OCC Exhibit ____________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the 2018 Long-Term Forecast Report on behalf of Ohio Power Company and Related Matters.	)))	Case No. 18-0501-EL-FOR
In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into Renewable Energy Purchase Agreements for Inclusion in the Renewable Generation Rider.	)))))	Case No. 18-1392-EL-RDR
In the Matter of the Application of Ohio Power Company to Amend its Tariffs.	))	Case No. 18-1393-EL-ATA

PUBLIC VERSION

DIRECT TESTIMONY
OF
JONATHAN A. LESSER, PH.D.

On Behalf of
The Office of the Ohio Consumers' Counsel
65 East State Street, 7th Floor
Columbus, Ohio 43215

January 2, 2019

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I. INTRODUCTION, PURPOSE, AND SUMMARY

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A1. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is P.O. Box 590, La Veta, CO 81055.

Q2. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A2. I am an economist specializing in market and litigation analysis in the energy industry. I have 35 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, the Federal Energy Regulatory Commission, state legislative committees, and before international regulators.

Before founding Continental Economics in 2009, I was a Partner in the Energy Practice with the economic and litigation consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic

Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS degree, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the co-author of three textbooks: *Fundamentals of Energy Regulation*, *Principles of Utility Corporate Finance*, and *Environmental Economics and Policy*. I have published peer-reviewed journal articles in academic journals including the *Journal of Regulatory Economics*, *Land Economics*, *Energy Policy*, and *The Energy Journal*, as well as dozens of articles in industry publications. I also serve on the Editorial Board of *Natural Gas & Electricity*, and previously served a three-year term as one of the Energy Bar Association "Deans" for educational programs. A copy of my curriculum vitae is attached as Exhibit JAL-1.

Q3. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A3. Yes. I am a member of the Energy Bar Association and the Society for Benefit-Cost Analysis.

Q4. WHO IS SPONSORING YOUR TESTIMONY?

A4. My testimony is sponsored by the Office of the Ohio Consumers' Counsel ("OCC").

Q5. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A5. Yes. I have testified before the Public Utilities Commission of Ohio ("PUCO") in a number of cases, which are listed in Exhibit JAL-2.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A6. I have been asked by the OCC to respond to Ohio Power's ("AEP Ohio" or "the Utility") request for the PUCO to determine whether there is a "need" for 900 MW of renewable generation resources in Ohio[1] and the approval of a non-

[1] *In the matter of the Long-term Forecast Report of Ohio Power Company and Related Matters,* Case No. 18-501-EL-FOR Amendment (September 19, 2018), p. 1.

bypassable Renewable Generation Rider ("RGR" or "Renewable Charge") to support the development of 400 MW of solar generation.[2]

The origins of AEP Ohio' request is the Stipulation approved by the PUCO in 2015 (for which I understand OCC was not a signatory). The 2015 Stipulation stated that "AEP Ohio and its affiliates" would develop at least 500 MW of wind generation in Ohio.[3] The Stipulation also called for AEP Ohio to develop 400 MW of solar generation.[4]

AEP Ohio admits that it has sufficient renewable energy credits ("RECs") and solar renewable energy credits ("S-RECs") for customers. Thus, it is requesting PUCO permission to assess customers for the Renewable Charge based on a much broader, and erroneous, definition of "need" than under R.C. 4928.143(B)(2)(c) or under the renewable energy requirements of R.C. 4928.64. AEP argues that need is established for the renewable projects so long as the projects are "economically beneficial" to customers (leading to lower energy costs) and so long as customers

[2] *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into Renewable Energy Purchase Agreements for Inclusion in the Renewable Generation Rider*, Case No. 18-1392 et al., (September 19, 2018), p. 1.

[3] *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, et al.*, Case Nos. 14-1693-EL-RDR and 14-1694-EL-AAM, Joint Stipulation and Recommendation, December 14, 2015 ("2015 Stipulation"), p. 31, Section I.1.

[4] The language in Section I.2 of the 2015 Stipulation is slightly different. It states that "AEP Ohio will develop a total of at least 400 MW" of solar generation. However, it also states that the "same approach and parameters described above in Section III.1.1a through III.1.1e of this Stipulation will apply to the solar projects." I interpret this language to mean that solar generation will be developed by AEP and its affiliates.

desire in-state renewable power. AEP also defines need to include considerations of larger economic development impacts and the state's energy independence (so as to diminish Ohio's status as a net-importer of energy).[5]

Q7. CAN YOU SUMMARIZE THE 900 MW RENEWABLE ENERGY PROJECTS AND ASSOCIATED RENEWABLE ENERGY PURCHASE AGREEMENTS?

A7. Yes. In this proceeding, AEP Ohio is requesting to implement a non-bypassable charge for two specific solar energy projects totaling 400 MW.[6] The projects are the 300 MW Highland Solar Project and the 100 MW Willowbrook Solar Project, both of which are to be located in Highland County.[7] According to the testimony of AEP Ohio witness Jon Williams, the Utility has signed a solar Renewable Energy Purchase Agreement ("REPA" or "Renewable Agreement") with Hecate Energy Highland LLC for the Highland Project and a REPA with Willowbrook Solar I, LLC for the Willowbrook project.[8]

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[5] See testimony of William Allen at 7-8, Case No. 18-501-EL-FOR.

[6] Current usage over 833,000 kWh per month is exempted from the proposed RGR.

[7] Direct Testimony of Joseph Karrasch on Behalf of Ohio Power Company, Case No. 18-1392-EL-RDR, September 27, 2018 ("Karrasch RDR Direct"), Exhibits JAK-1 and JAK-2 (providing summary term sheets for the two REPAs).

[8] Direct Testimony of Jon Williams on Behalf of Ohio Power Company, Case No. 18-1392-EL-RDR, September 27, 2018 ("Williams Direct"), p. 5, lines 7 – 13.

Q8. CAN YOU PROVIDE A SUMMARY OF YOUR CONCLUSIONS?

A8. Yes. The PUCO should find that AEP Ohio has not demonstrated that its customers need their utility to build 900 MW of generation generally or renewable generation specifically. Because AEP Ohio has failed to demonstrate customer need for its proposed projects, the PUCO must also reject AEP Ohio's application to levy a non-bypassable charge on customers for these two Renewable Agreements.

Q9. PLEASE EXPLAIN.

A9. AEP Ohio's justification for the alleged need for at least 900 MW of renewable energy generation resources in Ohio and for the two associated solar Renewable Agreements is inconsistent with the definition of need in Ohio law and unreasonable for the following reasons:

- The plain language of R.C. 4928.143(B)(2)(c) defines need as "based on resource planning projections submitted by the electric distribution utility." AEP Ohio is part of PJM. PJM's most recent generation reserve margin forecast (for its region that includes Ohio) shows reserve margins far greater than the approximately 16% reserve requirement PJM has determined is required to meet

NERC reliability standards for customers.[9] Thus, AEP's proposed Renewable Agreements are not required to provide customers adequate generating capacity and energy. Thus, based on traditional definitions of resource need to provide safe, adequate, and reliable electric service for customers, as reflected in the Ohio law, there is no need for the 900 MW of renewable generation resources in Ohio and the two solar Renewable Agreements proposed by AEP Ohio.

- AEP Ohio admits that it is fully compliant with Ohio's renewable energy generation mandate. In fact, the Utility currently has a surplus of Renewable Energy Certificates ("RECs").[10] Thus, AEP Ohio does not need the 900 MW of in-state renewable generation resources and the two associated Renewable Agreements to meet Ohio's renewable mandates.

- While AEP Ohio's failure to meet the Ohio General Assembly's standard of customer need for the renewable projects means that AEP Ohio's application should be denied, other claims by AEP

[9] PJM, "Draft 2018 PJM Reserve Requirement Study," October 10, 2018 ("PJM 2018 IRM Study"). Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20181025/20181025-item-05-2018-reserve-requirements-study.ashx

[10] Direct Testimony of William Allen on Behalf of Ohio Power, Case No. 18-501-EL-FOR, September 19, 2018 ("Allen Direct FOR"), p. 13, lines 3-6. Ohio Power's confidential response to Staff- 1-1(a) provides data on the magnitude of the current surplus of RECs and S-RECs.

Ohio should also be rejected. AEP Ohio has not demonstrated that its proposed Ohio renewable energy resources would be economically beneficial to customers. The estimated present value reductions in revenue requirements associated with the terms of the two REPAs under the scenarios presented in the exhibits to the testimony of AEP Ohio witness Torpey[11] are erroneous and overstate the potential savings (if any) for AEP Ohio customers for the following reasons. First, AEP Ohio's estimated revenue requirements reductions are based on inaccurate and overestimated future natural gas prices. Second, they are based on a capacity price forecast of the PJM region that lacks any credibility whatsoever and which ignores basic economic concepts. Third, AEP Ohio's estimated present value of customer savings (or reductions in revenue requirements) should be further reduced by the additional debt equivalency costs that AEP Ohio intends to collect from its customers. Fourth, a significant percentage of the claimed customer savings are based on AEP Ohio's assumption of a nationwide carbon tax. No such tax exists today and the prospects for passage of such a tax are uncertain. Fifth, the revenue requirement reductions as alleged by AEP Ohio are further overstated because AEP Ohio ignores the costs associated with

[11] See Direct Testimony of John Torpey on Behalf of Ohio Power Company, Case No. 18-1392-EL-RDR, September 27, 2018 ("Torpey RDR Direct"), Exhibits JFT-2 and JFT-3.

back-up generation needed to "firm up" inherently intermittent solar power. Those costs will be incurred by PJM, collected from AEP Ohio and then passed on to the customers of AEP Ohio under the proposed Renewable Agreements. Sixth, the savings estimates by AEP Ohio Witness Torpey also ignore the fact that AEP Ohio customers will be forced to pay the costs of all penalties for nonperformance by the 400 MW solar energy projects in the PJM capacity market. Thus, if these additional costs are included to more accurately reflect costs to customers, there is no basis to conclude that the proposed Renewable Agreements for the 400 MW of solar generation will reduce costs (or provide savings) to AEP Ohio's customers.

- AEP Ohio's claim that the solar power Renewable Agreements are justified to promote "energy independence" because Ohio is a net importer of electricity belies the fact that Ohio (and its retail electric customers) benefits from membership in PJM in the form of lower costs and greater system reliability by buying and selling electricity outside Ohio. AEP Ohio's argument that Ohio should pursue a policy of "energy independence," or more correctly "electricity self-generation," lacks any economic justification. AEP Ohio's argument is contrary to the fact that its membership in PJM (and thus its engaging in energy "trading" across state lines) provides AEP Ohio customers with the greatest level of system reliability at the lowest possible cost. In this regard I note that AEP Ohio is not even proposing to develop the renewable plants to sell the renewable energy to Ohio customers. Instead, AEP Ohio claims – wrongly – that the units will serve as a financial hedge relative to the pricing of other generation.

- The claimed hedge benefits of the Renewable Agreements by AEP Ohio are speculative and insignificant. They should not be used by the PUCO in deciding whether there is "need" for 900 MW of in-state renewable generation resources. Moreover, AEP Ohio's proposal for buying capacity and energy from these in-state renewable projects and re-selling this capacity and energy in the PJM market (instead of using the output to supply Ohio customers[12]) further confirms there is no need (either for reliability or for economic benefits) for these 900 MW of energy projects. AEP Ohio's claimed hedge benefits ignore at least four salient facts. First, hedging is a form of insurance, and all insurance has a net expected cost. (Otherwise, insurers would go out of business.) AEP Ohio has not demonstrated that the expected benefits of

[12] In other words, the renewable energy from the AEP projects will not be sold to Ohio customers.

hedging (if any) are greater than the expected costs of hedging by entering into these two Renewable Agreements. Second, AEP Ohio retail customers who purchase electricity from retail electric marketers ("Marketers") can already contract for offerings that provide hedges against volatile prices and allow them to balance for themselves reductions in price volatility against higher expected costs. Third, the contracts used to serve AEP Ohio's customers on the Standard Service Offer ("SSO" "or "Standard Offer") are obtained by the Utility through competitive bidding with the use of laddering, and thus are designed specifically to reduce price volatility. Fourth, and most importantly, AEP Ohio ignores the fact that the inherent intermittency of solar generation (as well as wind power) requires costly back-up generation, which can lead to additional price volatility in the PJM market. In other words, when solar generation is suddenly unavailable, more costly additional generation must be available to customers to replace the lost solar generation. The intermittency of solar generation thus can increase the volatility of locational market prices in PJM. This can affect both AEP Ohio customers who purchase electricity from retail energy marketers and customers who purchase generation under AEP Ohio's Standard Offer.

- As the PUCO "energychoice.gov" website shows, numerous retail energy marketers are already offering fixed-price contracts for energy, including renewable energy. Fixed-price contracts hedge those marketers' customers against price volatility. But as price volatility increases, the cost of hedging that volatility increases as well. Thus, the more there is intermittent generation in the market, the costlier it becomes for retail energy marketers to offer fixed-price contracts. Higher-priced contracts harm those retail marketers' customers. A similar concern holds for AEP Ohio's Standard Offer customers, who obtain power from competitively solicited, "laddered" contracts. Again, as price volatility increases, so will the costs of those contracts increase that customers pay. Finally, because intermittent generation must be firmed up by PJM, which is costly to do, PJM's overall cost to ensure reliability increases for customers. Those costs are passed on to all PJM customers, including the customers of AEP Ohio.

- AEP Ohio's ultimate justifications for the need for 900 MW of Ohio renewable generation resources and the two solar Renewable Agreements are based on: (i) a flawed survey showing Ohio customers "like" the idea of in-state renewable generation; and (ii) a flawed study showing that in-state development of solar generation will boost the Ohio economy. Neither of these rationales justifies a non-bypassable charge to be paid by all AEP Ohio customers.

- Nothing prevents AEP's competitive generation subsidiary, AEP Renewables, from accepting the risk (instead of shifting the risk to captive monopoly customers) and building or contracting for solar generating facilities within Ohio and competitively selling the output of such generating facilities to Ohio customers who desire to purchase green energy. Moreover, if AEP Ohio believes the results of the Navigant survey it commissioned, then development of in-state renewable generation by its affiliate AEP Renewables or by contracting for renewable generation by AEP Energy (an AEP affiliated retail energy marketer) will be purchased, not only by AEP Ohio's residential and commercial customers, but by all of the state's residential and commercial electric customers.

- Finally, AEP Ohio is also proposing a bypassable Green Tariff for customers who wish to purchase renewable energy based on their personal (or corporate) preferences. If AEP Ohio believes the results of the Navigant survey, then the Utility must expect that a majority of AEP Ohio's residential and business customers will sign up to purchase renewable energy under that Green Tariff – obviating a reason for the proposed Renewable Charge on customers.

Q10. APART FROM THE FACT THAT THERE IS NO DEMONSTRATED NEED FOR THE 900 MW OF OHIO RENEWABLE GENERATION RESOURCES OR SPECIFICALLY THE 400 MW OF SOLAR GENERATION TO SERVE UTILITY CUSTOMERS, DO YOU HAVE AN OPINION ON WHETHER AEP OHIO'S PROPOSAL WILL HARM ITS CUSTOMERS AND OHIO'S ECONOMY?

A10. Yes. The proposal will likely harm AEP Ohio's customers and the Ohio economy. AEP's regulatory proposal transfers financial and operating risk of power plants from AEP shareholders to AEP Ohio's captive monopoly customers. This is contrary to the General Assembly's plan for Ohio that, with limited exceptions, generating plants (including renewable projects) should be developed in the marketplace, without involvement of monopoly utilities and charges to their captive customers. The reason for the likely harm to customers is that one of the key objectives of electric industry restructuring in Ohio was to transfer the risks of generating plant construction and operation to generation owners, who can manage such risks, and away from retail customers, who should not bear such risks.

Under current Ohio law, AEP Ohio customers cannot (and should not) be forced to bear the financial risks of power plant generation, including entering into initially above-market cost solar generation purchase agreements in hopes that these contracts will be offering power at a below-market cost well into the future.[13] Nor can (or should) AEP Ohio customers be forced by AEP Ohio to bear the risks of paying penalties levied by PJM for any non-performance by the renewable projects resulting from the intermittent nature of solar generation resources. Contrary to Ohio law, the proposed Renewable Agreements will hinder competitive development of renewable energy resources, distort the competitive retail electric market in the state, and force AEP Ohio's captive monopoly customers to subsidize renewable energy with unpredicted costs over an unknown period of time.

Q11. CAN AEP CUSTOMERS DESIRING TO PURCHASE RENEWABLE ENERGY FREELY DO SO?

A11. Yes. If AEP Ohio retail customers value wind and solar generation, they can purchase it in the marketplace, as the Ohio General Assembly envisioned when it enacted laws deregulating the generation market, which would enable lower electricity prices and incent innovations for the benefit of customers. There are numerous competitive offerings of 100% green energy, including offers by AEP Ohio's competitive affiliate, AEP Energy. (AEP Energy is a subsidiary of AEP

[13] See Torpey Direct RDR, Exhibit JFT-1.

Corporation that supplies retail electricity in competitive retail electric markets and offers customers 100% green energy options).

Additionally, Ohio's deregulated generation market provides opportunities for competitors such as AEP Energy, Inc. to construct and operate renewable generation facilities in Highland County, Ohio or elsewhere.[14] Relying upon the market place to develop power sources, including renewables, not only is consistent with the Ohio General Assembly's plan for Ohioans to be served by non-utility owned competitive power plants, it was the objective of the Assembly.

That AEP Ohio believes a non-bypassable charge on customers is required for the Renewable Agreements and the development of Ohio renewable generation resources belies the Utility's claims that the proposed renewable energy resources have below-market costs. That AEP Ohio seeks to force its captive customers to pay for the projects belies the Utility's claim that, based on the Navigant survey results presented as Exhibit TH-1,[15] the vast majority of AEP Ohio customers are willing to pay more for renewable energy developed in the state. In other words, if the proposed solar energy projects are as economical and desired by AEP Ohio

[14] AEP Renewables, LLC is a subsidiary of AEP Energy Supply, LLC. AEP Energy Supply, LLC is "a nonregulated holding company for AEP's competitive generation and retail businesses and a wholly-owned subsidiary of AEP." See AEP 2018 SEC Form 10-k, p. ii. Available at: https://www.sec.gov/Archives/edgar/data/4904/000000490418000009/aep10klegal20174q.htm

[15] Direct Testimony of Trina Horner on Behalf of Ohio Power Company, Case No. 18-501-EL-FOR, September 19, 2018 ("Horner Direct"), Exhibit TH-1.

customers as AEP Ohio claims, then there would be no need to impose a non-bypassable charge and force all AEP Ohio customers to pay for it.

Q12. BUT DON'T THE RENEWABLE PURCHASE POWER AGREEMENTS BENEFIT CUSTOMERS BY PROVIDING A HEDGE AGAINST VOLATILE MARKET PRICES?

A12. No. The hedging "benefit" arguments advanced by AEP Ohio are similar to those made previously by AEP Ohio to support power purchase agreements ("PPA") with customer subsidies for the coal plants of the Ohio Valley Electric Corporation ("OVEC"), of which AEP is part owner. However, the benefits of the OVEC PPAs have not materialized and, consequently, AEP Ohio customers are paying a higher cost for electricity as a result of the OVEC PPAs.

A recent estimate by FirstEnergy Solutions, as part of its bankruptcy proceeding, shows the net above-market cost of its 4.85% share of the OVEC contracts will be $268 million for FirstEnergy Solutions alone.[16] AEP Ohio's ownership share of the OVEC contracts is more than four times larger than FirstEnergy Solutions' ownership share.[17] The potential net above-market cost of the OVEC contracts for AEP Ohio's customers can easily top $1 billion for the life of the contracts.

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[16] *In re: First Energy Solutions Corp., et al.*, United States Bankruptcy Court, Northern District of Ohio, Eastern Division, Case No. 18-50757, Declaration of Kevin T. Warvell, April 1, 2018 (Attached as Exhibit JAL-3).

[17] Source: Ohio Valley Electric Corporation, http://www.ovec.com/OVECHistory.pdf (Attached as Exhibit JAL-4).

The PUCO should be extremely wary of these similar front-loaded arrangements for Ohio's renewable generation resources that promise customer benefits years in the future (which may or may not be realized many years from now) in exchange for customers paying above-market costs that benefit AEP Ohio today.

II. AEP OHIO HAS NOT ESTABLISHED A "NEED" FOR THE TWO SOLAR GENERATION PROJECTS AS DEFINED BY OHIO'S GENERAL ASSEMBLY UNDER R.C. 4928.143(B)(2)(c) OR R.C. 4928.64.

Q13. WHAT DOES R.C. 4928.143(B)(2)(c) SPECIFICALLY STATE?

A13. R.C. 4928.143(B)(2)(c) states that an electric distribution utility's ("EDU") Electric Security Plan may include:

> The establishment of a non-bypassable surcharge for the life of an electric generating facility <u>that is owned or operated</u> by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. <u>However, no surcharge shall be authorized unless the commission first</u>

> determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements. (Emphasis added).

Q14. WHAT IS YOUR UNDERSTANDING OF THE LANGUAGE QUOTED ABOVE?

A14. The language of R.C. 4928.143(B)(2)(c) is quite clear. Specifically, it requires a finding of "need" for the generation that will be provided by the two solar projects (totaling 400 MW) in a resource planning sense, based on projections contained in AEP Ohio's 2018 Long-Term Forecast Report, which are submitted by the utility in a proceeding under Chapter 4935 of Ohio's Revised Code. It also requires that the two solar projects be owned or operated by AEP Ohio, and that the energy and capacity of the two projects be dedicated to Ohio consumers.

Q15. IS THERE A NEED FOR THE TWO PROJECTS FROM A RESOURCE PLANNING SENSE?

A15. No. AEP Ohio itself admits there are sufficient reserve margins and sufficient renewable energy credits, which belie a "need" for the projects.[18]

Q16. WILL AEP OHIO OWN OR OPERATE EITHER OF THE TWO SOLAR PROJECTS?

A16. No. AEP Ohio will not own the two solar facilities.[19] Nor will AEP physically operate the facilities. Instead, day to day maintenance and other operational activities at each facility will be undertaken by the sellers of the two solar projects. AEP Ohio characterizes this as the sellers operating "on behalf of the company." The Utility's responsibility with respect to these two solar facilities is that it will be the market participants for the projects, offering /scheduling renewable energy from the projects into PJM. [20]

Q17. WILL THE ENERGY AND CAPACITY OF THE TWO SOLAR FACILITIES BE DEDICATED TO OHIO CUSTOMERS?

A17. No. AEP has stated it will sell the energy and capacity into the PJM wholesale markets.[21] Thus, the money that AEP customers pay (through the non-bypassable

[18] Allen Direct FOR, p. 8, lines 3-7.

[19] See AEP response to OCC-INT 3-24, Case No. 18-501-EL-FOR (attached as Exhibit JAL-5).

[20] See Company Response to OCC INT- 1-005, Case No. 18-1393-EL-ATA (attached as Exhibit JAL-6).

[21] *Id.*

charge (RGR rider)) will not be used to purchase solar power generated from the Willowbrook or Highland facilities. Instead, the money collected from customers is an insurance payment (separate from the actual power) to AEP that AEP alleges will help protect against volatile PJM market prices.

Q18. DOES AEP ADMIT THAT PJM WHOLESALE MARKETS ARE PROVIDING ADEQUATE CAPACITY?

A18. Yes. AEP Ohio's 2018 Amended LTFR admits that PJM's wholesale market is providing adequate capacity.[22] Nevertheless, AEP Ohio states that "There is a resource planning need for at least 900 MW of renewable generation resources located in Ohio and deliverable to AEP Ohio's service territory."[23] AEP Ohio's statement is simply untrue.

Q19. ARE YOU FAMILIAR WITH RESOURCE PLANNING CONCEPTS AND PRACTICES, INCLUDING LOAD FORECASTING?

A19. Yes. I began my professional career as an electricity load and price forecaster for Idaho Power Company. I also developed load forecasts while employed at the Pacific Northwest Utilities Conference Committee ("PNUCC"), an industry trade group, where I worked closely with load forecasters at the Northwest Power Planning Council and the Bonneville Power Administration. Furthermore, as Manager, Economic Analysis at Green Mountain Power, I was part of the

[22] 2018 Amended LTFR, p. 3.

[23] *Id*. at 5.

Resource Planning group, which prepared peak and energy load forecasts, and evaluated resource alternatives to meet those forecasted loads in a least-cost manner. At Green Mountain Power, I also worked with staff at the Electric Power Research Institute ("EPRI") to develop new methodologies to forecast loads at the distribution circuit level and determine least-cost alternatives in meeting the forecast loads, and was later presented with an "EPRI Innovators" award for those efforts. As an economic consultant, I have prepared load forecasts and worked with clients on resource planning issues. I have also published articles on new methodologies for resource planning and load forecasting, which are listed in the publications section of Exhibit JAL-1. Therefore, I consider myself to be an expert on load forecasting and resource planning issues.

Q20. WHAT ARE THE GOALS OF ELECTRIC UTILITY RESOURCE PLANNING?

A20. Utility resource planning involves first forecasting future energy and peak loads of customers as accurately as possible, and then ensuring that customer' electric needs can be met at the lowest expected cost ("least cost") with a portfolio of resources. In other words, the forecasting exercise first establishes whether there is a "need" for new resources–whether generating resources or energy efficiency resources.

Q21. BASED ON YOUR EXPERIENCE WITH RESOURCE PLANNING, WHAT DOES THE "NEED" FOR NEW RESOURCES MEAN?

A21. Prior to electric utility restructuring, all electric utilities had an obligation to serve customers. That meant that a utility was required to meet its customers' demand for electricity at all times, which utilities typically did by building generating plants or entering into long-term purchase contracts with other utilities. Therefore, "need" in a resource planning sense related to an electric utility having sufficient electric resources—either generating resources or energy efficiency resources—to meet customer demand at all times, and to ensure that customers were provided with reliable service. In other words, "need" means having sufficient electricity supplies to ensure that customers' lights will always stay on, which includes a minimum amount of excess generating capacity in case of unplanned or forced outages.

Excess generating capacity is typically referred to as an "installed reserve margin" ("IRM") or just "reserve margin." To ensure there is sufficient generating capacity to meet peak electric demand and to meet reliability standards, PJM requires the total amount of generating capacity to be greater than forecast peak demand. In that way, if some generators are unable to operate at such times, or if a transmission line is not operating, PJM can still meet reliability standards. For example, on October 10, 2018, PJM released a draft of its newest reserve study for the 11-year planning horizon June 1, 2018 – May 31, 2029.[24] The PJM 2018 IRM Study recommends a reserve margin of 16.0% in the 2019/2020 planning year, decreasing slightly to 15.7% by the 2023/2023 planning year.[25]

After electric utility restructuring, many vertically integrated utilities (including AEP Ohio) divested themselves of their generating resources and became EDUs. Customers of these utilities can purchase electricity from retail energy market providers, and thus the EDUs' obligation is to provide electricity sourced from the wholesale market to those remaining customers who either cannot or will not select an alternative retail provider. This is the situation in Ohio and refers to its Standard Service Offer ("SSO") customers. AEP Ohio's SSO customers' electricity needs are served by the winners of auctions held by the Utility.

Q22. DOES AEP OHIO OWN ANY GENERATING RESOURCES THAT IT USES TO SERVE SSO CUSTOMERS?

A22. No.

[24] PJM, "Draft 2018 PJM Reserve Requirement Study," October 10, 2018 ("PJM 2018 IRM Study"). Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20181025/20181025-item-05-2018-reserve-requirements-study.ashx (Attached as Exhibit JAL-7.)

[25] PJM 2018 IRM Study, p. 9, Table 1.

Q23. ONCE A NEED FOR NEW RESOURCES TO MEET CUSTOMERS' FUTURE DEMAND IS ESTABLISHED, HOW IS A PORTFOLIO OF RESOURCES SELECTED?

A23**.** Once the need for new resources is determined, the resource planning exercise examines all of the available alternatives and selects those which meet that need at the lowest expected cost.

Q24. IS THAT THE APPROACH TAKEN IN THE AEP 2018 INTEGRATED RESOURCE PLANNING REPORT ("2018 IRP")?

A24**.** No. The 2018 IRP,[26] which is attached to the testimony of AEP Ohio witness Torpey,[27] appears to be one where the assumptions and analysis are designed to demonstrate two pre-conceived conclusions: (i) that there is a demonstrated "need" for the 900 MW of renewable generation resources AEP Ohio seeks to obtain; and (ii) the two REPAs for 400 MW of solar generation are "cost-effective" and can therefore serve that "need."

[26] AEP Ohio. "Integrated Resource Planning Report and Forecast Report Requirements for Electric Utilities to the Public Utilities Commission of Ohio," Case No. 18-50-1-EL-FOR, September 19, 2018.

[27] Torpey Forecast Direct, Exhibit JFT-1.

Q25. HOW DO YOU INTERPRET THE LANGUAGE IN R.C. 4928.143(B)(2)(c) ADDRESSING "NEED"?

A25. I interpret the language of R.C. 4928.143(B)(2)(c) as a type of market "safety valve." To understand what this means, we need to consider the market environment in which AEP Ohio operates.

AEP Ohio is an electric distribution utility ("EDU)" and a member of PJM, which operates several different types of electricity markets. These PJM markets provide access to both EDUs (for SSO service) and retail energy marketers (for shopping customers) with the energy and capacity needed to meet customer demand and reserve requirements established by PJM to ensure reliable electric service. Competitive markets work for customers by equating supply and demand. As supply and demand change, so will market prices. For example, as shale gas production has increased, market prices for natural gas have decreased. Not only has that lowered the price of natural gas for customers, it has also reduced the spot market prices of electricity for customers, because the cost of generating electricity with natural gas has decreased. Of course, competitive market conditions can change over time, increasing and decreasing in response to changes in customers' demand and changes in supply. However, competitive markets are also self-correcting. That is, expectations of high market prices lead to increased supplies, which reduce market prices, and vice-versa.

Under R.C. 4928.143(B)(2)(c), the benefits and costs of a generating resource must flow through to an EDU's Ohio customers. An EDU cannot levy a non-bypassable surcharge on its customers to build a generating resource and then sell all of the energy and capacity into the market and keep the profits for its shareholders. That is why R.C. 4928.143(B)(2)(c) also states that "the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility."

Q26. DOES AEP OHIO CONSIDER R.C. 4928.143(B)(2)(c) TO BE CONSISTENT WITH "NEED" IN THE CONTEXT YOU HAVE DESCRIBED, THAT IS, TO PROVIDE SAFE, ADEQUATE, AND RELIABLE ELECTRIC ENERGY AND CAPACITY SUPPLIES TO ITS CUSTOMERS?

