract claim was preempted by FERC's exclusive jurisdiction on the grounds that the state court's interpretation of terms could interfere with FERC rates); see also Pub. Util. Dist. No. 1 of Snohomish Cnty. v. Dynegy Power Mktg., Inc., 384 F.3d 756, 758

(9th Cir. 2004) (acknowledging FERC's "exclusive jurisdiction over interstate sales of wholesale electricity"); Appalachian Power Co. v. Pub. Serv. Comm'n of W. Va., 812 F.2d 898, 902 (4th Cir. 1987) ("FERC's jurisdiction over interstate wholesale rates is exclusive.").

Accordingly, it appears well accepted that Congress intended to use the FPA to give FERC exclusive jurisdiction over setting wholesale electric energy and capacity rates or prices and thus intended this field to be occupied exclusively by federal regulation. Thus, state action that regulates within this field is void under the doctrine of field preemption.[46]

a. The Generation Order

Plaintiffs contend that the PSC has impermissibly regulated in the field of wholesale electric energy price setting because the Generation Order effectively sets the price received by CPV for its wholesale energy and capacity sales to PJM in the PJM Markets. Defendants contend the Generation Order does not "set

[46] The preemptive effect of the FPA on the Generation Order does not depend on whether FERC intended to preempt the actions of the PSC in this case. See generally N. Natural Gas Co. v. Iowa Utils. Bd., 377 F.3d 817, 824 (8th Cir. 2004) ("The preemptive effect of the [Natural Gas Act] does not depend on whether the FERC intends to preempt state authority."). However, FERC has acted pursuant to its exclusive authority by determining that the rates set by the PJM Markets and ultimately received by generation facilities that participate in such markets are just and reasonable.

wholesale prices" because it is a purely financial arrangement that secured the construction and development of a new generation facility in Maryland.

(i) Purpose of the Generation Order

Defendants take the position that the Court cannot, or at least should not, construe the PSC's regulatory action in connection with the Generation Order as invading the exclusive field of FERC because the Order sought to secure the construction of a generation facility, an act within the jurisdiction reserved to the states under the FPA.

The Court agrees with Defendants' position that the FPA preserved states' jurisdiction over certain direct regulation of physical generation facilities. For instance, it appears that the states hold the authority to do the following: (1) take regulatory action to require existing generation facilities to retire; (2) limit the type or amount of generation facilities constructed in the state; (3) promote certain environmentally desired types of generation facilities; and (4) determine the siting or location of a new generation facility within the state. See 16 U.S.C. § 824(b)(1); Conn. Dep't of Pub. Util. Control v. F.E.R.C., 569 F.3d 477, 481 (D.C. Cir. 2009). The Court can accept Defendants' position that FERC and/or PJM cannot directly order the construction of a new generation facility, let alone require or direct a state to permit such construction to occur within its borders. See Tr. Mar. 5 (PM) at 21:1-14, 82:4-21 (Nazarian); Tr. Mar. 6 (AM) at 44:1-21, 46:12-47:7 (Massey); Tr. Mar. 7 (AM) at 32:10-21 (Wodyka). The Court also can accept the position that the State of Maryland has a legitimate interest and federally permissible role in securing an adequate supply of electric energy for Maryland residents in the present and in the future. See 16 U.S.C. § 824o(i); Md. Code Ann., Pub. Util. § 5-101(a).

Yet after a generator physically comes into existence and operation and participates in the wholesale electric energy market, the prices or rates received by that generator in exchange for wholesale energy and capacity sales are within the sole purview of the federal government. While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders, the scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices under, inter alia, the Supremacy Clause and the field preemption doctrine. Based on this principle, Maryland cannot secure the development of a new power plant by regulating in such a manner as to intrude into the federal field of wholesale electric energy and capacity price-setting. Furthermore, Maryland's stated purpose to use the Generation Order to secure the existence of sufficient and reliable electric energy for Maryland residents does not permit invasion into a federally occupied field. Where a state action falls within a field Congress intended the federal government alone to occupy, the good intentions and importance of the state's objective are immaterial to the field preemption analysis. Field preemption requires the state to "yield to the force of federal law . . ., notwithstanding that [the state's action] is constructed upon values familiar to many and cherished by most, and notwithstanding that it may fit neatly within or alongside the federal scheme." See French v. Pan Am Exp., Inc., 869 F.2d 1, 6 (1st Cir. 1989).

Defendants maintain that the Generation Order cannot be field preempted because states may take a variety of actions to incentivize the development of generation facilities that affect wholesale energy and capacity prices without infringing on FERC's jurisdiction. The Court does not doubt that state action that promotes the development of power plants contemplated to participate in the wholesale energy market would not be field preempted merely because the action – by increasing the supply of available energy and capacity – affects wholesale energy and capacity prices in the PJM Markets. Indeed, Plaintiffs do not contend that the Generation Order is field preempted solely because it will have an effect on wholesale prices. Rather, Plaintiffs assert that the Generation Order is field preempted because it seeks to secure new generation by setting or establishing the prices to be received by CPV for its wholesale energy and capacity sales in the PJM Markets for the next twenty (20) years.

Therefore, the Court rejects Defendants' position that because the Generation Order sought to accomplish an objective within the purview of state jurisdiction contemplated by the FPA, the Order cannot be held to be field preempted. It is the means by which the PSC sought to secure a new generation facility that Plaintiffs challenge as field preempted, not the securing of the facility itself or the purpose for taking action to do so. Consequently, the fact that the Generation Order secured the construction of a generation facility capable of serving the electric energy needs of Maryland is not determinative of the field preemption issue. The Court must assess whether the compensation mechanism, the CfD, impermissibly set wholesale prices for CPV's energy and capacity sales into the PJM Markets.

(ii) The Contract for Differences

The price or rate received by CPV or by any generation resource within the PJM region for energy and capacity sales to PJM in the PJM Markets is regulated exclusively by FERC under the FPA. PJM sets the prices received by generators for sales into the PJM Markets through market-based auction processes that are filed with, and approved by, FERC. The heart of the parties' dispute relates to whether the PSC has effectively "set the wholesale prices" that CPV will receive for its energy and capacity sales into the PJM Markets by issuing the Generation Order, which requires the Maryland EDCs to enter into the CfD with CPV. In essence, the CfD permits CPV ultimately to recover its proposed "contract price" — accepted and approved by the PSC in the Generation Order — for energy and capacity sales into the PJM Markets.

Allegedly impermissible wholesale rate setting by a state usually occurs with respect to the demand side of the energy market. That is, a state takes direct or indirect action that effectively alters the rate paid by an LSE for wholesale energy and capacity purchases by exercising jurisdiction over retail sales to preclude such a regulated utility from passing FERC-mandated wholesale rates through to retail consumers. See, e.g., Miss. Power & Light, 487 U.S. at 371-72 (recognizing the "filed rate doctrine," a subset of field preemption, which ensures that regulated utilities can recover the costs incurred by payment of just and reasonable FERC-determined rates from retail customers). However, the instant case relates to an action that affects the wholesale supply side of the energy market because the CfD deals with a rate for wholesale energy sales received by CPV, a generator. The Court does not perceive, for purposes of field preemption, any meaningful difference between state actions directed to the demand side and those directed to the supply side of the wholesale energy market. The foundation that FERC has exclusive authority to determine the reasonableness of wholesale rates and that, therefore, state regulation of such matters is void under the Supremacy Clause, holds firm whether the rate or price in question is that received by a generation facility for wholesale sales or is that paid by an LSE for wholesale purchases.

Pursuant to the CfD, CPV agreed to, inter alia:

- "[C]onstruct, own, operate, and maintain" a generation facility "physically located entirely within the Southwest MAAC;"

- "[W]arrant[] that the Facility . . . will participate in and offer [its output and products] into all PJM Markets . . . . including but not limited to the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market consistent with PJM Rules;"

- Not enter into any "bilateral contract or other arrangement to sell any of its output, products or services, . . . with another third party, PJM, or any Government Agency during the Term of the Agreement, unless approved by the [PSC];"

- Beginning on the Commercial Operation Date, have the generation facility offer and participate in the PJM Wholesale Energy Market and Capacity Market and submit only cost-based offers; and

- Engage in a monthly compensation scheme with the Maryland EDCs based upon a comparison of the revenue received by CPV for its actual sales of energy and capacity into the PJM Markets and the "contract price" for energy and capacity provided for in the CfD.

P.2 (2011 RFP), Attachment 8 (Sample CfD) at 18, 19, 32, 33.

Under the compensation scheme outlined in the CfD, CPV is guaranteed to receive the "contract price" for each unit of energy and capacity it sells to PJM in the PJM Markets up to a ceiling quantity of 661 MW. The contract price is a dollar figure assigned to a unit of energy and capacity.[47] CPV configured and proposed the contract price to the PSC as part of its proposal, and the PSC adopted and accepted CPV's contract price in the Generation Order.[48] The compensation scheme

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[47] The contract price for energy is different and separate from the contract price for capacity.

[48] The Court finds unpersuasive Defendants' contention that the contract price is a competitive market price because CPV initially proposed that price as part of the RFP. In the RFP, CPV bid the contract price it was willing to receive for its energy and capacity sales into the PJM Markets in exchange for developing and operating a generation facility in SWMAAC and selling the facility's output (up to 661 MW) in the PJM Markets. The contract price became operative only after reviewed, evaluated, and accepted by the PSC in an agency order. Testifying based upon his involvement in the selection process, former PSC Chairman Nazarian testified that the contract price

operates through a monthly netting mechanism that calculates the volume of units sold by CPV into the PJM Markets and then compares the market price actually received by CPV for the units it sold to PJM with the contract price for the same amount of units. See id. at 38, 88-94. If the aggregate market price received by CPV for its actual energy and capacity wholesale sales is less than the contract price, then the Maryland EDCs must pay CPV the difference. If the aggregate market price received by CPV for its energy and capacity wholesale sales is more than the contract price, then CPV must pay the EDCs the difference. Id. at 38. Any loss or gain to the Maryland EDCs is passed onto Maryland SOS ratepayers in the form of a rate increase or rate credit.

The following chart, using completely hypothetical numbers, illustrates the compensation mechanism employed by the CfD:

accepted by the PSC in the Generation Order represented a unilateral decision by the PSC, and that under the RFP guidelines, the PSC had reserved the right to select none of the proposed contract prices. Tr. Mar. 5 (AM) at 122:3-123:6 (Nazarian). Accordingly, although it was proposed by CPV, the contract price in the CfD is a price "set" or "determined" by the PSC.

	Energy	Capacity	Total ($)
Total Units Sold to PJM in PJM Markets in One Month by CPV	2000[49]	3000[50]	
Contract Price per Unit	100[51]	120	
Market Price per Unit	50[52]	75[53]	
CPV Market Revenue (Units Sold * Market Price)	$100,000.00	$225,000.00	$325,000.00
Contract Payment Stream (Units Sold * Contract Price)	$200,000.00	$360,000.00	$560,000.00
Payment from EDC to CPV:	$100,000.00	$135,000.00	$235,000.00
Payment from CPV to EDC:	$0	$0	$0

Pursuant to the terms of the CfD, assuming that CPV clears the BRA, for each unit of capacity and energy CPV actually sells

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[49] This represents the total amount of energy dispatched by CPV into the PJM Energy Market during a one-month period.

[50] Capacity that clears the RPM is sold or offered in MW-days. The total amount of capacity sold during any one month would be the capacity offered (100 MW-days) multiplied by the number of days in the month (30).

[51] The contract price per unit is comprised of the Indexed Variable O&M (VOMe), $/MWh, Heat rate, MMBtu/MWh, and the Gas Index Price, $/MMBtu (the average of the daily Gas Price Index). The contract per unit energy price or the "strike price" is the indexed VOM + [Heat rate * Gas Index Price]. As explained by Plaintiff's witness, the heat rate multiplied by the gas index price converts the gas price from dollars per BTU into dollars per MWh. Then, the variable O&M expenses are added to that number. Tr. Mar. 4 (PM) at 82:7-20 (Cudwadie).

[52] This price would be the average energy price, or the sum of hourly market energy revenue divided by total energy dispatched.

[53] The market price for capacity would be the capacity price set in the RPM auction.

to PJM in the PJM Markets (up to a ceiling amount), CPV will ultimately realize or be compensated according to the "contract price" set by the PSC in the Generation Order and not according to the market-based rates set in the FERC-approved PJM Markets. Thus, the Generation Order fixes the monetary value of the energy and capacity generated by CPV's facility and actually sold by CPV into the PJM Markets. The monetary value of CPV's wholesale energy and capacity sales dictated by the PSC in the Generation Order is determined outside of the auction mechanisms approved by FERC and utilized by PJM.

Accordingly, the Court finds that the Generation Order, through the CfD, establishes the price ultimately received by CPV for its actual physical energy and capacity sales to PJM in the PJM Markets. However, under field preemption principles, the PSC is impotent to take regulatory action to establish the price for wholesale energy and capacity sales. FERC has exclusive domain in that field and has fixed the price for wholesale energy and capacity sales in the PJM Markets as the market-based rate produced by the auction processes approved by FERC and utilized by PJM.

(iii) Alleged Mere Financing Arrangement

Defendants assert that despite the fact that the CfD's compensation mechanism provides CPV with the contract price for its actual capacity and energy sales to PJM in the PJM Markets, the Court cannot consider the Generation Order field preempted because the Order is a mere financing arrangement outside the jurisdiction of FERC. According to Defendants, the contract price represents CPV's "revenue requirements . . . to construct a power plant," and therefore, any payments between the EDCs and CPV are in return for CPV's construction of a generation facility and not for the sale of energy and capacity. Defs.' Post-Trial Br. [Document 146] at 19-20, 22.

The evidence established that CPV formulated the contract price it submitted in response to the RFP based upon, inter alia, the cost of constructing the proposed Charles County Facility. But, the financial considerations taken into account by CPV when computing the contract price go beyond recouping the costs for physically constructing a generation facility. Mr. Knight, a representative of CPV, testified that CPV formulated the contract price submitted to the PSC based upon its calculation of the annual revenue requirement necessary for CPV to construct the facility, operate the facility going forward, and receive a reasonable return on the project. Tr. Mar. 7 (AM) at 122:15-123:19 (Knight). Indeed, evidence was presented that the same types of financial concerns or factors are taken into account by an existing generation resource when formulating the price at which it is willing to bid into the BRA. See id. at 129:5-130:7. As Mr. Knight explained, the CfD exchanged the "unknown or variable energy prices" received in the PJM Markets for the fixed contract price, and, from CPV's perspective, all CPV needed to know was that the contract price plus the minor profit it estimated from ancillary services "covers our total costs on a forward going basis." Id. at 124:16-21. The evidence establishes that the contract price represents a fixed revenue stream for actual energy and capacity sales into the PJM Markets that replaces the non-fixed wholesale market revenue that CPV would otherwise depend upon to finance and operate a power plant, i.e., to pay for the costs of construction, operating, capital, etc.

Based on the foregoing, the Court finds that the market revenue for wholesale energy and capacity sales into the PJM Markets and the contract price under the CfD serve basically the same goal: incoming revenue that enables CPV's facility to exist, operate, and dispatch electric energy into the PJM region. Consequently, the variables used by CPV to configure the contract price submitted to and accepted by the PSC in the Generation Order do not support Defendants' position that the CfD is limited to a financing arrangement outside the reach of FERC and is therefore incapable being field preempted.

The CfD is not a purely financial contract, financial hedging agreement, or swap agreement,[54] as those terms are commonly understood in the energy or financial industry. The Court finds credible and reliable the expert testimony of Mr. Cudwadie. Mr. Cudwadie explained that participants in the financial market enter into contracts that in essence bet on what the market price of energy or capacity (or any other article of commerce) will be at some defined point(s) in the future in reference to some market pricing index. See Tr. Mar. 4 (PM) at 76:11-77:13 (Cudwadie). Using an example provided by Mr. Cudwadie, a hypothetical (and oversimplified) swap agreement for energy prices works as follows:

- A and B enter into a swap agreement for 50 MW of electric energy for 10 hours for tomorrow ("Day X") at a price of $40 using the settlement index of PJM West. The amount of MW that would be subject to the swap would be 500 (10 hours * 50 MW).

- The fixed price under the swap is $40. The floating price is based upon the market or actual energy sales on Day X (i.e., PJM West pricing index that shows prices for actual real time energy sales), and thus will not be known until delivery on Day X. The floating price is used to create a settlement price.

- Under the swap, A is the "seller" and is betting that prices are going to be lower than $40, and B is the "buyer" and is betting prices will be

[54] A swap agreement is a specific type of purely financial contract or financial hedging agreement. See Tr. Mar. 4 (PM) at 63:11-13 (Cudwadie). Industry participants may also label a swap agreement as a contract for differences. See id. at 63:3-10. To avoid confusion with the "CfD", the Court shall simply refer to such financial arrangements as swap agreements.

higher than $40. Stated differently, A is hypothetically selling 500 MW of power at the floating price to B and B is simultaneously hypothetically selling 500 MW of power at the fixed price to A. Therefore, if the fixed price is higher than the floating price, A will hypothetically be entitled to receive a payment upon settlement.

- On Day X, PJM posts the 10 hours of real time prices for energy on its PJM West index, which shows a market price of $38. Thus, the settlement price is $38.

- Because the settlement price is below the fixed price, B owes $1,000 to A ([$40-$38] * 500).[55]

See id. at 63:14-65:25.

Though swap agreements refer to "buying" and "selling," those terms are used in relation to how the agreement settles — who "wins," and how much, based upon the agreed fixed price and the actual floating price. Id. at 65:22-25. Thus, A (seller) and B (buyer) agree to use a fixed price of $40 at the conclusion of the contract period for a hypothetical sale of 500 units. If the actual (floating) price is $38, A (seller) "wins" and is entitled to receive $1,000 from B (buyer). There is no actual delivery or receipt of energy as between A and B. See id. at 66:1-20. Furthermore, there is no contractual requirement between A and B that either party actually sell or deliver energy to a third party in order to receive payment

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[55] The same result would be reached if the amount was computed by calculating the selling price for A ($19,000) and the selling price for B ($20,000). Because B will be paying more to A, A makes $1,000 in the transaction after a setoff.

under the swap. Id. at 66:6-69:16. Because the swap is a purely financial arrangement, the parties to the agreement could be participants in the financial market that have no ownership interest in, or economic relation to, any facility that buys or sells electric energy in the wholesale market. See id. at 66:24-67:1.

Participants in the energy industry may enter into swap agreements as a financial hedge for actual energy transactions conducted independently with third parties in the market. Id. at 67:6-9, 68:24-69:16. Thus, a party intending to purchase energy can guarantee that it will cost $40 per unit by entering into a swap transaction. If the actual market price is $42, the party pays $42 for the energy but receives $2 from the hedge transaction, making its net cost $40 per unit. If the actual market price is $38, the party will pay $38 for the energy but an additional $2 to the other side of the hedge transaction, also making its net cost $40 per unit. Payment under the swap agreement is not conditioned upon actual physical sales or deliveries into the energy market. Id. at 69:22-70:13. As a result, the swap agreement on its own has no contractual effect or relation to the swap parties' behavior in the market upon which the deal is based because the swap agreement is not a real sale of a tangible product.

The Court agrees with Mr. Cudwadie that the CfD is critically distinguishable from a swap or similar agreement and cannot be categorized as a "purely financial arrangement" as that term is commonly understood in the energy industry. Unlike the swap agreement described above, the CfD: (1) obligates CPV to construct and operate the generation Facility; (2) requires CPV to participate and offer that Facility's output into the PJM Markets; (3) dictates the manner in which CPV participates in the PJM Markets, (4) mandates a financial settlement only if CPV clears the BRA in any given year; and (5) determines the amount of settlement based on CPV's physical energy and capacity sales into the PJM Markets. See id. at 94:12-98:14. Indeed, because the CfD requires CPV to bid and clear the BRA at a price different from the amount that CPV will actually receive, the CfD directly affects the market price. Accordingly, the Court finds that the CfD does not constitute a pure financial contract of the type used by participants in the energy market for hedging purposes. Consequently, the Court rejects Defendants' position that the CfD is not field preempted because it amounts to a non-FERC jurisdictional financial swap agreement.[56]

[56] Defendants seek to utilize the contract between PPL and Longview Power LLC (the "PPL Longview Contract") to assert that the CfD is not field preempted. The PPL Longview Contract is not before this Court for review. Thus whether or not one of the Plaintiffs entered into a state-mandated contract that shares similar components with the CfD is not controlling as to whether the CfD is field preempted. In addition, Defendants have not presented any sort of estoppel position.

Defendants' contend that the compensation mechanism implemented by the CfD does not regulate in an exclusively federal field because any payments to CPV are in return for CPV's construction of the Facility and not for energy and capacity sales into the PJM Markets. That is, because the payment mechanism to CPV is for the construction of the Facility and not for CPV's wholesale energy and capacity sales, the payment scheme does not impinge on FERC's exclusive jurisdiction to set wholesale energy and capacity prices. An obvious aspect and objective of the CfD is, of course, the construction of the Facility by CPV. As all parties agree, and as is plain from the terms of the CfD, there could be no payment to CPV under the CfD if the Facility was never built or was never operational. Nevertheless, the Court finds that the payment scheme to CPV under the CfD is in return, at least in part, for CPV's wholesale sales of capacity and energy in the PJM Markets.

First, the compensation scheme orchestrated by the PSC in the CfD renders payment directly contingent upon CPV's clearing capacity in the BRA. If CPV does not clear any capacity in the annual BRA, then it gets <u>nothing</u> under the CfD. Specifically, "[n]o Monthly Payment shall be provided during any period in which [CPV] has not been selected to provide capacity in PJM's BRA." P.2 (2011 RFP), Attachment 8 (Sample CfD) at 37. Even if CPV constructs and operates the Charles County Facility, CPV will receive no payment under the compensation scheme if it does not clear capacity in the BRA. Yet, a power plant that does not clear the BRA may still sell its electric energy to PJM in the PJM Wholesale Energy Market. See Tr. Mar. 8 (AM) at 13:19-14:2 (Willig). The clearing pre-condition in the CfD rewards CPV for clearing the BRA because CPV only obtains the contract price for wholesale energy and capacity sales into the PJM Markets if the CPV bid clears. Thus, the Court finds that the CfD's payment scheme compensates CPV, in part, for making wholesale capacity sales to PJM in the PJM Wholesale Capacity Market.

A second illustration of how the contract price compensates CPV for its wholesale energy and capacity sales into the PJM Markets is provided by the way in which monthly settlements are calculated under the CfD. If CPV clears the BRA, the pricing terms in the CfD are linked directly to the quantity of energy and capacity sold from the CPV Facility into the PJM Markets. Mar. 7 (PM) at 11:11-13:3, 16:20-17:7 (Knight). As discussed supra, CPV is compensated based upon how much capacity and energy it actually sells to PJM in the PJM Markets up to a ceiling figure. As Mr. Cudwadie testified, "to get paid [CPV] ha[s] to clear the auction. That same type of principle applies to the energy market as well. If they're going to get payment under the contract, they must clear megawatts in the energy market." Tr. Mar. 4 (PM) at 98:4-8 (Cudwadie).