A26. No. In its response to IGS-INT-2-001 (attached as Exhibit JAL-8), AEP Ohio states:

> AEP Ohio is not an integrated utility and cannot perform integrated resource planning. And the ESP statute uses the phrase "resource planning" -- not "integrated resource planning" -- which is a concept that has meaning in the context of post-corporate separation and in the context of an electric distribution utility as an RTO member. Thus, the "resource planning" concept in the ESP

statute is distinctly different from integrated resource planning in the context of traditional regulation.

Thus, AEP Ohio argues that R.C. 4928.143(B)(2)(c), which it refers to as the "ESP Statute," is not about resource planning in the sense I have described above.

Q27. DO YOU AGREE WITH AEP OHIO ABOUT ITS INTERPRETATION?

A27. No. While I cannot provide a legal opinion on the meaning of R.C. 4928.143(B)(2)(c), the plain language of the statute states that "no surcharge shall be authorized unless the commission first determines in the proceeding that there is <u>need for the facility based on resource planning projections submitted by the electric distribution utility.</u>" It is obvious that "resource planning projections" refer to supply and demand. If there is insufficient supply to meet customers' demand – for example, were AEP Ohio's SSO load to increase – then AEP Ohio would need to obtain additional supplies to meet that demand.

Moreover, the testimony of AEP Ohio witness Williams highlights R.C. 4928.02, which states that it is the policy of the state to "Ensure the availability to consumers of adequate, safe, efficient, nondiscriminatory, and reasonably priced retail electric service."[28] That definition is consistent with the plain language of "need" in R.C. 4928.148(B)(2)(c).

[28] Williams Direct, p. 9, lines 21-22.

Thus, I conclude that AEP Ohio's attempt to distinguish between "resource planning" and "integrated resource planning" so as to justify a non-bypassable charge for the two solar projects, even though the Utility admits there is no need for those plants' output, is sophistry. Instead, AEP Ohio wishes to define "need" as meaning whatever it chooses.

Q28. IS THERE IS A "NEED" FOR RENEWABLE RESOURCES THAT <u>DOES</u> FALL WITHIN THE LANGUAGE OF R.C. 4928.143(B)(2)(c)?

A28. No. As I discuss below, renewable resource requirements are set out separately under R.C. 4928.64. The language of R.C. 4928.143(B)(2)(c) has nothing to do with renewable resource requirements or the "need" for renewable resources.

Q29. WHAT ISSUES DOES R.C. 4928.64 ADDRESS?

A29. R.C. 4928.64 sets out "alternative energy resource" requirements. Specifically, R.C. 4928.64(B) sets out an annual schedule for the quantities of renewable energy resources, including solar energy resources, that all load serving entities—both EDUs and retail energy marketers—must have in proportion to their overall electric energy sales to their retail customers.

Q30. DOES AEP OHIO NEED TO OBTAIN ADDITIONAL SOLAR RENEWABLE ENERGY CERTIFICATES ("S-RECS") TO MEET ITS STATE RENEWABLE ENERGY MANDATES?

A30. No. AEP Ohio witness Allen testifies that the Utility does not need to acquire additional RECs to meet statutory requirements.[29] As shown in Confidential Attachment 1-a to AEP Ohio's response to Staff-01-001 (attached as Confidential Exhibit JAL-9), AEP Ohio has [redacted] In a subsequent confidential discovery response to IGS-INT-1-5, (attached as Confidential Exhibit JAL-10), AEP Ohio stated that [redacted] Thus, AEP Ohio has no need for S-RECs until at least [redacted]

In terms of non-solar RECs, AEP Ohio's response to Staff-01-001 indicates it has [redacted]

[29] Direct Testimony of William Allen on Behalf of Ohio Power, Case No. 18-501-EL-FOR, September 19, 2018 ("Allen Direct FOR"), p. 13, lines 3-6.

[redacted] Therefore, AEP Ohio has no need for non-solar RECs to meet the statutory mandates.

Q31. HAVE SOLAR RENEWABLE ENERGY CREDIT ("S-REC") PRICES INCREASED IN OHIO SINCE 2012?

A31. No. The prices of S-REC in Ohio have fallen in recent years. According to an October 2018 report prepared by the National Renewable Energy Laboratory ("NREL"), prices for Ohio S-RECs have declined significantly between 2012 and 2017.[30] According to Confidential Attachment 1 to the response to OCC-INT-03-030 (attached as Exhibit JAL-12), prices for S-RECs [redacted] respectively, compared to just [redacted] in Ohio.

[30] Eric O'Shaughnessy, et al., "Status and Trends in the U.S. Voluntary Green Power Market (2017 Data)," NREL, October 2018 ("NREL 2018"), p. 21. (Attached as Exhibit JAL-11). Available at: https://www.nrel.gov/docs/fy19osti/72204.pdf

Q32. [redacted]

A32. [redacted] Moreover, consistent with AEP Ohio witness Allen's testimony, AEP Ohio has a surplus of S-RECs and thus has no need for additional S-RECs until at least [redacted]

III. AEP OHIO HAS NOT ESTABLISHED A "NEED" FOR IN-STATE GENERATION TO PROMOTE "OHIO ENERGY INDEPENDENCE".

Q33. AEP OHIO WITNESS ALLEN TESTIFIES THAT THERE IS AN IN-STATE ENERGY "GAP" IN OHIO BECAUSE THE DEMAND FOR ELECTRICITY IS GREATER THAN IN-STATE GENERATION. DOES THIS "GAP" JUSTIFY THE NEED FOR THESE RENEWABLE PROJECTS AND A NON-BYPASSABLE CHARGE FOR THE RENEWABLE PROJECTS?

A33. No. Mr. Allen testifies that, "[f]or years, the state of Ohio has failed to produce enough electricity within the state to meet the usage in the state. … Ohio depends on energy produced in other states to be brought in to meet the needs of its people, businesses, and industry."[31] This alleged in-state generation "gap" is a

[31] Allen Direct FOR, p. 9, line 19 – p. 10, line 5.

silly economic concept and is not a reasonable and sound basis for development of in-state generating resources and cost recovery of those resources through non-bypassable charges.

Q34. CAN YOU EXPLAIN WHY SO-CALLED OHIO ENERGY "INDEPENDENCE" IS NOT A USEFUL ECONOMIC CONCEPT?

A34. Yes. There are several reasons. The major reason has to do with a fundamental economic concept known as "comparative advantage." Rather than being self-sufficient in everything, it makes more economic sense to specialize in what we do most efficiently. Ohio farmers do not build their own tractors because doing so would be extremely costly. Instead, there are specialized manufacturers of agricultural tractors that do the job. Similarly, Ohio farmers do not grow oranges because it would require building huge and expensive greenhouses. Instead, Ohioans purchase oranges from states like California and Florida, which have climates that are conductive to growing oranges and other citrus fruit.

The same is true for energy resources. According to data published by the US EIA, in 2016 Ohio consumed just over 217 million barrels of petroleum products. At the same time, Ohio produced slightly less than 2 million barrels of crude oil. Thus, Ohio imports approximately 99% of the crude oil consumed in the state. Does this mean Ohioans are at risk of being cut-off from supplies of gasoline and heating oil from hostile external powers, such as Indiana and Michigan? Hardly.

Policy makers in Ohio are not calling for Ohio to massively increase crude oil production, nor is it clear that the state could ever produce sufficient crude oil to meet demand.

For natural gas, the situation is the reverse. In 2016, Ohio sold about 1.8 Trillion cubic feet of natural gas. Total in-state consumption was slightly more than half that amount, 931 Billion cubic feet. The remainder was exported to other states. Yet, it is doubtful that Ohio policymakers believe that customers in other states should be prevented from buying natural gas produced in Ohio and required to purchase natural gas produced in their respective states only.

Q35. DO OHIO CUSTOMERS BENEFIT FROM AEP OHIO PARTICIPATING IN PJM, WHICH IS A MULTI-STATE ENTITY?

A35. Yes. Because PJM coordinates generation and transmission in 13 states and the District of Columbia, PJM members (and their customers) enjoy improved efficiency, reliability and lower overall costs than any individual utility like AEP Ohio could achieve on its own. This is the reason power pools like PJM were first formed. By having a larger group of integrated resources, the risk of outages is reduced, thus increasing reliability to customers. Similarly, the ability to rely on a multi-state pool of generating resources means that the lowest-cost generating resources are far more likely to be available to dispatch by PJM, thus reducing costs to consumers.

IV. THE PURPORTED ECONOMIC DEVELOPMENT BENEFIT DOES NOT MEET THE DEFINITION OF "NEED" UNDER R.C. 4928.143(B)(2)(c).

Q36. MR. ALLEN ARGUES THAT THE SOLAR PLANTS ARE "NEEDED" BECAUSE IN-STATE GENERATING RESOURCES BENEFIT THE OHIO ECONOMY. DO YOU AGREE?

A36. No. First, the language of R.C. 4928.143(B)(2)(c) says nothing about economic development impacts as a "need" criterion. Second, as discussed above, Mr. Allen's argument entirely ignores the benefits of comparative advantage. Third, nothing prevents AEP's competitive subsidiaries, such as AEP Energy and AEP Renewables, from developing as much in-state generation as they like without relying on funding from their captive monopoly customers.

Mr. Allen testifies that, "Ohio depends on energy produced in other states to be brought in to meet the needs of its people, businesses, and industry. This results in energy dollars from Ohio customers being exported to generators outside of Ohio and providing economic development benefits to residents and businesses in those other states."[32] Mr. Allen's argument is based on fundamental economic fallacies. First, if one accepts the energy independence premise for electricity, then one should also support policies that promote economic independence in all manner of goods and services. For example, for the sake of "financial independence" and

[32] Allen Direct FOR, p. 10, lines 3-7.

promoting the local economy, AEP Ohio should obtain its financing solely from banks and other funding sources in Ohio. For the sake of "promoting jobs in Ohio" and helping the local economy, AEP Ohio should refrain from hiring or promoting high-paying executives from outside of Ohio. But the result of such policies would be economic ruin because such policies explicitly ignore comparative advantage.

Second, although it is natural to promote state economic development, doing so via subsidies and risk transfers has a significant net cost to the state economy. In effect, such subsidies benefit the few at the expense of the many. AEP Ohio argues it wishes to promote economic development with in-state generation, but only if it can force its customers to bear all of the financial risks of doing so.

AEP Ohio also emphasizes the in-state job creation of the two solar projects. But if one views the purpose of building and operating generating resources as job provision, then generating units should be built and operated using as many workers as possible. Thus, one should have workers dig foundations entirely by hand, rather than use backhoes. Concrete should be mixed in wheelbarrows, rather than large trucks. Solar panels should be cleaned by workers who walk among the panels with small damp cloths. The list is virtually endless. And it would not stop with generation construction and operation. AEP Ohio would be encouraged to add hundreds of more employees to its workforce. Rather than using complex computer models to forecast future electricity demand, the PUCO could require AEP employees to use pen and paper. Doubtless, such arguments sound ridiculous. Yet, they are the logical extension of pursuing economic policies focused, not on overall economic benefits and value, but simply on job creation.

Fourth, subsidies for economic development – and to be clear forcing a group of customers to bear all of the financial and operational risk of the solar projects is a subsidy – damages market competition and thus *reduce* economic growth. If AEP Ohio succeeds in imposing a non-bypassable charge for developing in-state renewable generation, then unsubsidized competitors will be at a competitive disadvantage and will be less likely to develop (make investment in) renewable generation in Ohio.

In other words, the net in-state renewable capacity and energy from the two proposed REPAs may not increase at all. The renewable energy projects proposed by AEP Ohio and paid by its customers are likely to crowd out competitive in-state renewable energy projects owned and operated by other suppliers who do not benefit from subsidies paid for by captive utility customer subsidies.

Q37. WILL THE TWO PROPOSED RENEWABLE PROJECTS IMPROVE OHIO'S ENVIRONMENT?

A37. Not necessarily. As I discussed earlier, these two renewable projects are likely to crowd out other renewable energy projects that could be built in Ohio in the competitive market without subsidies paid by captive utility customers. Moreover, the back-up generation required to address these projects' inherent intermittency can lead to higher air pollution emissions.

Q38. HAS THERE BEEN ROBUST DEVELOPMENT OF IN-STATE SOLAR AND WIND GENERATION?

A38. Yes. First, in December 2017, as required under Paragraph III.D.12.e of the Joint Stipulation and Recommendation in Case Nos. 14-1693-EL-RDR and 14-1694-EL-AAM, AEP Ohio submitted a report to the Ohio PUC that was prepared by Navigant Consulting entitled, "Ohio Renewable Energy Manufacturing & Company Establishment Analysis" ("Navigant 2017 Report").[33] It is attached here as Exhibit JAL-13. As that report states, "Navigant concluded that Ohio currently has a thriving renewable energy market with a variety of different types of wind and solar companies. This market has likely resulted from Ohio's proximity to a strong central and Midwest wind market and a strong solar market driven by policy and incentives in the state of Ohio and the Northeast."[34]

[33] This report is available at: http://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A17L13B44605F01699.

[34] Navigant Report 2017, p. 18.

As shown in Table 1 below, between 2009 and December 7, 2018, the Ohio Siting Board has approved a total of 2,650 in-state solar Photovoltaic ("PV") facilities, which supply 201 MW of electricity. On average, the Ohio Siting Board has approved about 300 such application, most of which are behind-the-meter facilities, each year. The Siting Board also has approved a total of 42 in-state wind generators, totaling 646 MW.

Table 1: Approved Wind and Solar Applications in Ohio

Year	Solar PV Approved Applications	Solar PV Ohio MW	Wind Approved Applications	Wind Ohio MW
2009	14	13.41	2	7.21
2010	150	6.72	8	2.54
2011	339	22.33	10	408.66
2012	431	29.77	4	2.72
2013	339	28.64	7	7.67
2014	254	9.31	2	1.23
2015	298	14.65	2	100.50
2016	387	16.23	3	9.00
2017	249	37.94	2	100.81
2018 1/	189	22.24	2	6.00
Total	**2,650**	**201.2**	**42**	**646.3**

1/ Through 12/7/2018. Source: PUCO
http://www.puco.ohio.gov/puco/?LinkServID=03DBECBA-02E8-D9D6-B58697A05C0CDB37

Q39. DOES AEP OHIO HAVE NON-BYPASSABLE RIDERS FOR THE COMPANY'S THREE EXISTING IN-STATE REPAS?

A39. No. According to the 2018 AEP Factbook, AEP Ohio has REPAs with the Fowler Ridge and Timber Road wind energy projects, totaling 199 MW. AEP

Ohio also has a REPA with the 10 MW Wyandot Solar Project.[35] Unlike what AEP Ohio is proposing for the Highland and Willowbrook facilities, the costs of Fowler Ridge, Timber Ridge, and Wyandot are recovered through AEP Ohio's *bypassable* Alternative Energy Rider.

Q40. DO ANY OF OHIO'S OTHER ELECTRIC UTILITIES HAVE RENEWABLE ENERGY PROJECTS WHOSE COSTS ARE COLLECTED FROM CUSTOMERS THROUGH NON-BYPASSABLE RENEWABLE GENERATION RIDERS?

A40. No.

Q41. ARE THERE LARGE-SCALE IN-STATE SOLAR AND WIND FACILITIES IN THE PJM GENERATION QUEUE?

A41. Yes. As shown in Exhibit JAL-14, the most recent PJM generation queue report lists 71 in-state solar projects, with an overall maximum facility output ("MFO") of 7,460 MW that are categorized under the "Active," "Under Construction," or "Engineering and Procurement" stages. (This excludes facilities already in-service.) Similarly, as shown in Exhibit JAL-15, the PJM generation queue report lists 20 wind projects, with an overall MFO of almost 4,500 MW of capacity that

[35] 2018 AEP Factbook, p. 26. Available at: http://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/2018FactBook_AllSections_Final.pdf

are categorized under the "Active," "Under Construction," or "Engineering and Procurement" stages.

Q42. ARE ALL RESOURCES IN THE PJM GENERATION QUEUE EVENTUALLY DEVELOPED?

A42. No. There is no "guarantee" that all of the resources shown in Exhibits JAL-14 and JAL-15 will be built. However, developers do not enter into the PJM generation queue lightly, because there are significant costs associated with completing the required interconnection studies. Thus, although not all of these resources may be developed, it is unreasonable to assume that none of them will be developed. It is also unreasonable to assume that none of them will be developed *but for* non-bypassable charges. Once again, given the current market conditions for renewable generation, AEP Ohio has failed to demonstrate that its proposal regarding the two solar energy projects is the best or the only viable approach to develop renewable energy resources in Ohio.

Given that numerous competitive electric suppliers, including AEP Energy, already offer customers renewable energy options, and given the quantities of in-state wind and solar generation shown in the PJM generation queue, there is no economic basis for concluding that renewable energy will not be developed in Ohio *but for* the PUCO approving non-bypassable riders associated with long-term power purchase contracts.

V. AEP OHIO HAS NOT DEMONSTRATED THE PROPOSED IN-STATE RENEWABLE ENERGY RESOURCES ARE ECONOMICALLY BENEFICIAL TO ITS CUSTOMERS.

Q43. DO YOU AGREE THAT THE ANALYSIS OF AEP OHIO WITNESS TORPEY DEMONSTRATES THE TWO SOLAR ENERGY PROJECTS AND ASSOCIATED REPAS WILL LOWER COSTS FOR AEP OHIO CUSTOMERS?

A43. No. AEP has not credibly demonstrated that there are economic benefits to customers from the two renewable energy projects. First, the assumptions made in the 2018 AEP Ohio Integrated Resource Plan ("2018 AEP IRP"), on which Mr. Torpey's "savings" analysis are based are outdated and unrealistic. Second, Mr. Torpey's analysis excludes all costs that AEP Ohio customers will be forced to pay for non-performance penalties the projects will be required to pay under the PJM capacity performance regime that takes effect on June 1, 2020. Third, Mr. Torpey's analysis excludes all costs associated with "firming" inherently interruptible solar power, whether through back-up generation or battery storage.

Q44. CAN YOU EXPLAIN THE BASIS FOR YOUR STATEMENT THAT THE ASSUMPTIONS IN THE AEP IRP ARE OUTDATED AND UNREALISTIC?

A44. Yes. As AEP Ohio witness Bletzacker testifies, "Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units."[36] Given the increasing importance of natural gas-fired generation to meet electric demand, forecasts of future gas prices are a crucial component of the long-term forecast. However, as explained in Section 11.1.14 of the 2018 AEP Ohio IRP, AEP Ohio relied on forecast prices from the Energy Information Administration's ("EIA") <u>2017 Annual Energy Outlook</u> ("2017 AEO") which was released in January 2017, almost two years ago. AEP did not rely on natural gas price data published by the EIA <u>2018 Annual Energy Outlook</u> ("2018 AEO") even though it was released in January 2018.

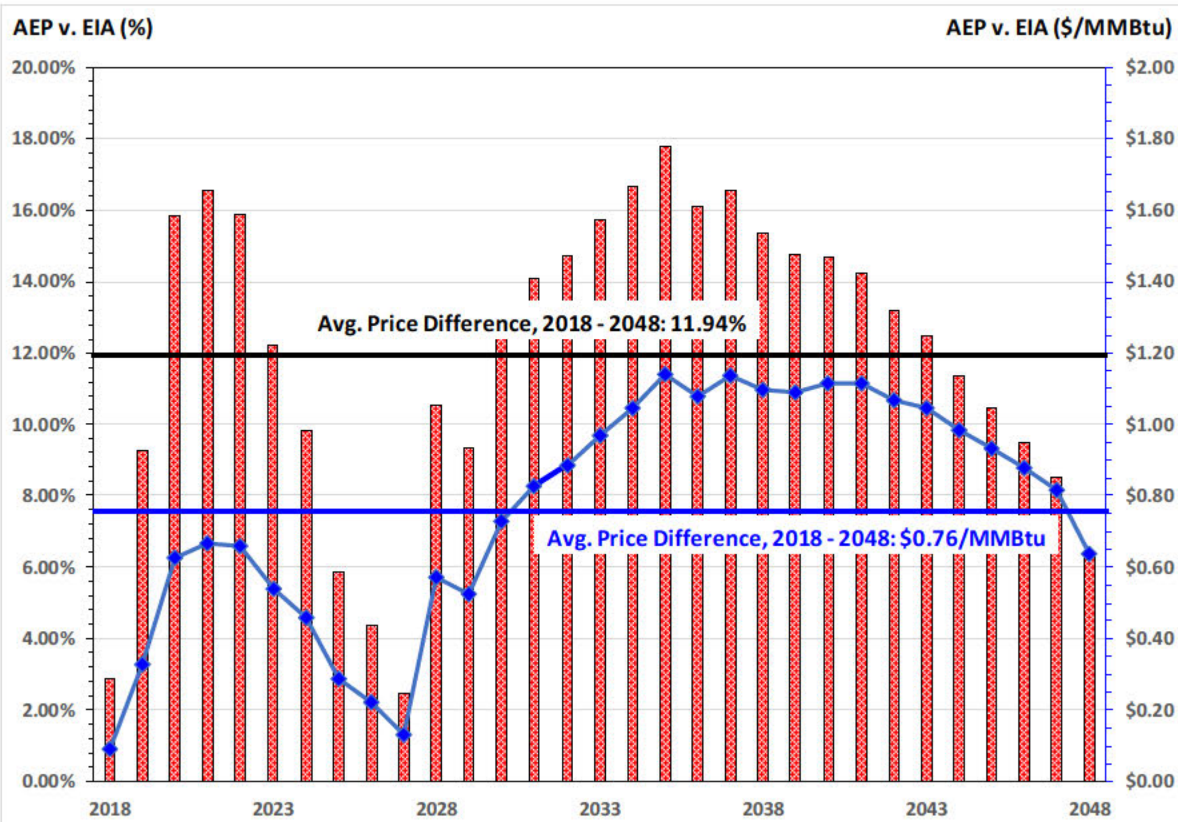
Q45. HOW DO THE NATURAL GAS PRICES USED BY AEP OHIO COMPARE TO THOSE IN THE EIA 2018 AEO?

***A45*.** Figure 1 below provides a comparison. In general, the natural gas prices for Henry Hub price assumed by AEP vary between 2.5% and 18% higher than the EIA 2018 AEO forecast prices. For the entire 30-year period, 2018 – 2048, the AEP forecast Henry Hub natural gas prices average just under 12% higher than

[36] Direct Testimony of Karl Bletzacker on Behalf of Ohio Power Company, Case No. 18-501-EL-FOR, September 19. 2018 ("Bletzacker Direct"), p. 7, lines 19-20.

the prices published in the EIA 2018 AEO. AEP's higher natural gas price forecast drives up its overall PJM wholesale electric energy price forecast. In turn, this will tend to overstate the revenues to be received for selling the output of the 400 MW solar projects into the PJM market.

Figure 1: AEP 2018 IRP v. EIA 2018 AEO Henry Hub Natural Gas Prices



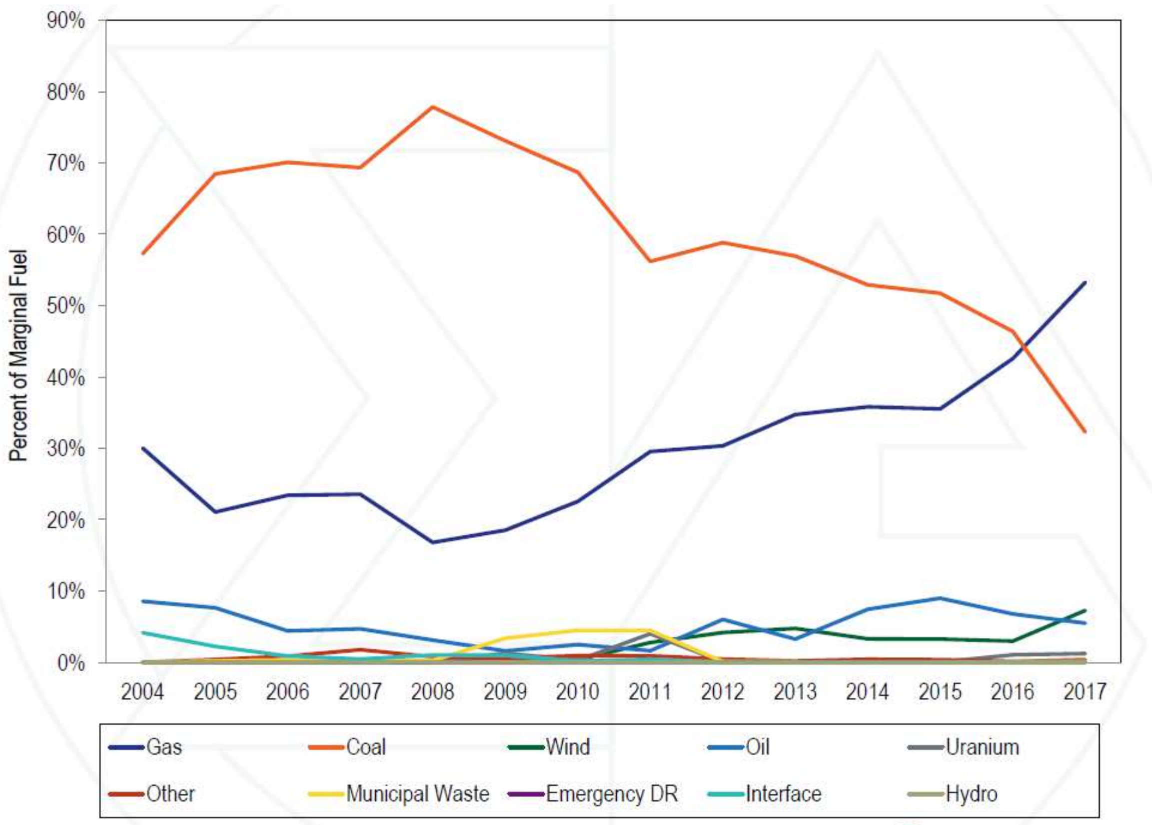
Source Data: EIA AEO 2018 Reference Case, Table A13; AEP 2018 Base Case Forecast (IEU-RPD-001)

Q46. CAN YOU ESTIMATE HOW MUCH AEP'S HIGHER NATURAL GAS PRICES INCREASE ITS FORECAST OF ELECTRIC PRICES IN PJM?

A46. I cannot determine the actual impacts of gas prices on the forecast market prices of electricity in AEP's forecast because AEP uses a proprietary forecasting model.

However, according to the PJM Market Monitor, natural gas-fired generation was the marginal resource in 53.26% of all hours in calendar year 2017, as shown in Figure 2.

Figure 2: Type of Fuel Used by Marginal Generating Units (2017)



Reprinted from: 2017 PJM State of the Market Report, p. 108.[37]

Natural gas generation is most likely to be the marginal resource during peak demand hours because, during off-peak hours, marginal resources are more likely to be low variable cost resources, such as nuclear and coal. If we assume that a typical marginal gas-fired generator has a heat rate of 10,000 Btus/kWh, or 10

[37] Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-sec3.pdf

million Btus per MWh ("MMBtus/MWh"), then a $1/MMBtu price in natural gas will increase such a generator's fuel cost by $10/MWh.

Over the 2018 – 2048 period, the average difference between AEP's Henry Hub natural gas price forecast and the 2018 EIA AEO forecast is $0.76/MMBtu. At a 10,000 MMBtu/kWh average heat rate for gas-fired generators that are the marginal generating unit in PJM that translates into a $7.60/MWh price difference for the AEP forecast of PJM wholesale prices when natural gas is on the margin. And, because the overall mix of generating resources in PJM is increasingly natural gas-fired as coal and nuclear units retire, the number of hours per year in which AEP's price forecast overstates wholesale market clearing prices likely increases over time. This overstatement of PJM energy market clearing prices artificially inflates the energy cost savings to AEP Ohio consumers under Mr. Torpey's analysis.

Q47. DOES THE 2018 AEP IRP ALSO ASSUME CARBON TAXES IN ITS IRP?

A47. Yes. According to the testimony of Mr. Bletzacker, the 2018 AEP IRP assumes a carbon tax of $15/ton beginning in the year 2028, which escalates at a rate of 5% per year thereafter. Thus, in 2048, the AEP IRP assumes a carbon tax of $40/ton.

Q48. CAN YOU ESTIMATE THE EFFECT OF AEP OHIO'S ASSUMED CARBON TAX ON THE PROJECTED ENERGY REVENUES FOR THE TWO SOLAR PROJECTS?

A48. Yes. AEP Ohio witness Torpey's Exhibits JFT-2 and JFT-3 provide the forecast average market energy prices each of the solar plants will receive between 2021 and 2040 under both the "Status Quo" (no carbon tax) and "Base Case" (carbon tax) scenarios. These prices are based on the confidential generation profiles for each generating resource and are based on the peak and off-peak energy prices in the AEP Fundamentals forecast.

Although the carbon tax is not assumed to begin until 2028, the forecast average energy market prices are slightly higher under the Base Case than under the Status Quo case between 2021 and 2027. To estimate the annual revenue differences, I multiplied the difference in the forecast average energy prices for each generating plant by the forecast annual energy generation of each. The results are shown in Confidential Exhibit JAL-16.

As this exhibit shows, the total revenue difference over the 20-year life of the two solar facilities is [redacted] Using Mr. Torpey's assumed 8.5% discount rate, the discounted present value revenue amount associated with the assumed carbon tax is about [redacted]

[redacted] In other words, *but for t*he assumed carbon tax, the market revenues received by AEP Ohio would be that much lower.

AEP Ohio witness Torpey's analysis shows an estimated Base Case present value revenue reduction for the Highland facility of $67.3 million[38] and an estimated present value revenue reduction for the Willowbrook facility of $32.3 million,[39] or $99.5 million in total. Thus, AEP Ohio's assumption of a future carbon tax accounts for over [redacted]] of the total present value revenue reduction "benefits" that Mr. Torpey estimates.

Q49. HAS THE U.S. CONGRESS ENACTED A CARBON TAX THAT WILL BEGIN IN 2028?

A49. No.

[38] Exhibit JFT-2, p. 1.

[39] Exhibit JFT-3, p. 1.

Q50. ARE YOU AWARE OF ANY PENDING NATIONAL LEGISLATION THAT WILL IMPOSE A CARBON TAX IN THE AMOUNTS ASSUMED IN THE 2018 AEP IRP?

A50. Yes. On November 27, 2018, a bill was introduced in the U.S. House of Representatives that would impose a carbon tax of $15/ton this year (2019) and raise the tax by $10/ton each year thereafter.[40] The bill is regarded as having no chance of passage.[41]

Regardless of one's beliefs as to the merits of a carbon tax in the United States, AEP's assumption that such a tax will be enacted is pure speculation. It should <u>not</u> be used to demonstrate that the REPAs are cost-effective relative to the market and will provide future benefits to AEP Ohio customers. Moreover, these purely speculative benefits should not form the basis to force AEP Ohio customers, including customers who purchase green energy voluntarily, to pay for the output of the two proposed REPAs. Forcing regulated utility customers to pay for purely speculative benefits is not just and reasonable.

[40] A copy of the bill can be found at: https://teddeutch.house.gov/uploadedfiles/energy_innovation_and_carbon_dividend_act_-_deutch.pdf

[41] Nick Sobczyck, "Lawmakers roll out landmark bipartisan carbon bill," E&E News, November 28, 2018. https://www.eenews.net/stories/1060107547

Q51. ARE THERE OTHER PROBLEMATIC ASSUMPTIONS REGARDING THE 2018 AEP IRP THAT OVERSTATE THE BENEFITS TO CUSTOMERS OF RENEWABLES?

A51. Yes.

AEP assumes that it will be able to offer all of the solar capacity from the projects into the PJM market. See Company Ex. JFT-2, JFT-3, Column L. However, there is uncertainty as to whether AEP Ohio will be able to collect capacity revenues for the proposed solar resources. Recently at the federal level, there have been proposals to prevent subsidized resources from participating in the regional market. (Federal Energy Regulatory Commission Docket No. EL18-178 et al). If adopted, these changes could reduce (if not eliminate) the amount of capacity revenues received by AEP from the solar projects (which are subsidized through the purchase power agreement rider). A reduction or elimination of the capacity revenues will result in increased costs being charged to consumers through the non-bypassable RGR.

AEP Ohio also assumes unreasonably rapid growth of prices in the PJM capacity market. These capacity prices matter because AEP Ohio witness Torpey estimates a capacity credit benefit for the REPAs that is driven by future capacity prices. In some cases, that capacity credit value accounts for as much as twothirds of the estimated present value change in revenue requirements estimated by Mr. Torpey.

Q52. WHAT IS AEP'S CAPACITY PRICE FORECAST?

***A52*.** The 2018 AEP IRP Base Case assumes market capacity prices increase at an average rate of 14.6% per year, rising from \$30.12 per MW-day in 2022 to \$350.55 per MW-day in 2040. AEP assumes the rapid increase in capacity market prices will continue unabated, topping out at over \$500/MW-day in 2048.

Q53. DO YOU KNOW HOW AEP FORECAST THESE CAPACITY MARKET PRICES?

***A53*.** I know that, for the years 2021 – 2046, AEP uses the following quadratic equation to forecast capacity market prices that increase over time at an increasing rate:

$$\text{Price} = \$17.817 + \$12.968\ x\ (\text{Year} - 2020) + \$0.241\ x\ (\text{Year} - 2020)^2$$

I know this because this curve <u>exactly</u> matches the AEP forecast capacity market prices.[42] However, there is nothing in Mr. Bletzacker's testimony that discusses the economic basis for this forecast.

[42] The curve fits the 2021 – 2046 price data with an "R-squared" value of exactly 1.0, indicating a perfect fit.

Q54. DOES THE 2018 AEP IRP EXPLAIN HOW IT DEVELOPED ITS CAPACITY PRICE FORECAST?

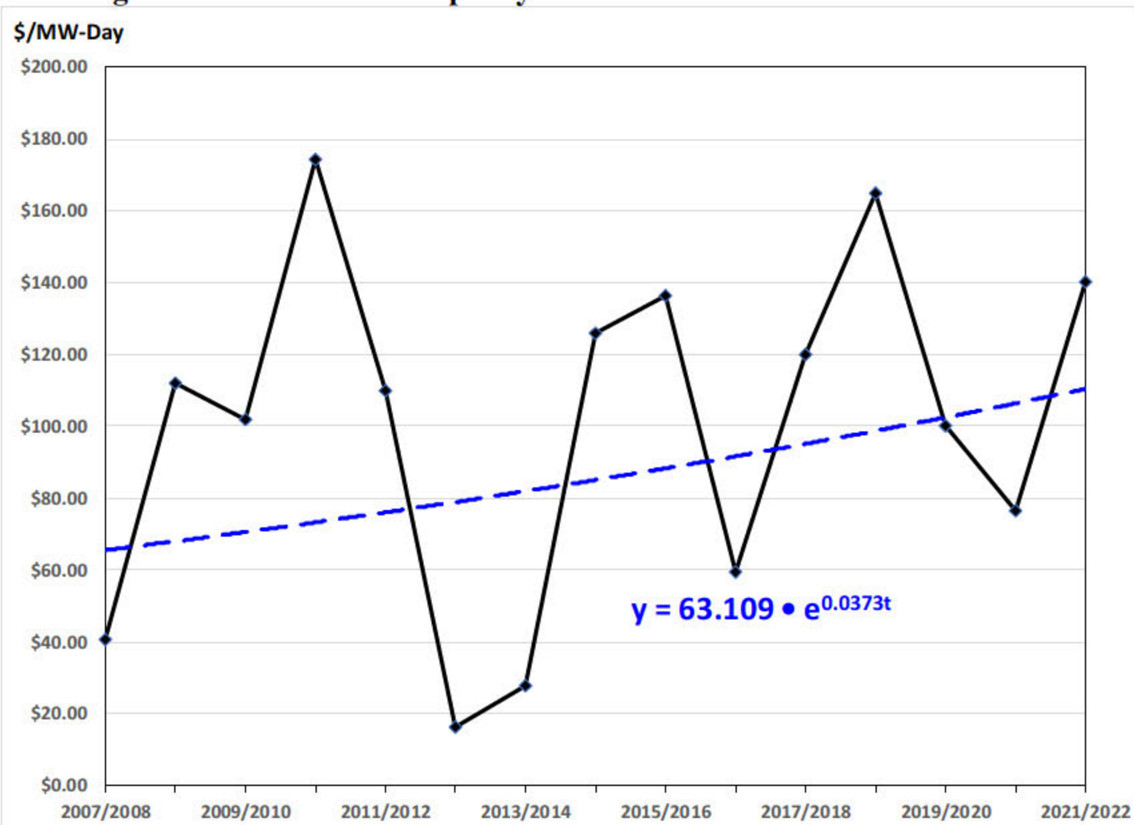
A54. No. Mr. Torpey testifies that, "The monetary value of capacity resources was calculated using the AEP Fundamental Analysis Department's 2018 Fundamentals Forecast."[43] However, nothing in the testimony of Mr. Bletzacker, who sponsors the Fundamentals Forecast, explains how AEP developed its forecast of PJM capacity market prices.

Q55. IS THE ASSUMED RAPID INCREASE IN FORECAST PJM CAPACITY PRICES CONSISTENT WITH THE PAST BEHAVIOR OF THE PJM CAPACITY MARKET?

A55. No. Figure 3 shows the PJM RTO capacity market prices since the inception of the forward capacity market in 2007/2008. The chart also shows the best fitting exponential trend line, which allows me to estimate an annual average percentage increase in prices.

[43] Torpey RDR Direct, p. 9, lines 2-4.

Figure 3: PJM Historic Capacity Market Prices: 2007/2008 – 2021/2022



Q56. CAN YOU EXPLAIN HOW YOU ESTIMATED THIS TRENDLINE?

A56. Yes. As can be seen in Figure 3, PJM capacity prices have followed a "see-saw" price pattern. As prices increase, new supply enters the capacity market, causing prices to decrease. As prices decrease, less supply enters, causing prices to subsequently increase.

Rather than attempt to predict new entry, changes in the cost of new entry, and changes in the administratively determined PJM capacity demand curve based on reliability criteria, instead I fit an exponential curve to extrapolate future capacity prices using Microsoft Excel ™, based on the observed historic prices. This trend line captures the general direction of PJM capacity prices, but it not designed to forecast future prices each year, given the multitude of factors affecting PJM capacity market prices.

AEP Ohio appears to have taken the same approach, the difference being the functional form of the trend line and the starting point. In my case, I developed a trend line starting with the 2007/08 planning year. By contrast, as shown in Figure 5 below, AEP Ohio appears to have started in 2022.

Q57. BASED ON THIS CURVE FIT, WHAT WAS THE AVERAGE ANNUAL INCREASE IN THE PJM RTO PRICE BETWEEN THE FIRST AUCTION FOR THE 2007/2008 PLANNING YEAR AND THE MOST RECENT AUCTION FOR THE 2021/2022 PLANNING YEAR?

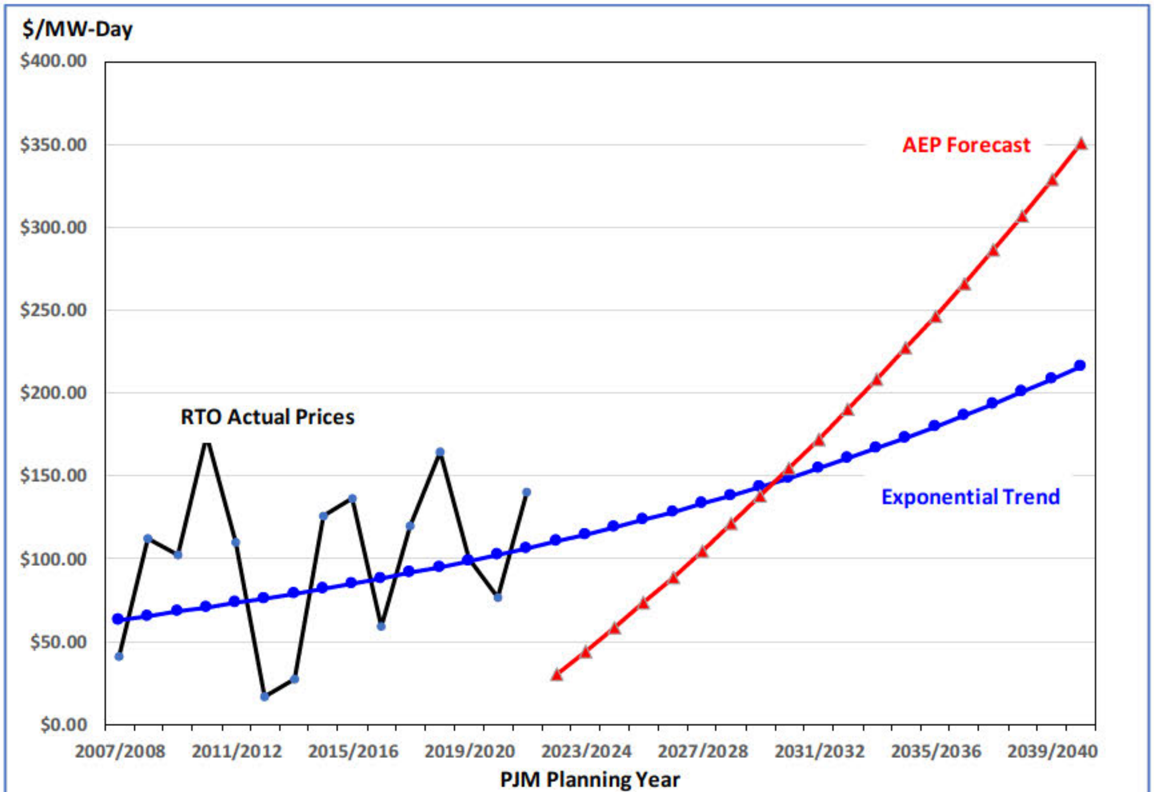
A57. The average annual rate of growth ("AARG") is 3.8%.[44]

Q58. IF THIS EXPONENTIAL TREND CONTINUED, WHAT WOULD BE THE PJM RTO CAPACITY PRICE FOR THE 2040/2041 PLANNING YEAR?

A58. The average RTO capacity price in the 2040/2041 planning year would be $216/MW-day. By comparison, AEP forecasts a capacity market price of $350/MW-day, as shown in Figure 4.

[44] Mathematically, the AARG is $e^{0.0373} - 1 = 0.0380$ or 3.8%. This value is clearly different than simply looking at the AARG based solely on the first and most recent RTO prices.

Figure 4: AEP Capacity Price Forecast vs. Exponential Trend of Actual PJM RTO Prices



Sources: PJM; AEP Fundamentals Forecast, Base Case

In 2048, AEP forecasts a capacity price of $520/MW-day. By contrast, extrapolating the existing exponential trend would result in a capacity price of just over $290/MW-day. AEP's unrealistic capacity price forecast artificially inflates the capacity revenue benefits to AEP Ohio customers in Mr. Torpey's analysis from the REPAs.

Q59. DO YOU CONSIDER AEP'S CAPACITY PRICE FORECAST TO BE REASONABLE?

A59. No. First, AEP offers no explanation of how it determined the quadratic equation described above as the basis for its capacity price forecast.

Second, the forecast is inconsistent with basic economic principles. Specifically, if capacity prices actually increased as rapidly as AEP forecasts, it would incent significant quantities of new capacity resources, including demand-response ("DR") and energy efficiency resources. As shown in Figure 3, actual RTO capacity prices in PJM have followed a "see-saw" pattern – increasing in one year or two, then decreasing, then increasing again, and so forth. This is to be expected in a competitive market because price trends tend to be self-correcting. The reason for this observed price pattern is that higher market prices incent new market entry and increases supply, leading to lower market prices. Lower market prices, in turn, can drive some competitors out of the market, reducing supply and leading to higher prices.

I know of no markets whatsoever in which market-clearing prices increased by almost 15% per year for decades, as the AEP capacity price forecast assumes. Even if one accepts, *arguendo*, that AEP Ohio has forecast a capacity market price trend line rather than a more detailed forecast based on economic fundamentals, the underlying basis for that trend line forecast has never been explained. Therefore, I conclude that the AEP fundamentals capacity price forecast lacks any credibility.

Q60. WOULD THE CAPACITY MARKET PRICES FORECAST BY AEP ALSO INCENT NEW GAS-FIRED GENERATING RESOURCES TO ENTER THE MARKET?

A60. Yes. In April 2018, as part of the RPM auction process, the Brattle Group provided a report to PJM on the Cost of New Entry ("CONE") for new gas-fired combustion turbines and combined-cycle generating plants for the 2022/2023 planning year.[45] The Brattle 2018 CONE Report found that CONE values decreased by 28% below the 2021/2022 CONE value for combustion turbines and 40% below the 2021/2022 CONE value for combined-cycle plants to $269/MW-day and $301/MW-day on a levelized basis. The Brattle 2018 CONE Report states that the decrease in CONE values were lower plants costs because of economies of scale, a lower cost of capital to finance such plants, and lower income taxes. (In addition, for combined-cycle plants, Brattle determined that lower fixed operation and maintenance costs were also a driver of lower overall costs.)[46]

[45] The Brattle Group, "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," April 19, 2018 ("Brattle 2018 CONE Report"). Available at: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx

[46] Brattle 2018 CONE Report, pp. v – vi.

Q61. DOES THE BRATTLE 2018 CONE REPORT EXPLAIN THE BASIS FOR THE 27,000 MW OF NEW GAS-FIRED GENERATING CAPACITY THAT HAVE CLEARED THE CAPACITY MARKET SINCE THE 2015/2016 AUCTION?

A61. Yes. The Brattle 2018 CONE Report stated that new entry by gas-fired generation has been driven by retirements of existing generators, improved performance of new plants, lower financing costs, and lower natural gas prices, especially plants built near shale gas production areas, many of which have limited pipeline capacity to export natural gas, resulting in lower natural gas prices.

Q62. WHAT ARE THE IMPLICATIONS OF SIGNIFICANT INVESTMENTS IN NEW GAS-FIRED GENERATING RESOURCES EVEN THOUGH THE CAPACITY MARKET-CLEARING PRICES HAVE BEEN BELOW THE ESTIMATED CONE VALUES?

A62. From an economic standpoint, it means that future capacity market prices are likely to be lower than simple price extrapolations indicate. Such extrapolations, including the trend line I present in Figure 4 above, fail to capture the price-dampening impacts of market competition. Specifically, high capacity market prices will incent new entry by Demand Response and energy efficiency resources, dampening further the rapid increases in capacity prices projected by AEP.

Q63. DOES MR. TORPEY'S ANALYSIS OF CAPACITY REVENUES ACCOUNT FOR DEGRADATION OF SOLAR OUTPUT OVER TIME?

A63. No. Mr. Torpey's revenue requirement analysis assumes a [redacted] annual degradation rate in energy output,[47] which is a fairly standard assumption.[48]

However, for purposes of estimating capacity market revenues, Mr. Torpey assumes the capacity of the Highland and Willowbrook units will never change. That is physically impossible. As solar panels degrade over time, the amount of output they can produce instantaneously decreases. Hence, if the energy production from the panels is decreasing over time, their instantaneous power output (i.e., capacity) must also decrease over time.

Q64. WILL AEP OHIO CUSTOMERS BE RESPONSIBLE FOR ALL PENALTIES LEVIED BY PJM AGAINST THE SOLAR PROJECTS FOR LACK OF AVAILABILITY DURING CRITICAL PERFORMANCE PERIODS?

A64. Yes. Mr. Allen testifies that:

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[47] Mr. Torpey's confidential workpapers provide the hourly generation profiles for each solar plant over their assumed 20-year lifetime.

[48] See, e.g., Dirk Jordan and Sarah Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," National Renewable Energy Laboratory, June 2012. https://www.nrel.gov/docs/fy12osti/51664.pdf

> It would be unfair and counterproductive for the Company to bear additional risk of capacity performance assessments in order to yield additional capacity revenues to benefit customers through the RGR. This is especially true for an intermittent resource like a solar facility. The Company cannot control production of the solar facility in the same manner as a fossil generation plant and, therefore, cannot control whether the solar facility is operating when the peak load occurs throughout the PJM system. If the Commission does not want to allow recovery of capacity performance assessments for the REPAs, then it should acknowledge that the solar facilities are not expected to produce capacity revenues.[49]

This is an additional risk of higher costs for AEP Ohio's customers that has not been incorporated into Mr. Torpey's analysis. Moreover, capacity non-performance payments that AEP Ohio customers will be required to pay if the two solar plants fail to deliver power during capacity performance events, undermines AEP Ohio's claimed hedge benefits as well as the overall claimed economic benefits of the solar projects. Those risks should properly be borne by the plant owners not by utility customers, as the Ohio General Assembly has decreed. Finally, as I discuss below, if capacity revenues are excluded from Mr. Torpey's

[49] Allen Direct RDR, p. 11, lines 12-21.

analysis, then the net present value of the REPAs become negative in most of the cases Mr. Torpey presents.

Q65. WILL AEP OHIO CUSTOMERS BE COMPENSATED IF THE ACTUAL LIFETIMES OF THE HIGHLAND AND WILLOWBROOK SOLAR FACILITIES TURN OUT TO BE LESS THAN THE 20-YEAR REPA DURATION?

A65. Although both contracts have liquidated damages provisions related to less than expected generation for the 20-year duration of the REPAs, it is unclear whether the damages paid to AEP Ohio by the project developers, if any, would be refunded to AEP Ohio customers. Thus, AEP Ohio customers may be forced to bear operational risks over which they have no control.

Q66. CAN COMPETITIVE GENERATION SUPPLIERS IN PJM SIMPLY PASS ALONG CAPACITY NONPERFORMANCE PENALTIES TO THEIR CUSTOMERS?

A66. No. Competitive generation owners and their investors take on the risk of non-performance penalties. This provides an economic incentive for those generation owners to maximize performance. Indeed, this reallocation of risk to generation owners – because generation owners can control those risks – was one of the principle reasons for electric utility restructuring as implemented by the Ohio

General Assembly. AEP Ohio customers should not be required to bear the costs of nonperformance risk.

Q67. DOES MR. TORPEY'S ANALYSIS OF THE CHANGE IN REVENUE REQUIREMENTS INCORPORATE MR. ALLEN'S DEBT EQUIVALENCY COSTS?

A67. No. Mr. Allen testifies that AEP Ohio will include debt equivalency costs as part of the RGR calculation in the amount of $4.30 million per year for the Highland Solar Project and $1.36 million per year for the Willowbrook Solar Project.[50] Mr. Allen's confidential workpapers show that the net present value ("NPV") revenue requirement AEP Ohio intends to recoup for the Highland and Willowbrook Projects are [redacted] respectively.

Q68. HOW DO THE DEBT EQUIVALENCY COSTS CHANGE THE NPV REVENUE REQUIREMENT VALUES ESTIMATED BY MR. TORPEY?

A68. Table 2 shows the net change in present value revenue requirements of Mr. Torpey's analysis when Mr. Allen's debt equivalency costs are included.

[50] Allen Direct RDR p. 15, lines 10-13.

Table 2: Present Value Revenue Reqt. Changes – Highland and Willowbrook (Millions of $)

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

As Table 2 shows, when Mr. Allen's debt equivalency costs are included, overall revenue requirements increase for the 300 MW Highland Plant under the "Status Quo" and "Low" cases. Under the "Base" case, the present value reduction is less than 1/3 of the $67.3 million value Mr. Torpey reports and under the "High" scenario, his present value savings are [redacted]

Similarly, although the present value revenue requirements remain negative under all four cases for the Willowbrook facility, the savings are sharply reduced. Under the "Status Quo" case, savings are reduced by [redacted]] Thus, the claimed "benefits" to AEP Ohio customers are greatly reduced or become net costs.

Q69. HOW DO THE VALUES IN TABLE 2 CHANGE IF CAPACITY REVENUES ARE EXCLUDED, AS DISCUSSED BY MR. ALLEN IN HIS TESTIMONY?

A69. Table 3 provides revised net present value revenue requirement values, excluding all capacity revenues.

Table 3: Present Value Revenue Requirement Changes – Highland and Willowbrook, Excluding Estimated Capacity Revenues (Millions of $)

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

As shown in Table 3, if capacity revenues are eliminated from consideration, as suggested in the previous discussion of Mr. Allen's testimony regarding nonperformance penalties, the present value revenue requirements for the Highland Solar Plant REPA increase relative to the market under all but the "High" case, meaning that AEP Ohio customers' costs will increase. The present value revenue requirements for the Willowbrook Solar Plant REPA increase under the Status Quo and Low cases. Again, these changes in present value revenue requirements to AEP Ohio customers are based on AEP's energy price forecast, which assumes natural gas prices that exceed the most recent EIA forecast by an average of 12%.

Q70. DO THE REVENUE CHANGES YOU ESTIMATE IN TABLES 2 AND 3 INCLUDE THE SAVINGS (OR REDUCTION IN REVENUE REQUIREMENTS) ARISING FROM AEP OHIO'S ASSUMPTION THAT A NATIONWIDE CARBON TAX WILL BE LEVIED BEGINNING IN THE YEAR 2028

A70. Yes. As discussed previously, Mr. Torpey's analysis assumes that the carbon tax will increase the present value benefits (savings) of the two solar projects by [redacted] If this amount is subtracted from Mr. Torpey's estimated present value revenue requirement reductions in three of the four scenarios (Base, Low, and High) shown in Table 3, then the present value revenue requirement for AEP Ohio customers would be higher under all four scenarios.[51]

[51] AEP Ohio did not provide "Low" and "High" scenarios without carbon taxes. Therefore, it is not possible to isolate the impact of a carbon tax on energy market prices in those scenarios.

Q71. DID YOU PREPARE AN INDEPENDENT ANALYSIS OF THE OVERALL FORECAST COST AND REVENUE IMPACTS OF THE TWO SOLAR PROJECTS?

A71: No, for several reasons. First, AEP relies on a proprietary model to estimate the daily output of the two solar facilities. I do not have expertise in modeling solar photovoltaic output, so I could not prepare any independent forecast of hourly plant production. Second, AEP relies on a proprietary model to forecast future PJM energy market prices. I do not have access to that model. As such, preparing a forecast of future energy prices, along with an accompanying forecast of future PJM capacity market prices, was far outside the scope of my assignment for OCC. Therefore, my analysis of present value revenue requirements of the two facilities relies entirely on AEP Ohio's own modeling results.

Q72. WHAT DO YOU CONCLUDE REGARDING THE ECONOMIC ANALYSIS PRESENTED BY AEP OHIO SHOWING THAT THE TWO SOLAR FACILITIES WILL REDUCE REVENUE REQUIREMENTS?

A72. I conclude that the AEP Ohio analysis significantly overstates the "economic benefits" to AEP Ohio customers and are unrealistic for the following reasons:

- AEP's PJM wholesale market energy price forecast is biased upwards because its "Base" case natural gas price forecast is, on average, 12% higher than the most recent EIA forecast.

- AEP's capacity market price forecast is absurdly high. There is no evidence that capacity market prices will increase and at an increasing rate for the foreseeable future. The evidence of actual entry by new generating resources, DR, and energy efficiency belies AEP's capacity market price assumptions.

- Mr. Torpey's revenue requirement analysis assumes that, even though total solar output degrades over time, the instantaneous capacity the units can supply does not and, hence, the capacity credit MW remain constant over the full 20 years of the REPAs. That is physically impossible.

- When Mr. Allen's debt equivalency costs are accounted for, Mr. Torpey's own analysis shows that the Highland Project will result in higher revenue requirements for AEP Ohio customers under the Status Quo case and a slight decrease for Willowbrook. Overall, under the Status Quo case, AEP Ohio customers will pay more for the REPAs.

- If capacity credits are eliminated, which Mr. Allen testifies that AEP Ohio will insist on if AEP Ohio customers are not responsible for capacity nonperformance penalties, then the Highland Solar Project REPA will result in <u>higher</u> costs for AEP Ohio customers in all but AEP's High Case scenario. The Willowbrook Solar Project REPA will result in higher costs for AEP Ohio customers under the Status Quo and Low Case scenarios.

- Inclusion of a carbon tax by AEP Ohio to increase forecast electric prices and overstate benefits to customers is unreasonable and speculative because no such tax exists today. Excluding the "savings" from the assumed carbon tax shows that the present value revenue requirements for AEP Ohio customers would be higher under all four of AEP Ohio's modelled scenarios.

The net effect of AEP Ohio's analysis is to promise its customers' future benefits that are unlikely to materialize. When AEP Ohio's analysis is modified to reflect realistic assumptions, the effect is that AEP Ohio customers will pay much more for electricity produced by the renewable projects than AEP is projecting and would otherwise be available through the competitive market.

VI. AEP OHIO HAS NOT DEMONSTRATED THE PROPOSED REPAS WILL PROVIDE HEDGING BENEFITS TO ITS CUSTOMERS.

Q73. AEP OHIO ARGUES THAT THE REPAS WILL HEDGE VOLATILE PJM ELECTRIC PRICES AND THUS BENEFIT THE UTILITY'S CUSTOMERS. DO YOU AGREE?

A73. No. AEP Ohio witness Torpey simply asserts that, "The REPAs are fixed price contracts and, as such, offer a hedge against volatile market prices."[52] AEP Ohio did not provide a more detailed explanation on how the REPAs will hedge PJM market prices, nor provide any empirical estimates of the benefits to AEP Ohio customers. In fact, as I discuss below, these two solar projects and their associated REPAs are unlikely to provide any hedging benefits to AEP Ohio's customers and, instead, may impose higher costs on those customers to compensate for the two projects inherently intermittent generating output.

Q74. DOES HEDGING ALWAYS HAVE A NET EXPECTED COST?

A74. Yes. Hedging is a form of insurance, and insurance always has an expected net cost. Otherwise, insurers would go out of business. In the case of the REPAs, the hedge takes the form of front-loaded, fixed-price contracts, with above-market prices in the near-term and potentially (but unlikely) below-market costs in the long-term. This means that AEP Ohio customers' electric bills initially will

[52] Torpey Direct RDR, p. 8, lines 5-6.

increase but may decrease far in the future. However, as discussed previously, given the erroneous assumptions of Mr. Torpey's analysis, it is likely that, on a present value basis, AEP Ohio customers' bills will increase because of the REPAs.

Q75. WILL THE TWO REPAS MEASURABLY REDUCE WHOLESALE PRICE VOLATILITY IN PJM?

A75. No. The PJM wholesale energy and capacity markets encompass thousands of MW of generating capacity. PJM publishes real-time, locational marginal prices energy market prices every five minutes. Market prices respond to numerous factors, including customer demand, weather conditions, generator outages, transmission outages, and so forth. To suggest that two REPAs totaling 400 MW will reduce price volatility in PJM (as claimed by AEP Witness Torpey), is not credible.[53]

Moreover, Mr. Torpey ignores the broader fact that the inherent intermittency of solar generation (as well as wind power), which requires costly back-up generation, can increase costs in the PJM market, as generators must be brought

[53] *See* Torpey Testimony at 8, Case No. 18-1393-EL-RDR. The PUCO previously found that the claimed hedging benefits associated with the OVEC contracts were too small to have any significance. *See In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case No. 13-2385-EL-SSO, Opinion and Order, February 25, 2015, p. 25. ["Although the magnitude of the impact of the proposed PPA rider cannot be known to any degree of certainty, the Commission agrees with OCC, IEU-Ohio, and other intervenors that the evidence of record reflects that the rider may result in a net cost to customers, with little offsetting benefit from the rider's intended purpose as a hedge against market volatility."]

on-line when intermittent solar generation goes off line, such as because of a cloud passing over a facility.

Furthermore, Mr. Torpey ignores the fact that, as Mr. Allen testifies, under the non-bypassable rider, AEP Ohio customers will bear the penalty costs imposed by PJM if the two solar generating units fail to deliver energy during capacity performance hours.[54] Given the inherent intermittency of solar generation and the relative unavailability of solar generation in winter, it is more likely that AEP Ohio customers will be forced to bear the costs of capacity performance penalties during events such as the 2014 Polar Vortex.

Q76. ARE AEP OHIO'S SSO CUSTOMERS ALREADY PROTECTED TO A LARGE EXTENT FROM VOLATILE MARKET PRICES?

A76. Yes. The contracts used to serve AEP Ohio SSO load are purposely laddered over three-year periods and thus designed specifically to reduce the exposure of SSO customers to price volatility.

[54] Allen Direct RDR, p. 10, lines 20-21. "[t]he net cost or benefit of the rider will be determined by offsetting the REPA price plus the debt equivalency cost less the PJM market revenues (*supplemented by any capacity performance credit or assessment*) received for the REPAs output…"

Q77. CAN AEP OHIO CUSTOMERS WHO PURCHASE ELECTRICITY FROM RETAIL ENERGY MARKETERS HEDGE THEIR EXPOSURE TO PRICE VOLATILITY?

A77. Yes. AEP Ohio customers who purchase electricity from retail energy marketers can already contract for offerings that provide hedges against volatile prices and allow them to balance for themselves reductions in price volatility against the higher expected costs. In other words, CRES customers can select the amount of hedging insurance that is best for them, rather than being forced to accept AEP Ohio's version of "best" hedging. From a pure economic standpoint, allowing consumers to select their own pricing regimes, much as allowing them to decide whether or not they wish to purchase green energy, is economically more valuable than forcing such choices on those customers.

Q78. DO ANY RETAIL ENERGY MARKETERS OFFER 100% RENEWABLE ENERGY PRODUCTS AT FIXED RATES?

A78. Yes. According to the offers posted on the energychoice.gov website, there are fixed price offers for as long as 27 months.[55]

[55] The energy choice website shows that Star Energy Partners provides a 27-month, fixed-price offer that is 100% renewable energy. See: http://energychoice.ohio.gov/ApplesToApplesComparision.aspx?Category=Electric&TerritoryId=2&RateCode=1 (Accessed November 6, 2018).