The Generation Order, the 2011 Amended RFP, and the CfD contain other representations that rebut the notion that the CfD does not compensate CPV for wholesale energy and capacity sales. For instance, the CfD provides that the Maryland EDCs "shall not pay for Capacity and Energy that PJM deems was not made available up to the performance standards required by PJM Agreements and PJM Tariff." See P.2 (2011 RFP), Attachment 8 (Sample CfD) at 38. The CfD obligates CPV to bid its 661 MW of the Facility only into the PJM Markets. See id. at 32. However, wholesale energy and capacity sales may occur through bilateral contracts or other arrangements outside the PJM Markets. The RFP explains that the structure of the CfD is such that "the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy." Id. at 5. The Court finds that the CfD compensates CPV for more than developing a new power plant. Under the CfD, the PSC has provided payment to CPV for its wholesale energy and capacity sales to PJM in the PJM Markets at a price different from that generated by the FERC-approved market auction processes implemented by PJM.

Defendants assert that the Generation Order is outside the purview of the FERC-regulated field because the CfD is not an agreement for the physical delivery or sale of energy and capacity between CPV and the Maryland EDCs.[57] The Court does not find that the lack of physical delivery of energy between the parties to the CfD (CPV and the Maryland EDCs) insulates the Generation Order from a field preemption attack. If the PSC had ordered CPV to sell, at wholesale, and deliver energy to the EDCs for the contract price, then the unconstitutionality of the Generation Order would certainly be obvious. Here, the CfD provides payment in the form of the contract price to CPV based upon CPV's physical sales and delivery of energy and capacity to PJM in the PJM Markets. That is, if CPV makes no physical delivery of energy and capacity in the PJM Markets, then CPV gets no payment under the CfD. As former PSC Chairman Nazarian testified, CPV's physical delivery of energy and capacity into the PJM Markets "was a central component" of the Generation Order and the regulatory actions leading thereto. See Tr. Mar. 5 (AM) at 17:15-22 (Nazarian). By making CPV's compensation

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[57] The CfD does contain a provision that would enable the EDCs to take title to output generated, delivered, or sold by CPV's facility:

> [The Maryland EDCs] shall not take title to or risk loss to any products or services generated, delivered, or sold by the Facility unless ordered to do so by the MDPSC upon the recommendation of the Buyer or Supplier. Either Party can initiate an amendment to the Agreement to require that the Buyer receive title to the Supplier's output.

P.2 (2011 RFP), Attachment 8 (Sample CfD) at 35.

contingent upon the number of megawatts sold in the PJM Markets up to the contract cap of 661 MW-days and by also including other provisions related to CPV's delivery of energy to PJM, the PSC sought, through the CfD, to have CPV make physical deliveries of energy to PJM and to compensate CPV with the contract price for those deliveries from CPV's facility. Accordingly, the Generation Order involves, and compensates for, CPV's delivery of energy and capacity to PJM in the PJM Markets, which provides further evidence that the CfD is not a purely financial contract generally considered to be outside FERC's jurisdiction. See generally Puget Sound Energy, Inc., 96 FERC ¶ 63,044, 65,381 n.318 (2001) ("Commission precedent on this issue is clear - the Commission has asserted jurisdiction only over those transactions that result in the physical delivery of electricity. The Commission has jurisdiction under Sections 205 and 206 of the Federal Power Act only where three conditions are present: where '[(i)] the electricity futures contract goes to delivery, [(ii)] the electric energy sold under the contract will be resold in interstate commerce, [(iii)] and the seller is a public utility.'") (alteration in original) (quoting N.Y. Mercantile Exch., 74 FERC ¶ 61,311, 61,987 (1996)).

b. CPV's Market-Based Rate Tariff Argument

Defendants contend that Plaintiffs' field preemption claim is moot because a finding of field preemption subjects adjudication of the instant matter to the jurisdiction of FERC.

CPV filed an application with FERC pursuant to Section 205 of the FPA on November 8, 2012 (and amended the application on December 4, 2012) seeking, inter alia, "authorization to make market-based wholesale sales of energy, capacity, and ancillary services pursuant to [an attached] market-based rate tariff." P.611 (CPV FERC Application for Market-Based Rate Authorization) at 1. On February 1, 2013, FERC approved CPV's market-based rate tariff (the "MBR Tariff"). Defendants assert that if "the CfD were a contract within FERC's jurisdiction, that contract is now authorized by FERC and controlled by the MBR Tariff [and] any complaint by Plaintiffs regarding the CfD . . . would have to be directed to FERC, and not this Court."[58] Defs.' Post-Trial Br. [Document 146], at 27.

"[Market-based rate t]ariffs, instead of setting forth rate schedules or rate-fixing contracts, simply state that the seller

[58] Prior to trial, CPV filed the Motion to Dismiss Preemption Claims as Moot [Document 103] asserting that even if Plaintiffs were correct that the CfD is subject to FERC's jurisdiction, Plaintiffs would not be entitled to relief on their preemption claims because FERC granted CPV authority under the FPA to sell wholesale electricity pursuant to the MBR Tariff. The Court denied the motion without prejudice to the right of CPV, or of any other party, to present the mootness contention after trial [Document 110].

will enter into freely negotiated contracts with purchasers." Morgan Stanley, 554 U.S. at 537. Contracts entered into under market-based rate tariffs need not be filed immediately with FERC. Instead, the wholesale seller must file quarterly reports summarizing the contracts into which it has entered. Id. A market-based rate tariff authorizes a seller to enter into bilateral transactions "for resale of electric energy, capacity, or ancillary services at market-based rates." See 18 C.F.R. § 35.36(b); Tr. Mar. 4 (AM) at 40:2-9 (Alessandrini) (explaining that market-based rate authority gives a seller "the ability to buy and sell electricity with two willing counter-parties at arm's length and at market-based rates"). However, "FERC will grant approval of a market-based tariff only if a utility demonstrates that it lacks or has adequately mitigated market power, lacks the capacity to erect other barriers to entry, and has avoided giving preferences to its affiliates." Morgan Stanley, 554 U.S. at 537.

As a result of its MBR Tariff, CPV has FERC approval to sell electric energy, capacity, or ancillary services at wholesale through freely negotiated contracts with purchasers, including wholesale sales made to PJM in the PJM Markets. See Tr. Mar. 7 (PM) at 5:4-8 (Knight) (explaining that CPV would be required to obtain market-based rate authority from FERC prior to making the sales required under the CfD to PJM). Of course, the MBR Tariff would affect only those transactions that are subject to FERC's jurisdiction.

In CPV's application for market-based rate authorization, it provided in a footnote that:

> CPV Maryland has included as Exhibit E the most current public draft of the CFD that is under view before the MPSC solely for informational purposes. The Commission has determined that financial contracts that do not provide for sales of capacity or energy are not subject to the filing and reporting requirements under Section 205 of the Federal Power Act. However, CPV Maryland is not requesting that Commission to address or discuss its jurisdiction over the contract for differences in its decision on this request for market based rates.

P.611 (CPV FERC Application for Market-Based Rate Authorization) at 4 n.7 (internal citations omitted). In its order authorizing CPV's MBR Tariff, FERC referenced CPV's above-quoted representation, but did not address the CfD as part of the proceeding for market-based rate authority, limiting its discussion to whether CPV had horizontal or vertical market power. CPV Shore, LLC, 142 FERC ¶ 61,081, at *7-10 (2013). FERC has not passed judgment, one way or another, on the reasonableness or fairness of the terms of CfD, whether the CfD is a "FERC-jurisdictional" contract, or any other potential issue within its regulatory jurisdiction.

Defendants contend that a finding in favor of Plaintiffs on the field preemption claim means that FERC would have jurisdiction over the CfD and, since CPV has been granted its MBR Tariff, the only forum to debate the enforceability of the CfD is FERC. The Court does not agree.

Even if the MBR Tariff granted by FERC authorized CPV, in the first instance, to enter into the CfD with the Maryland EDCs, thereby rendering any dispute over the CfD within the primary jurisdiction of FERC, such an authorization would not by extension preclude this Court from granting relief to Plaintiffs on a field preemption claim against the Maryland PSC. Plaintiffs' Complaint seeks relief enjoining the PSC from enforcing the Generation Order, which includes the requirement that the Maryland EDCs enter into the CfD with CPV. In this action, Plaintiffs have not directly challenged the CfD (i.e., the ability of the Maryland EDCs and CPV to enter into the CfD absent state directive). Plaintiffs do not seek relief against CPV and do not assert that CPV has engaged in an unlawful practice in connection with the CfD. Contrary to the situation in Pub. Util. Dist. No. 1 of Snohomish Cnty. v. Dynegy Power Mktg., Inc., 384 F.3d 756, 761 (9th Cir. 2004),[59] relied upon by Defendants, Plaintiffs are not asking that this Court determine

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[59] In Dynegy, "a utility providing electricity to consumers in Washington state, has sued various generators and traders of wholesale electricity for violations of California state antitrust and consumer protection laws." 384 F.3d at 758. A state or state agency was not a party to the suit.

a price or rate for CPV's energy and capacity sales that would be fair. Plaintiffs also are not seeking a determination that CPV violated or breached its MBR Tariff. The Court recognizes that its determination vis-à-vis the Generation Order may have collateral consequences and give rise to the implication that the CfD is the type of agreement governed by CPV's MBR Tariff. However, such implications do not deprive this Court of jurisdiction to answer the question of whether the Generation Order as a state action is unconstitutional.

Plaintiffs have challenged the Maryland PSC's ability under the Supremacy Clause to issue the Generation Order, which directed market participants to enter into the CfD with CPV. While the Court's finding that the Generation Order is field preempted raises the implication that the CfD, standing by itself, is a FERC-jurisdictional contract as opposed to a purely financial arrangement that is generally considered outside the purview of FERC, such an implication does not strip this Court of jurisdiction to decide the constitutionality of the PSC's regulatory actions and to enjoin enforcement of an unconstitutional state action.

c. Resolution

When it issued the Generation Order, the PSC sought "to ensure the continued, long-term reliability of the electricity supply to Maryland customers" by securing the construction and operation of a generation facility within SWMAAC. See P.2 (2011 RFP) at 1. By themselves, those actions and objectives of securing the construction and operation of a generation facility may not invade a federally occupied field and most likely do fall within the permissible realm of regulation reserved to the states under the FPA. But, the FPA recognizes limits on the permissible role of the states in regulating generation facilities. Specifically, when generators are selling energy and capacity at wholesale, Congress intended the price or rate of such sales to be regulated exclusively by FERC. See supra Part III.A.2; see also Miss. Indus., 808 F.2d at 1545 n.74 (explaining that "under the clear terms of the [FPA], the Commission has been awarded jurisdiction over generating facilities 'to the extent provided in other sections,' including jurisdiction necessary to effectuate regulation of interstate wholesale rates"). Because states have no authority, either traditional or otherwise,[60] to set wholesale rates, the

[60] The Court does not agree with Defendants that the PSC's actions are subject to a strong presumption against preemption because states have traditionally occupied the field of regulating the construction and siting of physical generation

compensation received by CPV for its wholesale energy and capacity sales is exclusively subject to the regulation of FERC. While there exist legitimate ways in which states may secure the development of generation facilities, states may not do so by dictating the ultimate price received by the generation facility for its actual wholesale energy and capacity sales in the PJM Markets without running afoul of the Supremacy Clause.

In the Generation Order, the PSC directed the Maryland EDCs to enter into the CfD with CPV. Under the CfD, CPV is guaranteed to receive the contract price – an out-of-market price set by the PSC – for its actual wholesale energy and capacity sales up to 661 MW in the PJM Markets. Based on the evidence presented at trial as discussed herein, the Court finds that the Generation Order sets or establishes the ultimate price received by CPV for these wholesale energy and capacity sales. The doctrine of field preemption forecloses state regulation in a field occupied entirely by the federal government, even if the state's purpose is admirable or the state regulation does not

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facilities. As explained herein, the PSC's objective certainly fell within that traditional state purview continually referenced by Defendants, but the manner in which the PSC accomplished that objective involved establishing the amount received by CPV for its wholesale activity in the PJM Markets. Regulating in the field of wholesale price-setting is occupied by FERC, so therefore the strong presumption against preemption is not present. See United States v. Locke, 529 U.S. 89, 108 (2000). However, even if the strong presumption existed, this Court would still conclude the Generation Order unconstitutionally encroached into a federal field.

conflict with achievement of the federal scheme. See Arizona v. United States, 132 S. Ct. 2492, 2502 (2012). Where Congress intended FERC alone to regulate wholesale energy and capacity prices, and this Court has found the Generation Order sets or establishes the wholesale energy and capacity prices to be received by CPV for its sales into the PJM Markets, the PSC has encroached upon an exclusive federal field. In line with the principles of the Supremacy Clause, the Generation Order cannot stand.

The Court finds that the Generation Order is field preempted and, therefore, is unconstitutional as a violation of the Supremacy Clause.

3. Conflict Preemption

Conflict preemption exists "where state law 'stands as an obstacle to the accomplishment and execution of the [Congress'] full purposes and objectives.'" Freightliner Corp. v. Myrick, 514 U.S. 280, 287 (1995) (alteration in original) (quoting Hines v. Davidowitz, 312 U.S. 52, 68 (1941)). The Court's decision that the Generation Order violates the Supremacy Clause because it is field preempted, renders moot the question of whether the Order would also be held to violate the Supremacy Clause because it is conflict preempted.

The Court will not undertake an academic exercise to hypothecate the findings that it would have made in a decision holding that the Generation Order is not field preempted and then hypothecate what would have been this Court's conflict preemption decision with those findings substituted for those actually made.

Accordingly, the Court simply will note that there are reasonably debatable issues as to whether the Generation Order violated the Supremacy Clause by virtue of conflict, as well as field, preemption.

B. The Dormant Commerce Clause (Count II)

As discussed herein, the Court does not accept any of Defendants' plethora of contentions that would prevent consideration of the merits of Plaintiffs' dormant Commerce Clause claim. However, on consideration of the ultimate issue, the Court does not find that the Generation Order violates the dormant Commerce Clause.

1. Legal Principles

The enumerated powers delegated to Congress by the United States Constitution include the power "[t]o regulate Commerce with foreign Nations, and among the several States, and with the

Indian Tribes." U.S. Const. art. I, § 8, cl. 3. "Although the Commerce Clause is phrased merely as a grant of authority to Congress . . . it is well established that the Clause also embodies a negative command forbidding the States to discriminate against interstate trade." Associated Indus. of Mo. v. Lohman, 511 U.S. 641, 646 (1994). This negative aspect of the Commerce Clause, or dormant Commerce Clause, prohibits economic protectionism ("that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors") on part of the States. See New Energy Co. of Ind. v. Limbach, 486 U.S. 269, 271, 273 (1988) (invalidating under the dormant Commerce Clause a statute that provided a tax credit for sales of ethanol produced in Ohio but not for sales of ethanol produced in certain other states). Such state economic protectionism "violates the principle of the unitary national market by handicapping out-of-state competitors." W. Lynn Creamery, Inc. v. Healy, 512 U.S. 186, 193 (1994).

In any dormant Commerce Clause challenge to state action, a court must determine as a preliminary matter whether the state's actions are of the type subject to the strictures of the dormant Commerce Clause. If the state's actions are not exempted from the Commerce Clause, then the court must determine whether the state has affirmatively discriminated against interstate commerce or, though regulating evenhandedly, has unduly burdened interstate commerce. See Maine v. Taylor, 477 U.S. 131, 138 (1986); McBurney v. Young, 667 F.3d 454, 468 (4th Cir. 2012), aff'd, 133 S. Ct. 1709 (2013). Affirmative discrimination is subject to strict scrutiny and will be prohibited unless "'demonstrably justified by a factor unrelated to economic protectionism.'" McBurney, 667 F.3d at 468-69 (quoting Brown v. Hovatter, 561 F.3d 357, 363 (4th Cir. 2009) (explaining that it is insufficient for a dormant Commerce Clause violation that a statute provides a benefit to only state citizens and that the state action must discriminate against out-of-state economic interests). State regulation that incidentally burdens interstate commerce is less rigorously evaluated and "will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits." Pike v. Bruce Church, Inc., 397 U.S. 137, 142 (1970); see also Yamaha Motor Corp., U.S.A. v. Jim's Motorcycle, Inc., 401 F.3d 560, 567 (4th Cir. 2005) (quoting Pike, 397 U.S. at 142).

2. "Exemption" from the Dormant Commerce Clause

Defendants contend that the PSC's challenged actions are not covered by the strictures of the dormant Commerce Clause. Defendants contend that in connection with issuing the Generation Order, the PSC operated without Commerce Clause confinement because: (1) state spending or subsidization to advance a legitimate public purpose operates outside the Commerce Clause; (2) the PSC acted as a market participant in the new generation market; and/or (3) Congress has expressly authorized states to discriminate against interstate commerce in the siting of generation facilities.

a. State Spending or Subsidization to Advance a Legitimate Public Purpose

Defendants urge the Court to hold that the dormant Commerce Clause does not apply to the PSC's actions because, by ultimately requiring Maryland ratepayers to shoulder the financial burden of the CfD, the PSC has merely spent money to subsidize the construction of a power plant in order to advance a legitimate public purpose. See Defs.' Post-Trial Br. [Document 146], at 43-45. In essence, Defendants request this Court to recognize a sweeping exception to the dormant Commerce Clause that would permit a state or local government to discriminate against interstate commerce so long as that government’s actions can be categorized as spending or subsidization to advance a legitimate public purpose. For the reasons stated herein, the Court declines to do so.

Defendants' spending and subsidy contentions are separable into two distinct categories: (1) state or local spending on any matter and (2) administration of state or local subsidies or subsidy programs provided to private business. In their post-trial briefing, Defendants treat state spending generally and state administration of a subsidy program as a single class of state action wholly outside the Commerce Clause. Yet, a state subsidy is a sub-set that falls under the much broader umbrella of state or local spending.[61] The Court will address each category separately.

(i) Spending to Advance a Legitimate Public Purpose

Relying on several Supreme Court cases addressing the market participant exception and state laws that prefer public entities, Defendants contend that the Supreme Court has made clear that "governmental entities are not subject to Commerce Clause scrutiny when they spend money . . . whatever the source of the funding." See Defs.' Post-Trial Br. [Document 146] at 43-44. Plaintiffs assert that the Supreme Court has not recognized such an exemption and has firmly rejected the argument a state law to promote with the purpose of promoting a

[61] In the general sense, a subsidy refers to a grant of money or other pecuniary aid by a governmental body to another, such as a private entity or group of private entities. See W. Lynn Creamery, Inc. v. Healy, 512 U.S. 186, 194 (1994) (describing money distributed to Massachusetts dairy farm producers from state tax fund as a subsidy).

public benefit is necessarily insulated from the Commerce Clause. The Court agrees with Plaintiffs.

The Supreme Court jurisprudence relied upon by the Defendants does not demonstrate a separate and categorical dormant Commerce Clause exception for state activity pigeonholed as spending money to advance public health, safety, or welfare. Rather, those decisions indicate a recognition that (1) in certain instances, when a state or local government spends its own revenues, that government may be considered a market participant free to operate without Commerce Clause hindrance (White v. Mass. Council of Const. Emp'rs, Inc., 460 U.S. 204 (1983); Reeves, Inc. v. Stake, 447 U.S. 429 (1980)) and that (2) in certain instances a state's favoring or benefiting a government or public entity while treating all private companies without distinction does not discriminate against interstate commerce (Dep't of Revenue of Ky. v. Davis, 553 U.S. 328 (2008); United Haulers Ass'n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth., 550 U.S. 330 (2007)).

Specifically, in White the Supreme Court held that "[]nsofar as the city [of Boston] expended only its own funds in entering into construction contracts [to which the city was a signatory] for public projects, it was a market participant,"[62]

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[62] In White v. Mass. Council of Const. Emp'rs, Inc., the city executive order at issue also applied to funds received from the

and therefore the dormant Commerce Clause placed no limitation on its ability to favor city residents in connection with those contracts.[63] 460 U.S. at 209 n.5, 214-15. In Reeves, the Supreme Court held that South Dakota's construction and operation of a cement plant rendered it a market participant and thus left the state free to favor South Dakota customers over out-of-state customers when selling the plant's output without implicating the dormant Commerce Clause. 447 U.S. at 439-40. With respect to public entities, in United Haulers, the Supreme Court held a "flow control" ordinance requiring all trash haulers to deliver solid "waste to [a 'clearly public'] facility[y] owned and operated by a state-created public benefit corporation"[64] did not discriminate against interstate commerce within the meaning of the dormant Commerce Clause.[65] 550 U.S. at 334. Similarly, in

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federal government. 460 U.S. 204, 206, 208 (1983). The Supreme Court found that to the extent the order applied to projects funded in part with funds acquired by the city through federal programs, the order had been specifically authorized by Congress and thus fell within the congressional authorization exception to the Commerce Clause. See id. at 212-16.

[63] In White, the executive order issued by the city "required that all construction projects funded in whole or in part by city funds . . . should be performed by a work force consisting of at least half bona fide residents of Boston." Id. at 205-06.

[64] As to funding the facility, the defendant waste management authority collected "tipping fees" from private trash collectors to cover operating and maintenance costs, and if the costs were not recouped through the tipping fees and other charges, then the state counties served by the facility would make up the difference. United Haulers Ass'n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth.,550 U.S. 330, 335-36 (2007).

[65] The Court reasoned that state governments are distinct from

Davis, the Supreme Court, relying on United Haulers, held that Kentucky's tax exemption for state-issued bonds did not discriminate against interstate commerce because Kentucky treated all private bond issuers exactly the same.[66] 553 U.S. at 341-43 (recognizing that state tax exemptions for state-issued bonds were a common and historically rooted practice).

Accordingly, the Supreme Court has by no means made clear that when a state or local government spends money to advance a legitimate public purpose it is free to discriminate against interstate commerce or is considered not to discriminate against interstate commerce. Further, the PSC's actions at issue herein are entirely distinguishable from the actions at issue in the aforementioned cases. Here, the PSC is not: (1) spending its own funds to construct a power plant; (2) entering into a contract to which it is a signatory for the construction of a power plant; (3) owning or operating a power plant; (4) creating a clearly public entity that will own and operate a power plant; and/or (5) issuing bonds to generate state revenue to fund a

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private businesses because the state "is vested with the responsibility of protecting the health, safety, and welfare of its citizens." Id. at 342. Thus, "[l]aws favoring local government . . . may be directed toward any number of legitimate goals unrelated to protectionism," unlike laws favoring in-state business over out-of-state business. Id. 343.

[66] Justice Souter, who delivered the opinion of the Court in Dep't of Revenue of Ky. v. Davis, 553 U.S. 328 (2008), opined that the Kentucky law would also evade dormant Commerce Clause review under the market participant exception, but a majority of Justices did not join in that portion of the opinion.

power plant. To the contrary, the PSC procured a market actor, CPV, to construct, own, and operate a private facility in the interstate energy market and then used its regulatory authority to order other market actors, and ultimately Maryland ratepayers, to provide the Facility with financial backing.