Q79. DOES AEP ENERGY ITSELF OFFER PROTECTION FROM VOLATILE PRICES TO SHOPPING CUSTOMERS WHO WISH TO PURCHASE RENEWABLE ENERGY?

A79. Yes. The PUCO energychoice.gov website shows that AEP Energy (an affiliate AEP Ohio that markets electricity to retail customers) offers customers 100% renewable energy with a price that is fixed for 12 months.

Q80. ARE THERE FIXED-PRICE OPTIONS FOR AEP OHIO SHOPPING CUSTOMERS WHO DO NOT WISH TO PURCHASE 100% RENEWABLE ENERGY?

A80. Yes. According to the PUCO energychoice.gov website, a total of 17 retail energy marketers are offering AEP Ohio retail customers fixed price contracts for terms of 36 months. AEP Energy offers a 12-month fixed price contract for retail energy marketers with zero percent renewable content.[56]

Q81. DO YOU CONCLUDE THAT A NON-BYPASSABLE CHARGE FOR THE REPAS IS NECESSARY TO PROVIDE AEP OHIO CUSTOMERS WITH PROTECTION AGAINST VOLATILE ENERGY MARKET PRICES?

A81. No. First, it is obvious that there are numerous fixed-price contracts available to AEP Ohio customers (both SSO and shopping customers) who wish to purchase electricity from retail energy marketers, including offers from AEP Ohio's sister

[56] Source http://www.energychoice.ohio.gov/. Accessed December 10, 2018.

company, AEP Energy. Second, SSO customers are already shielded to a large extent from volatile market prices through the use of laddered contracts. Third, although the REPAs are fixed-price contracts, the intermittency of solar generation means that AEP Ohio customers will be exposed to additional market volatility associated with the need to provide replacement generation at a moment's notice. Additionally, customers face the likelihood they will have to pay penalties assessed by PJM because of the solar plants' unavailability during capacity performance events.

VII. THE STATE'S EXPERIENCE WITH THE OHIO VALLEY ELECTRIC CORPORATION SHOULD SERVE AS A WARNING REGARDING UNMET EXPECTATIONS OF BENEFITS

Q82. WHAT IS THE OHIO VALLEY ELECTRIC CORPORATION ("OVEC")?

A82. OVEC was formed in 1952 by investor-owned utilities in Ohio, originally to develop generating facilities that would provide electricity to uranium enrichment facilities then under construction by the U.S. Dept. of Energy ("DOE") near Portsmouth, Ohio.

In 1953, the sponsoring utilities entered into an Inter-Company Power Agreement ("OVEC Agreement"). Under that agreement electricity not needed for the DOE facilities would be sold to the sponsoring companies. In 2011, the sponsoring companies entered into a revised agreement, which continues through 2040.

OVEC constructed two generating plants: (1) the Clifty Creek Generating Station, a 1,300 MW coal-fired generating plant, which began operation in 1955; and (2) the Kyger Creek Generating Station, a 1,100 MW coal-fired power plant that also entered service in 1955.

Q83. IS AEP OHIO RESPONSIBLE FOR A PORTION OF THE COSTS OF THESE PLANTS?

A83. Yes. Under the ICPA, AEP Ohio is responsible for 19.93% of the costs.[57] Those costs, after adjusting for the proceeds of liquidating the output of OVEC at the PJM market, are collected by AEP Ohio from its customers through a non-bypassable OVEC rider ("Purchase Power Agreement Rider").

Q84. DO THE TWO OVEC GENERATING PLANTS PROVIDE HEDGE BENEFITS FOR AEP OHIO CUSTOMERS?

A84. No. The cost of the power supplied by the two coal-fired plants is above-market and the source of significant financial losses (if not subsidized by the utilities' captive customers) for the OVEC owners. For example, in testimony submitted by Kevin Warvell on behalf of First Energy Solutions ("FES") in its bankruptcy

[57] Source: Ohio Valley Electric Corporation, http://www.ovec.com/OVECHistory.pdf (Previously attached as Exhibit JAL-4).

proceeding,[58] Mr. Warvell testified that its 4.85% share of the power generated by the two OVEC plants would result in an undiscounted loss of $268 million through 2040, the current end year of the contract.[59] Given that AEP Ohio's share of the OVEC output is just over four times larger than FirstEnergy Solution's output share, the equivalent above-market cost to AEP Ohio customers, who must pay AEP Ohio for the OVEC costs through a non-bypassable rider, is just over four times the FES loss calculation, or $1.07 *billion*. Moreover, AEP Ohio customers have already paid more than $77 million since 2017 for costs related to the OVEC PPAs.[60]

Q85. ARE YOU SUGGESTING THAT THE REPAS WILL RESULT IN ABOVE-MARKET COSTS OF THE SAME MAGNITUDE AS THE OVEC AGREEMENT?

A85. No. I am not. The 400 MW capacity of solar generation associated with the two REPAs is smaller than the 2,400 MW capacity of the two OVEC coal-fired plants, but the 400 MW capacity is quite close to AEP's share of the OVEC plants, approximately 480 MW. I use the OVEC experience to illustrate the fact that promised benefits do not always materialize. In the case of OVEC, AEP Ohio

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[58] Previously attached as Exhibit JAL-3.

[59] *Id*. Par. 18.

[60] Sources: Case No. 14-1693-EL-RDR, et al., AEP Ohio, Quarterly Tariff filings, Schedule 3, dated: June 1, 2017, August 30, 2017, December 1, 2017, February 28, 2018, and June 1, 2018; Case No. 18-1004-EL-RDR, AEP Ohio, Quarterly Tariff Filing, Schedule 3, August 31, 2018; Case No. 18-1759-EL-RDR, AEP Ohio, Quarterly Tariff filing, Schedule 3, November 30, 2018.

customers, along with other Ohio utility customers, are saddled with tremendous above-market costs.

The Ohio electric industry was restructured by the Ohio General Assembly almost two decades ago, in part to avoid saddling captive customers with generating costs over which they have no control, such as those arising under the OVEC Agreement. Forcing AEP Ohio customers to fund the construction costs of generating facilities through non-bypassable charges is contrary to Ohio law and long-standing state policy. As R.C. 4928.02(H) states, state policy is to:

> ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates.

VIII. AEP OHIO'S CLAIM OF "NEED" FOR NON-BYPASSABLE CHARGES TO DEVELOP IN-STATE RENEWABLES BASED ON SURVEY RESULTS IS NOT CREDIBLE.

Q86. DO YOU HAVE ANY EXPERIENCE WITH SURVEY DESIGN?

A86. Yes. I have helped design what economists call "contingent valuation surveys." These are typically used to value non-market and public goods, such as environmental quality, by estimating individual's willingness to pay ("WTP") for these non-market goods. In my case, in the early 1990s, I assisted with surveys in the Pacific Northwest regarding the value of preserving endangered salmon species. In my textbook, *Environmental Economics and Policy*, I discuss contingent valuation surveys and their application, including the different types of bias that can arise if questions are not written properly.[61]

Q87. ARE THESE CONTINGENT VALUATION SURVEYS USED TO VALUE MARKET GOODS AND SERVICES?

A87. No. The "Willingness To Pay" or "WTP" for goods and services sold in markets can be determined directly from their market prices. One would not need to perform a contingent valuation survey to determine Ohio consumers' WTP for, say, milk, because we can directly observe consumer behavior in the grocery store. Similarly, we can examine Ohio electric consumers' willingness to pay for

[61] Jonathan Lesser, Daniel Dodds, and Richard Zerbe, *Environmental Economics and Policy*, (New York: Addison Wesley Longman 1997), pp. 282-304.

renewable energy by observing consumer demand for renewable energy sold by electricity providers.

Q88. DID YOU REVIEW THE RESULTS OF THE NAVIGANT SURVEY ATTACHED TO THE TESTIMONY OF AEP OHIO WITNESS HORNER?[62]

A88. Yes. The Navigant survey is what I characterize as a typical "feel good" survey, which asked questions about the benefits of renewable energy, development of renewable energy within the state, and so forth of a biased and unrepresentative sample of residential, commercial, and industrial customers. The survey relied on e-mail responses from individuals and businesses that were sent copies of the survey.

As stated in AEP Ohio's response to IGS-INT-4-9 (attached as Exhibit JAL-17), residential customers without email addresses were excluded from the survey. Email surveys such as this introduce what is called "nonresponse bias," not only because individuals and businesses who are interested in the subject are most likely to be willing to answer the survey questions, but also because a group of individuals of unknown size is excluded (whether intentionally or not) from the survey.

[62] Direct Testimony of Trina Horner on Behalf of Ohio Power Company, Case No. 18-501-EL-FOR, September 19, 2018 ("Horner Direct"), Exhibit TH-1.

Q89. WAS THE NAVIGANT SURVEY STATISTICALLY REPRESENTATIVE OF AEP OHIO'S CUSTOMERS?

A89. No. First, Navigant admits that the survey of large business customers "should not be considered statistically representative of AEP's C&I customer base or even its largest corporate customer base due to the targeted selection approach and relatively limited number of responses."[63] Second, customers without email were excluded and only the results of customers responding to the emailed surveys were included. Thus, Navigant automatically excluded from consideration the views of customers lacking email addresses known by AEP Ohio and also assumed that the results of customers responding to the email survey were representative of all customers. There is no statistical justification for such an assumption.

As for "Sustainability Minded Large Customers," Navigant first eliminated from consideration C&I customers with annual loads less than 100,000 kWh[64] and then, as stated in the response to IGS-INT-4-8 (attached as Exhibit JAL-18), Navigant targeted remaining commercial customers "associated with one of the four sustainability organizations identified elsewhere in Exhibit TH-1."[65]

[63] Exhibit TH-1, p. 7.

[64] *Id.*, p. 5.

[65] Page 6 of Exhibit TH-1 lists the organizations: "Powering Ohio," "RE100," "EPA Green Power Partnership," and "Buyers' Principles."

Clearly, by identifying C&I customers who were members of "Sustainability Commitment Organizations," the Navigant survey was far more likely to elicit support for green energy than for C&I customers as a whole. In fact, the Navigant survey admits this, stating, "Navigant used a two-step process to identify companies with a higher likelihood of interest in renewable energy and then estimated the potential magnitude of that interest."[66] It is thus not surprising that "A majority of respondent companies indicated they prefer that a portion of their renewable supply be based on local/regional projects in Ohio, assuming no significant difference in price."[67]

Q90. CAN YOU PROVIDE EXAMPLES OF "FEEL GOOD" QUESTIONS IN THE SURVEY?

A90. Yes. For example, one question asked was, "What do you view as the most important benefits to utility investments in renewable energy?"[68] There were six possible answers: "Better world for future generations," "Improve air quality," "Reduce greenhouse gas emissions," "Energy independence," "Local job creation," and "Other."

[66] *Id*., p. 5.

[67] *Id*., p. 7.

[68] *Id*., p. 18, Figure 7. (All page numbers refer to the labeled exhibit number pages, not the page of the Navigant report.)

The question is inherently biased. First, the six categories are vague. For example, "Better world for future generations" can mean a variety of things, including all of the other five categories. (This is another problem with such ranking exercises: when the items to be ranked overlap, ranking them becomes virtually meaningless.)[69]

Second, there is an inherent bias by having respondents assume that renewable energy provides all of these different types of benefits. Such questions, because they are not directly paired with willingness to pay levels, have no analytical value. The reason is that, asking a survey respondent to rank presumed benefits provides no information regarding the respondent's WTP for those benefits. Thus, rather than asking what respondents' WTP for a "Better world for future generations," "Energy independence," and so forth, the survey simply asked respondents to rank those vague categorizations by preference.

Separately, the survey then asked respondents about their willingness to pay for 900 MW of renewables in a series of questions. Those questions were prefaced with an assumption of benefits. Specifically, the survey stated that, "AEP Ohio can reduce the environmental impact of electricity generation while creating skilled green energy jobs in Ohio and stimulating the local economy with

[69] Consider, as an example, try the following preference-ranking exercise: (1) ice cream, (2) dessert, (3) something sweet. All three items overlap, but none is a subset of another. For example, ice cream is a type of dessert (if eaten after a meal), but individuals may eat ice cream without eating a meal. Similarly, dessert might be something sweet (but not always), but something sweet might not be dessert.

additional tax revenue."[70] Note that the presumed benefits stated for the WTP questions are not the same benefits respondents were asked to rank in the earlier question. Moreover, none of the benefits the WTP questions assume will necessarily materialize. Nor was there any comparative scenario offered. In other words, the survey did not provide customers with any alternatives with which to compare. In effect, the survey assumed that, *but for* developing the 900 MW of renewables, these benefits would not materialize.

Another question was "On a 5-point scale in which 1 means "Strongly disagree" and 5 means "Strongly agree", how would you rate your agreement with the following statement: AEP Ohio should proactively take steps to reduce the amount of air pollution and greenhouse gas emissions resulting from its operations." The survey found that 80% of residential customers agreed with that statement, as did 71% of small C&I customers.[71] Given the phrasing of the question, those results are surprisingly low. How many customers, for example, would prefer *increased* levels of air pollution?

[70] Exhibit TH-1, p. 31.

[71] *Id.*, pp. 21-22, and Figure 11.

Q91. ARE THE SURVEY QUESTIONS ABOUT CUSTOMER MONTHLY ENERGY BILLS FLAWED?

A91. Yes. For example, one question asked of respondents was whether maintaining their current energy bill was more important than AEP Ohio investing in wind and solar energy.[72] Note that the question did not ask respondents about their *electric* bill, but rather the more generic "energy bill." Furthermore, asking customers to rank the relative "importance" of their energy bill vs. AEP's investments in wind and solar energy provides no information regarding WTP. In other words, "importance" is a function of cost; presumably, the costlier are AEP's investments in wind and solar energy, the less important customers such investments would become. But the survey question did not make such a distinction.

Q92. ARE THE SPECIFIC QUESTIONS ABOUT WILLINGNESS TO PAY FLAWED?

A92. Yes. WTP questions, such as the close-ended ones asked in the survey (i.e., with specific cost brackets) depend on numerous factors, including the size of the brackets and the amounts considered. The maximum range for residential customers was $1.75/month. Furthermore, the WTP was framed in a biased manner. Specifically, the question asked was "By developing utility-scale renewable generation in Ohio, AEP Ohio can reduce the environmental impact of electricity generation while creating skilled green energy jobs in Ohio and

[72] Exhibit TH-1, p. 22. Some customers were asked if "AEP Ohio investing in wind and solar energy is more important than maintaining my current energy bill amount."

stimulating the local economy with additional tax revenue."[73] Notice that the question assumes only positive impacts of renewables. The question ignores any possibility of adverse environmental impacts, such as wind turbines that are associated with adverse health impacts caused by low-frequency sound and have adverse visual impacts because of their size. Thus, the form of the question introduces a bias for respondents to pay for "benefits."

Q93. DID THE SURVEY ASK SMALL COMMERCIAL CUSTOMERS WHAT THEY WOULD BE WILLING TO PAY FOR RENEWABLE ENERGY?

A93. Yes, but the form of the question was not a dollar amount, as was the question for residential customers. Instead, the survey asked small commercial respondents the same question as residential customers but asked them to select a percentage range on their monthly electric bill.[74] That is problematic because some customers may not know what their bill is and, consequently, asking them if they would be willing to pay a small percentage increase on that unknown bill is not valid.

Q94. DID THE SURVEY ASK WHETHER CUSTOMERS WOULD BE WILLING TO PAY MORE FOR RENEWABLE ENERGY?

A94. Yes. However, the survey results conflict with observed Ohio customer behavior. In other words, the percentage of Ohio retail customers who actually purchase

[73] Exhibit TC-1, p. 38.

[74] Exhibit TC-1, p. 21.

"green" electricity from competitive energy suppliers – as opposed to the majority of customers who responded that they would be willing to pay extra for green energy – is quite small.

For example, the Navigant survey finds that 57% of non-PIPP residential customers (that is, customers whose electric bills are not limited by their incomes) would be willing to pay as much as $1.75 month extra on their energy bills for renewable power. The problem with such open-ended questions is that survey respondents are often unclear as to what exactly they are purchasing. In other words, the Navigant survey only asked what customers would be willing to pay "to increase the proportion of renewable energy in ARP Ohio's electric mix."[75] That's entirely different from asking how much customers would be willing to pay for AEP to have a specific percentage of renewable energy in its electric mix.

Q95. DID THE SURVEY DISTINGUISH BETWEEN AEP OHIO'S STANDARD OFFER CUSTOMERS AND CUSTOMERS WHO PURCHASE ELECTRICITY FROM COMPETITIVE RETAIL MARKETERS?

A95. No. Although the survey excluded Percentage of Income Payment Plan ("PIPP") customers,[76] none of the demographic questions asked whether the respondent

[75] Exhibit TH-1, p. 12.

[76] *Id.*, p. 8.

was an SSO customer or a customer who purchased electricity from a retail marketer.

Q96. IS THAT DISTINCTION IMPORTANT?

A96. Yes. The reason is that customers who purchase electricity from retail marketers already have options to purchase many different green energy alternatives, whereas Standard Offer customers do not. For example, according to the PUCO's energychoice.gov website, as of December 28, 2018, there were 36 separate offers for 100% renewable energy content, including AEP Energy, and five offers for 50% renewable energy portfolios.

Q97. DO YOU CONCLUDE THAT THE NAVIGANT SURVEY HAS ANY PROBATIVE EVIDENCE ON WHICH THE PUCO SHOULD BASE A DECISION TO IMPOSE A NON-BYPASSABLE SURCHARGE ON AEP OHIO CUSTOMERS FOR DEVELOPMENT OF 900 MW OF RENEWABLE GENERATION?

A97. No. The result of the survey should not be used as a basis to determine if AEP Ohio's customers do indeed support renewable energy and are willing to pay the full costs of renewable energy if offered. The survey suffers from inherent bias based on self-selection of respondents and poorly-designed questions.

Q98. IS THERE A MORE ACCURATE WAY TO GAUGE AEP OHIO CUSTOMERS' WILLING TO PAY FOR RENEWABLE OR GREEN ENERGY?

A98. Yes. The most accurate way to examine WTP for green energy is to consider the actual choices made by the approximately 2.5 million residential and commercial customers in the state who purchase their electricity from retail energy marketers.[77] As I noted previously, the PUCO website lists 36 different offers of 100% renewable energy, including an offer by AEP Energy, and an additional five offers for 50% renewable energy. The number of customers who are actually purchasing green energy from retail energy marketers is an obvious indicator of customer WTP for green energy.

Q99. ARE THEIR ANY PUBLICLY AVAILABLE ESTIMATES OF THE NUMBERS OF OHIO ELECTRIC CUSTOMERS WHO ARE PURCHASING RENEWABLE OR GREEN ENERGY?

A99. The October 2018 National Renewable Energy Laboratory report I cited previously estimates how many customers have signed up for green pricing programs by state. According to that report, fewer than 3,000 utility customers in Ohio have voluntarily signed up to green pricing alternatives. Approximately another 84,500 have signed up for green energy pricing programs with retail

[77] Source: PUCO website, Retail Activity by Customer Class. https://www.puco.ohio.gov/industry-information/statistical-reports/electric-customer-choice-switch-rates-and-aggregation-activity/ Accessed: December 6, 2018.

energy marketers. Another 100,000 customers participate in green energy programs through community choice aggregators.[78] Thus, in total, just 7.5% of Ohio residential and commercial customers have actually chosen to purchase green energy, as compared to the Navigant survey results showing the vast majority of customers would be willing to pay extra for green energy. The difference between the number of customers <u>saying</u> they are willing to pay extra for green energy and the number of customers who <u>actually</u> do so is thus quite large. As such, the Navigant survey results are an extremely poor predictor of actual customer behavior.

Q100. DO THE NAVIGANT SURVEY RESULTS SUPPORT AEP OHIO IMPOSING A NON-BYPASSABLE CHARGE ON CUSTOMERS FOR RENEWABLE ENERGY?

A100. No. Nothing prevents AEP Ohio's sister company, AEP Energy, from contracting with the developers of the Highland and Willowbrook plants in the competitive market, and then marketing the output to all Ohio retail customers. Similarly, nothing prevents AEP Renewables, another AEP subsidiary that has developed solar generating plants in California, Nevada, and Utah, from developing solar generating plants in Ohio.

[78] NREL 2018, p. 48.

If AEP Ohio believes the Navigant survey results accurately reflect retail customers' desire for renewable generation, then it should have no difficulty signing up thousands of customers for renewable energy produced by Highland and Willowbrook. The fact that AEP Ohio is not doing so but is instead requesting a non-bypassable charge to be levied on all of its customers, including customers who purchase electricity from retail energy marketers, is evidence that AEP Ohio does not believe the survey results will translate into voluntary customer sign-ups for renewable energy offerings. Hence, AEP Ohio seeks to force all of its customers to pay for two front-loaded contracts and bear all of the non-performance risks of those contracts.

Q101. DOES AEP OHIO IN FACT PLAN TO OFFER ITS CUSTOMERS AN ABILITY TO <u>VOLUNTARILY</u> OBTAIN RENEWABLE ENERGY FROM WIND AND SOLAR RESOURCES?

A101. Yes. As described in the testimony of AEP Ohio witness Williams, the Utility proposes to offer a Green Tariff. As he testifies:

> The Green Tariff will provide all customer classes the opportunity to purchase RECs to cover some or all of their generation supply. Customers can meet sustainability goals or personal preference with renewable energy resources, regardless of whether the

customer purchases generation service from the SSO or from a retail energy marketer.[79]

He further testifies that, "A customer may voluntarily opt in and out of the Green Tariff as they choose."[80]

Q102. DO YOU OPPOSE A VOLUNTARY GREEN TARIFF SUCH AS THE ONE DESCRIBED BY AEP OHIO WITNESS WILLIAMS?

A102. No. Offering Standard Offer customers and customers who purchase their electricity from retail energy marketers an opportunity to purchase green energy resources consistent with their own personal and corporate preferences is reasonable. However, there is one crucial caveat: the costs of the green energy purchased by such customers should <u>not</u> be forcefully subsidized by any other AEP Ohio customers. Yet, such mandatory subsidization is exactly what AEP Ohio is proposing with the non-bypassable Renewable Charge.

[79] Williams Direct, p. 13, lines 9 – 12 (emphasis added).

[80] *Id*. p. 14, lines 21 – 22.

IX. THE ECONOMIC IMPACT ANALYSIS PRESENTED BY AEP OHIO IS IRRELEVANT TO THE ESTABLISHMENT OF "NEED" FOR THE SOLAR PROJECTS.

Q103. DID THE PUCO ACCEPT AEP OHIO'S ARGUMENTS TO JUSTIFY A NON-BYPASSABLE CHARGE ON ITS PROPOSED TURNING POINT SOLAR FACILITY ON THE BASIS OF ECONOMIC IMPACTS AND JOB CREATION?

A103. No. The PUCO found that "need" should be appropriately based on the language in R.C. 4928.143(B)(2)(c) and not broad economic benefits, such as job creation.[81]

Q104. DID YOU REVIEW THE TESTIMONY OF AEP OHIO WITNESSES BUSER AND LAFAYETTE AND THEIR ACCOMPANYING REPORT?[82]

A104. Yes.

Q105. DO YOU FIND THEIR ANALYSIS TO BE CREDIBLE?

A105. No. Moreover, they attempt to justify the proposed non-bypassable charge not only on the basis of economic impacts from the Renewable Agreements, but also

[81] *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case Nos. 10-501-EL-FOR et seq., Opinion and Order, p. 19 (Jan. 9, 2013).

[82] Direct Testimony of Stephen Buser on behalf of Ohio Power Company, September 27, 2018 ("Buser Direct"); Direct Testimony of Bill Lafayette on behalf of Ohio Power Company, September 27, 2018 ("Lafayette Direct"); Exhibit SB/BL-1.

on the basis of reducing coal mining and oil production-related deaths,[83] promoting "gender fairness and equality,"[84] and combating the opioid crisis.[85] Addressing such social issues is far afield from the standard in Ohio law requiring that customer need be shown for utility generation and from the PUCO's regulatory purview under that law.

Q106. CAN YOU EXPLAIN THE FUNDAMENTAL FLAW IN THEIR ECONOMIC IMPACT ANALYSIS STUDY?

A106. Yes. The fundamental flaw in their study is they assume the money to be spent on the two solar plants comes from on high, rather than AEP Ohio customers. This is the problem with subsidies I identified above. The Buser and Lafayette study entirely ignores opportunity costs because it never evaluates what would happen if the money that AEP Ohio extracts from its customers under the Renewable Agreements were instead to be spent by customers on other goods and services. In my experience, this is the most common error of economic impact studies that purport to show untrammeled economic benefits associated with renewable energy development.

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[83] Buser Direct, p. 7, line 12 – p. 8, line 19.

[84] *Id.*, p. 9, line 12.

[85] *Id.*, p. 10, lines 10-21.

Q107. DOES THIS CONCLUDE YOUR TESTIMONY?

A107. Yes. However, I reserve the right to incorporate new information that may subsequently become available through outstanding discovery or otherwise.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the Direct Testimony of Jonathan A. Lesser, Ph.D, on Behalf of the Office of the Ohio Consumers' Counsel, Public Version, was served upon the persons listed below via electronic transmission this 2nd day of January 2019.

/s/ Maureen R. Willis
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SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has over 30 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in risk management, cost-benefit analysis, valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including risk management strategies for regulated natural gas and electric utilities, cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, utility financing and the cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous US states; before the US Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; and in commercial litigation cases. He has also testified before the U.S. Congress, and legislative committees in numerous states on energy policy and market issues. Dr. Lesser has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is the coauthor of *Environmental Economics and Policy* (1997), *Principles of Utility Corporate Finance* (2011), and *Fundamentals of Energy Regulation* (2007; 2d ed., 2013). Dr. Lesser previously served a three-year term as one of the Energy Bar Association "Deans" overseeing education programs on energy regulatory and ratemaking concepts for attorneys. He is currently an Adjunct Fellow with the Manhattan Institute for Policy Research, where he studies energy policy issues.

AREAS OF EXPERTISE

- State, federal, and international electric rate regulation—cost of capital, depreciation, cost of service, cost allocation, pricing and rate design, incentive regulation, regulatory policy, wholesale and retail market design, and industry restructuring
- Risk management
- Cost-benefit analysis, asset valuation, and cost-effectiveness analysis of regulatory programs
- Natural gas and oil pipeline rate regulation
- Electricity and natural gas market analysis
- Commercial damages estimation and litigation
- Economic impact analysis and input-output studies
- Environmental policy and analysis
- Market power analysis
- Load forecasting and energy market modeling
- Market valuation and due diligence
- Antitrust

EDUCATION

- PhD, Economics, University of Washington, 1989 (Fields of specialization: Microeconomics, Econometrics, Industrial Organization and Antitrust).
- MA, Economics, University of Washington, 1982.
- BSc, Mathematics and Economics (with honors), University of New Mexico, 1980.

EMPLOYMENT HISTORY

- 2018 – Present: Adjunct Fellow, Manhattan Institute for Policy Research.
- 2016: Adjunct Lecturer, Dept. of Economics, University of New Mexico. [Course: Energy Regulation and Policy].
- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.

- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont. [Courses taught: Business and the Environment, Regulation of Business]
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College. [Courses taught: Money and Banking, Microeconomics]
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

SELECTED EXPERT TESTIMONY AND REPORTS
ENERGY LITIGATION

Eastern New England Consumed-Owned Systems

- FERC proceeding (*Constellation Mystic Power, LLC*, Docket No. ER18-1639-000)

  Subject: Testimony on allowed rate of return, vertical and horizontal market power, associated with a reliability-must-run contract.

State of New Jersey Board of Public Utilities

- I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief, Docket Nos. ER18010029 and GR18010030

  Subject: Testimony on allowed rate of return for PSEG's electric and natural gas operations, and approval of incentive returns.

Pipeline Shippers

- FERC proceeding (*Venice Gathering System*, Docket No. RP16-975-000)

  Subject: Testimony on depreciation and rate of return analysis.

Kern River Pipeline Company

- FERC proceeding (*Kern River Pipeline*, Docket No. RP17-248-000)

  Subject: Depreciation study prepared for Kern River as part of rate settlement proceeding

Kansas City Board of Public Utilities

- Proceeding before the Kansas Corporation Commission (*In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc for Approval of the Acquisition of Westar Energy, Inc by Great Plains Energy Incorporated*, Docket No. 16-KCPE-593-ACQ).

- FERC proceeding (*Great Plains Energy Corp*., Docket No. EC16-146-000)

  Subject: Financial risk and hold-harmless provisions for the proposed merger between Great Plains Energy and Westar

Eastern Massachusetts Consumer Owned Systems

- FERC proceeding (*Belmont Municipal Light Department, et al, v Central Maine Power, et al*. Docket No. EL16-64-002)

  Subject: Allowed rate of return for New England Transmission Owners

Industrial Energy Users – Ohio

- Proceeding before the Ohio Public Utilities Commission (*In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, et al*., Case No. 14-1693-EL-RDR)

  Subject: Reasonableness of nonbypassable rider associated with a long-term proposed purchase power agreement between AEP Generation and AEP Ohio.

Coaltrain Energy

- FERC proceeding, Office of Enforcement (*Coaltrain Energy*, *L.P.*, *et al*, Docket No. IN16-4-000)

  Subject: Alleged market manipulation in the PJM energy market

Mainline Shippers Group

- FERC proceeding (*Re: Gulf South Pipe Line Company, LP*, Docket No. RP15-65-000

Subject: Allowed rate of return and capital structure.

Exelon Corporation

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. ER15-623-000

  Subject: Redesign of PJM forward capacity market to incorporate Capacity Performance resources.

Indicated Shippers of California

- Proceedings before the California Public Utilities Commission (*Re: Pacific Gas and Electric Company*, Application No. 13-12-012 and Investigation 14-06-016 (risk management procedures for PG&E's natural gas transmission facilities and reasonableness of revenue requirement)

Summit Metro Parks

- FERC proceeding (*Re: New Summit Hydro LLC* , Docket No. P-14612-000)

  Subject: Application of Summit Hydro LLC for development of a proposed pumped-storage hydroelectric facility in Norton, Ohio.

Utah Industrial Energy Consumers

- Proceeding before the Utah Public Service Commission (*Re: Rocky Mountain Power Corporation*, Docket Nos. 13-035-184 and 13-034-196 (revenue requirement, cost allocation, and design of back-up service rates)

Paiute Pipeline Company

- FERC rate proceeding (*Re: Paiute Pipeline Company,* Docket No. RP14-540-000)

  Subject: Natural gas supplies and depreciation rates for transmission, storage, and general plant accounts.