Additionally, the Court does not find any basis for recognizing the general "spending exception" advocated by Defendants. Such an exception would endorse a formalistic approach to the Commerce Clause, long discouraged by the Supreme Court. See W. Lynn Creamery, 512 U.S. at 201. As the Supreme Court pointed out in the not-too-distant past: "The commerce clause forbids discrimination, whether forthright or ingenious. In each case it is our duty to determine whether the statute under attack, whatever its name may be, will in its practical operation work discrimination against interstate commerce." Best & Co., Inc. v. Maxwell, 311 U.S. 454, 455-56 (1940). In addition to its reluctance in fashioning exemptions that place form over substance, the Supreme Court has flatly cast aside any notion that a state may regulate in a manner that discriminates or burdens interstate commerce so long as it acts for a legitimate public purpose. See, e.g., Or. Waste Sys., Inc. v. Dep't of Envtl. Quality of State of Or., 511 U.S. 93, 100 (1994) (explaining the "purpose of, or justification for, a law has no bearing on whether it is facially discriminatory"); Dean Milk

Co. v. City of Madison, 340 U.S. 349, 354 (1951).

The Court does not agree with Defendants' position that subjecting the PSC's actions to the dormant Commerce Clause will have severe adverse effects by raising questions as to whether commonplace state spending activity, such as a decision to fund the expansion of a state university's campus with student tuition, is permissible under the Commerce Clause. There are, of course, multitudes of state spending schemes that by their nature most likely raise no discernible Commerce Clause issue because those activities simply do not regulate commerce in any meaningful sense or fall within an already recognized Commerce Clause exception. See Davis, 553 U.S. at 358 (2008) (Stevens, J., concurring). Just the same, one can certainly envision state spending schemes that do give rise to significant Commerce Clause concerns. See W. Va. Univ. Hosps., Inc. v. Rendell, No. 1:CV-06-0082, 2007 WL 3274409, at *9-10 (M.D. Pa. Nov. 5, 2007) (finding a Pennsylvania law that excluded all out of-state hospitals that provide trauma care to Pennsylvania residents from receiving trauma payments available to Pennsylvania hospital invalid as unjustified facial discrimination against interstate commerce).

Whether any particular state spending activity is subject to, or passes muster under, the dormant Commerce Clause will depend on the nature and contours of that particular scheme.

The Court will, therefore, address Plaintiffs' claim that the specific actions taken by the PSC implicate and violate the dormant Commerce Clause.

(ii) State Subsidies

Defendants contend that the PSC's actions amount to a constitutionally permissible subsidy program not subject to dormant Commerce Clause scrutiny. Plaintiffs assert that the Supreme Court has never explicitly addressed the constitutionality of subsidy programs in connection with the dormant Commerce Clause and that, in any event, the PSC has not directly subsidized anything.

The Supreme Court has yet to decide whether or not state or local government subsidy programs are categorically outside the dormant Commerce Clause. See Camps Newfound/Owatonna, Inc. v. Town of Harrison, Me., 520 U.S. 564, 589 (1997) (explaining that there was no need to address the permissibility of a state subsidy under the dormant Commerce Clause because the law at issue was a tax exemption, which, although having the same effect as subsidy, is constitutionally distinct under Supreme Court jurisprudence); W. Lynn Creamery, 512 U.S. at 199 n.15. However, the Supreme Court has made several statements with respect to subsidies and the dormant Commerce Clause. For instance, in W. Lynn Creamery, the Supreme Court stated in dicta that "[a] pure subsidy funded out of general revenue ordinarily imposes no burden on interstate commerce, but merely assists local business." 512 U.S. at 198-99 (holding that a pricing program consisting of a subsidy and a nondiscriminatory tax on all dairy farmers violated the dormant Commerce Clause because the tax was effectively imposed only on out-of-state dairy farmers). In a case involving a discriminatory tax scheme, the Supreme Court stated that:

> The Commerce Clause does not prohibit all state action designed to give its residents an advantage in the marketplace, but only action of that description in connection with the State's regulation of interstate commerce. Direct subsidization of domestic industry does not ordinarily run afoul of that prohibition; discriminatory taxation of out-of-state manufacturers does.

New Energy, 486 U.S. at 278 (1988).[67]

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[67] Reference to direct subsidies by the Supreme Court is, in some ways, rooted in the market participant exception to the dormant Commerce Clause. In Hughes v. Alexandria Scrap Corp., 426 U.S. 794 (1976), the Supreme Court first recognized the market participant exception to the dormant Commerce Clause when sanctioning a state's cash subsidy program. In New Energy Co. of Ind. V. Limbach, the Supreme Court noted that simply because a "tax credit scheme has the purpose and effect of subsidizing a particular industry . . . [t]hat does not transform it into a form of state participation in the free market" outside of dormant Commerce Clause scrutiny under the market participation exception. 486 U.S. 269, 277-78 (1988). The Court explained that although it considered the cash subsidy program at issue in Alexandria Scrap to be proprietary activity, not all state subsidy programs necessarily fall into that characterization. See id. at 277; Reeves, Inc. v. Stake, 447 U.S. 429, 440 n.14 (1980) ("We have no occasion here to inquire whether subsidy programs unlike that involved in Alexandria Scrap warrant

At most, the Supreme Court's statements regarding subsidies suggest that a "pure [state or local government] subsidy funded out of general revenue" or "direct subsidization of domestic industry" by a state or local government is generally permissible under the Commerce Clause.[68] The Supreme Court has not given any indication that state activity that could be labeled as an indirect subsidy or a subsidy equivalent — in that it has the purpose or effect of funding domestic business – necessarily is permissible under the dormant Commerce Clause. To the contrary, the Supreme Court has subjected state laws that have the purpose and/or effect of subsidizing only local industry to dormant Commerce Clause scrutiny. See Bacchus Imports, Ltd. v. Dias, 468 U.S. 263, 265-66, 272 (1984) (finding that a tax exemption for certain locally produced alcoholic beverages violated the dormant Commerce Clause even though the state's asserted purpose for the tax exemption was an attempt to

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characterization as proprietary, rather than regulatory, activity."). Thus, the Supreme Court has recognized that a state may be considered a "market participant" free to discriminate against interstate commerce when administering a subsidy program, but that simply because a state activity is labeled as a subsidy or has that purpose or effect does not automatically render the state's actions proprietary as opposed to regulatory.

[68] However, the Supreme Court's statements do not clarify whether it considers a "direct subsidy" as: (1) an independent category of state activity exempted from the dormant Commerce Clause (i.e., permitting discriminatory direct subsidies); (2) falling within the market participant exception; or (3) a type of state action that is generally not considered as discrimination or as a burden on interstate commerce.

subsidize financially troubled local business).[69] The Supreme Court has also refused to consider state laws that have the purpose and/or effect of subsidizing a particular industry necessarily to be a form of market participation, as opposed to a form of regulation, by the state. See New Energy, 486 U.S. at 277-78.

In the instant case, the PSC is not directly funding or providing pecuniary aid to a domestic business through general taxes, municipal bonds, or some other source of Maryland or PSC revenue. The PSC has elected to exercise its regulatory authority over the Maryland EDCs in such a way as to order those market actors to provide a local generation facility selected by the PSC with 20 years of financing in the form of the CfD and to permit the EDCs to recoup their losses and pass on their gains to Maryland SOS customers through increases or credits on retail electricity bills. The PSC has also opted to use the open market to earn revenues for its procured generation facility, as evidenced by the fact that any payment obligation of the EDCs, and, by extension, the Maryland ratepayers, under the CfD only

[69] The Supreme Court does distinguish between a direct subsidy and a tax exemption. The Supreme Court has explained that although tax exemptions and subsidies serve similar ends, "there is a constitutionally significant difference between" the two because discriminatory tax exemptions have been considered the type of state action "designed to give residents an advantage in the market place [that] is prohibited by the Commerce Clause." Camps Newfound/Owatonna, Inc. v. Town of Harrison, Me., 520 U.S. 564, 589-91 (1997).

arises if the generation facility actually sells its output into the interstate PJM Markets. Thus, the PSC's financing scheme is constitutionally distinct from a direct subsidy in a dormant Commerce Clause context. See C & A Carbone, Inc. v. Town of Clarkstown, N.Y., 511 U.S. 383, 394 (1994) (explaining that where a flow control ordinance served the purpose of financing a town-sponsored facility and that since the town "elected to use the open market to earn revenues for its project, the town may not employ discriminatory regulation to give that project an advantage over rival business from out of State" and contrasting that with a situation in which the town "subsidize[d] the facility through general taxes or municipal bonds"). Placing the ultimate financial risk of the PSC's decision to procure the construction and operation of private facility in SWMAAC on Maryland ratepayers is also distinctly different from a direct subsidization. See Alliance for Clean Coal v. Miller, 44 F.3d 591, 596 (7th Cir. 1995). Indeed, holding that the PSC's actions fall within the realm of subsidies noted by the Supreme Court to be "dormant Commerce Clause friendly" would render the adjectives "pure" and "direct" meaningless.

Accordingly, the Court finds the PSC's actions cannot be characterized as a direct subsidization of the construction and operation of a local generation facility, irrespective of whether direct subsidies would be permissible under the Commerce

Clause.

b. Market Participant Exception

Defendants assert that the PSC, on behalf of the Maryland ratepayers, is a "financier" of a new generation facility and thus should be considered a market participant in the market for new generation facilities whose actions are therefore not subject to the dormant Commerce Clause. Plaintiffs assert the market participant doctrine is inapplicable because the PSC is not buying or selling anything in the new generation market.

The market participant exception permits a state to discriminate against interstate commerce and prefer its own citizens when it acts as a participant in the market, and not as a regulator. See Hughes v. Alexandria Scrap Corp., 426 U.S. 794, 802, 809-10 (1976) (finding that a law giving "Maryland processors an advantage over . . . non-Maryland processors in the competition for bounty-eligible hulks" was not subject to the dormant Commerce Clause where Maryland had acted as a market participant in using state monies to create and fund the "bounties" and concluding that the state was free to favor its own citizens in receiving such bounties). The Supreme Court has explained that the market participant exception makes "good sense" because "the Commerce Clause responds principally to state taxes and regulatory measures impeding free private trade in the national marketplace. There is no indication of a constitutional plan to limit the ability of the States themselves to operate freely in the free market." Reeves, 447 U.S. at 436-37 (internal citations omitted). That is, when acting as a proprietor, states, like any private business, should be able to make decisions without Commerce Clause limits. See id. at 439.

Under the Generation Order and the CfD, the PSC is not buying, selling, or directly paying for anything in the new generation resource market. The CfD requires the generation facility to sell its energy and capacity to PJM in the PJM Markets. As the evidence at trial demonstrated, PJM sells the energy and capacity that it purchases from generation resources to LSEs within the PJM region, including the Maryland EDCs, who then resell the energy and capacity to Maryland end-use customers. With respect to "payment," the PSC is not a signatory to the CfD; that compensation scheme is between the generation facility and the Maryland EDCs. The EDCs have PSC authorization to pass on losses and gains under the CfD to Maryland ratepayers who pay the EDCs for retail electric sales. Under this scheme, the PSC is not acting as a proprietor or even directly participating in the free market or in a market it created, and therefore is not entitled to be treated as a private actor procuring a new generation facility for purposes of the Commerce Clause. Cf. Brooks v. Vassar, 462 F.3d 341, 357 (4th Cir. 2006) (finding that where Virginia elected to sell alcohol from state-owned and state-operated stores, it was a participant in the alcohol retail market and therefore could elect not to sell out-of-state wines at its stores without dormant Commerce Clause concerns). Rather, as the face of the RFP makes clear, the PSC is acting as a regulator of electric distribution companies. See P.2 (2011 RFP) at 1 n.1 (citing regulatory authority relied upon by PSC in issuing the RFP). The fact that this regulatory action may have the "effect of subsidizing" the operation and construction of a local generation facility, "does not transform it into a form of state participation in the free market." New Energy, 486 U.S. at 277.[70]

Accordingly, the Court finds the PSC's actions do not fall within the market participant exception.

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[70] Furthermore, Defendants' contention that the PSC is acting as a market intermediary on behalf of Maryland ratepayers to finance a new generation facility and that the PSC is therefore a market participant is without merit or legal support. If the market participant exception were applicable solely because the state government propounded to be acting on behalf of its citizens (or some discrete group thereof), the exception would swallow the rule.

c. Explicit Authorization from Congress

Defendants assert that the PSC's actions cannot give rise to a dormant Commerce Clause claim because Congress expressly authorized the states to regulate freely the siting of generation facilities within each respective state in Section 201(b)(1) of the Federal Power Act. 16 U.S.C. § 824(b)(1)). Plaintiffs contend that Defendants have failed to meet their burden of demonstrating a clear intent on behalf of Congress to permit states to discriminate against interstate commerce.

In exercising its authority under the Commerce Clause,

> Congress may "confe[r] upon the States an ability to restrict the flow of interstate commerce that they would not otherwise enjoy." If Congress ordains that the States may freely regulate an aspect of interstate commerce, any action taken by a State within the scope of the congressional authorization is rendered invulnerable to Commerce Clause challenge.

W. & S. Life Ins. Co. v. State Bd. of Equalization of Ca., 451 U.S. 648, 652-53 (1981) (internal citations omitted). To exempt the states from scrutiny under the dormant Commerce Clause, "Congress must manifest its unambiguous intent before a federal statute will be read to permit or to approve . . . a violation of the Commerce Clause." Wyoming v. Oklahoma, 502 U.S. 437, 458 (1992).

Section 201(b)(1) of the FPA provides, inter alia, that FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). In examining the particular part of Section 201(b)(1) that references states' existing lawful authority over hydroelectric energy, the Supreme Court concluded that "§ 201(b) simply saves from pre-emption under Part II of the Federal Power Act such state authority as was otherwise 'lawful'" and that "[n]othing in the legislative history or language of the statute evinces a congressional intent 'to alter the limits of state power otherwise imposed by the Commerce Clause.'" New Eng. Power Co. v. New Hampshire, 455 U.S. 331, 341 (1982) (citation omitted). As later recognized by the Supreme Court: "Our decisions have uniformly subjected Commerce Clause cases implicating the Federal Power Act to scrutiny on the merits." Wyoming, 502 U.S. at 458.

The Court finds Defendants have failed to demonstrate a clear and unambiguous intent on behalf of Congress to permit states to discriminate against interstate commerce in connection with the siting of generation facilities within a state.

3. Proof of Discrimination

The Court has found that the PSC's actions challenged by

Plaintiffs do not fall within an established or recognized "exception" to the dormant Commerce Clause. As a result, "the Commerce Clause stands as constitutional limitation on the means by which [the PSC] can constitutionally seek to achieve [its] goal" of incentivizing the development and operation of a private local generation facility. See Bacchus Imports, 468 U.S. at 271.

Plaintiffs bear the burden to demonstrate that the Generation Order "'discriminates [against interstate commerce] facially, in its practical effect, or in its purpose.'" Yamaha Motor Corp., 401 F.3d at 567 (alteration in original) (citation omitted). If Plaintiffs make such a showing, then the Generation Order will be struck down unless Defendants demonstrate "both that the statute 'serves a legitimate local purpose [unrelated to economic protectionism],' and that this purpose could not be served well by available nondiscriminatory means." Maine, 477 U.S. at 138 (citation omitted). However, if Plaintiffs demonstrate that the Generation Order "amounts to simple economic protectionism, a 'virtually per se rule of invalidity' has [been] applied" by the Supreme Court. See Wyoming, 502 U.S. at 454-55 (1992) (citation omitted).

a. "SWMAAC" Locational Requirement Does Not Preclude a Finding of Affirmative Discrimination

The fact that the locational requirement is defined as "SWMAAC," which includes the District of Columbia and only part of Maryland, does not "insulate" the Generation Order from Plaintiffs' contention that by virtue of the locational restriction in the RFP, the PSC affirmatively discriminated against interstate commerce. See C & A Carbone, 511 U.S. at 391 ("The ordinance is no less discriminatory because in-state or in-town processors are also covered by the prohibition."); Dean Milk, 340 U.S. at 354 n.4 ("It is immaterial that Wisconsin milk from outside the Madison area is subjected to the same proscription as that moving in interstate commerce."). Nor does the fact that SWMAAC includes the District of Columbia make any discrimination by the PSC no longer discriminatory. See New Energy, 486 U.S. at 274 (explaining that making a tax credit available to some out-of-state manufacturers does not make the credit not discriminatory); Alliance for Clean Coal v. Bayh, 72 F.3d 556, 560 (7th Cir. 1995) ("Protection of local, or even regional, industry is simply not a legislative action that is consistent with the Commerce Clause.").

The Court finds that there was little, if any, realistic possibility that the generation facility in question would be located in the District of Columbia. Mr. Massey testified that about 98% of SWMAAC geographically is within Maryland. Tr. Mar. 6 (AM) at 37:16-18 (Massey). In addition, evidence as to the availability of useable sites in the District of Columbia, established a high degree of improbability – if not impossibility – that an acceptable facility could be located there. Moreover, the RFP required any proposal to include a "[d]escription of the reliability and direct economic benefits to Maryland ratepayers as a result of the Generation Capacity Resource" and provided that in scoring bids, 2.5% of the non-price score consisted of the "benefits to the State of Maryland." P.2 (2011 RFP) RFP at 10, 14-15 (emphasis added). In any event, even if the facility realistically could have been located in the District of Columbia rather than Maryland, this fact would have no bearing on the affirmative discrimination claim.

The Court finds that the PSC's regulatory action would be repugnant to the dormant Commerce Clause if it discriminates against economic interests outside a particular zone of the PJM region.

b. Differential Treatment of In-State and Out-of-State Economic Interests

Plaintiffs assert that the evidence establishes that the Generation Order discriminates against interstate commerce on its face and in its practical effect. Plaintiffs contend that the SWMAAC locational requirement treats in-state and out-of-state economic interests differently, "the former benefitting from exclusive rights to participate in the RFP and the latter precluded from participation."[71] Pls.' Post-Trial Br. [Document 144] at 63. Defendants contend that Plaintiffs have failed to prove affirmative discrimination against interstate commerce.

The dormant Commerce Clause "prevents a State from 'jeopardizing the welfare of the Nation as a whole' by 'plac[ing] burdens on the flow of commerce across its borders that commerce wholly within those borders would not bear.'" Am. Trucking Ass'ns, Inc. v. Mich. Pub. Serv. Comm'n, 545 U.S. 429, 433 (2005) (alteration in original) (citation omitted). Precluding this type of state action enforces the principle that "[t]he mere fact of nonresidence should not foreclose a producer in one State from access to markets in other States." Granholm v. Heald, 544 U.S. 460, 472 (2005). As the Supreme Court explained in 1949:

> Our system, fostered by the Commerce Clause, is that every farmer and every craftsman shall be encouraged to produce by the certainty that he will have free access

[71] A representative of PPL testified that PPL reviewed the PSC's RFP but did not participate because PPL "did not have generation asset facility [sic] that was in SWMAAC and available to participate based on that requirement" and the "RFP acted in a manner inconsistent with [PPL's] market principles." Tr. Mar. 4 (AM) at 71:9-24 (Alessandrini).

> to every market in the Nation, that no home embargoes will withhold his exports, and no foreign state will by customs duties or regulations exclude them. Likewise, every consumer may look to the free competition from every producing area in the Nation to protect him from exploitation by any. Such was the vision of the Founders; such has been the doctrine of this Court which has given it reality.

H.P. Hood & Sons, Inc. v. Du Mond, 336 U.S. 525, 539 (1949).

Discrimination for purposes of the dormant Commerce Clause "simply means differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter." Or. Waste Sys., 511 U.S. at 99-100 (holding that a greater surcharge on disposal of in-state waste than on disposal of out-of-state waste facially discriminated against interstate commerce). For instance, states may not "provid[e] a direct commercial advantage to local business." Nw. States Portland Cement Co. v. Minnesota, 358 U.S. 450, 458 (1959). "Permitting the individual States to enact laws that favor local enterprises at the expense of out-of-state businesses 'would invite a multiplication of preferential trade areas destructive' of the free trade which the Clause protects." Boston Stock Exch. v. State Tax Comm'n, 429 U.S. 318, 329 (1977) (citation omitted). The Supreme Court has considered states to have impermissibly favored in-state economic interests over out-of-state economic interests by: (1) providing only tax credits for in-state sales of products actually produced in-state, New Energy, 486 U.S. at 271; (2) precluding out-of-state producers from shipping products directly to in-state consumers, Granholm, 544 U.S. at 473-74; and (3) giving property tax exemptions to in-state entities that primarily serve state residents but not to in-state entities that principally serve interstate clientele, Camps Newfound/Owatonna, 520 U.S. at 576-77.

The Court finds that Plaintiffs have failed to prove that the SWMAAC locational requirement is facially discriminatory for purposes of the dormant Commerce Clause.[72] The mere fact that the PSC sought to procure a new generation facility located within SWMAAC does not, standing alone, discriminate against the flow of interstate commerce. The Generation Order does not erect any barriers to the sale or transmission of electric energy at wholesale in and out of SWMAAC and within the PJM region or to providing a competitive advantage to an in-SWMAAC generation facility selling electric energy at wholesale at the expense of other generation facilities competing in the same market. CPV's facility would compete in the PJM Markets with all other resources to sell its energy and capacity to PJM. The Maryland EDCs directed to enter into the CfD would likewise

[72] Plaintiff's dormant Commerce Clause claim is limited to the SWMAAC locational requirement. Hence, there is no contention that the Generation Order sans the SWMAAC locational requirement discriminated against interstate commerce by orchestrating long-term financing for a preferred market participant.

continue to purchase energy and capacity from the wholesale energy markets, including from PJM in the PJM Markets. Cf. Wyoming, 502 U.S. at 455-56 (finding that a law that required all in-state coal-fired power plants to burn a mixture of coal containing 10% coal mined in the state discriminated on its face and in practical effect against interstate commerce because such a requirement explicitly operated to the exclusion of coal mined in other states); Dean Milk, 340 U.S. at 350, 353 (holding that a city ordinance that "ma[de] it unlawful to sell any milk as pasteurized unless it has been processed and bottled at an approved pasteurization plant within a radius of five miles" from the city of Madison violated the dormant Commerce Clause).

Though the PSC has exercised its regulatory power to create and sustain another competitor in the wholesale energy market through indirect subsidization, the fact that the PSC limited its financial backing to a yet-to-built facility in SWMAAC does not equate to affirmative discrimination against interstate commerce or out-of-state economic interests within the meaning of the dormant Commerce Clause. See generally McBurney, 667 F.3d at 469 (explaining that the dormant Commerce Clause "'does not purport to . . . protect the participants in intrastate or interstate markets, nor the participants' chosen way of doing business'" (alteration in original) (citation omitted)).

Relying on Alliance for Clean Coal v. Miller, 44 F.3d 591

(7th Cir. 1995), Plaintiffs assert the SWMAAC "locational requirement discriminates against out-of-state commerce [because] it effectively displaces imported power with locally produced power." Pls.' Post-Trial Br. [Document 144] at 64. However, the Seventh Circuit's decision in Alliance for Clean Coal does not stand for the broad proposition that displacing imported energy discriminates against interstate commerce. In Alliance for Clean Coal, Illinois passed a law that, while not compelling all in-state coal burning generators to burn high-sulfur coal mined in Illinois, implemented several statutory mechanisms[73] that significantly hindered, if not totally prevented, Illinois utilities from switching to low-sulfur out-of-state coal to meet environmental mandates. 44 F.3d at 594-96. Through these statutory mechanisms, the Seventh Circuit held that Illinois discriminated against interstate commerce by making out-of-state coal a less viable option for in-state generators to meet environmental mandates. See id. at 596. Alliance for Clean Coal is less than comparable to the instant

[73] For instance, the Illinois law: (1) required the state regulatory entity to take into account the local coal industry when considering plans to comply with sulfur-related environmental mandates; (2) mandated that certain generating units install scrubbers so that those units could burn the high-sulfur Illinois coal; (3) guaranteed the cost of the scrubbers would be passed through to consumers; and (4) required a utility to get regulatory approval before changing its fuel source in a way that would result in a 10% or greater decrease in the use of Illinois coal. Alliance for Clean Coal v. Miller, 44 F.3d 591, 595-96 (7th Cir. 1995).

case because the PSC did not act for the explicit purpose of protecting some in-state business, like coal mining, in the wake of new federal regulation threatening to wipe out that local business. See id. at 594-96 (explaining that federal amendments to the Clean Air Act "meant the end of the salad days for high-sulfur coal-producing states such as Illinois"). Moreover, the PSC has in no way regulated to make energy generated outside SWMAAC a less viable and/or less competitive option for distribution in Maryland.

Furthermore, the evidence does not support the claim that the Generation Order will discriminatorily displace imported power. The Generation Order will add additional supply to the wholesale energy marketplace, but whether or not any power is displaced will depend upon demand and all the factors that play into the market-based auction process administered by PJM. If demand for electric energy increases in proportion to the capacity of a new facility, then the facility’s effect is neutral. Also, the generator called for in the Generation Order would sell to PJM in the PJM Markets so that any displacement of power will be the result of PJM's dispatch and procurement models. See Tr. Mar. 6 (AM) at 18:1-19:18, 22:5-10, (Massey). Even absent the SWMAAC locational requirement, the procurement of a new generation facility would have the same displacement effects complained of by Plaintiffs because that facility would still increase the available supply of electric energy and capacity.

The Court does not find persuasive Plaintiffs' position that the SWMAAC locational restriction discriminates against interstate commerce because it requires economic activity to take place in-state to the exclusion of out-of-state sources of the same activity. As discussed supra, the Generation Order does not impose any hindrance on the ability of market participants to buy and sell wholesale energy and related products in the PJM region. Therefore, the existence of a facility in Maryland does not operate to the exclusion of generation facilities outside of SWMAAC, which are still free to supply electric energy to Maryland EDCs through the PJM Markets or bilateral transactions. The decisions relied upon by Plaintiffs in support of their position are inapposite. For instance, in Tri-M Grp., LLC v. Sharp, the Third Circuit struck down a residency requirement as facially discriminatory under the dormant Commerce Clause because the regulatory scheme required a contractor to set up and maintain a permanent office location in the state to be eligible to pay lower apprentice wage rates for work done on in-state public projects. 638 F.3d 406, 412, 413 (3d Cir. 2011). The Third Circuit explained this type of in-state presence requirement "forces out-of-state contractors . . . to 'surrender whatever competitive advantages they may possess' by burdening them with expenditures for a new local operation, or with the payment of increased wages on their contracts." See id. at 427-28. Here, the Generation Order does not require any out-of-state competitor to establish a physical presence in SWMAAC or Maryland to supply electric energy to Maryland residents.[74]

Accordingly, the Court finds that the Plaintiffs have failed to demonstrate that the Generation Order discriminates against interstate commerce either facially, in its practical effect, or in its purpose as a consequence of the SWMAAC locational requirement in the RFP.

4. Burden on Interstate Commerce

Plaintiffs contend that the Generation Order imposes a significant burden on interstate commerce and that there is no evidence in the record demonstrating that the Order was needed to maintain reliability in Maryland. Defendants maintain that Plaintiffs have failed to meet their burden of demonstrating

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[74] The Generation Order also cannot be construed as an in-state processing requirement of the kind considered to discriminate against interstate commerce because it imposes no requirement that Maryland EDCs purchase electric energy and/or capacity from a generator located within SWMAAC. Cf. C & A Carbone, Inc. v. Town of Clarkstown, N.Y., 511 U.S. 383, 386-87, 394 (1994) (finding that a local regulation had the practical effect of discriminating against interstate commerce where it only allowed a preferred local facility to provide commercial service of processing waste within the town limits).

that the benefits of the Generation Order are clearly outweighed by the burdens it imposes on interstate commerce.

State action that does not affirmatively discriminate against interstate commerce may nonetheless violate the dormant Commerce Clause if it places an undue burden on interstate commerce. See Yamaha Motor Corp., 401 F.3d at 567. The Supreme Court has noted:

> [I]t must be borne in mind that the Constitution when 'conferring upon Congress the regulation of commerce, . . . never intended to cut the States off from legislating on all subjects relating to the health, life, and safety of their citizens, though the legislation might indirectly affect the commerce of the country.'"

Huron Portland Cement Co. v. City of Detroit, Mich., 362 U.S. 440, 443-44 (1960) (alteration in original).

To determine whether state action burdens interstate commerce in violation of the dormant Commerce Clause, courts apply the Pike undue burden balancing test:

> Where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits. If a legitimate local purpose is found, then the question becomes one of degree. And the extent of the burden that will be tolerated will of course depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate activities.

Pike v. Bruce Church, Inc., 397 U.S. 137, 142 (1970) (internal citation omitted). The undue burden test is less scrutinizing than the test for affirmatively discriminatory state actions. See Yamaha Motor Corp., 401 F.3d at 567.

As discussed herein, Maryland has a legitimate interest in ensuring that Maryland residents have available to them an adequate and reliable supply of electric energy. Presumably,[75] Plaintiffs take the position that the SWMAAC locational requirement constitutes an undue burden on interstate commerce. The PSC regulated to finance indirectly the development and operation of a generation facility within SWMAAC, which will participate in the wholesale energy and capacity markets in the PJM region like any other generation facility. Other than increasing the available supply of electric energy and capacity in the PJM region by adding a new generation facility in SWMAAC, the Generation Order does not affect the ability of other market participants to sell energy and capacity in the PJM Markets. The Court does not find evidence that the addition of a state-sponsored market participant physically located within SWMAAC imposes a burden, let alone an undue burden, on interstate commerce.

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[75] Plaintiffs' position is not perfectly clear on this point.

Even if the Generation Order could be viewed as placing or imposing some burden on interstate commerce, the burden would be de minimis, and thus, not clearly excessive in relation to the benefits to Maryland. The soundness of the PSC's reasoning in choosing to limit the RFP to generators physically located within SWMAAC can, like the rationale for most regulatory actions, be the subject of reasonable debate. However, the rationale reflected in the Generation Order and related materials is not so irrational as to be outweighed by an incidental burden on interstate commerce.

Accordingly, the Court finds that Plaintiffs have failed to demonstrate that the Generation Order, as a consequence of the SWMAAC locational requirement in the RFP, imposes an undue burden on interstate commerce that is clearly excessive in relation to the putative local benefits.

C. Violation of 42 U.S.C. § 1983 (Count III)

In Count III, Plaintiffs claim that the PSC deprived them of their federal statutory rights protected by 42 U.S.C. § 1983. To the extent that Plaintiffs have not abandoned that claim, the Court finds it meritless because the Fourth Circuit has "held that the Supremacy Clause is not a source of substantive individual rights that could support an action brought pursuant to Section 1983." Md. Pest Control Ass'n v. Montgomery Cnty., Md., 884 F.2d 160, 162-63 (4th Cir. 1989) (per curiam).

IV. CONCLUSION

For the reasons set forth herein, the Court decides that:

1. The Generation Order is violative of the Supremacy Clause of the United States Constitution.

2. The Generation Order is not violative of the dormant Commerce Clause of the United States Constitution.

3. Plaintiffs have not presented a viable claim under 28 U.S.C. § 1983.

SO DECIDED, this Monday, September 30, 2013.

/s/
Marvin J. Garbis
United States District Judge

APPENDIX

TERM/ACRONYM	DEFINITION
PSC	Maryland Public Service Commission
Order / Generation Order	Order No. 84815 issued by the PSC on April 12, 2012
EDCs	Electric Distribution Companies
CfD	Contract for Differences entered into by CPV and the Maryland EDCs pursuant to the Generation Order
FPA	Federal Power Act
FERC	Federal Energy Regulatory Commission
RTO	Regional Transmission Organization
PJM region	13 states and the District of Columbia
PJM	PJM Interconnection, LLC
LSE	Load Serving Entity, an entity that has state or local authority to sell electric energy to end-use customers located within the PJM region
RAA	Reliability Assurance Agreement
BRA	Base Residual Auction
RPM	Reliability Price Model
RTEP	Regional Transmission Expansion Plan
FRR	Fixed Resource Requirement Alternative
Uprate	Action taken by an existing generation facility to expand its generation capacity
TrAIL	Trans-Allegheny Interstate Line, a transmission line constructed and placed into service by PJM
EQR	Electronic Quarterly Report, pursuant to a FERC requirement, entities that have market-based rate tariffs are required to file on a quarterly basis a report of all the transactions and contracts entered into that

	are subject to the jurisdiction of FERC. Tr. Mar. 7 (AM) at 114:16-115:8 (Knight).
MOPR	Minimum Offer Price Rule
PJM Tariff	The Open Access Transmission Tariff pursuant to which PJM operates

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NEW JERSEY

PPL ENERGYPLUS, LLC, et al., Plaintiffs, v. ROBERT M. HANNA, in his official capacity as President of the New Jersey Board of Public Utilities, et al., Defendants.	Civil Action No.: 11-745 MEMORANDUM

SHERIDAN, U.S.D.J.

This non-jury case was tried before the Court over thirteen separate days in April and May, 2013. After trial, the parties submitted proposed findings of fact and conclusions of law as well as briefs, and thereafter, summations were heard. The Court, having considered the parties' submissions and having deliberated over the facts and the law, submits this memorandum as its decision.

In broad terms, the issue before the Court is whether the New Jersey Long-Term Capacity Pilot Project Act, P.L. 2001, c. 9, approved Jan. 28, 2011, codified at N.J.S.A. §§ 48:3-51, 48:3-98.2-.4 ("LCAPP" or "Act"), should be declared unconstitutional as violating the Supremacy Clause, and whether the New Jersey Board of Public Utilities ("NJBPU", "BPU", or as referred to herein as the "Board") should be enjoined from engaging in activities in furtherance of the Act because the LCAPP is preempted by the Federal Power Act, 16 U.S.C. § 824 *et seq.*. That is, whether actions by the State of New Jersey taken pursuant to the LCAPP intrude upon and interfere with the authority delegated to the Federal Energy Regulatory Commission (as referred to herein, "FERC" or "Commission") by the Federal Power Act.

Before proceeding to the substance of this case, the Court provides two cautionary observations regarding writing style and organization and a general reservation as to the presentation and scope of the findings within this decision. First, on writing style. The electric energy industry has its own jargon which makes great use of acronyms. With so many acronyms being used, the testimony and briefs become like alphabet soup where all the letters swirl around and may confuse the reader. As such, a list of acronyms which have been substantially agreed upon by the parties is attached as Rider A. The Court minimizes use of these acronyms in this decision. By way of reservation, the first part of the trial reviewed the extensive history of how the electric energy industry has developed into its present state. This opinion includes an overview of the relevant background for the purpose of providing sufficient information to decide the issues, however, it does not purport to be a historical work. And lastly on organization, there are many non-controversial facts presented within the Court's overview of the relevant background, and a new term may present itself without prior introduction. In this case, the term will be explained later in the Court's decision. After sifting through a confluence of facts, the Court has gleaned a set of manageable facts with which to evaluate the preemption issue. The decision is subdivided into several sections: (A) an identification of the parties to the action; (B) an identification of important non-parties; (C) an identification of witnesses who testified at trial; (D) a description of some basic facts regarding electricity; (E) background information on the electric energy industry; (F) a description of the "Reliability Price Model" ("RPM") process; (G) a description of the LCAPP statute; (H) an explanation of the impacts of the LCAPP; (I) a description of the credibility of witness; (J) analysis; and (K) a conclusion.

A. PARTIES TO THE ACTION

1. Defendants

New Jersey Board of Public Utilities. The defendants are Robert M. Hanna[1], Jeanne M. Fox, Joseph L. Fiordaliso, and Nicholas Asselta, all of whom are current or former commissioners of the New Jersey Board of Public Utilities[2]. Each is named in his official capacity against whom declaratory and injunctive relief is sought. Since each currently serves or formerly served as a commissioner on the Board, this opinion collectively refers to them as the "Board." The Board has broad statutory authority over the activities of public utilities within the State of New Jersey. *See In re Centex Homes, LLC*, 411 N.J. Super. 244, 254 (App. Div. 2009). Specifically, Title 48 of the New Jersey Statutes provides that the Board has "general supervision and regulation of and jurisdiction and control over all public utilities." N.J.S.A. § 48:2-13(a). As part of that authority, the BPU is authorized to require any public utility operating within the State to furnish safe, adequate, and proper service to consumer ratepayers at "just and reasonable" rates. N.J.S.A. § 48:2-21.

CPV Power Development, Inc. CPV Power Development, Inc. ("CPV") is an Intervenor/Defendant. CPV is a Delaware corporation that, through its subsidiaries, is engaged in the development, ownership, and management of natural gas-fired facilities in North America (T. 1587, 10-24). CPV owns and manages a natural gas-fired generation facility in Riverside County, California, and has taken steps to develop other natural gas-fired facilities, including

[1] Mr. Hanna was named as President of the Board on December 21, 2011. At the time of the underlying facts, Lee A. Solomon served as Board President.

[2] In New Jersey, the Board has always been a distinguished public entity known for its practical and professional decision making. Over the years, many prominent New Jersey leaders have served on the Board. For example, Mr. Solomon and Mr. Asselta served in the New Jersey State Assembly. Both Governor Byrne and Governor Whitman have served as Board President. Moreover, William Hyland, a former New Jersey Attorney General who has served the State of New Jersey in many esteemed capacities, was a former Board President. In reviewing this matter, the Court has considered the Board and its members, their sound judgment, and their professionalism in furtherance of the public good.

projects in Maryland, New York and New Jersey. CPV began to develop its Shore Project in New Jersey prior to implementation of the LCAPP Act. (T. 1588, 6 through T. 1589, 17). Most importantly for purposes of this case, CPV was named an eligible generator under the LCAPP by the Board and cleared the RPM Auction on its 2012 bid (T. 1588, 15-22).

2. Plaintiffs

The Plaintiffs are a group of wholesale, retail, and marketing companies who produce and sell energy and are located within the PJM market[3]. Several Plaintiffs are identified below.

Plaintiff Calpine Corporation is an electric generation and marketing corporation with a number of subsidiaries. It is a publicly traded, independent power producer based in Houston, Texas which operates ninety-one (91) power plants throughout the United States and Canada. The Calpine generation companies are physically located in the PJM market and participate in the PJM wholesale energy and capacity markets.

Plaintiff Exelon Generation Company, LLC is a Pennsylvania corporation headquartered in Kennett Square, Pennsylvania. Exelon Generation is a wholly-owned subsidiary of Exelon Corporation. Exelon Generation's business consists of owning and operating electric generating facilities, wholesale power marketing operations, and competitive retail supply operations. Exelon Generation sells energy and capacity in the PJM interstate market and competes in PJM's wholesale capacity auctions.

The PPL Parties are a group of related companies principally located in Allentown, Pennsylvania which are market and generation subsidiaries of PPL Corporation. They are physically located in the PJM market and participate in the PJM wholesale energy and capacity

[3] Plaintiffs GenOnEnergy, NAEO Ocean Peaking Power, and Essential Power were never substantively discussed during trial and no injury was presented.

markets. Together they control or own about 19,000 megawatts of generating capacity in the United States, some of which is located within the PJM market.

Plaintiff PSEG Power, LLC is a Delaware limited liability company, headquartered in Newark, New Jersey. PSEG Power is a wholly-owned subsidiary of Public Service Enterprise Group, Inc.. PSEG Power owns approximately 11,850 megawatts of generating capacity within the PJM area, approximately 9,950 megawatts of which is located in New Jersey. PSEG Power sells energy and capacity at wholesale in interstate commerce, including in PJM's capacity and energy markets.

Plaintiff Public Service Electric and Gas Company ("PSE&G"), a subsidiary of Public Service Enterprise Group, is located in New Jersey and is one of the largest combined electric and gas companies in the United States. It is also New Jersey's oldest and largest publicly owned utility. PSE&G currently serves nearly three quarters of New Jersey's population from Bergen to Gloucester Counties.

Plaintiff Atlantic City Electric Company, based in New Jersey, is a subsidiary of Pepco Holdings, Inc., which provides electric service to approximately 547,000 customers in southern New Jersey. Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 1.9 million customers in Delaware, the District of Columbia, Maryland and New Jersey.

B. OTHER IMPORTANT NON-PARTIES

The Federal Energy Regulatory Commission ("Commission" or "FERC") and PJM Interconnection, LLC ("PJM") are two entities that are key players in the sale and delivery of energy. The Commission and PJM are not parties to this action, but are discussed throughout this memorandum.

Pursuant to the Federal Power Act, 16 U.S.C. § 824 *et seq.*, the Commission has federal statutory authority to regulate the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. (Stipulated Facts ¶ 5). In this case, the scope of the Commission's jurisdiction in regulating the sale of electric capacity in the wholesale market, and whether such jurisdiction is exclusive or concurrent with the Board's jurisdiction, is at issue. The applicable federal statute from which the Commission derives its authority reads:

> (b) Use or sale of electric energy in interstate commerce.
>
> (1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter. 16 U.S.C. § 824(b)(1).

PJM Interconnection, LLC is a voluntary association of different energy stakeholders which includes administrative bodies and electric generators.[4] (Stipulated Facts ¶ 13). PJM is primarily subject to Commission regulation through a tariff. It operates a regional wholesale

[4] PJM was not well defined at trial. The issue of how these competing companies and regulatory bodies interact in terms of governance and voting procedures was not adequately addressed by any of the litigants.

market that includes all or part of thirteen states including New Jersey. In addition, PJM is a regional transmission organization ("RTO"). (T. 47, 17 through T. 48, 11).

PJM was originally founded in 1927. The name "PJM" is the brainchild of its earliest members who were from the states of "Pennsylvania (P), New Jersey (J), Maryland (M)". (T. 410, 22 through T. 411, 8). It was formed as a "power pool" for traditional utilities which recognized that a regional transmission organization could easily accommodate sharing of electric capacity more efficiently (T. 39, 5-10). The sharing of electrical capacity through such arrangements drastically drops consumer costs by limiting the number of electrical generation facilities required for peak hour production. As noted above, PJM operates pursuant to a tariff filed by PJM with the Commission called the "Open Access Transmission Tariff." (Stipulated Facts ¶ 23).

PJM has been a relatively successful operation. For instance, today, PJM is the "largest centrally dispatched power market . . . in the world," covering 60 million customers and 185,000 megawatts. (T. 69, 20 through T. 70, 1). Within PJM there are over 1,300 power plants and approximately 56,000 miles of transmission lines. (T. 406, 24 through T. 407, 11). Mr. Massey testified that PJM is the most sophisticated of all of the regional transmission organizations. In fact, "there are government officials and market participants from around the world that regularly travel to PJM for briefings about how the markets work. So [it is] considered state of the art." (T. 70, 1-8).

Gradually, the traditional utilities within PJM transferred operational control of all their transmission to PJM. Currently, PJM is responsible for "[m]anaging a regional transmission grid encompassing all or part of thirteen states and the District of Columbia." (Stipulated Facts ¶ 11).

PJM, under the supervision of the Commission, is "responsible for planning the electric system to preserve the reliability of the electricity supply" in New Jersey. (Pl.'s Ex. 45, at 27). That is, PJM "plan[s] expansions to transmission to improve the ability to transmit energy from where it is generated to serve load." (Stipulated Facts ¶ 11). Most importantly, PJM is also responsible for the "dispatching" of generation in real time. It does this from "a very sophisticated control room in Valley Forge, Pennsylvania . . . which looks like an air traffic control system." (T. 50, 6-13). From this control room, PJM "direct[s] this generator[], to ramp up [and] . . . to ramp down all in real time. Because over this 13 state area they must insure that supply and demand are matched almost perfectly in real time." (T. 50, 12-13). Despite these functions, PJM has no authority to construct or build a power plant, and likewise it has no authority to retire antiquated power plants. (Def.'s Ex. 183).

C. TESTIFYING WITNESSES

There were a number of witnesses who testified at trial, each of whom is identified below. All of these witnesses were very professional and proficient in their careers, and the Court weighed their credibility in light of these qualifications.

1. Plaintiffs' Witnesses

William L. Massey obtained his Law Degree from the University of Arkansas School of Law in 1973, and later earned an LLM from Georgetown University Law Center in 1985. Upon his law school graduation, he clerked for the U.S. Circuit Court of Appeals for the Eighth Circuit. He later became Chief Counsel for U.S. Senator Dale Bumpers of Arkansas, where he focused on energy matters before the Senate Committee on Energy and Natural Resources. President Clinton later appointed Mr. Massey to be a Commissioner of the Commission where he served for over ten years. Mr. Massey currently serves as a partner in the Washington, DC office of the law firm Covington and Burling and is an Adjunct Professor at the Georgetown University Law Center. Mr. Massey was qualified as an expert "in the history and evolution of the electricity industry." (T. 23, 12-15).

Joseph Dominguez is the Senior Vice-President for Governmental and Regulatory Affairs and Public Policy for Exelon Corporation. He obtained a Bachelor of Science Degree in Mechanical Engineering from the New Jersey Institute of Technology and a Law Degree from Rutgers University School of Law. He previously worked at the law firm of White & Williams in Philadelphia, Pennsylvania and served as an Assistant United States Attorney in the Eastern District of Pennsylvania.

Robert D. Willig, Ph.D. is a Professor of Economics and Public Affairs at Princeton University. Professor Willig studied mathematics at Harvard College and later obtained a Masters of Arts in Operations Research and Statistics, and a Doctorate in Economics from Stanford University. Professor Willig previously worked at Bell Labs performing research on the theory of economic regulation of regulated industries. After working there for five years, he became a Professor of Economics and Public Affairs at Princeton in 1978. Professor Willig's specialty is industrial organization which involves the interrelationships between business, technology, the marketplace, and government. He was qualified as an expert in the fields of economics and regulatory policy with particular expertise in electric energy. (T. 623, 21-25).

Michael Cudwadie is employed by PPL Energy Plus as Vice-President of Trading East. In that role, he is responsible for the hedging and trading activities of 9,000 megawatts of generation in the PJM markets. He has a Bachelor's Degree in Accounting from Pennsylvania State University, and an MBA from Lehigh University.

Zamir Rauf has been employed by Calpine Corporation as its Chief Financial Officer since 2008. In that role, he is responsible for the accounting and treasury functions of Calpine which include project finance, investor relations and risk management.

Daniel Cregg is the Vice-President of Finance for PSEG Power within PSEG Services Corporation. In this role, he develops business plans and near term earnings forecasts, prepares forecasts of market direction and analyzes elements of major investment decisions. He has a Bachelor's Degree in Accounting from Lehigh University and an MBA from the University of Pennsylvania's Wharton School of Business.

Anthony Robinson is employed by PSE&G as Director of Basic Generation Service and Basic Gas Supply Service. He has a Bachelor's Degree in Economics, Applied Math and Statistics from Stoney Brook University. (T. 939, 14-17).