Energy Michigan

- Proceeding before the Michigan Public Utilities Commission (*Re: Consumers Energy Corporation*, Case No. U-17429)

  Subject: Certificate of Convenience and Necessity for Consumers Power combined-cycle generating plant.

Constellation New Energy Inc. and Exelon Generation Company, LLC

- Proceeding before the Ohio Public Utilities Commission (*Re: Columbus Southern Power Company and Ohio Power Company*, Case Nos. 12-3254-EL-UNC)

  Subject: Design of competitive auction process and rate blending for AEP Ohio.

Shell Energy North America, LP

- FERC proceeding regarding natural gas pipeline fuel cost allocation (*Re: Rockies Express Pipeline, LLC,* Docket Nos. RP11-1844-000 & RP12-399-000)

  Subject: Economic appropriateness of roll-in treatment of "lost and unaccountable" fuel

New York Association of Public Utilities

- FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (*Niagara Mohawk Power Co*., Docket No. EL14-29-000

- FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (*Niagara Mohawk Power Co*., Docket No. EL12-101-000)

  Subject: Allowed rate of return and capital structure

Caribbean Utilities Company, Ltd.

- Rebuttal report on weighted average cost of capital methodology and recommendations for Caribbean Utilities Company, Ltd.

Utah Industrial Energy Users Coalition

- Proceeding before the Utah Public Service Commission (*Re: Rocky Mountain Power Corp*., Case No. U-11035-200)

  Subject: Appropriate methodology for embedded cost allocation for Rocky Mountain Power.

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-2400-EL-UNC)

Subject: Just and reasonableness of Duke Energy Ohio cost-recovery mechanism for capacity resources.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-426-EL-SSO)

  Subject: Dayton Power & Light Co., Electric Security Plan; financial integrity, anticompetitive cross-subsidization and need for structural separation

- Proceeding before the Michigan Public Service Commission (Case No. U-17032)

  Subject: Indiana & Michigan Power Co. proposed capacity charges for customers taking retail electric service.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: Revised AEP Ohio energy security plan, benefits of retail market competition.

- Proceeding before the Ohio Public Utilities Commission (Case No. 10-2929-EL-UNC)

  Subject: Appropriate price for commercial retail electric suppliers to be charged by AEP Ohio for installed capacity under the PJM Fixed Resource Requirement tariff option.

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

  Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

  Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

Industrial Energy Users - Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

  Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.*, Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

  Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation
- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.
- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of the benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.
  - *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
  - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
  - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Clint Yoby v. City of Cleveland, et al*., Cuyahoga County Court of Common Pleas, Case No. CV-15-852708. Expert report demonstrating that the environmental adjustment levied by the City of Cleveland was based on verifiable costs and concluding plaintiffs suffered no damages.

- *Allco Renewable Energy, LLC v. Massachusetts Electric Company (d/b/a National Grid, et al*., U.S. District Court, District of Massachusetts, Case No. 1:15-cv-13515-PBS. Expert report on compliance of National Grid standard-offer rate with requirements under the US Public Utilities Regulatory Policy Act.

- *Winding Creek Solar, LLC v. Michael Peevey, et al*., U.S. District Court, Northern California District, Case No. 3:13-04934-JD. Expert report on compliance of California Public Utility Commission renewable energy acquisition programs with requirements under the US Public Utilities Regulatory Policy Act.

- *AEP Transmission v. Brutus Leasing, Inc.,* State of Ohio Court of Common Pleas, Case No. CV20140150. Expert testimony regarding public need for property condemnation to build a high-voltage transmission line.

- *Town of Barnstable, et al. v. Ann G. Berwick, as Chair of the Massachusetts Department of Public Utilities, et al*., U.S. District Court, District of Massachusetts, Case No. 1:14-cv-10148. Expert report on damages to Town of Barnstable associated with mandated purchases of above-market wind power.

- *Idaho Power Co. v. Glenns Ferry Cogeneration Partners, L.P*., U.S. District Court, District of Idaho, Case No. 1:11-cv-00565-CWD. Expert report on damages associated with breach of power sales contract.

- *Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico,* U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. Expert testimony and report on country risk and failure to provide adequate compensation to fresh milk processors in Puerto Rico.

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. District Court of Texas, 92nd Judicial Court, Hidalgo County, Cause No. C-356-10-A. Expert reports regarding liquidated damages associated with breach of retail electric supply contracts.

- *DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437. Expert report on economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.

- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.

- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.

- *Lyubner v. Sizzling Platters, Inc.* Performed an econometric analysis of damage claims based on sales impacts associated with advertising.

- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.

- *Nat'l. Association of Electric Manufacturers v. Sorrell.* U.S. District Court for the District of Vermont. Expert report and testimony on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For an alliance of industrial firms and a public ratepayer advocate, developed risk management methodologies for electric and natural gas utilities in California
- For the Manhattan Institute, prepared a comprehensive report on the effects of electric vehicles on air pollution and GHG emissions over the 2018 – 2050 time period.
- For the Manhattan Institute, prepared a comprehensive report on the cost-benefit analysis prepared by the US EPA for its Clean Power Plan.
- For Fortis-TCI, prepared report on the economic impacts of the electric industry in the Turks and Caicos.
- For the COMPETE coalition, prepared a report on the economic impacts of state subsidized electric generating plants.
- For a confidential client, provided analysis on rate of return and capital structure, as well as key business and financial risks, for renegotiation of a long-term power-purchase agreement.
- For the Manhattan Institute, prepared a comprehensive report on the economic impacts of shutdown of the Indian Point Nuclear Facility.
- For Energy Choice Now, prepared a report on the economic benefits of retail electric competition in Michigan.
- For the COMPETE Coalition, prepared a report on how electric competition creates economic growth.
- For an industry group, developed econometric models of the impacts of shale gas production on U.S. natural gas and electric prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.

- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For the South African Department of Minerals and Energy, recommended pricing methods and regulatory accounts to ensure that petroleum product prices appropriately reflected costs and to enhance the incentives for industry investment "Final Report for Task 141. "
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.

- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy Policy*

- Reviewer, *Journal of Regulatory Economics*
- Editorial Board Member, *Natural Gas & Electricity*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., and G. Briden, "Regulatory Arbitrage and the FERC Rate Settlement Process," *Journal of Regulatory Economics* 51 (April 2017): 184-196.
- Lesser, J., "A Case Study in Damages Estimation: Bolivia's Nationalization of EGSA," *Journal of International Arbitration* 2 (2014), pp. 113-17.
- Lesser, J., "The High Cost of Low-Value Wind Power," *Regulation*, Spring 2013, pp. 22-27.
- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
- Lesser, J., and E. Nicholson, "Abandon all Hope? FERC's Evolving Standards for Identifying Comparable Firms and Estimating the Rate of Return," *Energy Law Journal* 30 (April 2009): 105-132.
- Lesser, J. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.
- Lesser, J., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
- Lesser, J., and C. Feinstein. "Defining Distributed Utility Planning." *The Energy Journal*, Special Issue, Distributed Resources: Toward a New Paradigm (1998): 41–62.
- Lesser, J., and R. Zerbe. "What Can Economic Analysis Contribute to the Sustainability Debate?" *Contemporary Policy Issues* 13 (July 1995): 88–100.

- Lesser, J., and R. Zerbe. "The Discount Rate for Environmental Projects." *Journal of Policy Analysis and Management* 13 (Winter 1994): 140–56.
- Lesser, J., and D. Dodds. "Can Utility Commissions Improve on Environmental Regulations?" *Land Economics* 70 (February 1994): 63–76.
- Lesser, J. "Estimating the Economic Impacts of Geothermal Resource Development." *Geothermics* 24 (Winter 1994): 52–69.
- Lesser, J. "Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty." *Energy* 15 (December 1990): 949–61.
- Lesser, J. "Resale of the Columbia River Treaty Downstream Power Benefits: One Road From Here to There." *Natural Resources Journal* 30 (July 1990): 609–28.
- Lesser, J., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
- Lesser, J. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

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- "The Need for a Texas Capacity Market," Presentation to the Gulf Coast Power Association, April 9, 2013.
- "The Regulatory Compact and Pipeline Competition," presentation to the Energy Bar Association, Western Chapter, Annual Meeting, San Francisco, CA, February 22, 2013.
- "Public Policy and Energy Markets: Good Intentions Gone Astray," presentation to the Independent Power Producers of New York, Fall Conference, September 13, 2012.
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- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
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Jonathan A. Lesser, PhD

List of Testimony before the PUCO

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- *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.

- *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, et al*., Case Nos. 11-346-EL-SSO, *et seq*.

- *In the Matter of the Application of Duke Energy Ohio and to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, et al*., Case No. 11-3549-EL-SSO, *et seq*.

- *In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer, et al.*, Case Nos. 12-426-EL-SSO, *et seq.*

- *In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18, et al*., Case Nos. 12-2400-EL-UNC, *et seq*.

- *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, et al*., Case No. 14-1693-EL-RDR.

UNITED STATES BANKRUPTCY COURT
NORTHERN DISTRICT OF OHIO
EASTERN DIVISION

In re: FIRSTENERGY SOLUTIONS CORP., *et al.*,[1] Debtors.	Chapter 11 Case No. 18-50757 (Request for Joint Administration Pending) Hon. Judge Alan M. Koschik

DECLARATION OF KEVIN T. WARVELL IN SUPPORT OF: (1) THE MOTION OF FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC FOR PRELIMINARY AND PERMANENT INJUNCTION AND *EX PARTE* TEMPORARY RESTRAINING ORDER AGAINST THE FEDERAL ENERGY REGULATORY COMMISSION; AND (2) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT CERTAIN ENERGY CONTRACTS; AND (3) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT A CERTAIN MULTI-PARTY INTERCOMPANY POWER PURCHASE AGREEMENT WITH THE OHIO VALLEY ELECTRIC CORPORATION

I, Kevin T. Warvell, hereby declare under penalty of perjury:

1. I am the Vice President, Chief Financial Officer, Treasurer and Corporate Secretary for FirstEnergy Solutions Corp. ("FES"). I have been employed by the Debtors since 2001, initially as a Manager of Business Services, and I subsequently served as Director of Planning Analysis, Director of Wholesale Power/Transmission Utilization, and Director of Rate Strategy. I was promoted to my current position in January 2011. I am familiar with the Debtors' day-to-day operations and business affairs, and I am specifically familiar with the

[1] The Debtors in these chapter 11 cases, along with the last four digits of each Debtor's federal tax identification number, are: FE Aircraft Leasing Corp. (9245), case no. 18-50759; FirstEnergy Generation, LLC (0561), case no. 18-50762; FirstEnergy Generation Mansfield Unit 1 Corp. (5914), case no. 18-50763; FirstEnergy Nuclear Generation, LLC (6394), case no. 18-50760; FirstEnergy Nuclear Operating Company (1483), case no. 18-50761; FirstEnergy Solutions Corp. (0186); and Norton Energy Storage L.L.C. (6928), case no. 18-50764. The Debtors' address is: 341 White Pond Dr., Akron, OH 44320.

Debtors' negotiation, execution and performance of its wholesale energy contracts, including the Executory PPAs, defined below.

2. I submit this declaration in Support of (i) the *Motion of FES and FirstEnergy Generation, LLC* ("FG") *for Permanent and Preliminary Injunction and Ex Parte Temporary Restraining Order Against the Federal Energy Regulatory Commission* ("FERC") in the above captioned adversary proceeding; and (ii) the *Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject Certain Energy Contracts* (the "Rejection Motion"); and (iii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject a Certain Multi-Party Intercompany Power Purchase Agreement with the Ohio Valley Electric Corporation* (the "OVEC ICPA Rejection Motion", collectively, with the Rejection Motion, the "Rejection Motions").

3. By the Rejection Motions, the Debtors are seeking to reject certain long-term power purchase agreements (the "Executory PPAs"). As explained below, the Executory PPAs are executory contracts, running many years into the future, and are wholly unnecessary to the Debtors' business. The Executory PPAs constitute a very small and insignificant part of the Debtors' overall business, but impose a very significant financial burden that threatens the Debtors' ability to restructure. The Executory PPAs comprise the PPAs (defined in Paragraph 6) and the OVEC ICPA (defined in Paragraph 17).

The Renewable Power Purchase Agreements

4. Renewable portfolio standards ("RPS") obligate *retail* sellers of electricity to obtain a certain percentage or amount of their power supply from renewable energy sources. States develop their RPS programs individually, and each RPS mandate has its own parameters, rules, and requirements, especially with respect to qualifying generation sources, renewable

resource goals (usually expressed as a percentage of total load), and target dates for compliance. RPS requirements may be met by obtaining renewable energy credits ("RECs") that provide evidence that power has been generated by a qualifying renewable resource.

5. RECs provide evidence of the generation of electricity from a qualifying renewable facility. Typically, one REC is created for every megawatt-hour (MWh) of energy produced from a qualifying facility. The RECs may be sold with the power or separately. The ability to realize income from the sale of RECs is a contributor to the economics of a renewable facility.

6. FES presently sells power to retail customers in Illinois, Maryland, Michigan, New Jersey, Ohio, and Pennsylvania. Historically, FES obtained the necessary RECs through eight power purchase agreements that Plaintiffs entered with various counterparties between 2003 and 2011 (collectively, the "PPAs"),[2] each of which obligates FES to purchase renewable energy and the accompanying RECs at specified prices during the term of the agreement. These PPAs have remaining terms running to various end dates between 2024 and 2033. The counterparties supply their power directly to the grid; under the terms of the PPAs it is deemed as a financial matter to have been bought by Plaintiffs (at the contract price) and re-wholesaled back into the local Regional Transmission Organization at current market prices.

7. The contract price in each of the PPAs is a "bundled" price that includes the cost of power, RECs, capacity and ancillary services. The PPAs together represent a very small portion of the aggregate energy (less than 3%) the Debtors generate and/or acquire from others.

8. The PPAs and a summary of their material terms is below:

[2] Also included in the definition of "PPAs" as used herein is a certain power purchase agreement with Forked River Power, LLC, a dual-fuel fired cycle combustion turbine power producer.

a. Wind Power Purchase Agreements between FES and Allegheny Ridge Wind Farm, LLC (Phase 1 and Phase 2)
Contract Date: March 21, 2006
Termination Date: December 31, 2030
Contract Price: $65.00/MWh

b. Power Purchase Agreement between FES and Blue Creek Wind Farm LLC[3]
Contract Date: February 8, 2011
Termination Date: December 31, 2032
Contract Price: $61.91-88.08/MWh[4]

c. Wholesale Purchase and Sale Agreement for Wind Energy between FES and Casselman Windpower LLC
Contract Date: November 30, 2006
Termination Date: 23rd Anniversary of Delivery Commencement Date
Contract Price: $72.49-94.72/MWh[5]

d. Renewable Resource Power Purchase Agreement between FES and High Trail Wind Farm, LLC

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[3] Blue Creek Wind Farm is presently in default on this agreement. FES reserves all rights under this agreement, including the right to terminate the contract per its terms, rendering rejection unnecessary.

[4] Contract Price escalates during each year of the term as follows: January 1, 2018 through December 31, 2018: $61.91/MWh; January 1, 2019 through December 31, 2019: $63.49/MWh; January 1, 2020 through December 31, 2020: $65.11/MWh; January 1, 2021 through December 31, 2021: $66.77/MWh; January 1, 2022 through December 31, 2022: $68.48/MWh; January 1, 2023 through December 31, 2023: $70.22/MWh; January 1, 2024 through December 31, 2024: $72.01/MWh; January 1, 2025 through December 31, 2025: $73.85/MWh; January 1, 2026 through December 31, 2026: $75.73/MWh; January 1, 2027 through December 31, 2027: $77.67/MWh; January 1, 2028 through December 31, 2028: $79.64/MWh; January 1, 2029 through December 31, 2029: $81.67/MWh; January 1, 2030 through December 31, 2030: $83.76/MWh; January 1, 2031 through December 31, 2031: $85.89/MWh; January 1, 2032 through December 31, 2032: $88.08/MWh.

[5] Contract Price escalates during each year of the term as follows: December 1, 2017 through November 30, 2018: $72.49/MWh; December 1, 2018 through November 30, 2019: $74.00/MWh; December 1, 2019 through November 30, 2020: $75.53/MWh; December 1, 2020 through November 30, 2021: $77.10/MWh; December 1, 2021 through November 30, 2022: $78.71/MWh; December 1, 2022 through November 30, 2023: $80.35/MWh; December 1, 2023 through November 30, 2024: $82.00/MWh; December 1, 2024 through November 30, 2025: $83.70/MWh; December 1, 2025 through November 30, 2026: $85.50/MWh; December 1, 2026 through November 30, 2027: $87.30/MWh; December 1, 2027 through November 30, 2028: $89.10/MWh; December 1, 2028 through November 30, 2029: $91.0/MWh; December 1, 2029 through November 30, 2030: $92.90/MWh; December 1, 2030 through end of Term: $94.72/MWh.

Contract Date: September 14, 2007
Termination Date: 18th Anniversary of Facilities Completion Date/Facilities Completion Termination Deadline
Contract Price: varies by year, month and hour; average annual price is approximately $70.8/MWh

e. Power Purchase Agreement between FES and Krayn Wind LLC
Contract Date: August 20, 2008
Termination Date: December 31, 2030
Contract Price: $91.02-105.13/MWh[6]

f. Power Purchase Agreement between FES and Maryland Solar LLC
Contract Date: October 14, 2011
Termination Date: 20th Anniversary of Commercial Operation Date
Contract Price: $230.00/MWh

g. Master Power Purchase and Sale Agreement between FES and Meyersdale Windpower LLC
Contract Date: April 21, 2003
Termination Date: 20 year anniversary of Commercial Operation Date
Contract Price: $39.60/MWh

h. Wind Power Purchase Agreements between FES and North Allegheny Wind LLC (Phase 3 and Phase 4)
Contract Date: September 18, 2006
Termination Date: 23rd Anniversary of Commercial Operation Date
Contract Price: $74.00/MWh for years 1-12, $68.00/MWh thereafter

i. Master Power Purchase & Sale Agreement between FES and Forked River Power, LLC[7]
Contract Date: April 17, 2008
Termination Date: April 17, 2018
Contract Price: Variable based upon specified ratio

9. At the time the PPAs were entered between 2003-2011, they were necessary and appropriate for FES's business because: (a) FES's actual and projected retail sales were greater

[6] Contract Price escalates during each year of the term as follow: 2018: $91.90/MWh; 2019: $92.08/MWh; 2020: $93.74/MWh; 2021: $94.71/MWh; 2022: $95.72/MWh; 2023: $96.76/MWh; 2024: $97.83/MWh; 2025: $98.95/MWh; 2026: $100.10/MWh; 2027: $101.29/MWh; 2028: $102.53/MWh; 2029: $103.81/MWh; 2030: $105.13/MWh.

[7] The damages calculations discussed in this declaration do not include those associated with the Master Power Purchase & Sale Agreement between FES and Forked River Power, LLC. This contract will terminate by its own terms on April 17, 2018.

than they are today; (b) market prices and outlook for power and RECs were materially greater than the current environment; (c) RPS mandates were more demanding than today; and (d) the supply of RECs was more limited. At that time, a bundled PPA was typically the only way to contract for RECs in the long-term at a fixed price. Additionally, many states had requirements that a certain percentage of the RECs had to be generated in-state.

10. However, many state-specific RPS mandates have since been relaxed and there are now an abundance of RECs available for purchase. While the PPAs made sense to FES at the time they were entered into, a dramatic downturn in the energy market and prices of RECs now renders these contracts extremely burdensome and uneconomic to FES.

11. For example, pursuant to its PPA with Krayn Wind LLC for 2018, FES is obligated to pay a fixed amount of $91.02 per MWh (and associated REC), escalating to $105.13 per MWh (and associated REC) by 2030. This is nearly three times today's market value of $36.00 for such power and REC. Based on current expectations, FES will lose approximately $103 million over the remaining term of this one PPA alone.

12. The PPAs are all the more burdensome to the Debtors because FES does not have any business or regulatory need for the power, the RECs or the standby capacity that the Debtors receive under the PPAs. FES previously made the determination to phase out its retail business, and currently sells substantially less power in the retail market than it did just four years ago. In 2013, FES sold more than 110 terawatt hours ("TWh") of power. This year, FES expects to sell less than half of that amount. Crucially, FES's need for RECs is tied directly to its retail business, and such need will be eliminated entirely once FES has fully exited that business (at the conclusion of a successful bankruptcy process.)[8]

[8] FES is in the process of marketing its retail business for sale (the "Retail Book Sale").

13. Today, FES has enough of a surplus of RECs in inventory to engage in its retail business for three years. In fact, FES has such an excess of RECs in its inventory that it is currently selling those excess RECs in the open market. However, as FES expects to sell its entire retail business in the near term, it does not need to purchase additional RECs. Nor does FES have any other need for the power or capacity provided by the PPAs.

14. In 2016, FES determined that the PPAs were burdensome and began to attempt to quantify the losses to FES associated with these agreements over the near term. We estimated that such losses would be approximately $40 million to $50 million per year. In April 2017, Debtors' counsel retained ICF to perform more exacting calculations and to conduct such analysis through the end date of the PPAs, *i.e.* 2024-2033. I am familiar with ICF and believe they are well qualified to perform these calculations.

15. The power bought and sold under the PPAs constituted approximately less than 3% of FES's total wholesale business in 2017, yet the PPAs impose enormous losses. ICF has projected that FES will lose approximately $500 million on an undiscounted basis if FES is required to perform under the PPAs through the end of the contract terms. Those calculations are summarized in the accompanying Declaration of Judah Rose. I have reviewed that declaration and the attached calculations and I concur with ICF's assumptions, methodology and conclusions.

16. Because losses of this magnitude would impose an unsustainable financial burden on the Debtors, and because FES no longer has a need for the RECs which justified its entry into the PPAs in the first place, I concluded that the PPAs should be rejected.

The OVEC Intercompany Power Purchase Agreement

17. FG is a party to a multi-party intercompany power purchase agreement (the "OVEC ICPA") pursuant to which it and several other power companies "sponsor" and purchase power generated by fossil fuel from the Ohio Valley Electric Corporation ("OVEC").[9] The OVEC ICPA obligates FG to purchase 4.85% of the power that OVEC's fossil-fuel plants generate at an uneconomic rate until either the year 2040 or until OVEC ceases to operate. Last year, this resulted in FG purchasing approximately 0.6 TWh.

18. In 2017, the OVEC ICPA accounted for roughly 1.1% of the power FES sold at wholesale, yet the losses associated with this contract are enormous. ICF has calculated that FG would lose $268 million on an undiscounted basis if FG was required to perform under the OVEC ICPA through the end of the contract term.

19. As with the PPAs, losses of this magnitude would impose an unsustainable financial burden on the Debtors. Accordingly, I concluded the OVEC ICPA should be rejected.

No Effect on Power Supply

20. FES and FG conduct all of their business operations within the regional transmission organizations ("RTOs") overseen by PJM Interconnection LLC ("PJM"), which is a regional transmission organization that covers all or parts of Ohio, Pennsylvania, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM coordinates, controls, and monitors

[9] OVEC is owned jointly by: American Electric Power; Buckeye Power Generating; Dayton Power and Light Company; Duke Energy Ohio; LG&E and KU Energy; FirstEnergy; Vectren South; and Peninsula Generating Cooperative.

multi-state electricity grids, and controls generation and transmission operations 24 hours a day, providing instructions to producers to ensure that the electric grid performs as desired.

21. The total amount of energy bid/sold into PJM during 2017 was approximately 767 TWh. The power that FES and FG purchased under the Executory PPAs during 2017 was just 1.9 TWh, or 0.2% of the available energy in PJM. Further, the energy, capacity and RECs previously purchased by FES or FG will remain available for sale by the producers to PJM or to other wholesale suppliers because all such counterparties are connected directly to the PJM grid.

22. Given the foregoing, I cannot conceive how the rejection of the Executory PPAs will cause any disruption to the continued supply of wholesale electricity within our areas of operation, or impact the reliability of the transmission grid.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Dated:

Respectfully submitted,

Kevin T. Warvell
Vice President, Chief Financial Officer,
Treasurer and Corporate Secretary,
FirstEnergy Solutions Corp.

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 (DOE Power Agreement). On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

These investor-owned utilities and affiliates of generation and transmission rural electric cooperatives comprise the Sponsoring Companies and currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
FirstEnergy Solutions Corp.[1]	4.85
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:

[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]Vectren Corporation

**OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 18-501-EL-FOR 18-1392-EL-RDR AND 18-1393-EL-ATA
THIRD SET**

INTERROGATORY

OCC-INT-03-024 Does AEP Ohio or any of its affiliates own an equity interest in Hecate Energy Highland LLC, Willowbrook Solar I, LLC, MAP Royalty, Inc., Open Road Renewables, LLC, or any of affiliate of any of the foregoing? If so, state the relevant AEP affiliate, the relevant entity in which the AEP affiliate owns an equity interest, and the percentage interest.

RESPONSE

No.

Prepared by: Joseph A. Karrasch

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NOS. 18-501-EL-FOR, 18-1392-EL-RDR AND 18-1393-EL-ATA
FIRST SET

INTERROGATORY

OCC-INT-01-005 Please identify the specific role that AEP will play in operating each of the solar energy projects. Are the operational responsibilities of the solar power plants set forth in any document? If so, please identify the document(s) that establishes the operating responsibilities of Ohio Power and/or the Sellers (solar project developers) or other third party.

RESPONSE

The purpose of the REPAs, as originally solicited in the RFP and as reflected in the Introduction of the REPA, was to contractually fulfill AEP Ohio's intent to become the operator of the facilities. Under the REPAs as executed, the Company will be responsible for operation of the facilities under the REPAs, including but not limited to operating the facilities in the PJM Markets (*e.g.*, being the Market Participant for the projects and offering/scheduling Renewable Energy associated with the Facility into PJM using the Company's day-ahead forecast and offer curve). In addition, Seller must discharge various contractual obligations through to otherwise operate the facilities on behalf of the Company, support the Company's operation of the facilities in the PJM Markets, and perform other operation and maintenance activities on behalf of the Company. PJM OATT and Manuals are available directly from PJM (www.pjm.com/library/manuals) and the REPAs have already been provided in discovery responses.

Prepared by: Joseph A. Karrasch

2018 PJM Reserve Requirement Study

11-year Planning Horizon:
June 1st 2018 - May 31st 2029
Analysis Performed by PJM Staff

Reviewed by Resource Adequacy Analysis Subcommittee

October 10, 2018

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I. Results and Recommendations

PJM RRS Executive Summary

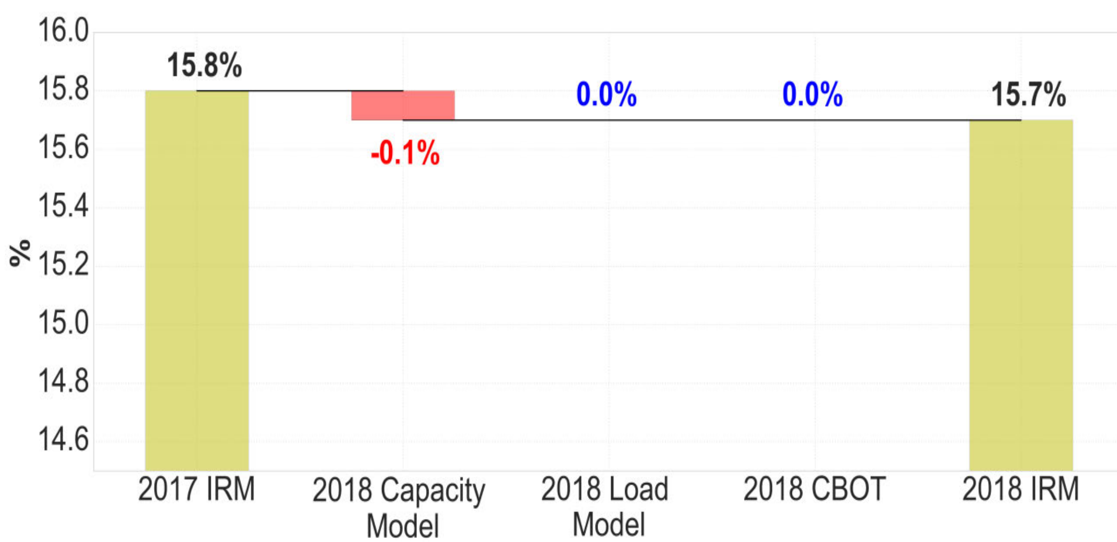
- The PJM Reserve Requirement Study's (RRS) purpose is to determine the Forecast Pool Requirement (FPR) for future Delivery Years, through calculating the Installed Reserve Margin (IRM). In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will re-establish the FPR for the 2019/2020, 2020/2021, and 2021/2022 Delivery Years (DY) and establish the FPR for the 2022/23 Delivery Year.

- This Study is used to satisfy the North America Electric Reliability Corporation (NERC) / ReliabilityFirst (RF) Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation. This Standard requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the final 2010 RF audit report, PJM was found to be fully compliant with Standard BAL-502-RFC-02.

- Based on results from this Study, PJM Staff recommends a **16.0% IRM for the 2019/2020 Delivery Year, a 15.9% IRM for the 2020/2021 Delivery Year, a 15.8% IRM for the 2021/2022 Delivery Year, and a 15.7% IRM for the 2022/2023 Delivery Year**.

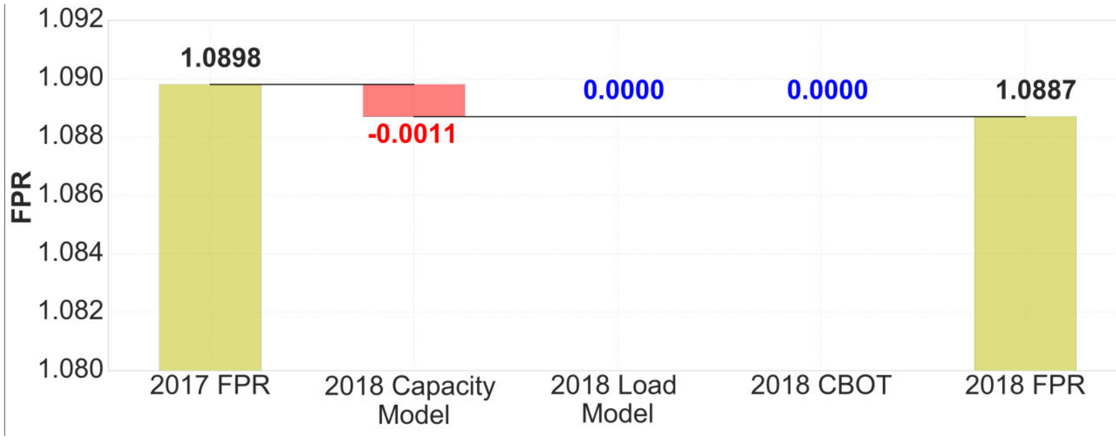
- The 15.7% IRM for 2022/2023 calculated in this year's study represents a decrease of 0.1 percentage points with respect to the IRM computed for 2021/2022 in last year's study. The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-1 below.