2. Defendants' Witnesses

James P. Giuliano is Director of the New Jersey Board of Public Utilities' Division of Reliability and Security. He is responsible for natural gas pipeline safety, underground damage prevention and emergency management and security. He has a Bachelor's Degree in Communications, and has completed many state certifications in courses related to his job.

Oden Sherman Knight is the Senior Vice President of Marketing and Organization at CPV where he manages power sales and gas purchases. (T. 1584, 16). He has a Bachelor's Degree in Mechanical Engineering from Stanford University and a Masters in Business from Columbia University (T. 1584, 4-7).

Craig R. Roach is a principal of Boston Pacific Company, a consulting firm which focuses on power plant development. He has a Bachelor's Degree in Economics from John Carroll University and a Doctorate in Economics from the University of Wisconsin. Mr. Roach was qualified as an expert in the design and implementation of competitive procurements and competitive markets for electricity.

Mr. Richard L. Levitan was the Board's advisor for implementation of the LCAPP. He has served as President of the consulting firm Levitan & Associates since its founding in 1989. The firm provides management consulting and analytic expertise to regional transmission organizations and short form independent system operators. He is a graduate of Cornell University and received a Masters with a specialization in Energy Economics from Harvard University.

D. BASIC FACTS REGARDING ELECTRICITY

Energy is "the actual electricity" that electric generators produce and which residential and business consumers ultimately use[5]. (Stipulated Facts ¶ 20). It cannot be stored in quantities large enough to supply customers during times of peak demand. (*Id*.). That is, energy cannot be canned or placed in a battery for a long period of time. It has no shelf life. As a result, "energy generally must be produced when it is needed, and at the rate at which it is consumed." (*Id*.) As Mr. Massey stated during his testimony, "[o]ne of the things about electricity is that it cannot be easily stored, and so supply and demand have to be matched instantaneously in real time." (T. 35, 4-6).

Energy is a product in interstate commerce. Regardless of which generator dispenses the energy, it ordinarily travels through interstate commerce to reach its destination. In 1927, the Supreme Court held that the interstate commerce clause prohibits states from regulating the rates for wholesale energy sales between utilities in different states because those sales are interstate transactions. *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927); (Stipulated Facts ¶ 4). Surprisingly, no witness precisely described the logistics of an energy

[5] Residential and business customers are often referred to as "consumers" or "ratepayers".

delivery transaction (i.e., how energy is transmitted from a generator to a consumer) except to say that the delivery of energy is overseen by PJM and PJM routes energy through its transmission system. (T. 50, 6-13)

Amount of Energy. Energy is usually measured in megawatts. One megawatt of electricity powers approximately 1,000 households. Usually, megawatts are associated with lengths of time such as "per day" or "per hour." (Stipulated Facts ¶ 18).

Capacity. "Capacity" is defined as "the ability to produce electricity when called upon." (Stipulated Facts ¶ 17). In essence, capacity is the ability to produce sufficient energy to meet demand. At certain times, such as during the summer months when temperatures increase, demand for energy increases. Regardless of fluctuations, there must be sufficient capacity to meet the demand of high energy use at all times.

Capacity Resources. "Capacity resources include electric generation facilities (e.g., nuclear, natural gas, coal, wind, or solar), demand resources (i.e., the ability to call upon consumers to reduce their electricity demand), and energy efficiency resources (measures that reduce demand)." (Stipulated Facts ¶ 19).

Reliability. "Reliability" is the delivery of electricity to customers in the amounts desired and within acceptable standards for frequency, duration and magnitude of outages and other adverse conditions or events. (T. 81, 23 through T. 83, 12). According to Mr. Levitan, electric reliability means being able to "keep consumers' lights on" under duress and maintaining the power system when operating contingencies arise. (T. 1549, 8-11); *see also* I/M/O the Petition of Public Service Gas and Electric Company for a Determination Pursuant to the Provisions of N.J.S.A. 40:55D-19 (Susquehanna-Roseland Transmission Line). Resource adequacy is a key component of reliability. (T. 1549, 6-14). The key factor in meeting the reliability standard is having sufficient generators and transmission lines available to deliver energy as required by the circumstances.

Generation Plants. Generation plants are categorized into three types – base load, mid-merit, and peaking plants. The parties agree on the definition of base load and mid-merit. A base load plant is a plant that operates all or most of the time. A mid-merit plant, such as a combined-cycle gas turbine, is a plant that operates less than a base load plant but more than a peaking plant. The parties disagree on the definition of a peaking plant; but generally, a peaking plant is "a gas turbine, a simple cycle unit, a unit that is typically run sparingly, a unit that has certain technology characteristics that allow it to get started from a cold stand-by mode, and achieve full operation in just a few minutes." (T. 1289, 12-16).

E. BACKGROUND OF THE ELECTRIC ENERGY INDUSTRY

In the beginning of the twentieth century, the New Jersey Legislature, like many other state legislatures at the time, enacted a statute creating a public utility to oversee the operation of electric and gas utilities. During the early stages of utility regulation, states had exclusive authority over such utilities. During this time, the energy industry "was dominated by vertically integrated utility companies" (hereinafter, referred to as "traditional utilities")[6]. (T. 24, 24 through T. 25, 1); (Stipulated Facts ¶ 1).

Typically, the traditional utility was granted an exclusive right by state and local governments to provide electric service to all consumers located in a defined territory. The traditional utility also had other powers, such as eminent domain authority, that would allow it to construct and operate power plants and local distribution networks to connect those power plants to local customers. In return, the traditional utility obligated itself to operate as a "common

[6] The parties refer to the traditional utility as a "vertically integrated utility." For purposes of minimizing confusion, this memorandum uses the term "traditional utility" because the word "utility" is now associated with an electric distribution company (EDC).

carrier" with the duty to provide service on a non-discriminatory basis, and to subject its rates to regulation by a state public utility commission. The regulatory standards adopted by state commissions permitted rates that would reimburse utilities for their costs incurred in providing service and debt incurred in financing the construction of power plants and other equipment. The standards were also meant to afford investors in these utilities a reasonable rate of return. This structure enabled the traditional utility to raise capital through the issuance of stock or selling of debt, which, in turn, would allow the utility to expand its facilities. Recovery of and on an investment in a traditional utility, however, was always subject to a “prudence review” by the Board in New Jersey. (Stipulated Facts ¶ 2).

In 1927, the Supreme Court of the United States decided the landmark case *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927). In that case, the Public Utilities Commission of Rhode Island attempted to regulate the sale of electricity from the Narragansett Electric Lighting Company to the Attleboro Steam & Electric Company located in Massachusetts. The Court struck down the Public Utilities Commission of Rhode Island’s efforts deeming that its regulation had placed a direct burden on interstate commerce. The Court’s decision ultimately created a regulatory gap wherein no regulator had the authority to oversee interstate transactions made by traditional utilities.

In 1935, envisioning that the federal government should have a role in regulating interstate energy transactions, Congress enacted the Federal Power Act, which gave the Commission exclusive regulatory authority over “the transmission of electric energy in interstate commerce” and “the sale of electric energy at wholesale in interstate commerce. 16 U.S.C. § 824(b). While the statute vested this authority in the Commission, it also “reserved to the States certain . . . regulatory authority, including that over generation facilities.” (Stipulated Facts ¶ 5).

Under the statute, state commissions "continued to regulate local utilities' construction of new power plants, operations, and rates charged for retail service to customers" including "the costs incurred by local utilities in constructing and operating the power plants they used to generate electricity to service their retail customers. (*Id*.) From 1920 until the late 1980s, utilities operated under the concurrent supervision of both federal and state regulations. During that time, the Board and Commission acted cooperatively and respected their jurisdictional limits.

Before the advent of federal authority in the electric power industry, a traditional utility "performed three main operational tasks: it built, owned, and operated electric power plants; it transmitted electricity from the power plants to the area of service in which it enjoyed a monopoly; and it distributed the electricity to its customers in that area of service using its local distribution network, that is, the poles and wires that it owned and maintained." (Stipulated Facts ¶ 1). Each traditional utility was, in essence, a "single company" that "generated power, transmitted that power, and distributed that power to its own customers, the homes and businesses that it serves". (T. 2008, 13-18). In these early years, there was little to no relationship among the traditional utility companies, so each company generally only produced sufficient capacity to service its own customers' needs. Each traditional utility had a service territory established by state regulation, a monopoly for electricity service within that territory, and an obligation to serve all customers in that service territory. "[I]n return for fulfilling that obligation to serve all customers, [traditional utilities] were given an assurance of a reasonable rate of return." (T. 27, 16-21); (Stipulated Facts ¶ 2). As a result, a traditional utility's sales of electricity to residential and business users within its service territory were considered retail sales to consumers and "largely regulated at the state level." (T. 25, 5-6); (T. 30, 12-13); (Stipulated Facts ¶ 5).

Often the lack of interaction among traditional utilities created inefficiencies because each utility would construct its own power plants to meet peak electric demand; that is, each traditional utility "was insuring that it had enough capacity to serve its own load." (T. 37, 16-18). Because electricity demand peaks at limited times throughout the year, a utility may have needed to build a power plant that runs only "10, 15, 20, 50 hours a year." (T. 35, 3-13). As a result, each traditional utility tended to have "plants that [were] sitting idle most of the time, because they [were] needed for a few hours." (T. 37, 16-24). "[T]hat created some inefficiencies in the sense [that] . . . too many power plants to provide this capability were being built." (T. 37, 16-24).

In the early twentieth century, some electric utilities smartened up, adjusted their strategy, and "began to sell power or standby capacity to each other." (Stipulated Facts ¶ 3). In order to accomplish this, the traditional utilities "built high voltage transmission lines among them in order to transact such 'wholesale' purchases and sales. This allowed utilities to lower costs because they no longer had to maintain sufficient capacity to supply peak demand at all times; instead, they could contract bilaterally in the interstate wholesale market to ensure that they had access to sufficient resources to supply peak demand when it was needed." (Stipulated Facts ¶ 3). Thereafter, to protect against outages, traditional utilities would buy and sell capacity from one another for future years, so that they could be assured they would have sufficient supply when operating contingencies arose, without having to develop more power plants.

As the traditional utilities engaged in increased wholesale sales and capacity purchases, the need for federal regulation became more obvious. In order to manage stand-by capacity sales, PJM was created to ensure reliability by managing interstate transmission lines and, in more recent years, by designing and operating wholesale auctions.

Deregulation of Wholesale Energy Sales by the Commission

In the 1980s, when governmental deregulation of business entities was a prevalent feature of federal policymaking, some federal legislators brainstormed that the structure for sales of energy and energy capacity could be modified from one in which sales were made at a governmentally imposed rate to one that was more economically efficient, competitive and based on the economic theory of supply and demand. This idea ultimately culminated in several initiatives during the 1990s.

In 1992, Congress enacted the Energy Policy Act of 1992 ("EPAct"), Pub. L. No. 102-486, 106 Stat. 2776, which authorized the Commission to ease restrictions on access to interstate transmission wires. This allowed more electric generators to provide energy to a broader area, and recognized the concept of separating generation facilities from other parts of traditional utilities. That is, the generation segment of a traditional utility could operate separately from the other segments of the utility. A key objective of the Energy Policy Act was to "encourage[e] the development of independent generators" – sometimes referred to as "independent power producers" – "that could sell into the marketplace." (T. 44, 11 through T. 46, 25).

In 1996, the Commission issued Order Number 888 which required "transmission owners in the United States . . . to offer access to their transmission wires to third-parties . . . on a non-discriminatory basis." (T. 45, 12-19). "Order 888 opened the transmission grid, and competition began to develop, and . . . . wholesale markets were actually emerging regionally." (T. 47, 12-16). In 1996, through Orders 888 and 889, the Commission "established national open-access rules that required all transmission-owning utilities under its jurisdiction- i.e., those utilities that 'own, control, or operate transmission facilities used for transmitting electric energy in interstate transmission' - to provide non-discriminatory transmission access under standardized tariffs. One significant impact of Orders 888 and 889 was to increase the opportunity for non-utility generators to sell their power to additional markets." (Stipulated Facts ¶ 8).

In December 1999, the Commission issued Order 2000 which encouraged industry participants to organize themselves into large regional entities called regional transmission organizations ("RTO"). The creation of such organizations "allow[ed] for regional operation of the transmission system and provide[d], among other things, a platform for regional wholesale electricity markets." (Stipulated Facts ¶ 9). Notably, PJM is an RTO.

PJM adapted some of its functions to meet the requirements of these statutes and regulatory directives. Most importantly, PJM instituted three types of wholesale markets: "[the] capacity market, the energy markets and the ancillary services markets." (T. 74, 21 through T. 75, 23). Each of these markets has a special function:

(a) the "regional capacity market, called the reliability pricing model (RPM), annually sets the price of capacity" three years forward. The controversy in this case involves the regional capacity market. (T. 74, 23-24).

(b) the energy markets price the cost of energy produced by the generators and used by consumers. (Stipulated Facts ¶ 20). PJM operates a "day ahead" energy market, meaning "generators offer to supply power into the market a day ahead of real time." The day ahead market is a "planning tool that PJM uses to [e]nsure that it knows a day ahead of time what resources are going to be available 24 hours thereafter, when the generation is actually dispatched to keep the lights on." PJM also operates a "real time energy market, which is an hourly market that is close to the time of operation. And capacity resources bid into that market, and offer to supply . . . the actual electricity." (T. 74, 21 through T. 75, 23); and

(c) the ancillary services markets price the sale of "ancillary services" such as "spinning reserves and load-following services" to improve reliability. (T. 74, 21 through T. 75, 23).

Deregulation of Electric Generators by the Board

Following the federal lead, many traditional utilities chose to restructure by separating their generation functions from their transmission and distribution functions. (Stipulated Facts ¶ 6). According to Mr. Massey, there were two methods to accomplish this. First, the traditional utilities could sell or transfer their power plants to a competitive generation company. Second, the traditional utilities could "create an affiliate corporation . . . within a holding company to own the generation." (T. 53, 13-21). During the 1990s, many states restructured their electric industries to promote competitive markets in wholesale power generation. "Typically, the [s]tate-ordered restructuring resulted in the unbundling of [traditional] utilities into separate generation, transmission, and distribution companies. The distribution entities came to be known as 'Electric Distribution Companies' or 'EDCs[.]'" (Stipulated Facts ¶ 6). In some cases, "restructuring also enabled third parties with no distribution assets to compete in the sale of electricity at retail." (*Id*.) These entities are referred to as "Load Serving Entities" ("LSEs") (*Id*.).

In 1999, New Jersey followed suit. It restructured its utilities in a slightly different format than described above, but with the same result. In enacting the Electric Discount and Energy Competition Act ("NJ Energy Competition Act"), N.J.S.A. § 48:3-49 *et seq.*, the New Jersey legislature unbundled the sale of energy to retail customers. The consumer could choose to be served by one of several load serving entities which would compete to provide service. These LSEs would deliver the energy through an electric distribution company ("EDC"). (T. 59, 2-9). As Mr. Dominguez explained in his testimony, the driving force behind the NJ Energy

Competition Act was "customer choice" – that customers would have the right to choose their electricity suppliers or LSE. (*Id.*) Although the New Jersey Legislature focused on the benefit to the consumer, the NJ Energy Competition Act also "required the State's [traditional] electric utilities to divest themselves of electricity generation assets." (Stipulated Facts ¶ 7). Once the generation component was stripped, the word "utilities" became associated with the term "electric distribution companies" because EDCs were responsible for distributing electricity over local distribution networks to consumers in monopolistic service areas and were required to act as common carriers.[7] "The electricity itself was supplied by retail electric suppliers, that is, LSEs." (Stipulated Facts ¶¶ 7, 9).

At the time of enactment, the New Jersey Legislature recognized the magnitude of this fundamental change by declaring that "this bill would effectively end the system of government regulation of the electricity generation industry, which has existed in New Jersey since the years when Woodrow Wilson served as Governor." Electric Discount and Energy Competition Act, P.L. 1999, c.23. eff. Jan. 25, 1999. Hence, the NJ Energy Competition Act recognized the demise of the traditional utility and the transformation of the electric energy industry into a more market driven system. Further, although the federal and state statutory amendments opened new competitive markets through restructuring, the State retained its authority over the siting and construction of power plants. (T. 167, 9 through T. 169, 6). So, after restructuring by the federal and New Jersey governments, the electric energy industry operates in the following manner:

(a) generators may sell energy and capacity at wholesale prices to PJM or negotiate power supply agreements (T. 64, 11 through T. 65, 4);

(b) PJM transmits and sells energy to load serving entities ("LSEs"); and

[7] The electric distribution company is referred to as a utility, but its operation is not as expansive as a traditional utility.

(c) LSEs sell to consumers and distribute the energy through electric distribution companies ("EDCs") which have monopolistic service areas and operate as common carriers. Since the EDC transmits the electric to consumers within its monopolistic area, it receives a delivery fee from the LSE.

In New Jersey, there are four EDCs: Rockland Electric Company, Public Service Electric & Gas Company ("PSE&G"), Jersey Central Power & Light Company ("JCP&L"), and Atlantic City Electric. (Pl.'s Ex. 45, at 16-17). Each EDC owns and operates the local distribution wires located within its service territory. (T. 66, 17-22). After the restructuring, the State's utilities "became more commonly known as 'electric distribution companies' ('EDCs') because they were responsible for distributing electricity over local distribution networks." (Stipulated Facts ¶ 7). An EDC is sometimes referred to as the "local utility," but "the term EDC, electric distribution company, is intended to convey that this company is in the business of delivering electricity." (T. 56, 6-12). The electricity sold to retail customers by LSEs is delivered by the EDC within their local distribution networks.

The 2008 New Jersey Energy Master Plan authorized by the Board summarized the importance of the NJ Energy Competition Act:

> The owners of New Jersey power plants now have no legal expectation that they can recover all of their costs or a guaranteed return from retail customers. Hence, the plant owners (and their financiers) make their own decisions to invest in existing or new power plants, without [Board] oversight. They also make their own decisions about the price, using market signals, at which they are willing to sell their electricity, without traditional [Board] oversight. (Pl.'s Ex. 45, at 16).
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> PJM, under the supervision of [the Commission], is responsible for planning the electric transmission system to preserve the reliability of the electricity supply in its territory. Electric generation companies and their financiers make decisions about how much generating capacity will be

> built, what types of power plants will provide that new capacity, and where the new plants will be located; those companies also decide what plants will be kept in service and what plants will be retired. Those decisions are informed by economic signals from the wholesale electricity markets that PJM designs and administers, again under the supervision of the [Commission]. (*Id*. at 27).

Despite deregulation which provided generators with more decision making powers, the Commission and PJM do not have substantial authority to require construction of power plants, prevent retirement of generation, select the generation technologies that will be constructed, or require demand resource or energy efficiency programs as a means of addressing resource adequacy. (Def.'s Ex. 563). However, as previously noted, the restructuring of the traditional utilities required PJM and the Commission to institute three competitive markets which effect energy and capacity prices. The market of primary interest in this case is the regional capacity market called the reliability pricing model ("RPM").

F. THE RELIABILITY PRICING MODEL ("RPM")

The RPM is intended to "secure sufficient capacity resources to meet standards for serving the highest aggregate demand of the region's electric customers." (Stipulated Facts ¶ 12). To meet that objective, the RPM "establishes an annual Base Residual Auction ('BRA') [or "RPM Auction"] through which PJM administers procurements of capacity." (*Id*.)

The RPM conducts the RPM Auction each May to secure the capacity that will be needed three years in the future. (T. 419, 3-8); (Stipulated Facts ¶ 25). New Jersey is a voluntary member of PJM and is a part of the RPM market. (Stipulated Facts ¶ 13). RPM is a provision of the PJM tariff which is approved by the Commission. (Stipulated Facts ¶ 23); (T. 80, 25 through T. 81, 4); (Def.'s Ex. 184). As the parties stipulated:

> Through the [RPM Auction] PJM seeks to procure . . . the amount of capacity that it has determined . . . will be needed to meet the system (or in some cases, the Locational Deliverability Area ('LDA')) peak three years in the future, plus a reserve margin. PJM then bills each participating load serving entity for its load-ratio share of the costs incurred by PJM to secure that capacity through the [RPM Auction]. (Stipulated Facts ¶ 26).

Generally, "The [RPM Auction] is a 'forward market,' meaning capacity is sold three years in advance of when it is needed. For example, the auction held in May 2012 [which is the subject of this lawsuit] concerned offers to sell capacity to be 'delivered' beginning June 1, 2015, through May 31, 2016." (Stipulated Facts ¶ 27).

RPM was designed to provide price signals for both new and existing generation. PJM Interconnection, LLC, 132 F.E.R.C. ¶ 61,173, 61,870 (2010). The Commission has emphasized that "RPM was designed to provide long-term forward price signals, and not necessarily long-term revenue assurance for "generators and developers." (Pl.'s Ex. 55, at 55-56). As Mr. Dominguez stated, "the RPM is a market-based mechanism that uses economic price signals to indicate scarcity and need for capacity," and generators will decide from the price signal whether or not to expand or create new generation. (T. 413, 1-8).

"In the [RPM Auction] capacity resources . . . bid to supply capacity to PJM for one year beginning three years in the future, each offering to supply a particular quantity of capacity at an offer price." (Stipulated Facts ¶ 28). The bids of capacity resources are "stacked" from lowest-cost bids to highest-cost bids to construct a supply curve. (T. 92, 19-25). PJM also constructs a demand curve that is based on a forecast of peak electricity demand ("peak load"), plus a reserve margin. (T. 661, 13 through T. 662, 19). The PJM "reserve margin" is typically around 15 percent or more. The reserve margin addresses the possibility that "some plants might fail, might not be able to meet their obligation," or that there could be a "transmission outage." (T. 89, 25 through T. 90, 13). As Mr. Massey indicated, "[i]t also takes into account the fact that . . . [it is]

hard to forecast electricity usage perfectly." (T. 90, 2-3). "And so this reserve margin is an insurance policy." (T. 90, 7). "The price of capacity in the [RPM Auction] is set by the intersection of supply and demand and is referred to as the 'clearing price.' That is, any capacity supplier that bids at or below the clearing price 'clears' the [RPM] auction and receives the clearing price for that capacity. Any capacity supplier that bids above the clearing price fails to 'clear' the [RPM] auction, and its capacity does not sell in the auction." (Stipulated Facts ¶ 29). The clearing prices for capacity sold in the RPM are the Commission approved rates for capacity sales made in PJM territory. (Pl.'s Ex. 26). When a generation resource has cleared the auction, it obligates itself to run through the delivery year. (T. 473, 22 through T. 474, 7). Thus, a capacity resource that clears the RPM Auction commits itself to make any investments necessary to fulfill its obligation. It also obligates itself to bid into the PJM energy and ancillary services markets. (T. 426, 1 through T. 473, 17).

As Mr. Dominguez testified, RPM is designed to procure the least expensive mix of resources that are necessary to keep the lights on for that one year period, three years hence. (T. 414, 14-18). Generally, the RPM Auction says to market participants "I am willing to serve capacity for one entire year three years forward." (T. 414, 14-18). "The purpose" of RPM was to "guarantee[] that the reliability target in PJM is met in the least cost possible way." (T. 763, 13-23). As PJM has explained to the Board, its "RPM Capacity Market is designed to commit the least-cost set of capacity resources to ensure that [Commission]-established resource adequacy targets are met in the PJM footprint on a three-year forward basis." (Pl.'s Ex. 230, at 10).

Generally, the single clearing price encourages capacity resources to operate more efficiently while keeping prices low. "[A] competitive market with a single, market-clearing price creates incentives for sellers to minimize their costs, because cost-reductions increase a seller's profits. And when many sellers work to minimize their costs, competition among them keeps prices as low as possible. . . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices." PJM Interconnection, LLC, 117 F.E.R.C. ¶ 61.331, 62678 (2006); (Pl.'s Ex. 19, at 57); (T. 436, 8-24). As Mr. Massey indicated, since there is a single price for the commodity, "the person who can provide the [capacity] cheapest will do the best in that market; [and the] person who cannot provide the [capacity] competitively is either going to go out of business or figure out how to do better." (T. 436, 19-24). Mr. Massey explained "economists would say it's the law of one price. . . . It [does not] matter whether the electric energy's produced by an old generator [or] new generator, [it is] electric energy, it has the same value in the marketplace. And that [is] why pursuant to [Commission] rules that single clearing price model is used." (T. 92, 19 through T. 93, 23).

Despite the goal of reaching a highly competitive price through the RPM Auction, price varies in certain areas of the PJM market. For example, in New Jersey the price is higher than that in western Pennsylvania because the transmission costs associated with delivering the energy in New Jersey are more costly. (Def.'s Ex. 204). "For purposes of the RPM, PJM is divided into regions known as [Locational Deliverability Areas, or] LDAs." (Stipulated Facts ¶ 30). "New Jersey is located in a Locational Deliverability Area called 'EMAAC,' which also includes parts of Maryland, Pennsylvania, and Delaware. EMAAC is located within a wider [LDA] called 'MAAC,' which includes EMAAC, additional parts of Pennsylvania and Maryland, and the District of Columbia." (Stipulated Facts ¶ 31). According to the parties, within EMAAC, "there are smaller LDAs, including (within New Jersey), one called 'PSEG', and within the PSEG LDA, another one called 'PSEG North.'" (Stipulated Facts ¶ 33). As the parties explained:

> When constraints on the transmission lines limit the amount of electricity that can be imported into an LDA, RPM capacity prices can be higher in the constrained LDA - reflecting the fact that the LDA must rely on more expensive capacity resources located within the LDA rather than cheaper capacity resources located elsewhere. (Stipulated Facts ¶ 33).

Prices are often different among the LDAs leading to "price separation." As the Commission has explained, "[c]apacity market prices must be locational in order to be fully effective. Because of transmission constraints, capacity in one location is not always deliverable to loads in other locations[.]" (Pl.'s Ex. 26, at 34). As such, separate capacity prices are necessary to reflect the differences in costs and capacity needs among the locations. "Further, if a single capacity price is set for the entire region, capacity prices do not reflect the need for generation" in those particular locations. (*Id*.) For instance, as Mr. Dominguez stated "higher price for capacity gives a signal to those in the generation industry to consider developing a new plant or resource within the LDA because a better profit could be realized." (T. 445, 24 through T. 446, 12). "[T]his price differential is reflective of the transmission constraints in moving power from west to east into New Jersey and [signals] the need for resources to be located inside New Jersey." (Pl.'s Ex. 75, at 7).

From its initial inception in the early 2000s, the Board did not accept the RPM theory. Rather, the Board predicted that RPM would curtail development of new generation into New Jersey. The Board recommended that new generators should be given assurances to overcome fears regarding the risk of long term financing packages of potential financiers. The Board also complained that the RPM functions unfairly against new generators. First, the Board argued that the long term price signals of the RPM Auction were insufficient to attract new generators in New Jersey since little development had occurred. (Pl.'s Ex. 197). Second, the Board argued that financial institutions were reluctant to loan money for development because of uncertainty. That is, capacity prices fluctuate and the clearing price of the RPM Auction only lasts a year ultimately rendering a long term loan very speculative. In reality, these variables caused energy prices to increase in New Jersey. As then-Board Commissioner Frederick Butler advised the Commission in February 2006:

> RPM, in its current form, will not have the intended effects on investment and will not result in the most cost effective means of solving future reliability problems. Thus, we are concerned that RPM, in its current form, will not ensure adequate electricity supply within New Jersey, and will lead to increased costs to our consumers. (Pl.'s Ex. 13, at 1).

Mr. Butler requested that the Commission undertake "additional dialogue . . . to shape the short term and long term needs of [the] wholesale electricity market[,]" rather than adopting the RPM. (*Id*. at 6). Notwithstanding New Jersey's policy objections, the Commission approved RPM because it disagreed with New Jersey's argument that "the [RPM] Settlement will raise prices without improving reliability." (Pl.'s Ex. 19, at 30); (T. 103, 11, through T. 104, 5).

In 2007, despite the Board's objections, the RPM rule was adopted which included the minimum offer price rule ("MOPR"). PJM subsequently adopted new rules on how the RPM would operate. These rules contemplated, among other things, who may enter into the RPM market and how each generator may bid (T. 2653, 2-8). Most notably, the MOPR governed biddings by new capacity resources. Over the last several years, the MOPR has been modified several times by PJM in 2011 and 2013. Some of these modifications occurred based on the facts of this case.

The RPM Auction is not based on a pure open bidding process. For instance, an existing generator which previously operated as a part of a traditional utility is permitted to bid at zero. (T. 1652, 23 through T. 1653, 2). The rationale for permitting such bids is that these generation facilities have been operating longer than projected so capital costs have been recaptured. As such, the capital costs are deemed to be zero.[8] The ability of these long time generators to bid at zero when they may have sufficient capacity to provide to PJM raises a question as to whether the RPM Auction is actually necessary. In response to this question, PJM developed the MOPR, which it administratively calculates each spring from costs associated with the entry of a new generator; and then it lists administratively determined amount as the net cost of new entry ("net cone"). PJM converts that net cone into a price of megawatts per day ("benchmark price") (T. 1662, 17-19). While existing generators still bid at zero, they are accepting the net cone benchmark price in the RPM Auction. Hence, an existing generator became commonly known within the industry as a "price-taker." If such a generator forecasted that the benchmark price would fall below its projected cost, that generator may choose not to bid and retire the plant. (Def.'s Ex. 235). However, PJM was also concerned that new generators would bid below the benchmark price in order to be accepted into the capacity market. Hence, MOPR was also a "mechanism that s[ought] to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Price Model (RPM) on a competitive basis." (Def.'s Ex. 331, at 4). In order to determine the competitiveness of a new generator, PJM applies a "MOPR screen." The MOPR screen has several components:

(i) a conduct screen (i.e., a benchmark price used to determine whether a sell offer may be competitively low and thus warrants mitigation upward (described below); (ii) an impact screen test that compares the capacity clearing price with and without mitigation; and (iii) an incentive test, or net-short requirement (designed to distinguish between sellers who are net buyers and may have incentives to depress market clearing prices below competitive levels and

[8] Peculiarly, if a long time generator added more capacity to an existing plant, it may still bid at zero despite the development costs.

sellers of planned generation who may have incentives to increase market clearing prices above competitive levels. (Def.'s Ex. 331).

Several exemptions applied to the MOPR's application including the "state mandated" and the "unit-specific" exemptions. When the MOPR was initially adopted, there was an exemption from the MOPR requirements if the project was undertaken pursuant to a state regulation or mandate (T. 1654, 12-15). According to Mr. Knight, a state mandated entrant could bid as an existing generator – price taker, and "bid whatever they wanted to bid." (T. 1654, 18). In addition, there was a unit-specific exemption applying to new gas-fired generation. Such unit-specific exemptions permitted bids down to 80% of the benchmark price upon a showing that the net cone costs were at that level. Such a bid may be lower than the administrative benchmark price.

As noted above, the MOPR was changed through tariff modifications in 2011 (MOPR II) and 2013 (MOPR III). MOPR II eliminated the exemption that previously permitted developers of certain state-sponsored projects from bidding as "price takers." It also raised the "price floor" for new entrants' bids from 80% to 90% of PJM's benchmark price. (Def.'s Ex., at ¶¶ 24, 43, 66). According to Mr. Knight's testimony, in May 2013, the Commission further ruled that: (1) state-sponsored projects should be subject to the MOPR (which led the Commission to eliminate the "state exemption"); (2) the default MOPR level should be 100% of net cone; and (3) new projects should be allowed to demonstrate that their own projected costs will be lower than the benchmark price and should be able to pass a MOPR screen based on those projected costs. (MOPR III). (T. 1679, 20 through T. 1680, 3).

In addition to the MOPR screens, there was another accommodation for new entrants called the New Entry Price Adjustment ("NEPA.") (Def.'s Ex. 238). The NEPA provision was intended to make investments in new generation less risky. The NEPA assures developers of projects in local deliverable areas ("LDAs") that after their facilities become operational they will continue to receive, for a period of subsequent years, the capacity price of the RPM Auction that prevailed at their time of their entry. In 2006, concerns regarding how long the NEPA guarantee should operate were addressed by PJM and the Commission. PJM and FERC ultimately settled on a period of three years. (Def.'s Ex. 238). Despite the MOPR and NEPA adjustments, the RPM costs left New Jersey residents with higher electricity prices due to associated transmission costs. These higher costs displeased the Board.

In addition to the RPM, two other energy issues arose in New Jersey at this time which adversely affected the industry and its regulations. First, PJM forecasted that the amount of energy required for New Jersey would be greater than the state's transmission capabilities potentially leading to outages. Notably, PJM identified twenty-three (23) power transmission violations which were likely to threaten PSE&G customers. Generally, these violations were deficiencies in service and reliability. (Def.'s Ex. 563, at 24-30); (Def.'s Ex. 567, at 20). The other adverse issue which arose was the adoption of new environmental regulations requiring that coal-fired plants be retired unless renovations substantially reducing emissions were made. As a result of these new environmental regulations, the Board projected that the amount of capacity within the PJM territory, particularly the amount of capacity in New Jersey, would be significantly reduced. Both of these adverse issues are discussed below.

Lack of Adequate Transmission Capabilities

In 2010, PJM disclosed to the Board that reliability issues may arise due to insufficient transmission capabilities in New Jersey. According to the PJM: "Based on the latest studies performed by PJM and the transmission owners, PJM, PPL and PSE&G concluded that there are

23 potential electric reliability violations that are expected to occur beginning in 2012, and extending out through PJM's 15-year planning horizon of 2022." (Def.'s Ex. 565, at 12). These violations had the potential to cause brownouts or blackouts. Since the violations were projected to occur within two or three years, the Board became concerned about whether transmission capabilities could be improved in such a short period of time. PJM found that this reliability issue could only be addressed in one of two ways — increased transmission through the construction of the Susquehanna-Roseland transmission line ("Susquehanna Connection") or construction of additional generation in or near the location where the reliability violations would occur. (Def.'s Ex. 563, at 33). Given the difficulties associated with implementing either of these contingency plans in such a short period of time, from the Board's perspective, New Jersey was at risk. As Mr. Roach summarized, "this is really, to put it mildly [an issue that] . . . [got] their attention." (T. 1893, 22 through T. 1894, 2).

Environmental Issues

In 2008, newly imposed environmental regulations cast their shadow over the New Jersey energy industry when the federal and state governments partially prohibited coal-fired plants from being operated unless significant environmental modifications were made. At that time, federal environmental rules required 12 to 19 gigawatts of capacity in the PJM territory, which amounted to about 7 to 11 percent of all PJM generation, be retired or renovated. (T. 1612, 7 through T. 1613, 15). In addition, about a year later, New Jersey adopted the High Energy Demand Day Rule ("HEDD") which created a potential reliability issue by limiting the number of hours that certain electric generating units could operate. (T. 1897, 9-24). In short, from a resource adequacy or capacity perspective, the Board believed that New Jersey was vulnerable to the shutdown of 11,000 megawatts of coal-fired generation. (Pl.'s Ex. 127); (T. 1289, 22 through

T. 1290, 9);(T. 1896, 21 through T. 1898, 10). As Mr. Roach explained it, the Board thought, "I've got to put iron in the ground[.] I've got to get a new power plant locally to protect against these things." (T. 1894, 12-16).

G. INTRODUCTION OF THE LCAPP STATUTE

The Board undertook several measurers to address its concerns. First, the Board appealed the Commission's decision implementing the RPM and MOPR rules. Second, the Board worked with the New Jersey Legislature to develop a bill that would create new capacity resources closer to or within the State.

The Board's petition of review of the Commission's decision was summarily denied by the United States Court of Appeals for the District of Columbia. In its decision, the Circuit Court concluded "that the Commission had a substantial basis on which to conclude that the RPM was an appropriate tool for increasing reliability in electricity markets, that the RPM did precisely what it was intended to do, even during the transition period before the three-year lag could take effect, and that the price hikes in its wake were attributable to legitimate causes." *Md. PSC v. FERC*, 632 F. 3d 1283, 1286 (D.C. Cir. 2011). The Court did not specifically address the Board's or the State of Maryland's contentions regarding lack of reliability, the regional nature of increased capacity prices, or the impact of the newly implemented environmental regulations governing coal-fired plants. Rather, the court seemed to accept the Commission's determination that the "rates were just and reasonable" at face value. *Id.* at 1285.

On January 28, 2011**,** the New Jersey Legislature, with the Board's support, enacted the LCAPP Act which authorized the construction of several gas-fired generators in or near New Jersey. (Stipulated Facts ¶ 35). The purpose of LCAPP was "[t]o address the lack of incentives under the reliability pricing model" by fostering the "construction of new, efficient generation . .

. [to] ensure[] sufficient generation is available to the region, and thus the users in the State in a timely and orderly manner[.]" N.J.S.A. § 48:3-98(d)(2); (Stipulated Fact ¶ 36). In general terms, the LCAPP Act established a "pilot program," overseen by the Board, to issue "Standard Offer Capacity Agreements" ("SOCAs") to selected eligible generators. N.J.S.A. § 48:3-98.3. The statute requires New Jersey's four electric distribution companies ("EDCs") to enter such contracts with eligible generators and obligates these EDCs to pay any difference between the RPM Auction price and their actual development costs approved by the Board. N.J.S.A. § 48:3-98.3(c)(9). The LCAPP contemplated the awarding of SOCAs for 2,000 megawatts of generation capacity. It further directed that the selected LCAPP generators were to "participate in and clear the annual base residual auction [RPM Auction] conducted by the PJM . . . for each delivery year of the entire term of the agreement." N.J.S.A. § 48:3-98.3(c)(12). In addition, the statute directed the Board to conduct a competitive solicitation of capacity and required winning bidders to enter into SOCAs lasting no longer than fifteen years with the State's electric distribution companies (EDCs). N.J.S.A. § 48:3-98.3(c)(1)-(4); *see also* (T. 121, 7 through T. 122, 24). The main purpose of the legislation was to provide a transaction structure that would result in new power plants being constructed in the PJM territory that benefit New Jersey. The New Jersey Legislature was ultimately interested in ensuring that new resources were constructed in time to help mitigate the reliability risks discussed above. N.J.S.A. § 48:3-98.2(b); *see also* (T. 1368, 17 through T. 1377, 1)

More specifically, the LCAPP statute required:

- that the Board hire an agent to: (1) "assist the Board with the establishment of the LCAPP program; (2) prequalify eligible generators for participation in LCAPP; and (3) recommend to the Board the selection of winning eligible generators based on the net benefit to ratepayers of each eligible generator's offer price and term." N.J.S.A. § 48:3-98.3(b)(1)-(3);

- that the Board "establish criteria associated with the prequalification of eligible generators in the LCAPP through a showing of environmental, economic, and community benefits, and through a demonstration of reasonable certainty of completion of development, construction, and permitting activities necessary to meet the desired in-service date" N.J.S.A. § 48:3-93.3(c)(6); (Stipulated Facts ¶ 39);
- that an "eligible generator" be "a developer of a base load or mid-merit electric power generation facility . . . that qualifies as a capacity resource under PJM criteria and that commences construction after the effective date" of the LCAPP. N.J.S.A. § 48:3-51; (Stipulated Facts ¶ 40);
- that a "Standard Offer Capacity Price ("SOCP") mean "the capacity price that is fixed for the term of the SOCA and which is the price to be received by eligible generators under a [B]oard-approved SOCA[.]" N.J.S.A. § 48:3-51. This price represents the development costs of the new generation as approved by the Board.
- that selected eligible generators "participate in and clear the annual base residual auction" (RPM auction) for the sale of their capacity to PJM." N.J.S.A. § 48:3-98.3(c)(12); and
- that the Board order that New Jersey's four electric distribution companies (EDCs) – Public Service Electric and Gas, Atlantic City Electric, Jersey Central Power & Light and Rockland Electric Company "procure 2,000 megawatts of financially-settled SOCAs from eligible generation" for a period up to 15 years. N.J.S.A. § 48:3-98.3(c)(1),(9). The Board was further obligated to "establish a method and the contract terms for providing

for selected eligible generators to receive payments from the electric public utilities for the difference between the SOCP and the RCP multiplied by the SOCA capacity." N.J.S.A. § 48:3-98.3(c)(4).

With the LCAPP, the New Jersey Legislature and the Board concluded that they would have to act to increase electric generation in the State due to the fact that the Commission's policies were not creating new capacity. As Dr. Roach noted in his testimony, the LCAPP created "some tension" between the Commission and the Board. (T. 2034, 25 through T. 2035, 1). One area of tension is summarized in the LCAPP. Within the statement of findings, the Legislature noted that the New Entry Price Adjustment was insufficient. It stated:

> The PJM reliability pricing model could, through structural changes, provide necessary incentives, such as the expansion of the "New Entry Price Adjustment" mechanism for the construction of new capacity, including new intermediate and base load plants, by allowing new resources to qualify and receive a guaranteed capacity price for a longer period of time. However, the implementation of similar structural changes was previously denied by FERC and any future implementation is uncertain at this time. N.J.S.A. § 48:3-98.2(c).

More specifically, the legislative findings declared that the Board would "allow new resources to qualify and receive a guaranteed capacity price for a longer period of time" than the RPM permitted. *Id*.

In addition, Board President Lee Solomon, in a September 16, 2010 memorandum to Governor Christie, affirmed that the purpose of the LCAPP was to establish a "multiyear pricing supplement" that would provide the new LCAPP generators with a premium payment or "RPM" adjustment that would guarantee a LCAPP generator a payment to secure multi-year capacity revenue." (Pl. Ex. 84, at 2). President Solomon also emphasized that the three year NEPA guarantee would be expanded to 15 years.

Moreover, LCAPP mirrors or overlaps the RPM Auction procedure. For instance, LCAPP requires that the price within a SOCA must be expressed in a "price per megawatt day" which is the same standard used in the RPM. *Compare* N.J.SA. § 48:3-98.3(c)(2) *with* (Stipulated Facts ¶ 8) (stating that "the price of capacity in RPM is generally measured in dollars per megawatt-day ("$/MW-day")).

Between 2008 and 2012, the transmission, reliability and environmental issues evolved. That is, many of the Board's concerns had subsided through the deliberate actions of PJM stakeholders and/or economic circumstances. As Mr. Roach characterized it, New Jersey "dodged a bullet." (T. 1894, 23 through 1895, 7). For example, PJM's reliability forecasts failed to predict the 2009 recession, and therefore overstated the amount of capacity required. (Pl.'s Exs. 34, 65, 116, 275, 362). Accordingly, PJM reissued forecasts with lower usage estimates which minimized PJM's reliability concerns. During the trial, there was little to no evidence that this revised usage data proved to be false.

In addition, PJM recommended the construction of the Susquehanna Connection, a new 145-mile high voltage transmission line to move electricity from Berwick, Pennsylvania to Roseland, New Jersey. Presently, officials of PJM and PSE&G anticipate that construction on the project should be completed in 2014 or 2015. This project has the potential to solve the reliability violations that PJM projected. (Def.'s Ex. 563). Despite its ongoing construction, the Board argues that the length of time needed to complete the Susquehanna Connection project has left New Jersey vulnerable to outages. As such, according to the Board, new generation within New Jersey is needed to alleviate future reliability issues.

Lastly, the retirement of coal-fired plants has been an ongoing process. Despite the Board's concerns, PJM has found that within its territory the RPM had sufficient bidders to cushion or absorb the impact of these shutdowns. In addition, through the RPM Auction, PJM has acquired more than sufficient capacity to serve its territory. As PJM reported, although changes in environmental rules have led to significant retirements, "[t]he announced generation retirements sen[t] a strong signal that there would be a need for new resources, and [the 2012] auction witnessed a record number of new generation offers." (Def.'s Ex. 204, at 2); (T. 1084, 15-22). In fact, the 2012 RPM Auction cleared enough capacity to have a 20.2% reserve margin – significantly above the 15.4% reserve margin usually reserved. It is noteworthy that one of the Board's witnesses confirmed that sufficient generation exists. Specifically, Mr. James Giuliano, Director of Reliability and Security of the Board, testified that he could not recall any power outages caused by insufficient generation. (T. 1104, 15-19).

Appointment of LCAPP Agent and MOPR Rules Revisited

In the first quarter of 2011, following enactment of the LCAPP, two significant events occurred. First, the Board appointed Levitan & Associates to be the LCAPP agent. (Pl.'s Ex. 136). Immediately after its appointment, Levitan began an exhaustive but expeditious selection process to identify generators capable of fulfilling both the requirements of the LCAPP statute and the policy objectives of the Board. Secondly, certain PJM stakeholders complained to PJM and the Commission that the state mandated exemption under MOPR should be prohibited because, under the exemption, the Board was unilaterally changing the price of capacity by imposing its own approved costs rather than relying on the competitive price of the RPM.

Levitan's evaluation of generators' proposals through the eligibility, prequalification and commercial proposal stages was based on an evaluation process "consistent with the LCAPP Law that [was] centered on the maximization of economic, environmental and community benefits from the standpoint of ratepayers in New Jersey." (Pl.'s Ex. 178, at 11). Specifically, "[a]pplicants were first reviewed in light of the requirements in the LCAPP Law to be an eligible generator. Eligible generators were then further reviewed to determine whether they should be prequalified on the basis of showing environmental, economic and community benefits, and the demonstration of meeting the proposed in-service date with reasonable certainty." (*Id*.). Furthermore, "[t]he evaluation of commercial proposals was completed in parallel with the prequalification review." (*Id*.).

According to Mr. Levitan, the "community benefits" aspect of the prequalification assessment concerned "the developer's ability to drum up support in the community to achieve the [LCAPP Act's] aggressive [construction] milestones." (T. 1313, 7-15). The benefit sought was the timely construction of a qualifying new generation facility within the PJM territory. In evaluating the economic benefit of potential projects, Levitan "look[ed] at the completeness of the technology and operating data forms . . . [to] facilitate [its] analysis in the next phase." (T. 1312, 22 through T. 1313, 3).