Figure I-1: 2018 Installed Reserve Margin Waterfall Chart



- The 1.0887 (8.87%) FPR for 2022/2023 calculated in this year's study represents a decrease of 0.11 percentage points with respect to the FPR computed for 2021/2022 in last year's study (1.0898 or 8.98%). The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-2 below.

Figure I-2: 2018 Forecast Pool Requirement Waterfall Chart



- The IRM decrease and the commensurate FPR decrease are driven by a lower standard deviation in the forced outages distribution in the 2018 Capacity Model (1.2%) relative to the standard deviation in the forced outages distribution in the 2017 Capacity Model (1.3%). This lower standard deviation can be attributed to a lower PJM average unit size: 121 MW in the 2018 Capacity Model vs. 129 MW in the 2017 Capacity Model.

- The results of the 2018 RRS are summarized below in Table I-1. PJM Staff recommends the values shown in bold in the following table.

Table I-1: 2018 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2018	2019 / 2020	15.97%	**16.0%**	6.08%	**1.0895**
2018	2020 / 2021	15.89%	**15.9%**	6.04%	**1.0890**
2018	2021 / 2022	15.84%	**15.8%**	6.01%	**1.0884**
2018	2022 / 2023	15.66%	**15.7%**	5.90%	**1.0887**

- For comparison purposes, the results from the 2017 RRS Study are below in Table I-2:

Table I-2: 2017 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2017	2018 / 2019	16.06%	**16.1%**	6.07%	**1.0905**
2017	2019 / 2020	15.92%	**15.9%**	5.99%	**1.0896**
2017	2020 / 2021	15.88%	**15.9%**	5.97%	**1.0898**
2017	2021 / 2022	15.77%	**15.8%**	5.89%	**1.0898**

- The Winter Weekly Reserve Target (WWRT) for the **2018/2019 winter period is recommended to be 22% for December 2018, 28% for January 2019, and 24% for February 2019**. The analysis supporting this recommendation is detailed in the "Operations Related Assessments" section of this report.

- The winter peak week capacity model changes approved by the Markets and Reliability Committee (MRC) in June 2018 and reflected in PJM Manual 20 were implemented in the 2018 RRS. These changes had no practical impact on the recommended IRM and FPR values. The recommended WWRT value for January described in the bullet point above, however, is impacted by these changes due to the fact that the winter peak week is modeled to occur in January.

- The IRM and FPR recommended in Table I-1 are reviewed and considered for endorsement by the following succession of groups.

    - Resource Adequacy Analysis Subcommittee (RAAS)
    - Planning Committee (PC)
    - Markets and Reliability Committee (MRC)
    - PJM Members Committee (MC)
    - PJM Board of Managers (for final approval)

- PJM's Probabilistic Reliability Index Study Model (PRISM) program is the primary reliability modeling tool used in the RRS. PRISM utilizes a two-area Loss of Load Probability (LOLP) modeling approach consisting of: Area 1 - the PJM RTO and Area 2 - the neighboring World.

- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (Dom), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC).

- The Outside World (or World) area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include New York ISO (NYISO) from the Northeast Power Coordinating Council (NPCC), TVA and VACAR from the South Eastern Reliability Corporation (SERC), and the Midcontinent Independent System Operator (MISO) (excluding MISO-South).

- Modeling of the World region assumes a Capacity Benefit Margin (CBM) of 3,500 MW into PJM, which serves as a maximum limit on the amount of external assistance. The CBM is set to 3,500 MW per Schedule 4 of the PJM Reliability Assurance Agreement. Figure I-7 shows the benefit of this interconnection at various values of CBM.

- There is a net addition of 14,240 MW of generation within the PJM RTO in the period 2018-2022. This reflects approximately 22,980 MW of new generation and 8,740 MW of retired generation. The RRS study does not include Demand Resources.

- For the fourth year in a row, the load model time period 2003-2012 was used in the RRS study. This load model time period was endorsed at the July 12, 2018 Planning Committee meeting.
- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-02 - Resource Planning Reserve Requirements, the 2018 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2018 and extends through May 31, 2029. (See Table I-4)

Results from the last ten RRS Reports are summarized below in Table I-3:

Table I-3: Historical RRS Parameters

RRS Year	Delivery Year	Calculated IRM	**Approved IRM**	Avg. EFORd	**FPR**
2008	2012/2013	16.2%	**16.2%**	6.44%	**1.0872**
2009	2012/2013	15.4%	**15.4%**	6.28%	**1.0815**
2009	2013/2014	15.3%	**15.3%**	6.30%	**1.0804**
2010	2012/2013	15.5%	**15.5%**	6.26%	**1.0827**
2010	2013/2014	15.3%	**15.3%**	6.25%	**1.0809**
2010	2014/2015	15.3%	**15.3%**	6.25%	**1.0809**
2011	2012/2013	15.6%	**15.6%**	6.58%	**1.0869**
2011	2013/2014	15.4%	**15.4%**	6.52%	**1.0859**
2011	2014/2015	15.4%	**15.4%**	6.51%	**1.0860**
2011	2015/2016	15.4%	**15.4%**	6.52%	**1.0859**
2012	2013/2014	15.9%	**15.9%**	6.73%	**1.0889**
2012	2014/2015	15.9%	**15.9%**	6.72%	**1.0889**
2012	2015/2016	15.3%	**15.3%**	6.59%	**1.0849**
2012	2016/2017	15.6%	**15.6%**	6.38%	**1.0902**
2013	2014/2015	16.2%	**16.2%**	6.66%	**1.0926**
2013	2015/2016	15.7%	**15.7%**	6.26%	**1.0920**
2013	2016/2017	15.7%	**15.7%**	6.29%	**1.0917**
2013	2017/2018	15.7%	**15.7%**	6.29%	**1.0916**
2014	2015/2016	15.6%	**15.6%**	6.19%	**1.0913**
2014	2016/2017	15.5%	**15.5%**	6.30%	**1.0896**
2014	2017/2018	15.7%	**15.7%**	6.34%	**1.0911**
2014	2018/2019	15.7%	**15.7%**	6.35%	**1.0835**
2015	2016/2017	16.4%	**16.4%**	6.57%	**1.0952**
2015	2017/2018	16.5%	**16.5%**	6.59%	**1.0959**
2015	2018/2019	16.5%	**16.5%**	6.58%	**1.0883**
2015	2019/2020	16.5%	**16.5%**	6.60%	**1.0881**
2016	2017/2018	16.6%	**16.6%**	6.54%	**1.0967**
2016	2018/2019	16.7%	**16.7%**	6.59%	**1.0901**
2016	2019/2020	16.6%	**16.6%**	6.59%	**1.0892**
2016	2020/2021	16.6%	**16.6%**	6.59%	**1.0892**
2017	2018/2019	16.1%	**16.1%**	6.07%	**1.0905**
2017	2019/2020	15.9%	**15.9%**	5.99%	**1.0896**
2017	2020/2021	15.9%	**15.9%**	5.97%	**1.0898**
2017	2021/2022	15.8%	**15.8%**	5.89%	**1.0898**

Introduction

Purpose

The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-02. This study is conducted each year in accordance with PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load in the PJM RTO.

The RRS results are key inputs to the PJM Reliability Pricing Model (RPM). These inputs include the Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR). More specifically, the FPR is used to calculate the Reliability Requirement for the PJM Regional Transmission Organization (RTO) in RPM Auctions.

The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR)

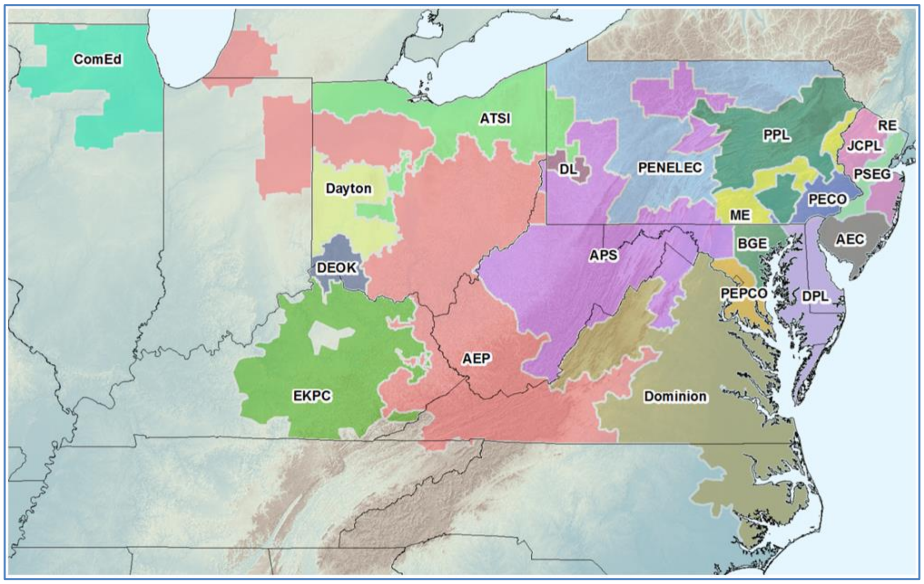
In addition to serving as inputs for the RPM market, the IRM and FPR calculated in the RRS are critical values as they satisfy compliance requirements for ReliabilityFirst (RF). (See Section II. For further details on the process, contact regional_compliance@pjm.com.)

The timetable for calculating and approving these values is shown in the June 2018 study assumptions letter to the PC, reviewed as agenda item 5 at the June 7, 2018 PC meeting.

Regional Modeling

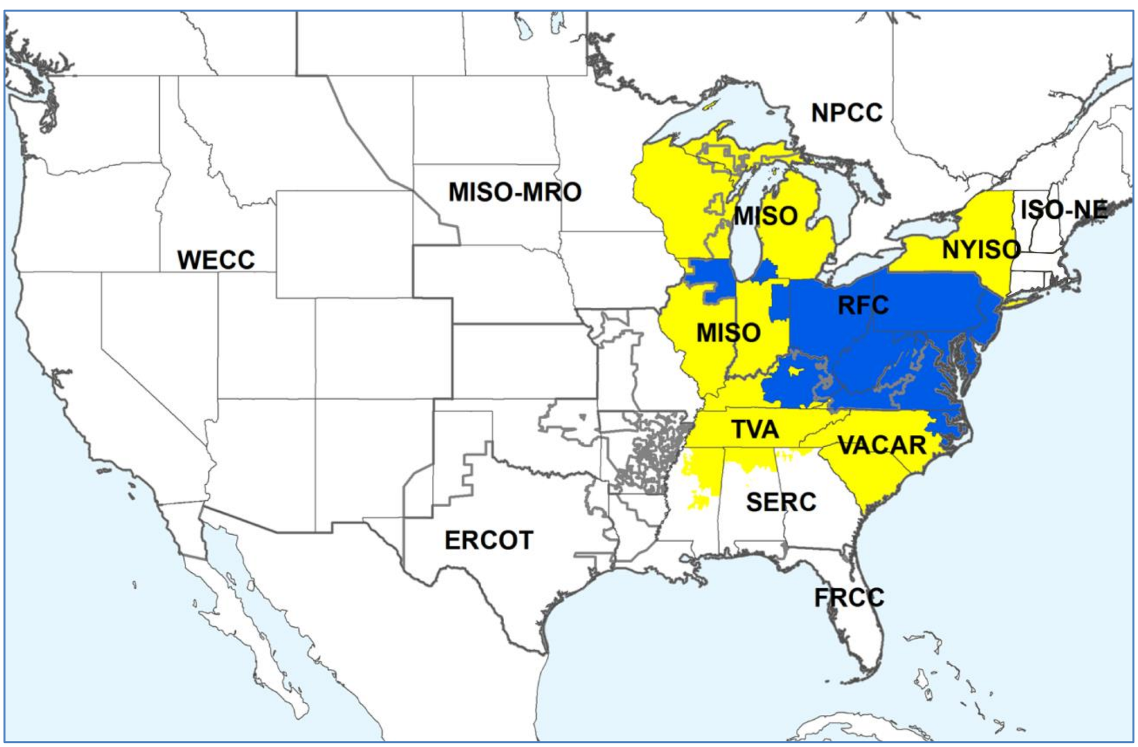
This study examines the combined PJM footprint area (Figure I-3) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOMVP), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC).

Figure I-3: Combined PJM Region Modeled



Areas adjacent to the PJM Region are referred to as the World (Figure I-4) and consist of MISO (excluding MISO-South), TVA and VACAR (both in SERC), and NYISO from the Northeast Power Coordinating Council (NPCC). Areas outside of PJM and the World are not modeled in this study.

Figure I-4: PJM RTO, World and Non-Modeled Regions (PJM Region in blue)



Summary of RRS Results

Eleven-Year RRS Results

Table I-4 below shows an eleven-year forward projection from the study for informational purposes. The Delivery Years for which the parameters must be finalized are highlighted in yellow. These results do not reflect any previous modeling or approved values. Note that the projected reserves in column H exceed the IRM in column A for each of the next eleven Delivery Years. The study, therefore, indicates there are no gaps between the needed amount of planning reserves and the projected planning reserves over the eleven-year study period.

Table I-4: Eleven-Year Reserve Requirement Study

	Calculated IRM					Forecast Reserve				
	A	B	C	D	E	F	G	H	I	J
Delivery Year	IRM PJM RTO % (2 area)	IRM Outside World %	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Require-ment (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	PJM Reliability Index without World Assistance (years/day)
2018	16.2%	18.2%	7.0%	7.5%	1.0963	183,994	143,013	28.7%	21.0%	5.9
2019	16.0%	18.2%	6.8%	7.2%	1.0961	190,169	143,366	32.6%	24.7%	6.0
2020	15.9%	18.1%	6.8%	7.5%	1.0890	191,474	144,287	32.7%	26.0%	6.0
2021	15.8%	18.1%	6.8%	7.4%	1.0884	197,015	144,672	36.2%	29.3%	6.0
2022	15.7%	18.0%	6.7%	7.6%	1.0887	196,597	145,166	35.4%	28.6%	6.0
2023	15.7%	18.0%	6.7%	7.7%	1.0889	196,365	145,885	34.6%	27.8%	6.0
2024	15.6%	18.0%	6.7%	7.7%	1.0879	196,365	146,459	34.1%	27.3%	6.0
2025	15.6%	17.9%	6.7%	7.7%	1.0879	196,365	147,118	33.5%	26.7%	6.0
2026	15.6%	17.9%	6.7%	7.7%	1.0879	196,365	147,862	32.8%	26.1%	6.0
2027	15.6%	17.9%	6.7%	7.7%	1.0879	196,365	148,706	32.0%	25.4%	6.0
2028	15.6%	17.9%	6.7%	7.7%	1.0879	196,365	149,688	31.2%	24.6%	6.0

Calculated IRM Columns (PRISM Run # 56552)

- Calculated IRM, column A is at an LOLE criterion of 1 day in 10 years.
- Column A is based on the PRISM solved load, not the January 2018 load forecast values issued by PJM.
- Calculated IRM, column B is the World IRM at an LOLE criterion of 1 day in 10 years which is within the valid range shown in Table I-5 (15.57 % to 20.39 %). The exact World reserve value depends on World load management actions at the time of the PJM RTO's need for assistance. The World reserve levels in Column B that yield a PJM Reliability Index (RI) equal to an LOLE of 1 day in 10 years are within the valid range.
- Results reflect calculated (to the nearest decimal) reserve requirements for the PJM RTO (column A) and the Outside World (column B).
- Calculated IRM results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
- The Average Effective Equivalent Demand Forced outage rate (EEFORd) (column C) is a pool-wide average effective equivalent demand forced outage rate for all units in the PJM RTO model (about 1,500 units). These are

not the forced outage rates to be used in the RAA Obligation formula (as mentioned earlier in the document, EFORd values are used in the FPR formula). The EEFORd of each unit is based on a five-year period (2013-2017, for this year's study).

- The average weekly maintenance (column D) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

Forecast Reserve Columns

- The capacity values in Column F include external firm capacity purchases and sales.
- 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions. These 2,500 MW are included in the Column F value.
- The Restricted Load in Column G corresponds to Total Internal Demand (at peak time) minus load management as per the 2018 PJM Load Forecast.
- The PJM forecast reserves are above the calculated requirement (see Column H vs. Column A for years in yellow).
- Reserves in Column H (as well as the capacity value in Column F) include about 22,980 MW of new generation projects identified through the Regional Transmission Expansion Plan (RTEP). Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value.
- The RTEP is dynamic and actual PJM reserve levels may differ significantly from those forecasted today. Another factor contributing to future reserve margin uncertainty is the fact that PJM allows units to retire with as little as 90 days' notice as per PJM's Manual 14D.

PJM Reliability Index without World Assistance

- The values in Column J are for informational purposes only. PJM Reliability Index (RI) is expressed in years per day (the inverse of the days per year LOLE). This column indicates reliability when all external ties into PJM are cut ("zero import capability" scenario) for the corresponding PJM IRM in Column A.
- In other words, the values in Column J represent the frequency of loss of load occurrences if the PJM RTO were not part of the Eastern Interconnection. Compared to the 1 in 10 criteria (RI = 10), the values in Column J are much lower. This comparison provides a sense of the value of PJM being strongly interconnected. More specifically, if PJM were not interconnected, it could experience loss of load events roughly twice as often.

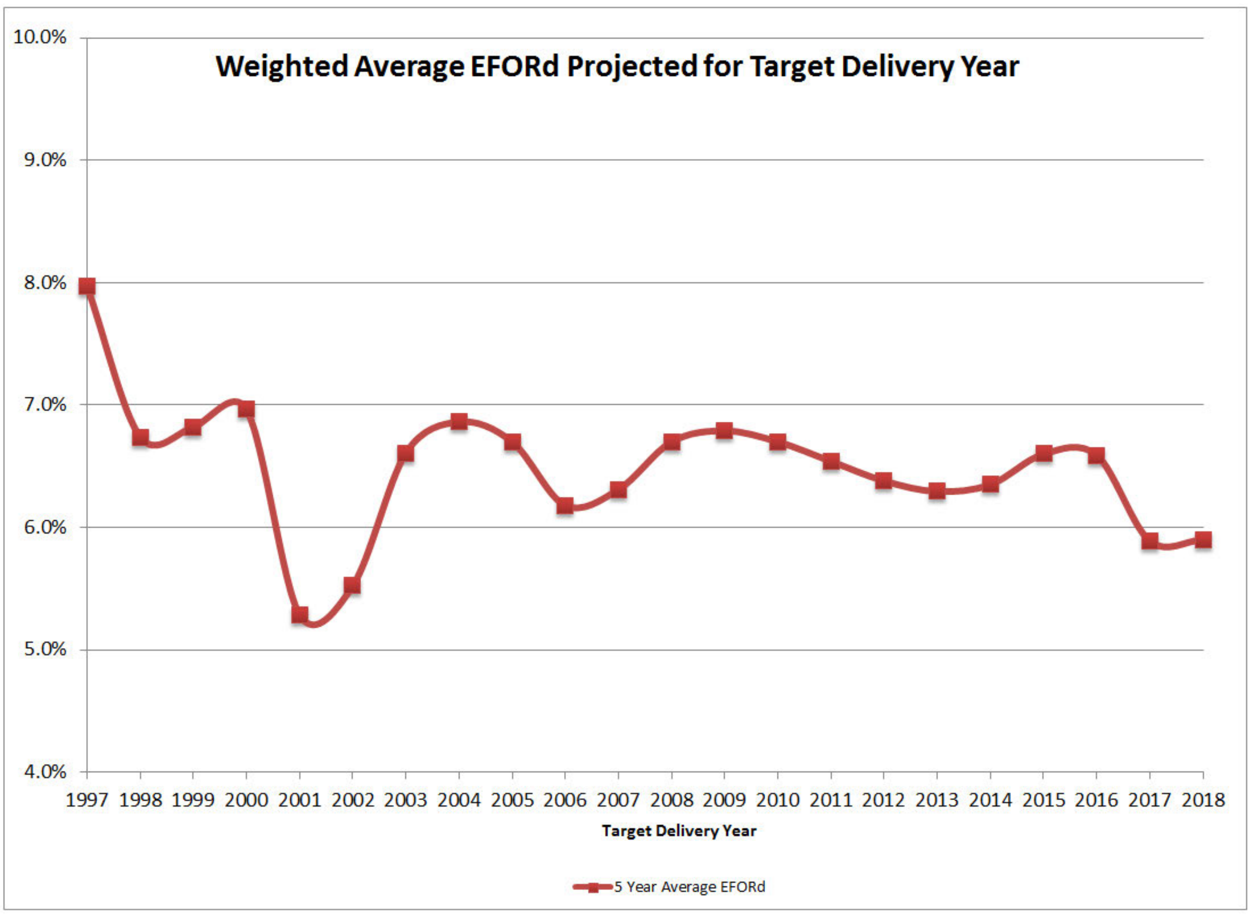
Key Observations

- General Trends and Observations
  - Pool wide average forced outage rate values (EFORd) for the target Delivery Year, in each of the annual RRS capacity models, are shown in Figure I-5. The forced outage rates of each unit are based on the historical five-year period used in a given study. It is important to note that the collection of generators included in each year's case varies greatly over time as new generators are brought in-service, some generators retire or mothball, and new generators are added due to PJM market expansion.
  - As shown in Figure I-5, average unit performance in the 2018 study model is very similar to the average unit performance in the 2017 study model (the weighted average EFORd in the 2018 RRS is 5.90% while in the 2017 RRS it was 5.89%).

- However, the RTO-wide forced outages distribution in the 2018 RRS has a lower standard deviation than in the 2017 RRS (1.2% vs 1.3%), which puts downward pressure on the IRM and FPR. This lower standard deviation can be attributed to a lower average unit size: 121 MW in the 2018 RRS vs 129 MW in the 2017 RRS.

The statistical parameters used in the RRS are consistent with those available on the PJM website's resource reports and information. However, the detailed data used in the RRS may not apply to other reporting parameters and requirements. PJM's resource reports are available at: http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx. This website, along with PJM Manual 22, contains the details concerning proper rules and calculation procedures of the statistical parameters used in the RPM marketplace for all units including: Mature Units, Mothballed Units, and Combined Cycle conversion of existing CT units.

Figure I-5: Historical Weighted-Average Forced Outage Rates (Five-Year Period)



The World reserves were assessed and modeled in a similar manner as performed in previous RRS studies. Among the regions modeled as part of the World, the New York and MISO regions have firm reserve requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with general statements of the NERC targets for these regions. Table I-5 summarizes the values used to determine a valid range for a World reserve level of 15.57% to 20.39%. The reserve requirements considered are shown in the IRM column. The diversity values shown are from an assessment of historic data, using the average of the values observed over the summer season. See Table II-3 for further details. Please reference Appendix F which presents a discussion of the modeling assumptions. It was agreed upon by the RAAS in previous years that the appropriate choice for World reserves is the one that satisfies the 1 in 10 reliability criterion for the World as long as it is within the valid range. This value in the 2018 study is 18.0% and it is within the valid range shown in Table I-5.

Table I-5: World Reserve Level, Valid Range to Consider

	NCP	IRM	Diversity	CP	LM	LM as % NCP	NCP- LM (NID)	CAP based on NID	CP- LM	Reserves as % of CP	Reserves as % of CP- LM
NY	32903	18.2%	0.9502	31266	965	2.93%	31938	37751	30301		
MISO	95432	17.1%	0.9904	94517	4272	4.48%	91160	106748	90245		
TVA	42208	15.0%	0.9521	40185	1719	4.07%	40489	46562	38466		
VACAR	44967	15.0%	0.9498	42710	1387	3.08%	43580	50117	41323		
Total Composite Region =	215510			208677	8343	3.87%	207167	241178	200334	15.57%	20.39%

LM: Load Management NCP: Non-Coincident Peak CP: Coincident Peak

Data Sources

NY - NPCC Reliability Assessment for Summer 2018, Appendix VIII, Table 4 & Table 6, April 2018

Available at https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2018_Summer.pdf

MISO - 2017 NERC ES&D Report - Peak Hour Demand Seasonal, 1st Year column

MISO excludes MISO-South

MISO LM Total from 2017 NERC ES&D Report- Controllable and Dispatchable Demand Response - Available (Year 1)

TVA and VACAR - 2017 NERC ES&D Report

Peak Hour Demand Seasonal, 1st Year column. TVA = SERC N (Summer), VACAR = SERC E (Winter)

Demand & Resources - Summer, Controllable and Dispatchable Demand Response - Available (Year 1). TVA = SERC N, VACAR = SERC E

NY and MISO are modeled at their approved IRMs as per the documents below:

http://www.nysrc.org/pdf/Reports/2018%20IRM%20Study%20Report%20Final%2012-8-17[2098].pdf

https://cdn.misoenergy.org/2018%20LOLE%20Study%20Report89286.pdf

TVA and VACAR are modeled at the soft target IRM of 15%.

- Load diversity between PJM and the World is addressed by two modeling assumptions. First, the historical period used to construct the hourly load model is the same for PJM and the World. Second, the world load model corresponds to coincident peaks from the four individual sub-regions.

- Figure I-6 shows the impact of the World reserves on the PJM RTO IRM. This figure assumes a CBM value of 3,500 MW at all World reserve levels. The green horizontal line labeled “valid range” shows the range of World generation reserve levels depending on the amount of World load management assumed to be curtailed or to have voluntarily reduced consumption in response to economic incentives, at the time of a PJM capacity emergency. The lower end of the range (at 15.57%) represents the World reserve level if no World load management were implemented. The higher end (at 20.39%) is the reserve level assuming all World load management is implemented or customers have reduced their loads at the time of a PJM emergency. Figure I-6 indicates that the impact of additional World Reserves on PJM’s IRM tends to decrease as World Reserves are outside of the valid range (above 19%).
- The PJM IRM at this “1 in 10” World reserve level is 15.66%. This is the basis for the recommended IRM, for Delivery Year 2022/2023, of 15.7%.

Figure I-6: Relation between the IRM and World Reserves

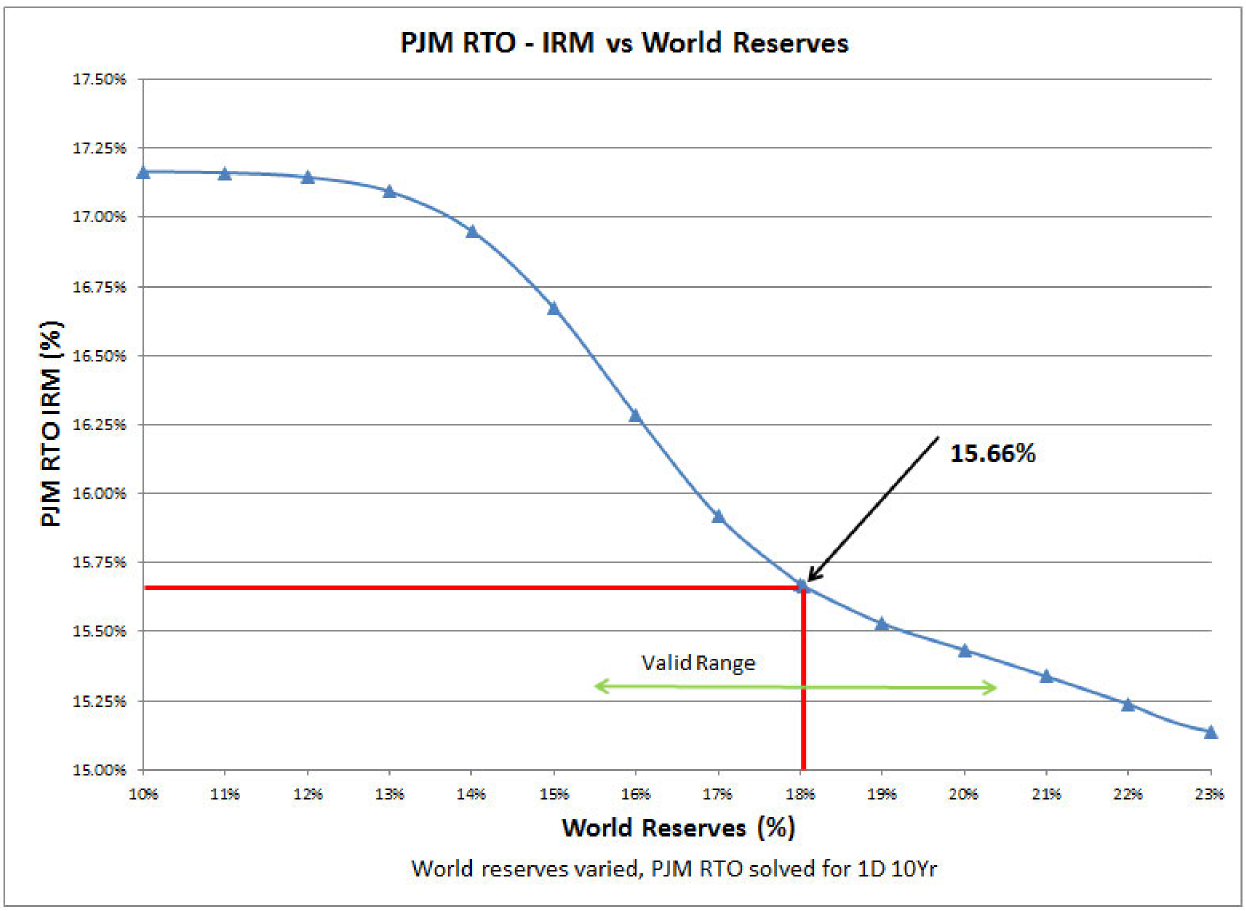
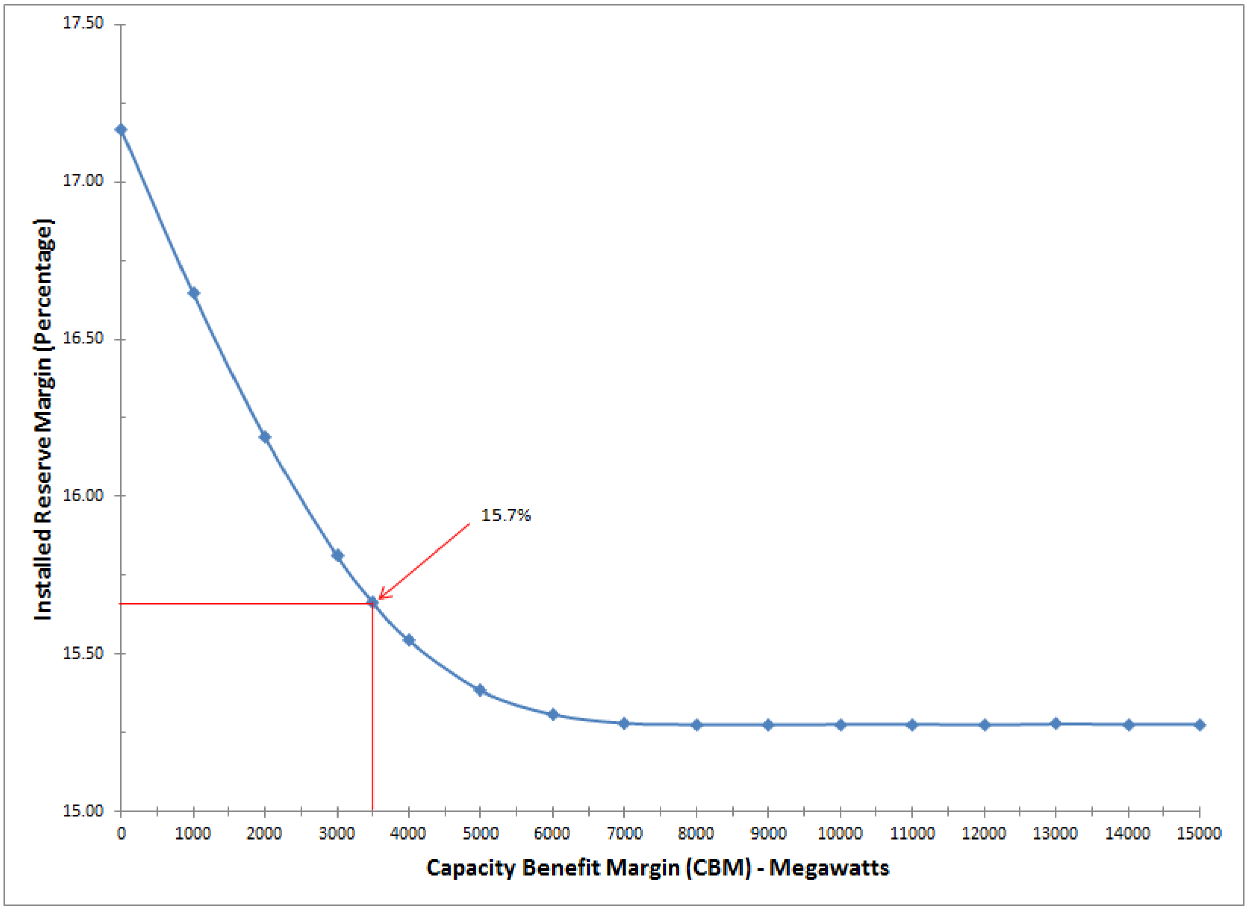


Figure I-7: Relation between the IRM and the CBM



- Figure I-7 shows how the PJM IRM varies as the CBM is varied. As indicated by the red line, the official CBM value of 3,500 MW results in a PJM IRM of 15.7%. Thus, the PJM IRM is reduced by 1.5% due to the CBM (from 17.2%, the intercept with the y-axis, to 15.7 %). Based on the forecasted load for 2022/2023, this 1.5% IRM reduction eliminates the need for about 152,887 MW x 1.5% = 2,293 MW of installed capacity. Therefore, the Capacity Benefit of Ties (CBOT) in this year's study is 2,293 MW.

- The underlying modeling characteristics of load, generation, and neighboring regions' reserves / tie size are the primary drivers for this study. Although consideration of the amount in MW of either load or generation can be a factor, it is not as significant due to the method employed to adjust an area's load until its LOLE meets the 1 day in 10 years reliability criterion. Small changes to the parameters that capture uncertainties associated with load and generation can impact the assessment results.

Recommendations

- Installed Reserve Margin (IRM) — based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of 16.0% for the 2019/2020 Delivery Year, 15.9% for the 2020/2021 Delivery Year, 15.8% for the 2021/2022 Delivery Year, and 15.7% for the 2022/2023 Delivery Year. The IRM is applied to the official 50/50 PJM Summer Peak Forecast which corresponds to the Expected Weekly Maximum (EWM) of the peak summer week in PRISM. The Resource Adequacy Analysis Subcommittee reviewed these study results on October 4, 2018.

- Forecast Pool Requirement (FPR) — the approved IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:
    - FPR = (1 + IRM) * (1 – PJM Avg. EFORd)

- Based on the recommended IRM values, the resulting FPRs would therefore be:
    - 2019 / 2020 Delivery Year FPR = (1.160) * (1 – 0.0608) = 1.0895
    - 2020 / 2021 Delivery Year FPR = (1.159) * (1 – 0.0604) = 1.0890
    - 2021 / 2022 Delivery Year FPR = (1.158) * (1 – 0.0601) = 1.0884
    - 2022 / 2023 Delivery Year FPR = (1.157) * (1 – 0.0590) = 1.0887

- Winter Weekly Reserve Target — the recommended 2018 / 2019 Winter Weekly Reserve Target is 22% for December 2018, 28% for January 2019, and 24% for February 2019. This recommendation is discussed later in the report.

II. Modeling and Analysis

Load Forecasting

PJM Load Forecast – January 2018 Load Report

The January 2018 PJM Load Forecast is used in the 2018 RRS. The load report is available on the PJM web site at:https://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis).

Monthly Forecasted Unrestricted Peak Demand and Demand Resources

The monthly loads used in the RRS are based on forecasted monthly unrestricted peak loads. PJM monthly loads are from the 2018 PJM Load Forecast report. World monthly loads are derived through an examination of data from NERC's Electric Supply and Demand (ES&D) dataset. These values are in Table II-1 on a per-unit basis relative to the annual peak.

Table II-1: Load Forecast for 2022 / 2023 Delivery Years

Month	PJMRTO Unrestricted Loads	WORLD Unrestricted Loads
June	0.942042	0.958578
July	1.000000	1.000000
August	0.969592	0.995779
September	0.849811	0.904954
October	0.708235	0.733070
November	0.723305	0.764473
December	0.827356	0.827240
January	0.872193	0.878586
February	0.834021	0.823269
March	0.744347	0.765545
April	0.707411	0.692111
May	0.786254	0.801448

Forecast Error Factor (FEF)

The Forecast Error Factor (FEF) represents the increased uncertainty associated with forecasts covering a longer time horizon. The FEF is 1.0% for all future delivery years. See PJM Manual 20 and the “PJM Generation Adequacy Analysis – Technical methods” (at http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx) and the Modeling and Analysis Section for discussion of how the FEF is used in the determination of the Expected Weekly Maximum (EWM).

With the implementation of the RPM capacity market in 2006, the FEF used in the RRS was changed to 1.0% for all future delivery years, based on a stakeholder consensus. This is due to the ability for PJM to acquire additional resources in incremental auctions close to the delivery year. This mitigates the uncertainty of the load forecast as RPM mimics a one-year-ahead forecast. Sensitivity number 8 in Appendix B shows the impact of different FEF values on the IRM.

21 point Standard Normal Distribution, for daily peaks

PRISM’s load model is a daily peak load model aggregated by week (1-52). The uncertainty in the daily peak load model is modeled via a standard normal distribution. The standard normal distribution is represented using 21 points with a range of +/- 4.2 sigma away from the mean. The modeling used is based on work by C.J. Baldwin, as presented in the Westinghouse Engineer journal titled “Probability Calculation of Generation Reserves”, dated March 1969. See PJM Manual 20 for further details.

Week Peak Frequency (WKPKFQ) Parameters

The load model used in PRISM is developed with an application called WKPKFQ. The application’s primary input is hourly data, determining the daily peak’s mean and standard deviation for each week. Each week within each season for a year of historical data is magnitude ordered (highest to lowest) and those weeks are averaged across years to replicate peak load experience. The annual peak and the adjusted WKPKFQ mean and standard deviation are used to develop daily peak standard normal distributions for each week of the study period. The definition of the load model, per the input parameters necessary to submit a WKPKFQ run, define the modeling region and basis for all adequacy studies. WKPKFQ required input parameters include:

- Historic time period of the model.
- Sub-zones or geographic regions that define the model.
- Vintage of Load forecast report (year of report).
- Start and end year of the forecast study period.
- 5 or 7 days to use in the load model. All RRS studies use a 5 day model, excluding weekends.
- Holidays to exclude from hourly data include: Labor Day, Independence Day, Memorial Day, Good Friday, New Year’s Day, Thanksgiving, the Friday after Thanksgiving, and Christmas Day.

The Peak Load Ordered Time Series (PLOTS) load model is the result of performing the WKPKFQ calculations. The resulting output is 52 weekly means and standard deviations that represent parameters for the daily normal distribution. The beginning of Week 1 corresponds to May 15th. Table II-2 shows these results of PJM RTO WKPKFQ run 51753 used in this study.

Table II-2: PJM RTO Load Model Parameters (PJM LM 51753)

ARC Week	Mean Seasonal	Standard Deviation	ARC Week	Mean Seasonal	Standard Deviation
1	0.65435	0.02948	27	0.69966	0.04610
2	0.68936	0.04662	28	0.71841	0.04074
3	0.76419	0.05566	29	0.74008	0.03914
4	0.81338	0.05705	30	0.78425	0.04755
5	0.80326	0.05548	31	0.80635	0.04948
6	0.90582	0.06378	32	0.77363	0.06534
7	0.87737	0.04236	33	0.74834	0.03923
8	0.90801	0.04359	34	0.80885	0.05956
9	0.91476	0.06763	35	0.75888	0.06048
10	1.00000	0.07936	36	0.81827	0.06918
11	0.93366	0.07599	37	0.82692	0.07005
12	0.97647	0.06388	38	0.76072	0.06249
13	0.94168	0.07409	39	0.79239	0.05882
14	0.88011	0.05815	40	0.77418	0.05183
15	0.83416	0.07388	41	0.76221	0.04497
16	0.81311	0.07053	42	0.75148	0.04977
17	0.76554	0.08464	43	0.72634	0.04383
18	0.73592	0.05863	44	0.69825	0.03725
19	0.71804	0.05015	45	0.68484	0.04225
20	0.66712	0.04296	46	0.67065	0.03812
21	0.68895	0.05611	47	0.65467	0.03991
22	0.67380	0.04057	48	0.64896	0.03313
23	0.65703	0.02370	49	0.64041	0.03102
24	0.65971	0.02964	50	0.63553	0.02433
25	0.66906	0.03183	51	0.66574	0.04267
26	0.69583	0.07594	52	0.67520	0.07718

Parameter	Value
Title	RRS2018YR10
Description	RTO 10YR LM, 2018 Start, 2028 End, 2018 LF
Year Range	2003 - 2012
Growth Factor	0.00359942
Growth Start Year	2018/2019
Growth End Year	2028/2029
Report Select	1
Zones	AE, AEP, APS, ATSI, BGE, COMED, DAY, DPL, DQE, DUKE, JCPL, METED, PECO, PEPCO, PN, PS, VEPO, RECO, UGI, PL, EKPC
Exclude Weekends	Y
Exclude Holidays	Y
Excluded Holidays	1,2,3,4,5,6,7,8

PJM-World Diversity

PJM-World diversity reflects the timing of when the World area peaks compared to when the PJM RTO area peaks. The greater the diversity, the more capacity assistance the World can give at the time when PJM needs it and, therefore, the lower the PJM IRM. Diversity is a modeling characteristic assessed in the selection of the most appropriate load model time period for use in the RRS. A comprehensive method to evaluate and choose load models, with diversity as one of the considerations, was approved by the Planning Committee and used for the 2018 RRS.

Historic hourly data was examined to determine the annual monthly peak shape of the composite World region. Monthly World coincident peaks are magnitude ordered (highest to lowest) and averaged across years to replicate peak load experience. Magnitude-ordered months are assigned to calendar months according to average historical placement. These results are highlighted in yellow below in Table II-3.

To examine seasonal diversity, an average of all historic years was used. The upper portion of Table II-3 summarizes the underlying historic data that led to a modeling choice of the values highlighted in yellow. Seasonal diversity is used in the determination of World sub-region coincident peaks in evaluating the range of permissible World reserve margins seen in Table I-5.

Table II-3: Intra-World Load Diversity

Annual Diversity

Area	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	18 year avg*
WORLD	3.00%	2.26%	2.20%	3.50%	3.33%	2.73%	4.42%	6.12%	3.44%	2.19%	2.30%	2.71%	2.81%	1.98%	3.18%	3.42%	3.10%	2.74%	2.00%	3.02%
MISO	0.09%	0.00%	0.00%	1.75%	0.00%	0.75%	1.94%	7.82%	0.00%	1.23%	0.00%	0.22%	0.42%	0.00%	0.00%	2.24%	0.88%	0.88%	0.00%	0.96%
NY	2.33%	2.06%	3.08%	5.25%	4.17%	2.00%	7.08%	3.07%	4.89%	6.75%	5.25%	4.98%	6.11%	3.75%	3.87%	6.41%	7.45%	8.36%	7.70%	4.98%
VACAR	8.58%	4.58%	5.11%	5.12%	5.64%	4.83%	6.29%	6.24%	9.46%	1.07%	3.72%	5.24%	2.73%	4.94%	6.67%	3.20%	5.27%	3.28%	3.40%	5.02%
TVA	4.71%	5.22%	3.88%	4.57%	8.81%	5.69%	5.92%	4.66%	4.87%	2.32%	4.56%	4.41%	5.68%	2.92%	8.27%	4.01%	2.95%	3.74%	3.87%	4.79%

Monthly Diversity

Month Number	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Forecast Shape**
1	88.3%	87.8%	85.9%	84.3%	89.1%	84.0%	91.0%	84.1%	85.4%	85.7%	83.9%	89.0%	92.5%	85.3%	89.7%	89.4%	83.4%	83.7%	89.4%	87.9%
2	83.6%	83.7%	81.8%	79.9%	85.3%	80.1%	85.6%	80.4%	81.8%	82.1%	79.7%	84.3%	86.9%	81.6%	85.2%	84.4%	79.0%	79.9%	85.2%	82.3%
3	77.3%	77.9%	76.2%	74.8%	79.2%	74.8%	78.6%	75.3%	76.4%	76.3%	74.8%	77.8%	79.9%	76.4%	78.9%	77.9%	73.4%	74.9%	79.2%	76.6%
4	69.9%	70.0%	68.8%	68.1%	71.0%	68.2%	69.9%	68.4%	69.3%	68.5%	68.5%	69.5%	71.2%	69.3%	70.9%	69.9%	66.6%	68.0%	71.3%	69.2%
5	81.3%	80.5%	79.9%	79.4%	81.8%	79.5%	80.5%	79.5%	80.8%	79.3%	80.1%	80.0%	81.7%	80.3%	82.0%	80.8%	77.5%	79.6%	81.8%	80.1%
6	96.6%	95.6%	95.7%	95.4%	96.6%	95.2%	95.9%	95.4%	96.3%	94.8%	95.6%	95.8%	96.6%	95.9%	96.9%	96.1%	93.0%	95.8%	96.6%	95.9%
7	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	99.5%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	98.6%	**100.0%**	**100.0%**	**100.0%**
8	98.8%	99.9%	99.7%	99.2%	99.1%	99.7%	99.7%	99.4%	99.2%	**100.0%**	99.3%	99.3%	98.7%	99.1%	98.6%	99.3%	**100.0%**	99.5%	98.4%	99.6%
9	89.8%	90.5%	90.5%	90.2%	89.9%	90.3%	90.7%	90.3%	90.1%	91.4%	89.8%	90.3%	88.8%	89.7%	88.7%	90.2%	92.2%	90.4%	88.1%	90.5%
10	73.2%	73.6%	73.6%	73.7%	73.4%	73.1%	74.1%	73.6%	73.3%	74.7%	73.0%	73.6%	71.8%	72.9%	71.8%	73.5%	76.0%	73.5%	71.2%	73.3%
11	76.6%	76.1%	77.2%	76.5%	76.6%	75.4%	77.7%	76.2%	77.2%	77.7%	75.4%	76.2%	74.9%	76.3%	73.8%	76.4%	79.7%	76.3%	74.0%	76.4%
12	83.7%	81.9%	84.0%	82.9%	83.4%	81.3%	85.0%	82.6%	84.7%	84.3%	81.3%	81.9%	81.8%	83.0%	79.3%	82.3%	87.4%	82.5%	80.2%	82.7%

**Annual Diversity is used to convert reported Subarea forecasts to coincident values associated with the World peak*
***Forecast shape takes into account historical diversity, current World composition, and forecasted World Subarea growth*

Generation Forecasting

GADS, eGADS and PJM Fleet Class Average Values

The Generator Availability Data System (GADS) is a NERC-based program and database used for entering, storing, and reporting generating unit data concerning generator outages and unit performance. GADS data is used by PJM and other RTOs in characterizing and evaluating unit performance.

The PJM Generator Availability Data System (eGADS) is an Internet based application which supports the submission and processing of generator outage and performance data as required by PJM and the NERC reporting standards. The principal modeling parameters in the RRS are those that define the generator unit characteristics. All generation units' performance characteristics are derived from PJM's eGADS web based system. For detailed information on PJM Generation Availability Data System (GADS), see the eGADS' help selection available through the PJM site at: https://egads.pjm.com/pjmpgads/login.

The eGADS system is based on the IEEE Standard 762-2006. IEEE Standard 762-2006 is available by going to the IEEE web site: http://standards.ieee.org/findstds/standard/762-2006.html

The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting.

For units with missing or insufficient GADS data, PJM utilizes class average data developed from PJM's fleet-based historical unit performance statistics. This process is called blending. Blending is therefore used for future units, neighboring system units, and for those PJM units with less than five years of GADS events. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated.
The actual generator unit outage events are blended with the class average values according to the generator class category for that unit. For example, a unit that has three years' worth of its own reported outage history will have two years' worth of class average values used in blending. The statistics, based on the actual reported outage history, will be weighted by a factor of 3/5 and the class average statistics will be weighted by a factor of 2/5. The values are added together to get a statistical value for each unit that represents the entire five-year time period.

The class average categories are from NERC's Brochure while the statistics' values are determined from PJM's fleet of units. A five-year period is used for the statistics, with 73 unique generator class keys. The five-year period is based on the data available in the NERC Brochure or in PJM's eGADS, using the latest time period (2012-2016 for 2017 RRS). A generator class category is given for each unit type, primary fuel and size of unit. Furthermore, this five-year period is used to calculate the various statistics, including (but not limited to):

- Equivalent Demand Forced Outage Rate (EFORd)
- Effective Equivalent Demand Forced Outage Rate (EEFORd)
- Equivalent Maintenance Outage Factor (EMOF)
- Planned Outage Factor (POF)

The class average statistical values used in the reserve requirement study for the blending process are shown in Table II-4.

In Appendix B, Sensitivity number 15 shows that a 1% increase in the pool-wide EEFORd causes a 1.42% increase in the IRM – indicating a direct, positive correlation between unit performance and the IRM.

Generating Unit Owner Review of Detailed Model

The generation owner representatives are solicited to provide review and submit changes to the preliminary generation unit model. This review provides valuable feedback and increases confidence that the model parameters are the best possible for use in the RRS. This review improves the data integrity of the most significant modeling parameters in the RRS.

Forced Outage Rates: EFORd and EEFORd

All forced outages are based on eGADS reported events.

- Effective Equivalent Demand Forced Outage Rate (EEFORd) – This forced outage rate, determined for demand periods, is used for reliability and reserve margin calculations. There are traditionally three categories for GADS reported events: forced outage (FO), maintenance outage (MO) and planned outage (PO). The PRISM program can only model the FO and PO categories. A portion of the MO outages is placed within the FO category, while the other portion is placed with the PO category. In this way, all reported GADS events are modeled.

  For a more complete discussion of these equations see Manual 22 at:

  http://www.pjm.com/documents/~/media/documents/manuals/m22.ashx.
  The equation for the EEFORd is as follows:

  Equation II-1: Calculation of Effective Equivalent Demand Forced Outage Rate (EEFORd)

  $$\boxed{\mathbf{EEFORd = EFORd + (1/4 * EMOF)}}$$

  The statistic used for MO is the equivalent maintenance outage factor (EMOF).

- Equivalent Demand Forced Outage Rate (EFORd) – This forced outage rate, determined for demand periods, is used in reliability and reserve margin calculations. See Manual M-22 and RAA Schedule 4 and Schedule 5 for more specific information about defining and using this statistic. The EFORd forms the basis for the EEFORd and is the statistic used to calculate the unforced capacity (UCAP) value of generators in the marketplace.

Table II-4: PJM RTO Fleet Class Average Generation Performance Statistics (2013-2017)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	EFORd	EEFORd	XEFORd	POF Weeks/Year	EMOF	Variance
1/1/2013	12/31/2017	FOSSIL All Fuel Types All Sizes	1	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	FOSSIL All Fuel Types 001-099	2	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL All Fuel Types 100-199	3	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL All Fuel Types 200-299	4	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL All Fuel Types 300-399	5	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL All Fuel Types 400-599	6	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL All Fuel Types 600-799	7	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL All Fuel Types 800-999	8	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL All Fuel Types 1000 Plus	9	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary All Sizes	10	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	FOSSIL Coal Primary 001-099	11	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Coal Primary 100-199	12	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Coal Primary 200-299	13	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary 300-399	14	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary 400-599	15	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary 600-799	16	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary 800-999	17	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Coal Primary 1000 Plus	18	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil Primary All Sizes	19	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	FOSSIL Oil Primary 001-099	20	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Oil Primary 100-199	21	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Oil Primary 200-299	22	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil Primary 300-399	23	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil Primary 400-599	24	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil Primary 600-799	25	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil Primary 800-999	26	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Gas Primary All Sizes	28	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	FOSSIL Gas Primary 001-099	29	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Gas Primary 100-199	30	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Gas Primary 200-299	31	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Gas Primary 300-399	32	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Gas Primary 400-599	33	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Gas Primary 600-799	34	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Gas Primary 800-999	35	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Lignite Primary All Sizes	37	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	NUCLEAR All Types All Sizes	38	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR All Types 400-799	39	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR All Types 800-999	40	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR All Types 1000 Plus	41	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR PWR All Sizes	42	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR PWR 400-799	43	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR PWR 800-999	44	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR PWR 1000 Plus	45	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR BWR All Sizes	46	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR BWR 400-799	47	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR BWR 800-999	48	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR BWR 1000 Plus	49	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	NUCLEAR CANDU All Sizes	50	1.398%	1.617%	1.333%	3	0.480	17312
1/1/2013	12/31/2017	JET ENGINE All Sizes	51	13.059%	13.498%	11.014%	2	1.210	446
1/1/2013	12/31/2017	JET ENGINE 001-019	52	18.151%	18.594%	16.894%	1	1.362	26
1/1/2013	12/31/2017	JET ENGINE 20 Plus	53	13.741%	14.297%	10.831%	2	1.332	158
1/1/2013	12/31/2017	GAS TURBINE All Sizes	54	13.059%	13.498%	11.014%	2	1.210	446
1/1/2013	12/31/2017	GAS TURBINE 001-019	55	18.151%	18.594%	16.894%	1	1.362	26
1/1/2013	12/31/2017	GAS TURBINE 020-049	56	13.741%	14.297%	10.831%	2	1.332	158
1/1/2013	12/31/2017	GAS TURBINE 50 Plus	57	9.590%	9.955%	7.621%	3	1.043	878
1/1/2013	12/31/2017	COMBINED CYCLE All Sizes	58	4.403%	4.892%	3.545%	5	1.034	2548
1/1/2013	12/31/2017	HYDRO All Sizes	59	13.603%	14.356%	12.237%	1	2.135	40
1/1/2013	12/31/2017	HYDRO 001-029	60	13.603%	14.356%	12.237%	1	2.135	40
1/1/2013	12/31/2017	HYDRO 30 Plus	61	13.603%	14.356%	12.237%	1	2.135	40
1/1/2013	12/31/2017	PUMPED STORAGE All Sizes	62	2.317%	2.721%	1.700%	4	0.930	3081
1/1/2013	12/31/2017	MULTIBOILER/MULTI-TURBINE All Sizes	63	13.059%	13.498%	11.014%	2	1.210	446
1/1/2013	12/31/2017	DIESEL Landfill	64	18.884%	18.536%	18.462%	0	0.448	2
1/1/2013	12/31/2017	DIESEL All Sizes	65	8.490%	9.166%	7.928%	0	1.740	1
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary All Sizes	66	12.123%	13.072%	11.493%	4	1.982	18414
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 001-099	67	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 100-199	68	12.581%	13.313%	11.815%	3	1.542	2125
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 200-299	69	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 300-399	70	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 400-599	71	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 600-799	72	11.968%	13.161%	11.429%	5	2.484	26979
1/1/2013	12/31/2017	FOSSIL Oil/Gas Primary 800-999	73	9.607%	13.161%	9.486%	5	2.484	26979
1/1/2013	12/31/2017	Wind All Sizes	74	0.000%	0.000%	0.000%	0	0.000	0
1/1/2013	12/31/2017	Solar All Sizes	75	0.000%	0.000%	0.000%	0	0.000	0

Table II-5: Comparison of Class Average Values - 2017 RRS vs. 2018 RRS

Unit Type & Primary Fuel Category	Gen Class Key	EFORd Change	EEFORd Change	XEFORd Change	POF Change Weeks/Year	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
FOSSIL All Fuel Types 001-099	2	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL All Fuel Types 100-199	3	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL All Fuel Types 200-299	4	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL All Fuel Types 300-399	5	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL All Fuel Types 400-599	6	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL All Fuel Types 600-799	7	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL All Fuel Types 800-999	8	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL All Fuel Types 1000 Plus	9	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL Coal Primary All Sizes	10	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
FOSSIL Coal Primary 001-099	11	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Coal Primary 100-199	12	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Coal Primary 200-299	13	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Coal Primary 300-399	14	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Coal Primary 400-599	15	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Coal Primary 600-799	16	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Coal Primary 800-999	17	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL Coal Primary 1000 Plus	18	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL Oil Primary All Sizes	19	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
FOSSIL Oil Primary 001-099	20	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Oil Primary 100-199	21	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Oil Primary 200-299	22	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil Primary 300-399	23	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil Primary 400-599	24	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil Primary 600-799	25	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil Primary 800-999	26	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL Gas Primary All Sizes	28	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
FOSSIL Gas Primary 001-099	29	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Gas Primary 100-199	30	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Gas Primary 200-299	31	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Gas Primary 300-399	32	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Gas Primary 400-599	33	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Gas Primary 600-799	34	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Gas Primary 800-999	35	0.86%	0.18%	0.85%	-0.01	0.01	633
FOSSIL Lignite Primary All Sizes	37	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
NUCLEAR All Types	38	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR All Types	39	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR All Types	40	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR All Types	41	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR PWR All Sizes	42	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR PWR 400-799	43	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR PWR 800-999	44	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR PWR 1000 Plus	45	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR BWR All Sizes	46	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR BWR 400-799	47	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR BWR 800-999	48	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR BWR 1000 Plus	49	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
NUCLEAR CANDU All Sizes	50	-0.20%	-0.21%	-0.18%	-0.15	-0.03	-2513
JET ENGINE All Sizes	51	-0.31%	-0.28%	-0.07%	0.23	0.03	3
JET ENGINE 001-019	52	0.67%	0.71%	0.45%	0.08	-0.01	0
JET ENGINE 20 Plus	53	-1.24%	-1.18%	-0.60%	0.22	0.10	-4
GAS TURBINE All Sizes	54	-0.31%	-0.28%	-0.07%	0.23	0.03	3
GAS TURBINE 001-019	55	0.67%	0.71%	0.45%	0.08	-0.01	0
GAS TURBINE 020-049	56	-1.24%	-1.18%	-0.60%	0.22	0.10	-4
GAS TURBINE 50 Plus	57	-0.17%	-0.17%	0.04%	0.31	0.02	-7
COMBINED CYCLE All Sizes	58	-0.33%	-0.30%	-0.34%	0.09	-0.10	-26
HYDRO All Sizes	59	-0.43%	2.03%	-0.21%	0.03	-0.01	3
HYDRO 001-029	60	-0.43%	2.03%	-0.21%	0.03	-0.01	3
HYDRO 30 Plus	61	-0.43%	2.03%	-0.21%	0.03	-0.01	3
PUMPED STORAGE All Sizes	62	-0.19%	-0.12%	-0.20%	0.01	0.05	-689
MULTIBOILER/MULTI-TURBINE All Sizes	63	-0.31%	-0.28%	-0.07%	0.23	0.03	3
DIESEL Landfill	64	0.92%	0.91%	0.97%	0.00	-0.04	0
DIESEL All Sizes	65	0.56%	1.79%	0.45%	-0.01	-0.07	0
FOSSIL Oil/Gas Primary All Sizes	66	-0.08%	0.13%	-0.02%	-0.03	0.04	1330
FOSSIL Oil/Gas Primary 001-099	67	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Oil/Gas Primary 100-199	68	-0.30%	0.01%	-0.28%	-0.10	0.02	465
FOSSIL Oil/Gas Primary 200-299	69	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil/Gas Primary 300-399	70	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil/Gas Primary 400-599	71	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil/Gas Primary 600-799	72	0.09%	0.18%	0.23%	-0.01	0.01	633
FOSSIL Oil/Gas Primary 800-999	73	0.86%	0.18%	0.85%	-0.01	0.01	633
Wind All sizes	74	0.00%	0.00%	0.00%	0.00	0.00	0
Solar All sizes	75	0.00%	0.00%	0.00%	0.00	0.00	0

Fleet-based Performance by Primary Fuel Category

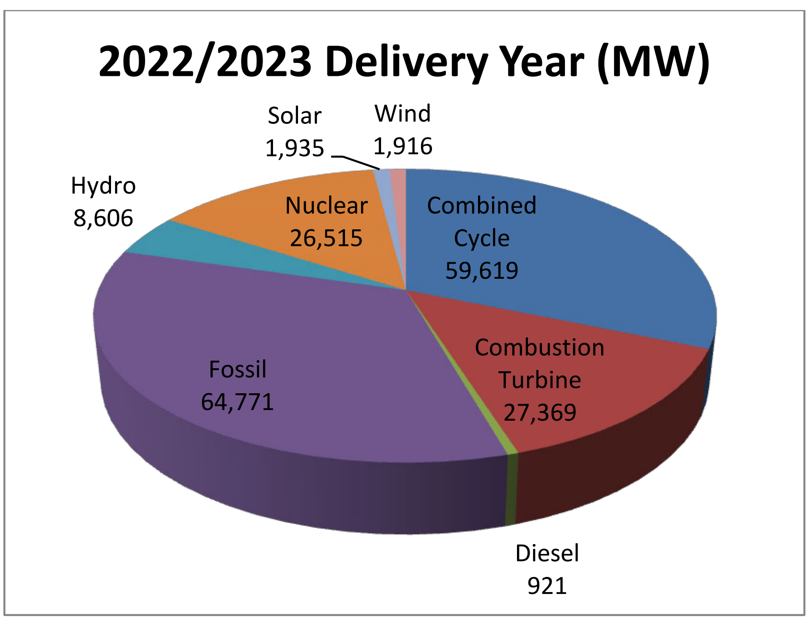
The PJM RTO fleet of units is summarized, by primary fuel, in Table II-6 for the 2022/2023 delivery year. This summary reflects the blending process discussed above to determine the table values. This summary also uses the summer net dependable rating (SND) of all units.