In total, thirty-four (34) generation projects submitted prequalification applications to Levitan. (Stipulated Facts ¶ 43). Many of these projects were disqualified for various reasons. Notably, Levitan eliminated twenty-one (21) of the projects because they "were tied to existing generation units and therefore did not meet the condition of being a new generation facility." (Stipulated Facts ¶ 45). The Board and Levitan also eliminated four (4) projects because they "were characterized as peaking units, rather than base load or mid-merit units as required by the LCAPP." (Stipulated Facts ¶ 46). After three (3) generators withdrew their applications, only six (6) generators were prequalified. (Stipulated Facts ¶ 48). Of the six generation facilities that prequalified, Levitan recommended, and the Board later approved, that three be awarded SOCAs. These generators were Hess (625.0 MW of capacity), NRG (680.1 MW of capacity), and CPV (663.4 MW of capacity). (Stipulated Facts ¶ 54). All three of these generator projects are located in New Jersey. (Stipulated Facts ¶ 52).

After the prequalification stage was completed, Levitan drafted the SOCA for each generator. The material terms of the three SOCAs are identical; they differ only with respect to the SOCA price, the quantity of capacity awarded, and the name of the generator. (T. 1368, 7-11). Herein the Court utilizes the SOCA of CPV as an example.

The Board awarded CPV a SOCA with a fifteen-year term. (Pl.'s Ex. 203). Each SOCA contains an Attachment F, which provides the schedule of Standard Offer Capacity Prices for the LCAPP generator for the fifteen-year term. CPV received the following price schedule:

Delivery Year (ending May 31st)	Standard Offer Capacity Price ($MW-day)
2016	286.03
2017	294.61
2018	303.45
2019	312.55
2020	321.93
2021	331.59
2022	341.54
2023	351.79
2024	362.34
2025	373.21
2026	384.41
2027	395.94
2028	407.82
2029	420.05
2030	432.65

Notably, CPV's SOCA has provisions which relate to PJM activity. For instance, the SOCA refers to the RPM, the RPM Auction and/or other actions that occur within PJM. (Pl.'s Ex. 203). The SOCA responsibilities which correlate to PJM activities are listed below:

> "Available Capacity Amount" means the lesser of: (i) the quantity of Unforced Capacity from the Capacity Facility that is offered by Generator and cleared by PJM in the relevant Base Residual Auction [RPM Auction], and (ii) the Awarded Capacity Amount.
>
> "Base Residual Auction" means the primary auction conducted by PJM as part of PJM's Reliability Pricing Model [RPM] to secure electrical capacity as necessary to satisfy the capacity requirements imposed under the PJM reliability assurance agreement for the Delivery Year.
>
> "Locational Deliverability Area" or "LDA" means the PJM sub-regions used to calculate Resource Clearing Prices as part of the Reliability Pricing Model.
>
> "PJM Interconnection, L.L.C." or "PJM" means the Regional Transmission Organization that manages the regional, high-voltage electricity grid serving New Jersey and all or parts of other states and, among other things, administers the Reliability Pricing Model, and any successor.
>
> "Reliability Pricing Model" or "RPM" means PJM's capacity-market model that secures capacity on behalf of electric load serving entities to satisfy load obligations not satisfied through
> the output of electric generation facilities owned by those entities or otherwise secured by those entities through bilateral contracts.
>
> "Resource Clearing Price" or "RCP" means the clearing price expressed in \$/MW-day for Unforced Capacity established by the Base Residual Auction for the LDA in which the Capacity facility is located and the applicable Delivery Year as posted by PJM.
>
> "RPM Rules" means the provisions of PJM's tariffs and agreements accepted by the Federal Energy Regulatory Commission and the provisions of PJM's manuals governing the Reliability Pricing Model, as in effect from time to time during the term of this Agreement. (Pl.'s Ex. 203).

In addition to these terms, the term "delivery year" corresponds to the RPM availability requirement. Specifically, "Delivery Year" means "each 12-month period from June 1st through May 31st numbered according to the calendar year." (Pl.'s Ex. 203). The term is the same under the SOCA. The SOCA obligates the generator to qualify within the RPM by clearing the RPM Auction and acting in accordance with PJM rules. The SOCA dictates the procedure:

> 2.3.1. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to qualify under the RPM Rules as a capacity resource in an amount no less than the Awarded Capacity Amount for the Base Residual Auction associated with each Delivery Year during the term of this Agreement, commencing upon the Awarded Commencement Date.
>
> 2.3.3. Throughout the Delivery Term, Generator shall:
>
> (a) Cause the Capacity Facility to comply with all obligations of a capacity resource under the RPM Rules, including without limitation the obligations relating to the submission of offers to supply electric energy and ancillary services in PJM markets, and Generator shall bear all costs associated with such compliance, including without limitation all fees and penalties imposed by PJM;
>
> (b) Submit supply offers for an amount of Unforced Capacity no less than the Awarded Capacity Amount from the Capacity Facility in accordance with the RPM Rules in the Base Residual Auction associated with each Delivery Year during the term of this Agreement, such that the Unforced Capacity shall be offered at the lowest commercially reasonable price under the RPM rules;
>
> (c) Submit supply offers from the Capacity Facility for the maximum amount of Associated Energy that the Capacity Facility can provide in the PJM day-ahead energy market in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Energy shall be offered at the lowest commercially reasonable price under PJM's Market Rules;
>
> (d) Submit supply offers from the Capacity Facility for the maximum amount of Associated Ancillary Services that the Capacity Facility can provide in the PJM ancillary services markets in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Ancillary Services shall be offered at the lowest commercially reasonable price under PJM's Market Rules;
>
> (e) Neither physically nor financially withhold any Unforced Capacity up to the amount of Awarded Capacity, or Associated Energy and Associated Ancillary Services, from the Capacity Facility;
>
> (f) Provide on a timely basis . . . (i) documentation provided to Generator by PJM after the conclusion of each Base Residual Auction

> showing the amount of Unforced Capacity offered from the Capacity Facility and cleared by PJM in such Base Residual Auction; (ii) documentation provided to Generator by PJM in advance of each Delivery Year showing all EFORd measurements for the Capacity Facility for the Delivery Year; (iii) the result of any capability test for the Capacity Facility conducted by PJM; (iv) documentation provided to Generator by PJM in advance of each Delivery Year showing the showing the Availability Capacity Amount for the Delivery Year or required to calculate the Available Capacity Amount for the Delivery Year; and (v) documentation notifying Generator of any correction to an input to a calculation." (Pl.'s Ex. 203).

The electric distribution companies have one broad obligation to the Board under the SOCA. (Pl.'s Ex. 203). That is, they must report their compliance with the abovementioned obligations to the Board. The SOCA reads, in relevant part:

> 2.4. Obligations of the Utility. The Utility shall prepare and file an annual report to the Board within thirty (30) calendar days after the end of each Delivery Year describing (i) the status of this Agreement, (ii) the amount of Unforced Capacity and cost of associated Transactions made under this Agreement, (iii) the performance of the Generator in supplying Unforced Capacity and Associated Energy and Associated Ancillary Services under this Agreement, and (iv) any material actions taken by the Generator or the Utility under this Agreement. Nothing in this Agreement imposes upon Utility the obligation to monitor, enforce, or declare an Event of Default with respect to the price of Unforced Capacity, or the price or amount of Associated Energy or Associated Ancillary Services, which Generator offers in or supplies to any PJM Market. (Pl.'s Ex. 203).

In addition, the SOCA sets forth a formula to make payments or receive refunds based on the SOCA amount and the clearing price at the RPM auction. The SOCA states:

> 4.1.1. If, for a Delivery Year, the SOCP is greater than the [Recourse Capacity Price] then, subject to Section 2.5, Utility will pay Generator each Month during the Delivery Year one-twelfth of the product of (i) the difference between the SOCP and the [Resource Capacity Price], (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year; and (iv) Utility Load Ratio, each for the applicable Delivery Year.
>
> 4.1.2. If, for a Delivery Year, the [Resource Capacity Price] is greater than the SOCP then, subject to Section 2.5, Generator will pay Utility each Month an amount equal to one-twelfth of the product of (i) the difference

> between the RCP and the SOCP, (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year, and (iv) Utility Load Ratio, each for the applicable Delivery Year.
>
> 4.2. Structure of Transaction. Nothing in this Agreement shall entitle or obligate Utility to purchase, or take title to or delivery of, capacity, electric energy, or ancillary services from the Capacity Facility.

Under the SOCAs, "the LCAPP generators receive the payment set forth in the SOCAs only if they successfully sell the capacity from their facilities in the RPM base residual auction." (Stipulated Facts ¶ 56). The SOCAs also require the winning bidder to use all commercially reasonable efforts to construct an electric generation facility prior to the "commencement date" of its RPM obligation. (Stipulated Facts ¶ 58).

Finally, the SOCA requires that eligible generators maintain all approvals they have with PJM, and to "comply with Commission and RPM rules." The agreement sets forth:

> 6.2. Maintain Authorizations. Each party will use all reasonable efforts, including the maintenance of records and provision of notices, to maintain in full force and effect all consents, licenses or approvals of PJM and of any Governmental Authority or other authority that are required to be obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security and its obligations hereunder and thereunder and will use all reasonable efforts to obtain any that may become necessary in the future.
>
> 6.3. Comply with Laws and RPM Rules. Each party will comply in all material respects with all Applicable Laws and orders and all RPM Rules to which it may be subject if failure so to comply would materially impair its ability to perform its obligations hereunder or under the Construction Period Security or Delivery Term Security.

In accordance with the terms of its SOCA, CPV (as well as the other two eligible generators) sought admission into the RPM Auction. According to Mr. Knight, as part of CPV's admissions process, representatives of CPV met with PJM to discuss the impacts of the MOPR II revisions and what information CPV would be required to submit. In response to a request for information issued by PJM, CPV sent an application consisting of more than 600 pages of materials. Within its application, CPV claimed it was exempt under the unit-specific exemption of MOPR II adopted in 2011, not the state mandated exemption provided for in the original MOPR. Under MOPR II, CPV could bid into the RPM auction at less than the minimum offer price floor (90 percent of net cone) if it could demonstrate that its actual costs were less than the benchmark price. (T. 1661:21 through T. 1673, 23); (Def.'s Ex. 51).

In determining whether CPV qualified for a unit-specific exemption pursuant to MOPR II, PJM did not consider any out-of-market payments that CPV would receive through New Jersey's LCAPP program. (Def.'s Ex. 183, 751); (T. 1674, 14 through T. 1675). Pursuant to its practice under the MOPR screen, PJM advised CPV that it would accept a bid of no less than $151.24 / MW-day, which is the level at which CPV bid. (T. 1678, 18-20). The May 2012 RPM Auction cleared at $167.46 / MW-day. (Def.'s Ex. 204); (Stipulated Facts ¶ 59). According to Mr. Knight, the RPM Auction price was different than the Board's approved costs due to "a difference in timing, and then secondarily a difference in the view on energy." (T. 1677, 12). With regard to the other eligible generator projects, Hess Corp's project cleared the auction while NRG's proposed project did not. Adamantly opposed, the four electric distribution companies signed the SOCAs under protest.

H. IMPACT OF THE LCAPP STATUTE ON GENERATORS

Plaintiffs' witnesses testified that their respective companies rely on the forward price signals of the RPM Auction in deciding whether to develop new generation resources or make investments in existing resources within a specific market. According to these witnesses, the LCAPP makes it more difficult for these companies to make such business decisions because they can no longer rely on the RPM Auction price signals to evaluate their future costs and predict future revenue streams. In the view of the plaintiffs, the RPM Auction clearing price

($167.46) was essentially displaced and supplanted by the SOCA price written into the SOCA contracts ($286.03), causing less predictability in the energy capacity markets.

Zamir Rauf, Plaintiff Calpine's Chief Financial Officer, testified that the RPM Auction price signals play a "huge role" in Calpine's assessment as to whether an investment should be made because those prices are the basis for "projections as to where [Calpine] think[s] the market is going to be." (T. 1112, 3-14); (Def.'s Ex. 289, at 1). He expressed Calpine's reluctance to proceed with expansion plans in light of the LCAPP's enactment. In fact, according to Mr. Rauf, the LCAPP was a "very strong factor" in Calpine's decision to construct only half of its Garrison project as opposed to completing the project as originally planned. (T. 1121, 15 through T. 1130, 15). Mr. Rauf noted that Calpine was initially attracted to invest in the PJM region because it was a competitive market "where you can put your capital at risk, and compete based on your efficiency[.]" (T. 1114, 15-18 through T. 1115, 6-21). While Calpine "would love to invest more money into PJM[,]" as a result of the LCAPP, the company is now "taking a step back and just holding up from putting too much money into PJM . . . pending this uncertainty." (T. 1134, 8-12). Mr. Rauf summarized the conundrum for energy developers after the LCAPP's enactment:

> [T]he PJM market was designed with certain rules, and everyone has to play by the same rules. . . . [H]ow do you know the state two months from now or six months from now, a year from now, two years from now suddenly decides we need to create jobs let's build another power plant, or whatever political reason they may have for doing so. And all of a sudden they decide to build another plant, whereas you may have been in -- in the process of building one anyway or you may have started building one and now your capital's at risk because the price signals that were in the marketplace are no longer there because of this new plant, so it really just disrupts the whole marketplace, it just in my mind creates enough chaos to where you've got to be very cautious about putting money in a market where you don't know what the rules are, especially when the rules are being manipulated by the politicians. (T. 1130, 20 through T. 1131, 14).

As Mr. Rauf plainly stated, in light of the LCAPP, Calpine would "put[] less money in PJM than [the company] otherwise would have, and [Calpine] would probably either be reinvesting that money in other regions, or buying back [its] stock." (T. 1132, 6-12).

PSEG Power also had similar concerns regarding the impact of the LCAPP. According to Daniel Cregg, the LCAPP Act "dramatically change[d] how we look at what the market is." (T. 888, 20 through T. 889, 8). He noted that PSEG Power "shifted entirely away from . . . looking at it as a merchant opportunity" and began rationalizing that the "opportunity [was] not going to be there for [them] this year". (T. 879, 2-7). In the May 2012 RPM Auction, PSEG Power bid its Essex County project "at a fairly high level" in order to serve "as a backstop to the extent that the LCAPP units [did not] bid." (T. 886, 22 through 888, 12). In other words, "absent the LCAPP Act . . . there might have been a price signal that would have been there" for the Essex County project, but instead, "the LCAPP units did bid in, and as a result [PSEG Power's Essex] unit did not clear." (T. 887, 4-8).

The LCAPP also had an impact on the operations of Exelon, as discussed by Mr. Dominguez during his testimony. Specifically, he testified that the RPM price signal "tells [Exelon] whether to make investments in existing plants; whether to increase the capacity of existing plants; whether to do environmental retrofits; [and] whether to keep plants open." (T. 527, 2-10). Mr. Dominguez further testified that, given its impact on Exelon's business strategies, the RPM is "fundamental to the way [Exelon] operate[s] [its] business." (T. 527, 8-10). In addition, Mr. Dominguez stated that the LCAPP Act has "fundamentally chang[ed] [Exelon's] ability to predict revenue streams for existing megawatts." (T. 564, 3-16). The LCAPP has also been a factor in Exelon's decision to place its nuclear uprate program on hold. (T. 564, 16).

PPL has also had to modify its business strategies in light of the requirements imposed by the LCAPP. Michael Cudwadie, Vice President for PPL EnergyPlus, testified that PPL relies on capacity forward market prices and energy forward market prices to make decisions regarding investments in new and existing generation, including whether to upgrade units, add pollution control equipment, or retire specific units. (T. 1041, 18-24).

The effects of the LCAPP described by these witnesses were echoed at trial by Plaintiffs' experts Mr. Massey and Professor Willig. For example, Mr. Massey declared that "[t]he entire fabric of the contract in my judgment makes it a price for capacity. It so happens that the contract calls it a standard offer capacity price, I . . . can hypothesize about a lot of things, but I don't know what can be clearer than that." (T. 296, 19-23). Mr. Massey elaborated by stating that "[t]he price is measured in terms of the netting of revenues, is measured in terms of comparing the standard offer capacity price, with the price determined in the PJM capacity market. It's all about capacity pricing." (T. 298:2-10). Furthermore, the payments under the SOCA are "inextricably linked to the sale of wholesale capacity." (T. 298, 2-10).

Similarly, Professor Willig described the effect of the LCAPP as "wiping out the pricing mechanism of PJM . . . [and] taking it away and putting this alterative, the SOCA price, in the place of the market price." (T. 638, 22 through T. 639, 1). Professor Willig opined that the "architecture" of the RPM Auction was appropriately designed to address concerns in the energy capacity market (T. 763, 19-23) and that the RPM clearing price "is being displaced, . . . overridden, [or] supplanted, by the SOCA price through this mechanism which is written into the SOCA contract and governed by the LCAPP." (T. 637, 15-18).

Professor Willig further stated that the LCAPP would actually undermine new generation projects because all future investors would insist on receiving similar government assistance. He explained:

> Even though this is supposed to be an interstate market, the kinds of freedoms for the states, which they may have political incentives to act on, favoring their own development projects, will lead in a contagious way to other states taking measures that they think are only there in self-protection but are really their own reaction to the beginnings of this movement if the Court allows it, so that it's truly a contagion. We could very well be seeing a rash of programs of this kind, only furthering the rational insecurity of new investors who are not going to be part of these programs, fearing that the market will just be full of unfair competition for them, and thereby discourage their own investment activities. (T. 698, 11-23).

Defendants' Perspective

The defendants have a completely different view concerning the impact and effects of the LCAPP based on two factual disagreements with the plaintiffs. First, the defendants contend that the RPM and the SOCA are two separate and unrelated transactions. The fact that each provides a different price does not, according to the defendants, frustrate the purpose or goals of the RPM Auction because, in their view, the SOCA is a purely financial contract not subject to Commission oversight and authority. Second, the defendants argue that any jurisdictional conflicts between the Board and the Commission were resolved by the Commission's 2013 MOPR revisions. Both of these arguments are addressed below.

According to the defendants, the RPM and the SOCA are unrelated. As Mr. Knight of CPV testified, the SOCA is "something separate and distinct." (T. 1646, 6-13). In describing this distinction, Mr. Knight elaborated that the "SOCA is between CPV and the EDCs, and does not go through PJM or have to do with PJM." (T. 1646, 6-13). He further pointed out that "[CPV] sell[s] physical capacity and energy to PJM," and does "not sell any physical capacity to anybody else." (T. 1644, 12-22). Mr. Knight distinguished the SOCA price from the RPM Auction clearing price by stating:

> The SOCA -- I mean the general terms of the SOCA are relatively simple and straightforward, but the obligation is for us to build a power plant, and to bid into, connect into PJM, and sell all our energy and capacity into PJM. And then in return for that we receive a financial payment from the EDCs, that is based upon a formula we're all . . . familiar with. It's a fixed price for a floating price, the floating price being the index in the PJM capacity market. (T. 1644, 12-22).

Defendants further contend that because the SOCA is a purely financial contract, it is not subject to Commission oversight. (T. 1911, 13-16). In fact, Defendants liken the SOCA to other financial contracts such as swaps, collars, or contracts for differences. (T. 682,2 through T. 683, 7). While the latter term (contract for differences) was mentioned frequently throughout trial, it was not fully defined except as an instrument that is routinely used to manage commodity price risks. (T. 1347, 1-15). For example, Mr. Levitan explained that a contract for differences is a "financially settled mechanism that provides revenue assurance for the seller and risk management benefits for the buyer." (T. 1282: 10-18). In the view of the defendants, because the SOCAs do not involve the sale of actual physical energy capacity, they fall outside the jurisdictional authority of the Commission. (T. 1282, 10-18). Mr. Knight agreed with this analysis and likened the SOCAs to insurance policies indemnifying against forced power outages. He testified:

> Because the payment mechanism is contingent upon something, it doesn't mean that we're delivering capacity . . . . [A]n example would be we have forced outage insurance in which we get paid by someone under a derivative contract if we are forced out. That doesn't mean that that's forced outages . . . it's just a contingency within the contract by which you get paid, it's not [like] you're actually delivering some good. T. 1648, 20 through T. 1649, 3).

So, under the defendants' analysis, the SOCAs are ultimately just financial risk management tools through which no capacity or energy is bought or sold. (T. 1283, 17-24); (T. 1360, 9 through T. 1369, 10); (T. 1644, 9 through T. 1645, 9).

With the adoption of the MOPR III revisions, the defendants argue that issues between the Board and the Commission concerning participation of new generators in the RPM Auction are resolved; and since there is no controversy between the Board and the Commission, there is no need for the Court to impose any remedy. The Court, however, rejects this argument for several reasons. Although the Board and the Commission may now have a more cooperative relationship, the Court is in the best position to determine whether the LCAPP and the related policies implemented by the Board violate the Supremacy Clause. In addition, despite the increased cooperation between the Board and the Commission, this remains a controversy between the plaintiffs (generators and distributors of electricity) and the Board.

Other Alternatives

Since the Board retained authority over the siting of generation facilities, a question arose as to whether the Board had any alternative means to incentivize construction of new generation facilities besides enacting a statute like the LCAPP. The parties agree that the Board had a number of ways to support and encourage the development of generation projects. These include the utilization of tax exempt bonding authority, the granting of property tax relief, the ability to enter into favorable site lease agreements on public lands, the gifting of environmentally damaged properties for brownfield development, and the relaxing or acceleration of permit approvals. (T. 266, 25-26 through T. 267, 6); (T. 1313-14 through T. 1316, 2).

I. CREDIBILITY OF WITNESSES AND WEIGHING OF THE EVIDENCE

As opposed to the facts set forth above, to which the Court has given considerable weight, the trial record reveals an extensive number of other facts which were given little weight in this decision. Those facts, and the reasons they were given little weight, are discussed below.

First, Defendants presented a plethora of facts about initiatives in Maryland and Connecticut which they believe present issues similar to those being considered in this case. The Maryland initiative is subject to a separate ongoing lawsuit. As Mr. Roach testified, it is based upon reimbursement of 400 megawatts of new demand response as opposed to a capacity requirement. (T. 2066, 20-24). Any analysis of the Maryland proposal would necessarily require this Court to review a set of facts as substantial as those presented herein. Based on the facts presented at trial, the Court is not able to discern whether Maryland's proposal is sufficiently similar to the LCAPP. As such, the Court considers the value in comparing and contrasting the Maryland initiative and the LCAPP to be minimal for purposes of this opinion.

In regards to the Connecticut proposal, the defendants contend that a Connecticut peaking facility has a very similar financial structure as a New Jersey peaking facility under the LCAPP. (T. 1377, 24 through T. 1379, 11). Evidently, PSEG Power or one of its subsidiaries previously accounted for SOCA-like payments to a New Haven generator as financial contracts. According to the defendants, the payments in question were not listed as energy or capacity contracts required to be filed with the Commission. (Def.'s Ex. 630). The defendants argue that this supports their proposition that SOCAs are purely financial instruments. The Court, however, did not have sufficient information to fully analyze the Connecticut payments and, therefore, gave the defendants argument little weight. In the Court's view, the most compelling evidence regarding how the SOCAs should be defined under the law was adduced by the witnesses at trial.

Therefore, in terms of credibility, the evidence regarding the Connecticut contracts was of little value.[9]

The Plaintiffs argue that certain written and oral statements allegedly made by Board staff and CPV executives are admissions against interest supporting the plaintiffs' case. Examples of these alleged admissions include:

a. Comments to President Solomon made by Frank Perrotti, Assistant Director of the Board, in which he stated that the LCAPP has the "potential to drive out other forms of investment or, at least, cause future developers to demand the same premiums before deploying capital." (Pl.'s Exs. 70, 406).

b. Comments made by President Solomon's aide Kristi Miller in which she stated that the LCAPP "could encourage future developers to demand identical premiums before deploying capital." (Pl.'s Ex. 406, at 20).

c. Comments made by CPV Chief Executive Officer Douglas Egan in which he indicated that in order to develop generation in New Jersey, a generator may need "out-of-market pricing" (Pl.'s Ex. 61) or "pricing that was higher than what was available at that point in time." (Pl.'s Ex. 409).

d. Comments made by the Board's Fed. R. Civ. P. 30(b)(6) designated witness, Mr. Dembia, in which he indicated that the LCAPP is a "guaranteed payout." (Pl.'s Ex. 406).

The Court gave little weight to these alleged admissions which occurred during the lobbying effort to enact the LCAPP. *See Kentucky W. Va. Gas Co. v. Pennsylvania Pub. Util. Comm'n*, 837 F.2d 600, 615 (3d Cir. 1988). The Court found that the witnesses at trial presented

[9] On a motion *in limine* prior to trial, the Court ruled that the Connecticut initiative was not relevant because it involved a different state. During trial, the Court reopened that decision since the plaintiff's presented evidence involving initiatives in other states. The Court determined fairness required an evaluation of the Connecticut evidence.

the facts and issues in a forthright manner. Since the statements were not subject to cross-examination, and could not be assessed for credibility, the Court believes the constitutionality of the New Jersey statute and program is best determined by reviewing the merits of the case rather than relying on isolated statements.

Plaintiffs also introduced a report prepared by the Brattle Group for purposes of showing the successes of the RPM. The Brattle Group is a consulting firm hired by PJM to evaluate the RPM. (Pl.'s Ex. 49). No one from the Brattle Group testified at trial. As a result, the Brattle Group's report on the RPM Auction was not subject to cross-examination. As such, the Court gave the report little weight.

J. ANALYSIS

"Preemption is a doctrine of American constitutional law under which state and local governments are deprived of their power to act in a given area, whether or not the state or local law, rule or action is in direct conflict with federal law . . . . The analysis of a preemption dispute focuses upon statutory construction . . . in the context of a constitutional framework of sovereignty, commerce regulation, or other predicate for federal powers."[10] More specifically, preemption doctrine is rooted in the Supremacy Clause of the United States Constitution. Article VI declares that the laws of the United States "shall be the supreme Law of the Land; . . . any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." U.S. Const. art. VI, cl. 2. In order to determine whether the LCAPP is preempted under federal law, the first factual issue to resolve is whether the Board-ordered SOCAs occupy the same field of regulation as the Commission and intrude upon the Commission's authority to set prices for wholesale energy sales.

[10] JAMES T. O'REILLY, FEDERAL PREEMPTION OF STATE AND LOCAL LAW: LEGISLATION, REGULATION AND LITIGATION 1 (2006).

According to the defendants, the Commission's oversight authority is "limited to sales of the actual physical electricity (or capacity) to a buyer." (Def.'s Post-Trial Br. at 11). Furthermore, the defendants contend that "[c]ontracts that do not effect a physical sale of electricity . . . are not subject to [Commission] jurisdiction." (*Id*.). In the defendants' view, the SOCAs are purely financial contracts that do not involve physical sales of electricity.[11] As such, according to the defendants, the SOCAs are separate and unrelated to the RPM Auction process and free from Commission oversight. Plaintiffs argue, in opposition, that the "State, through the LCAPP Act and Board-ordered SOCAs, has set a price to be received for the wholesale sale of capacity to PJM." (Pl.'s Post-Trial Br. at 3). In the plaintiffs' view, the LCAPP ultimately "award[s] an impermissible price supplement for an interstate wholesale sale of electricity" and replaces the RPM price with the Board-ordered SOCA price. (*Id*. at 1). In doing so, according to the plaintiffs, the Board essentially sets a price for wholesale energy sales and, therefore, "regulat[es] in a field that is reserved exclusively" for the Commission. (*Id*.).

The Court finds that the SOCAs occupy the same field of regulation as the Commission and intrude upon the Commission's authority to set wholesale energy prices through its preferred RPM Auction process. As previously discussed, many of the terms defined in the SOCAs make substantial use of RPM terminology. In addition, the SOCAs obligate eligible generators to:

(1) "qualify under the RPM rules as a capacity resource in an amount no less that the Awarded Capacity Amount for the [RPM Auction]" (Pl.'s Ex. 203, at 9);

(2) "comply with all obligations of a capacity resource under the RPM Rules" (*Id*.);

(3) "[s]ubmit supply offers . . . in accordance with the RPM Rules" (*Id*.); and

[11] The Commission has previously held that "electricity price risk management transactions (futures, options, swaps, and the like)" that do not result in the actual delivery of electricity are "purely financial" and need not be reported to the Commission." *Morgan Stanley Capital Group, Inc.*, 69 F.E.R.C. ¶ 61,175, 61,696 (1995).

(4) "[s]ubmit supply offers . . . in accordance with PJM Market Rules[.]" (*Id*. at 9-10). The LCAPP Act itself defines the SOCA as a "capacity price . . . to be received by eligible generators under a Board-approved SOCA." (Pl.'s Ex. 127, at 10). Furthermore, payment of the SOCA price is made only if the LCAPP generators successfully sell and deliver wholesale capacity to PJM. Given the fact that the SOCAs require eligible generators' to satisfy certain RPM rules and mandate that the generators undertake certain performance under those rules, the Court finds that the performance of the SOCAs is contingent upon clearing the RPM Auction. As such, the SOCAs are not separate from, and to the contrary, occupy the same field as the RPM Auction.

"Under the Supremacy Clause, federal law may supersede state law in several different ways." *Hillsborough County v. Automated Med. Labs., Inc*., 471 U.S. 707, 713 (1985). Specifically, the Supreme Court has recognized three types of preemption: express preemption, implied conflict preemption, and field preemption. *Id*. In this case, Plaintiffs argue that the Federal Power Act supersedes the LCAPP under both the field and conflict preemption theories.

Courts must begin their analysis of preemption questions by applying a presumption against preemption. *Cipollone v. Liggett Group, Inc.*, 505 U.S. 504, 516 (1992). "In areas of traditional state regulation, we assume that a federal statute has not supplanted state law unless Congress has made such an intention 'clear and manifest.'" *Bates v. Dow AgroSciences* 544 U.S. 341, 449 (2005) (citing *New York State Conference of Blue Cross & Blue Shield Plans v. Travelers Ins. Co.*, 514 U.S. 645, 655 (1995). "That assumption applies with particular force when Congress has legislated in a field traditionally occupied by the States." *Altria Grp., Inc. v. Good*, 555 U.S. 70, 77 (2008). Thus, when the "text of a pre-emption clause is susceptible of more than one plausible reading, courts ordinarily 'accept the reading that disfavors preemption.'" *Id.* (citing *Bates*, 544 U.S. at 449). *See also Cipollone*, 505 U.S. at 518. Nonetheless, in the face of clear evidence, the presumption against preemption can be overcome. *See Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 374 n.8 (citing *Hines v. Davidowitz*, 312 U.S. 52, 67 (1941). ("Assuming, *arguendo,* that some presumption against preemption is appropriate, we conclude . . . that the state Act presents a sufficient obstacle to the full accomplishment of Congress's objectives under the federal Act to find it preempted."). While applying the presumption against the preemption, the Court reviews whether the Federal Power Act preempts the LCAPP under either the field preemption or conflict preemption theories.

Field Preemption

Field preemption arises by implication when state law occupies a "field reserved for federal regulation." *United States v. Locke*, 529 U.S. 89, 111 (2000). The Supreme Court has explained that "[f]ield preemption reflects a congressional decision to foreclose any state regulation in the area, even if it is parallel to federal standards." *Arizona v. United States*, 132 S. Ct. 2492, 2502 (2012). This occurs when "Congress has left no room for state regulation of these matters." *Locke*, 529 U.S. at 111 (citing *Fidelity Fed. Savings & Loan Ass'n v. De La Cuesta*, 458 U.S. 141 (1982). The Supreme Court has explained that a congressional intent to occupy a field can be inferred when "[t]he scheme of federal regulation may be so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it." *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947). It may also be inferred where "an Act of Congress 'touches a field in which [the] federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject.'" *English v. General Elec. Co.*, 496 U.S. 72, 79 (quoting *Rice*, 331 U.S. at 230). Nonetheless, because field preemption typically arises in areas traditionally regulated by states under their police powers, "congressional intent to supersede state laws must be 'clear and manifest.'" *English*, 496 U.S. at 79 (quoting *Jones v. Rath Packing Co.*, 430 U.S. 519, 525 (1977). Generally, "[t]he factors used to determine if the field has been fully occupied by federal power include the dominant federal interest, the expression of congressional purpose, and the pervasiveness of the federal regulatory system." O'Reilly, *supra* note 10, at 70.

Since the Supreme Court's 1927 decision in *Public Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927), there has been a dominant federal interest over wholesale sales of electricity in interstate commerce. In that case, the Supreme Court invalidated an attempt by Rhode Island to regulate the rates charged by a Rhode Island plant selling electricity to a Massachusetts company, which resold the electricity to the City of Attleboro, Massachusetts. The Court found that the State's attempt to regulate rates "place[d] a direct burden upon interstate commerce" and, as a result, the "State [was] restrained by the force of the Commerce Clause." *Id.* at 89. Ever since the Court's ruling, the federal government has asserted jurisdiction over wholesale sales of electricity in interstate commerce. As noted in Section E of this memorandum, in the absence of any federal regulatory body, interstate wholesale electricity pricing was left entirely unregulated after the *Attleboro* decision. In order to fill that regulatory gap, Congress enacted the Federal Power Act which provided that the Commission shall have jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). *See New York v. FERC*, 535 U.S. 1, 20-21 (2002) ("It is clear that the enactment of the FPA in 1935 closed the '*Attleboro gap*' by authorizing federal regulation of interstate, wholesale sales of electricity – the precise subject matter beyond the jurisdiction of the States in *Attleboro*. . . . It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in *Attleboro*. The FPA authorized federal regulation not only of wholesale sales that had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation.").

Plaintiffs contend that in enacting the Federal Power Act, Congress "chose to occupy the field of wholesale electricity sales, including the price at which electricity is sold at wholesale, and the terms and conditions under which such electricity is sold." (Pl.'s Post-Trial Br. at 12). Such a contention is supported by previous decisions in which courts have held that the Commission has the exclusive authority to regulate wholesale electricity sales and the transmission of energy in interstate commerce. As stated by Justice Scalia, "It is common ground that if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject." *Miss. Power & Light Co. v. Miss. Ex rel. Moore*, 487 U.S. 354, 377 (1988) (Scalia, J., concurring in the judgment). The Supreme Court has held that the Federal Power Act "left no power in the states to regulate licensees' sales for resale in interstate commerce." *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964). Moreover, the Court has repeatedly held that the federal statute "delegated to . . . the Federal Energy Regulatory Commission, exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce, without regard to the source of production." *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982) (citing *United States v. Pub. Utils. Comm'n of Ca.*, 345 U.S. 295, 311 (1953). *See also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 956 (1986) (stating that the Commission "has exclusive jurisdiction over interstate wholesale power rates."). The Third Circuit has similarly found that the "wholesale market for electrical energy is regulated by [the Commission]" and "[o]ne of [the Commission's] duties is to set 'just and reasonable' wholesale electric rates." *Utilimax.com v. PPL Energy Plus LLC*, 338 F.3d 303, 305 (3d Cir. 2004). The

Commission's decision to exercise its exclusive authority to regulate wholesale electricity sales through the RPM Auction process indicates both a dominant federal interest in the RPM and a pervasive federal regulatory structure to ensure its proper implementation.

To support their proposition that the SOCAs are not "[c]ontracts . . . effect[ing] a physical sale of electricity" and, therefore, "not subject to [Commission] jurisdiction[,]" the defendants rely on the case of *New York Mercantile Exch.*, 74 F.E.R.C. ¶ 61, 311, 1996 F.E.R.C. LEXIS 454 (1996) ("*NYMEX*"); (Def.'s Post-Trial Br. at 12). In *NYMEX*, the Commission held that the Federal Power Act and its reporting requirements did not apply to an electricity futures contract that was approved for trading by the Commodity Futures Trading Commission ("CFTC") except if the "contract goes to delivery, the electric energy sold under the contract will be resold in interstate commerce, and the seller is a public utility." *NYMEX*, 74 F.E.R.C. at 61,984. Without reviewing all of the facts of *NYMEX*, the Court finds the case distinguishable for several reasons. First, no evidence was presented to indicate that the SOCAs have been approved for trading by a separate federal regulator. Second, there is a caveat in *NYMEX* that if a contract "goes to delivery" it may give rise to Commission jurisdiction. Here, the SOCA agreements are contingent upon the LCAPP generators' successful sale of capacity to PJM. Such capacity sales may constitute delivery within the meaning of *NYMEX* and, therefore, give rise to Commission jurisdiction.

The most credible testimony presented at trial confirming that the SOCA contracts are not purely financial contracts, and that they, therefore, intrude upon the exclusive jurisdiction of the Commission, was that of Professor Willig. He explained that, in economics, a purely financial arrangement is one that does not "involve any real performance." (T. 681, 5-6). He elaborated that "[a] financial deal does not involve any performance of a real side activity as part of the deal. So that's really the dividing line, and I think it's quite clear, it goes back to what we mean by price in economics, payment for performance." (T. 681, 21-24). Here, the SOCAs expressly condition payment on physical performance. As Professor Willig explained, under the SOCAs, the LCAPP generator has "got to build a plant, it's got to provide capacity, the capacity has to be available, had to be bid into RPM and into the auction, it has to clear the auction; there are all these elements of performance to which the SOCA payments are conditioned. So it's payment for performance." (T. 684, 10-15). Here, the LCAPP supplants the federal statute, and intrudes upon the exclusive jurisdiction of the Commission, by establishing the price that LCAPP generators will receive for their sales of capacity. The Court finds that in doing so, the LCAPP "places a direct burden upon interstate commerce" within the meaning of the *Attleboro* decision. Accordingly, the LCAPP Act invades the field occupied by Congress and is preempted by the Federal Power Act.

Defendants argue against preemption by stating that "Congress expressly reserved to the States exclusive jurisdiction to regulate generation." (Def.'s Post-Trial Br. at 23). According to the defendants, "State regulation of generation will not be pre-empted if the regulation's impacts on wholesale rates are merely 'incident of efforts to achieve a proper state purpose.'" (*Id.* (quoting *Nw. Central Pipeline Corp. v. State Corp. Comm'n of Kansas*, 489 U.S. 493, 515-16 (1989). Although the State of New Jersey and the Board retained the responsibility for the siting and construction of power plants, they are required to exercise this responsibility without interfering with the Commission's exclusive authority to regulate wholesale sales of electricity in interstate commerce. As discussed in Section H of this memorandum, there were other alternative measures which New Jersey could have employed to incentivize the development of new generation. While New Jersey retained the authority to take a wide range of actions to ensure reliable electric service for its citizens and encourage the construction of new electric generation facilities, it chose to advance those goals through a mechanism that intrudes upon the authority of the Commission and violates federal law.

The defendants also contend that preemption analysis "does not justify a 'freewheeling judicial inquiry into whether a state statute is in tension with federal objectives." (Def.'s Post-Trial Br. at 23) (quoting *Chamber of Commerce of U.S. v. Whiting*, 131 S. Ct. 1968, 1985 (2011). Here, however, the Commission's exclusive authority over wholesale energy sales has existed since *Attleboro* and been confirmed by the Supreme Court and many lower courts decisions. An application of these prior decisions acknowledging the exclusive authority of the Commission to regulate wholesale electricity sales to the facts in this case certainly does not constitute "freewheeling."

Conflict Preemption

Conflict preemption occurs where there is a conflict between a state law and a federal law. *See Crosby*, 530 U.S. at 372 ("[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute."). Such a conflict occurs when "the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." 132 S. Ct. at 2501. When confronting arguments that a law stands as an obstacle to Congressional objectives, a court must use its judgment: "What is a sufficient obstacle is a matter of judgment, to be informed by examining the federal statute as a whole and identifying its purpose and intended effects." Crosby, 530 U.S. at 373. The court must look to "'the entire scheme of the statute'" and determine "'[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect.'" *Id*. (quoting *Savage v. Jones*, 225 U.S. 501, 533 (1912)).

Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. In fact, the Supreme Court has held that "[u]nder the Supremacy Clause of the Federal Constitution, '[t]he relative importance to the State of its own law is not material when there is a conflict with a valid federal law,' for 'any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield.'" *Felder v. Casey*, 487 U.S. 131, 138 (1988) (quoting *Free v. Bland*, 369 U.S. 663, 666 (1962)); *see also Gade v.Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88, 108 (1992) ("[E]ven state regulation designed to protect vital state interests must give way to paramount federal legislation." (quoting *De Canas v. Bica*, 424 U.S. 351, 357 (1976)).

From reviewing the entire scheme of the RPM process, it is clear that the LCAPP Act poses as an obstacle to the Commission's implementation of the RPM. The testimonies of Messrs. Dominguez, Rauf and Cudwadie indicated that their companies rely on the competitive price signals of the RPM Auction to determine future company business plans. Each testified that the SOCA prices undermine their respective company's ability to use those RPM price signals to make sound business decisions. Each also contended that the future expansion of their respective companies would be contingent on whether the SOCA price continues to supplant the RPM Auction price. The effects described by the witnesses demonstrate that the SOCA's imposition of a government imposed price creates an obstacle to the Commission's preferred method for the wholesale sale of electricity in interstate commerce.

Commerce Clause

The Plaintiffs argue that the LCAPP Act also must be invalidated under the Commerce Clause. This argument concerns the procurement of the capacity wherein Plaintiffs argue that Board discriminated against out-of-state generators in its solicitation of bids to become eligible generators under the LCAPP. The "dormant" aspect of the Commerce Clause prohibits states from using their regulatory power to discriminate in favor of in-state producers at the expense of those out-of-state. *C&A Carbone, Inc. v. Town of Clarkstown*, 511 U.S. 383, 389-90 (1994); *W. Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 192 (1994); *Wyoming v. Oklahoma*, 502 U.S. 437, 454-55 (1992). The Supreme Court has defined forbidden discrimination as "differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter." *United Haulers Ass 'n v. Oneida-Herkimer Solid Waste Mgmt. Auth.*, 550 U.S. 330, 338 (2007) (quotation marks omitted): *W. Lynn Creamery*, 512 U.S. at 192.

When a law discriminates against out-of-state producers on its face, the State bears the burden of demonstrating, "under rigorous scrutiny, that it has no other means to advance a legitimate local interest." *C&A Carbone*, 511 U.S. at 392. "Statutes that discriminate by 'practical effect and design,' rather than explicitly on the face of the regulation, are similarly subjected to heightened scrutiny." *Tri-M Group, LLC v. Sharp*, 638 F.3d 406, 427 n.28 (3d Cir. 2011).

The plaintiffs argue that the "community benefit" points awarded to generators in New Jersey effectively prohibited out-of-state generators from competing to be eligible generators under the LCAPP Act. According to the plaintiff's, the LCAPP Act – through its express consideration of economic and community benefits – favored in-state enterprises over out-of-state enterprises." (Pl.'s Post-Trial Br. at 48). To demonstrate this, the plaintiffs rely on the following evidence: (1) President Solomon's letter to Governor Christie that mentions a preference for in-state generators (Pl.'s Ex. 84); (2) the initial draft of the LCAPP legislation that promoted construction of qualified in-state electric generators (even though such language was deleted prior to enactment) (Pl.'s Ex. 94); (3) language in the LCAPP which required the Board to consider the "economic[] and community benefits" of a project (Pl.'s Ex. 127); and (4) language in the 2011 New Jersey Energy Master Plan which discussed fostering the commercialization of new generation plants in New Jersey. (Pl.'s Ex. 270).

Despite the abovementioned evidence, the plaintiffs fail to overcome the most persuasive evidence that substantiates the reasons the State is seeking in-state development. A significant portion of the trial focused on locational deliverability areas (LDAs). (Stipulated Fact ¶ 30). As previously noted, New Jersey is located in such an area that is known as EMAAC. In addition, there are two other locational deliverability areas within New Jersey known as PSEG and PS North (T. 1529, 3-13). Generally, these LDAs have higher capacity prices than other PJM areas due to transmission costs. Even the Plaintiffs agree that a capacity price cannot be set for an entire region. (Pl.'s Ex. 26, at 34). As a result, there is separation in price which is authorized by PJM and the Commission. The record as a whole supports the proposition that the closer the generation facility is to the delivery area, transmission costs will subside. As Mr. Herling concluded when discussing the reliability crisis, reliability issues could only be resolved in one of two ways – transmission via the Susquehanna Connection or additional *generation in or near the location where the reliability issue will occur.* (Def.'s Ex. 563, at 33) (emphasis added). As such, it appears reasonable that the Board would incentivize construction in areas where reliability concerns are in flux. As such, the Board has the authority to incentivize construction within New Jersey. What is good for the goose is good for the gander. As such, the incentive for community benefits to generators in New Jersey appears reasonable. Since Plaintiffs have not briefed or argued the commerce clause in such a fashion, the Court finds that Plaintiff has not met its burden of proof.

K. CONCLUSION

Based on the foregoing facts and law, the Court declares that the Long Term Capacity Agreement Pilot Program Act (LCAPP) is preempted by the Federal Power Act and in violation of the Supremacy Clause of the United States Constitution; and is therefore null and void.

s/Peter G. Sheridan
PETER G. SHERIDAN, U.S.D.J.

October 11, 2013

GLOSSARY OF ACRONYMS

BGS	Basic Generation Service
BPU OR NJBPU	The Board of Public Utilities of the State of New Jersey; also referred to as "the Board"
BRA	Base Residual Auction
CC	Combined cycle
COD	Commercial Operation Date
CONE	Cost of New Entry
CT	Combustion Turbine
DAM	Day Ahead Market
DG	Distributed Generation
DR	Demand Response
EDC	Electric Distribution Company
EDECA	Electric Discount and Energy Competition Act
EE	Energy Efficiency
EMAAC	Easter Mid-Atlantic Area Council
EMP	Energy Master Plan
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FRR	Fixed Resource Requirement
GT	Gas turbine
GW	Gigawatt
GWh	Gigawatt hour
HEDD	High Energy Demand Day
ICAP	Installed Capacity
ISO	Independent System Operator
KW	Kilowatt
KWh	Kilowatt hour
LCAPP	Long Term Capacity Agreement Pilot Program
LDA	Locational Deliverability Area
LMP	Locational Marginal Price
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MAAP	Mid-Atlantic Power Pathway
MOPR	Minimum Offer Price Rule
MW	Megawatt
MWh	Megawatt Hour
NEPA	New Entry Price Adjustment
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
P3	PJM Power Providers Group

PATH	Potomac-Appalachian Transmission Highline
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
RCP	Resource Clearing Price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTM	Real Time Market
RTO	Regional Transmission Organization
SIS	System Impact Study
SOCA	Standard Offer Capacity Agreement
TO	Transmission Owner
TRAIL	Trans-Allegheny Interstate Line
TRC	Total Resource Cost
UCAP	Unforced Capacity
VRR	Variable Resource Requirement