The outage rate and actual capacity for wind and solar units, however, reflects the PJM stakeholder process modeling, not actual outage event data. This modeling assigns a forced outage rate of 0% to solar and wind units and an ICAP value equal to the wind and solar unit's capacity credit. The capacity credit is calculated as per PJM Manual 21. Figure II-1 shows all PJM RTO capacity by fuel type for the 2022/2023 Delivery Year.

Table II-6: PJM RTO Fleet-based Unit Performance

2022/2023 Delivery Year	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Combined Cycle	229	59,619	31.3%	4.52%	347
Combustion Turbine	424	26,278	13.8%	9.32%	610
Diesel	194	921	0.5%	13.00%	0
Fossil	214	64,771	34.0%	10.53%	1,399
Hydro	199	8,606	4.5%	4.98%	148
Nuclear	26	26,515	13.9%	1.56%	0
Solar	205	1,935	1.0%	0.00%	0
Wind	108	1,916	1.0%	0.00%	0
PJM RTO Total	**1599**	**190,561**	**100.00%**	**6.66%**	**2,504**

Figure II-1: PJM RTO Capacity



Modeling of Generating Units' Ambient Deratings

Per the approved rules in place for PJM Operations, Planning and Markets, a unit can operate at less than its SND rating and still not incur a GADS outage event. All modeled units' performance statistics are based on eGADS submitted data. The ambient derate modeling assumption, in addition to the eGADS data, allow all observed outages to be modeled in the RRS.

Derating certain generating units in the RRS is included to capture the limited output from certain generators caused by more extreme-than-expected ambient weather conditions (hot and humid summer conditions).

In the 2018 RRS, 2,500 MW of ambient derates in the peak summer period were modeled via planned outage maintenance. This modeling assumption was developed in early 2016 by analyzing Summer Verification Test data from 2013-2015. The impact of this assumption is an increase in the IRM of 1.37%.

Units on planned outage maintenance representing ambient derates were selected based on average characteristics of the types of units affected. PJM will continue to assess the impact of these ambient weather conditions on generator output.

Generation Interconnection Forecast

The criterion to include planned generation units was modified in last year's study. In previous years, each unit in the interconnection queue was included in the model, using a commercial probability to adjust each unit's size. The criterion has been changed to include in the model only interconnection queue units with a signed Interconnection Service Agreement (ISA) without further adjustments to each unit's size (in other words, a commercial probability of 100% is assumed for these units).

The change in the criterion for planned generation units was introduced to match the assumptions in the Capacity Emergency Transfer Objective (CETO) studies. Furthermore, a signed ISA is the final milestone in the PJM Interconnection Queue process; historically, a large proportion of the units achieving this milestone have ultimately ended up as in-service units.

For informational purposes only, Table II-7 shows the Average Commercial Probabilities for the projects in each of the Stages in the PJM interconnection queue. The commercial probabilities are calculated for each unit using a logistic regression model fitted to historical data (queues 'T' and after). The logistic regression models include predictors such as current stage in the queue (feasibility, impact, facilities, interconnection service agreement (ISA)), unit type (coal, gas, wind, etc.), location (US State), project type (new or uprate) and unit size (in MW).

Table II-7: Average Commercial Probabilities for Expected Interconnection Additions

Queue Stage	Average Commercial Probability
In the Queue, up to Feasibility Study Stage	6%
All of the above, plus Impact Study Completed	25%
All of the above, plus Facilities Study Completed	43%
All of the above and ISA executed	79%
Successful Completion	100%

Transmission System Considerations

PJM Transmission Planning (TP) Evaluation of Import Capability

PJM's Transmission Planning Staff performs the yearly Capacity Import Limit study to establish the amount of power that can be reliably transferred to PJM from outside regions (details of this study can be found in PJM's Manual 14b Attachment G). Although the PJM RTO has the physical capability of importing more than the 3,500 MW Capacity Benefit Margin (CBM, defined below), the additional import capability is reflected in Available Transfer Capability (ATC) through the OASIS postings and not reserved as CBM. This allows for the additional import capability to be used in the marketplace.

The use of CBM (on an annual basis) in this study is consistent with the time period of the RF criteria, and the Reliability Assurance Agreement, Schedule 4.

Capacity Benefit Margin (CBM)

The CBM value of 3,500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. The CBM is the amount of import capability that is reserved for emergency imports into PJM. As a sensitivity case for this study, the CBM was varied between 0 MW and 15,000 MW. The relationship of IRM with CBM is graphically depicted in Figure I-7. A decrease in the CBM from 3,500 MW to 0 MW increases the pool's reserve requirement by about 1.5%. This value is influenced by the amount of PJM-World load diversity, and the World reserve level.

Per an effective date of April 1, 2011 concerning capacity benefit margin implementation documentation, compliant with NERC MOD Standard MOD-004-1, PJM staff has developed a CBM Implementation document (CBMID) that meets or exceed the NERC Standards, and NAESB Business Practices. This document is part of the PJM compliance efforts and is available via the PJM stakeholder process by contacting regional_compliance@pjm.com .

Capacity Benefit of Ties (CBOT)

The CBOT is a measure of the reliability value that World interface ties bring into the PJM RTO. The CBOT is the difference between an RRS run with a 3,500 MW CBM and an RRS run with a 0 MW CBM. The CBOT result was 1.51% of the PJM forecasted load or roughly 2,696 MW of installed capacity. The CBOT is directly affected by the PJM/World load diversity in the model (more diversity results in a higher CBOT) and the availability of assistance in the World area. Firm capacity imports, which are treated as internal capacity, are not part of the CBOT. The CBOT is a mathematical expectation related to the total 3,500 CBM value. The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor.

Coordination with Capacity Emergency Transfer Objective (CETO)

CETO studies assumptions are consistent with RRS assumptions due to marketplace requirements and to ensure the validity of the RRS assumption stating that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load. By passing the load deliverability test, wherein CETO is one of the main components, this assumption is validated. See PJM Manual 14 B, attachment C for details on the Load Deliverability tests and refer to the RPM website cited in the RPM section for specific analysis details and results: http://pjm.com/markets-and-operations/rpm.aspx.

OASIS postings

The value of CBM is directly used in the various transmission path calculations for Available Transfer Capability (ATC). See the OASIS web site, specifically the ATC section for further specifics: http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx

Modeling and Analysis Considerations

Generating Unit Additions / Retirements

Planned generating units in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value. Table II-8 gives a summary of the generator additions and retirements as modeled in the 11 year RRS model.

Table II-8: New and Retiring Generation within PJM RTO

Zone Name	Total Additions/Changes (MW)	Retirements (MW)	Total
AE	1,220	150	1,070
AEP	2,010	0	2,010
APS	5,260	1,280	3,980
ATSI	2,910	2,910	0
BGE	0	120	-120
ComEd	150	0	150
Dayton	20	0	20
DLCO	100	1,810	-1,710
DomVP	2,830	900	1,930
DPL	460	0	460
DUKE	80	0	80
EKPC	0	0	0
JCPL	500	610	-110
METED	560	800	-240
PECO	940	50	890
PEPCO	1,730	0	1,730
PN	1,310	110	1,200
PPL	2,390	0	2,390
PSEG	510	0	510
Grand Total	**22,980**	**8,740**	**14,240**

World Modeling

This data is publicly available through the NERC Electric and Supply Database – and is a compilation of all the EIA-411 data submissions. Per the June study assumptions, approved at the June 2018 PJM Planning Committee meeting, each of the individual regions was modeled at its required reserve requirement. The world region immediately adjacent to the PJM RTO was deemed to be the most appropriate region to use in the study, per previous RRS assessments. Modeling the immediately adjacent region helps to address concerns for deliverability of outside world resources to the PJM RTO border.

Among the regions included in the World, only New York and MISO have a firm reserve requirement target. For these regions, their latest published reserve requirements were used for the delivery years of this study. For the TVA and VACAR sub regions of SERC, a reserve target of 15% was used; this is consistent with NERC's modeling for assessment purposes.

Figure II-2: PJM and Outside World Regions - Summer Capacity Outlook

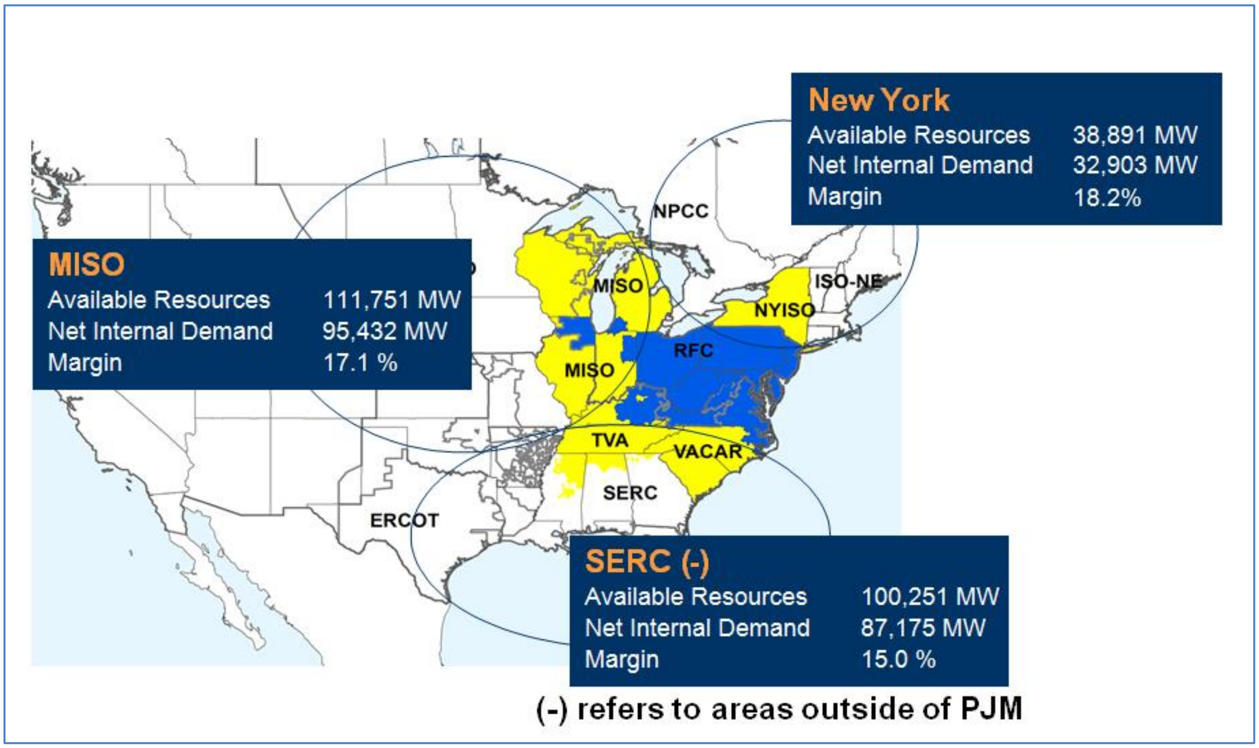


Figure II-2 depicts the assumed capacity summer outlook within each of the Outside World regions that are adjacent to PJM for the delivery year 2018. The West region includes most of MISO (except MISO-South). The SERC (-) region includes the World zones: TVA and VACAR (excluding Dominion which is part of PJM).

Expected Weekly Maximum (EWM), LOLE Weekly Values, Convolution Solution, IRM Audience

The Expected Weekly Maximum value (EWM) is the peak demand used by the PRISM program to calculate the loss of load expectation (LOLE). Both the EWM and LOLE are important values to track in assessing the study results. From observing these values over several historic studies, 99.9% of the risk is concentrated within a few weeks of the summer period. It is these summer weeks that have the highest EWM values (Refer to "PJM Generation Adequacy Technical Methods" and PJM Manual 20, for clarification and specifics of how the EWM is used and the resulting weekly LOLE). The EWM value is calculated per the following equation:

Equation II-2: Expected Weekly Maximum

$$EWM_X = \mu_X + 1.16295 * \sqrt{\sigma_X^2 + FEF^2}$$

Where:

μ_X = Weekly Mean,

1.16295 = A Constant, the Order Statistic when n=5

σ_X^2 = Weekly variance

FEF = Forecast Error Factor, for given delivery Year

x ranges from 1 to 52

In Figure II-3, the following EWM pattern can be seen for the PJM RTO and World regions. For all weeks not shown, the weekly LOLE approaches zero. The EWM pattern for PJM and the World in this year's study (blue line) are almost identical to the patterns observed in the 2017 RRS (dashed blue line).

Figure II-3: Expected Weekly Maximum Comparison – 2017 RRS vs. 2018 RRS

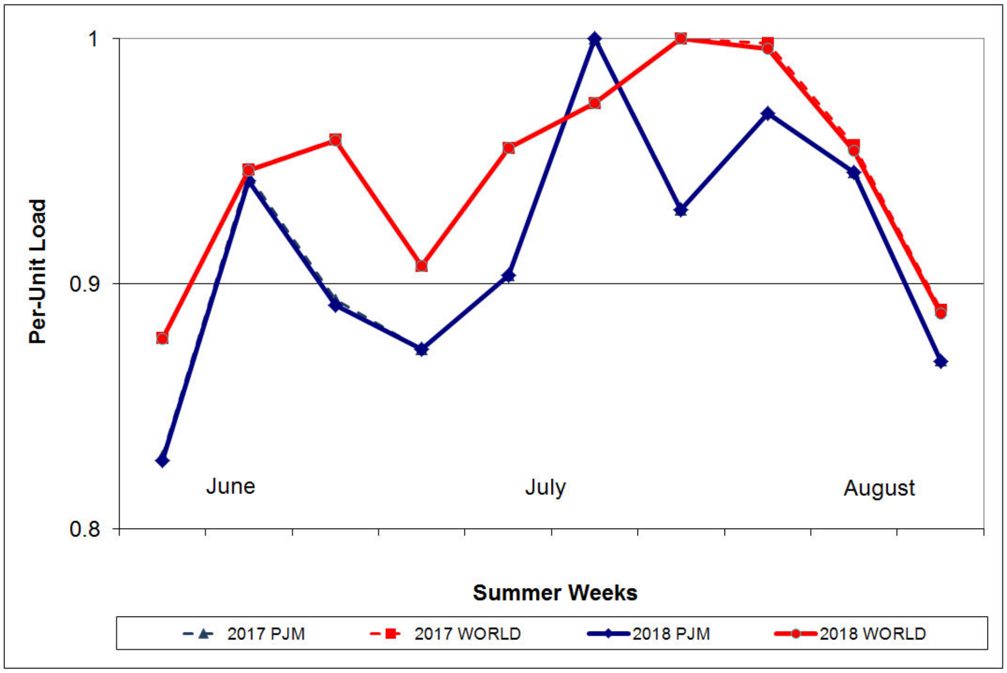


Figure II-4 shows the weekly share of Loss of Load for the PJMRTO in the 2017 RRS and 2018 RRS. No major differences in the weekly share of LOLE are observed between the two studies.

Figure II-4: PJMRTO LOLE Comparison 2017 RRS vs. 2018 RRS

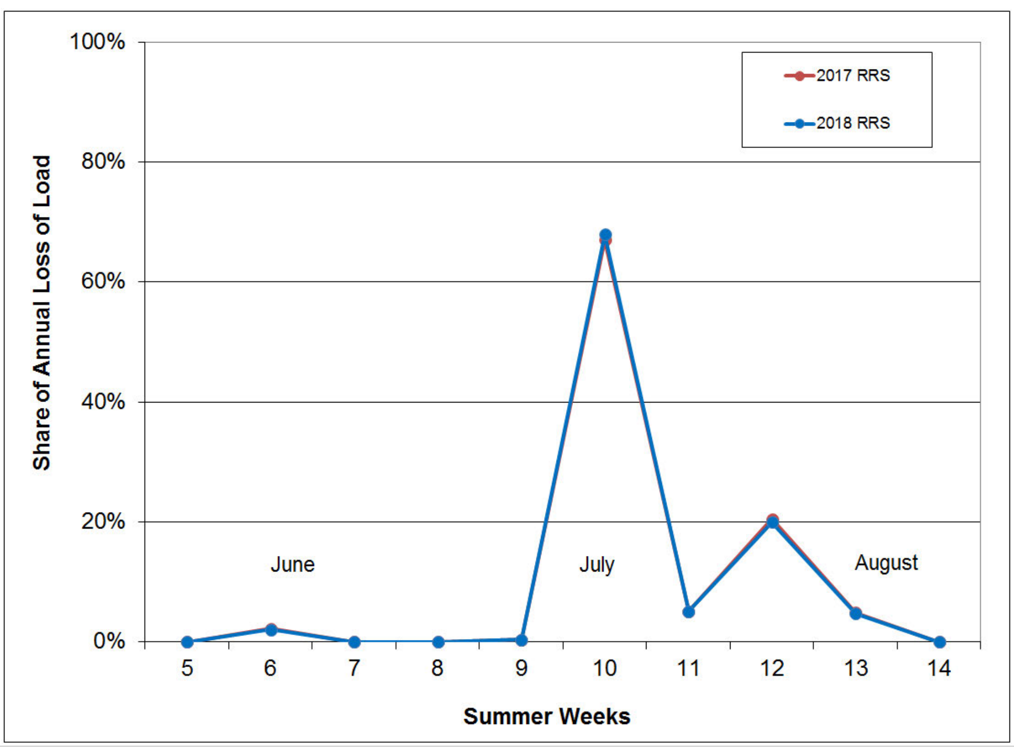
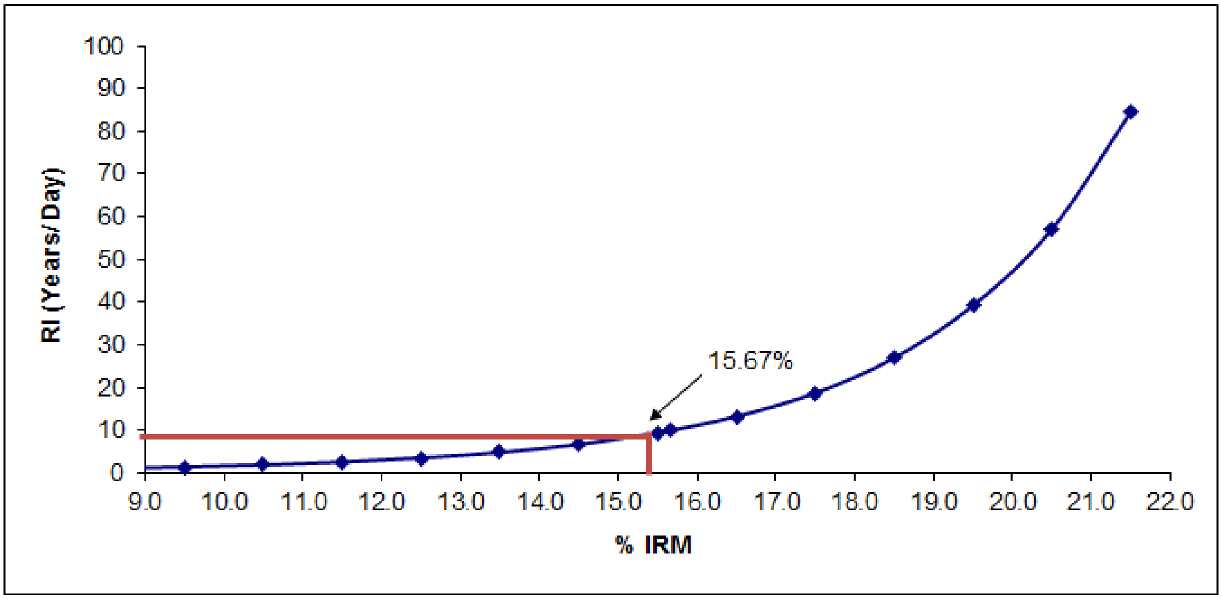


Figure II-5 shows how the PJM Reliability Index (RI) varies with the installed reserve margin. The plot is constructed by running a one area study, manually varying the PJM RTO reserve levels while assuming a constant CBOT at 1.5%. It can be observed that a reserve level of about 15.7% yields a loss of load event once every ten years.

Figure II-5: Installed Reserve Margin (IRM) vs. RI (Years/Day)



Standard BAL-502-RFC-02 clarification items

To provide clarity concerning several items in the Standard BAL-502-RFC-02 requirement section R1 titled "The planning Coordinator shall perform and document a Resource Adequacy analysis annually", the following is supplied:

R1.3.3.1 The criteria for including planned Transmission facilities: This is given in the RTEP assessments. The RTEP is overseen by the Transmission Expansion Advisory Committee (TEAC), a stakeholder group within the PJM committee structures. The Planning Committee also can establish and recommend appropriate criteria to be used for transmission facilities. See the Transmission System Considerations section for further details. The Criteria for inclusion of planned transmission facilities is given in the meeting minutes and presentations of the TEAC, PC, and the PJM manuals 14 A - E. The RRS is closely coordinated and integrated with these RTEP analyses, and with the decisions by the PC and TEAC as all are parts of the PJM Planning division efforts.

R1.4 Availability and Deliverability of fuel: An adhoc assessment was completed in July 2003, titled "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector" addresses this topic. The Executive Summary of this report, pages v – xviii, provides the results of this assessment. This is a confidential report.

R1.4 Common Mode Outages that affect resource availability: The report, "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector", address this issue in part. In general, these types of outages are considered by discrete modeling, with most outages assumed to be independent events. The assumption of independent outage events applies to both the resource and load models and avoids any need for a matrix of covariance states. The solution techniques for including a covariance matrix are considered not practically possible (long solution times). The Industry standard in the known solution methods is to make the assumption of independence for all outage events, treating any common mode outages by discrete modeling techniques. For example, for a "run of river" issue, more planned outages are modeled over the critical summer peak weeks due to several units using the same water source (same river). However, care should be used in drawing conclusions from the assumption for independence in the 21 point daily peak calculations. For example, there are steps involved in developing the load model parameters that do incorporate a correlation, particularly for the adjusted mean and standard deviations for each week. From a conceptual perspective this allows similar relationships, as those that exist in the development of the load forecast values, which allows the model to establish relationships between the weeks, such as magnitude ranking of weeks and the adjustment due to the load forecast monthly shape. The assumption of independence, understanding all the associated complexities, is implemented in the RRS modeling and calculation methods, which includes modeling of appropriate discrete common mode outage scenarios.

In addition, this report's assessment of the winter weekly reserve target is meant to address a common mode failure experienced in the Mid-Atlantic region, when several generating units experienced outages due to a region wide ice storm in the winter of 1994.

R1.4 Environmental or regulatory restrictions of resource availability: In the Generation Forecasting section, it is discussed that the resource performance characteristics are primarily modeled per the PJM manuals, 21, 22. In the eGADS reporting, there is consideration and methods to account for both environmental and regulatory restrictions. The RRS modeling of resources uses performance statistics, directly from these reported events. Both discrete modeling techniques and sensitivity analysis are performed to gain insights about impacts concerning environmental or regulatory restrictions. In the modeling of resources this can reduce the rating of a unit impacted by this type of restriction. The RRS model is coordinated with the Capacity Injection Rights (CIR) for each unit, which can be affected by these restrictions.

R1.4 Any other demand response programs not included in the load forecast characteristics: All load modeled and its characteristics are part of R1.3.1, per BAL-502-RFC-02. There are no other load response programs in the RRS model.

R1.4 Market resources not committed to serving load: In general, all resources modeled have capacity injection rights, are part of the EIA-411 filing and coordinated with the RTEP Load deliverability tests, documented in PJM Manual 14 B, attachment C. In addition, coordination with the RPM capacity market modeling is performed. An example of this is allowing the modeling of Behind-The-Meter (BTM) units, per the modeling assumptions. See Appendix A for further details regarding BTM modeling (See Manual M19, page 12; Manual 14D, Appendix A).

R1.5 Transmission maintenance outage schedules: Discussed in the Transmission System Considerations section is the coordination with the RTEP process and procedures. This issue is specifically addressed in the load deliverability tests, as discussed in this section. The CETO analysis is closely coordinated with the RRS modeling and report, and is fundamental to addressing and verifying the assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load.

Standard MOD - 004 - 01, requirement 6, clarification items

Capacity Benefit Margin (CBM) is established per the Reliability Assurance Agreement (RAA) section 4 and used in Planning Division studies and assessments. The Regional Transmission Expansion Planning Process (RTEP) provides a 15 year forecast period while the reserve requirement study provides an 11 year forecast period. Each individual year of these periods (15 and 11) are assessed. The RTEP and Reserve Requirement Study (RRS) are performed on an annual basis.

The RTEP and the RRS processes use full network analysis. Available Transmission Capability (ATC) and Flowgate analysis disaggregates the full network model in the short term (daily, weekly, monthly through month 18) as a proxy for full network analysis. The Available Flowgate Capability (AFC) calculator applies the impacts of transmission reservations (or schedules as appropriate) and calculates the AFC by determining the capacity remaining on individual flowgates for further transmission service activity. The disaggregated model used for the AFC calculation provides faster solution time than the full network model. The RTEP assessment is coordinated with the CBM, shown in the RAA, by its use of Capacity Emergency Transfer Objective (CETO) and load forecast modeling. CETO requirements are based on Loss of Load Expectation (LOLE) requiring appropriate aggregation of import paths for a valid statistical model.

Evidence:

- Annual RTEP baseline assessment report http://www.pjm.com/planning/rtep-development/baseline-reports.aspx

- Reliability Assurance Agreement (http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx)
- Annual RRS report(s) http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx
    - CETO load deliverability studies
    - Section 4, Manual 20 (http://www.pjm.com/~/media/documents/manuals/m20.ashx)
    - Section C.4, Manual 14B (http://www.pjm.com/~/media/documents/manuals/m14b.ashx)
- AFC/ATC calculations, Section 2 and 3 of PJM Manual 2 http://www.pjm.com/~/media/documents/manuals/m02.ashx

RPM Market

The Reliability Pricing Model (RPM) is the PJM's forward capacity market program that was implemented on June 1, 2007. The RPM requires the following input values derived from the RRS: IRM and FPR.

PJM's web based application, eRPM, is used to perform capacity transactions in the market place. The planning parameters derived from the RRS that are used in RPM are available at: http://www.pjm.com/markets-and-operations/rpm.aspx

IRM and FPR

The Installed Reserve Margin (IRM) is a percentage which represents the amount of installed capacity required above the forecast restricted 50/50 peak load demand. It is the buffer above expected peak load required to meet the reliability criterion. The IRM is a key input used to determine Load Serving Entity (LSE) capacity obligations. Calculation of the IRM is necessary to the determination of the Forecast Pool Requirement (FPR). The PRISM model adjusts the load level until it finds the solution load that meets the one day in ten years reliability standard. The IRM is calculated based on this solution load, for the peak day (which is also the peak week), using the installed capacity for that week in the numerator and the solution load in the denominator.

The FPR is a multiplier that converts load values into capacity obligation. The FPR has two necessary inputs to determine its value: the IRM and the PJM RTO pool-wide EFORd (equivalent demand forced outage rate). The FPR is defined by the following equation:

Equation II-3: Calculation of Forecast Pool Requirement (FPR)

$$\boxed{\text{FPR} = (1 + \text{Approved IRM}) * (1 - \text{PJM Avg. EFORd})}$$

The IRM and the FPR therefore represent identical levels of reserves expressed in different units. The IRM is expressed in units of installed capacity (or ICAP) whereas the FPR is expressed in units of unforced capacity (or UCAP). Unforced capacity is defined in the RAA to be the megawatt (MW) level of a generating unit's capability after removing the effect of forced outage events[1].

The capacity obligation associated with a particular PJM zone is an allocation of RTO resources procured in the RPM auction. The obligation is expressed in units of unforced capacity.

PJM's objectives are to establish an IRM that preserves reliability while not imposing an undue cost on load to pay for unnecessary generation reserves. PJM has used judgment in past recommendations for establishing an FPR due to some of the uncertainties associated with the current unforced capacity structure.

[1] This definition of Unforced Capacity largely applies to non-intermittent generators. For the purposes of this report, the UCAP value of an intermittent generator (such as wind or solar) is equal to its ICAP value, which in turn is equal to its capacity credit. The capacity credit is calculated as per PJM's Manual 21.

Operations Related Assessments

Winter Weekly Reserve Target Analysis

PJM calculates a Winter Weekly Reserve Target (WWRT) for each of the months in the 2018 / 2019 winter period (December 2018, January 2019 and February 2019). The WWRT is established to cover against uncertainties associated with load and forced outages during these winter months. It accomplishes this by ensuring that the total winter LOLE is practically zero. This year, PJM Staff recommends the values shown in Table II-9. The recommended values are required to be integers due to computer application requirements.

Table II-9: Winter Weekly Reserve Target

Month	WWRT
December 2018	22%
January 2019	28%
February 2019	24%

The procedure implemented to calculate the values in Table II-9 considers the following steps:

Step 1: Using GE-MARS, set up an RRS case with an annual LOLE equal to 0.1 days/year.
Step 2: In addition to the required planned maintenance schedule, simulate additional planned maintenance during each week of the three winter months until the annual LOLE is worse than 0.1 days/year.
Step 3: Calculate the available reserves in each of the winter weeks as a percentage of the corresponding monthly peak.
Step 4: The WWRT for each month is the highest weekly reserve percentage (rounded up to the next integer value).

Table II-10 shows the weekly available reserves that result from applying the above procedure.

Table II-10: Weekly Available Reserves in WWRT Analysis

Month	% Available Reserves	Max % Available Reserves (by Month)
December	17.86%	22%
	21.71%	
	21.98%	
	10.00%	
January	19.66%	28%
	12.74%	
	24.43%	
	27.22%	
February	20.08%	24%
	23.73%	
	18.70%	
	14.84%	

Monthly WWRT values were introduced for the first time in the 2016 RRS with the objective of addressing the larger load uncertainty in January compared to February and December. Prior to the 2016 RRS, the WWRT was a single value that applied to the entire winter season. Historically, January is the month where the PJM Winter peak is most likely to occur and also the winter month that historically has exhibited more peak load variability.

With this recommendation, the PJM Operations Department will coordinate generator maintenance scheduling over the winter period seeking to preserve a 22% margin in December 2018, 28% margin in January 2019 and 24% margin in February 2019 after units on planned and maintenance outages are removed**.** These margins are guides to be used by PJM Operations and are not an absolute requirement.

III. Glossary

Adequacy

The ability of a bulk electric system to supply the aggregate electric demand and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. One part of the Reliability term.

AEP

American Electric Power (AEP) is an Ohio-based company and control area within the RF that was integrated into the PJM footprint on October 1, 2004. AEP is located in the middle of the PJM RTO region. (http://www.aep.com/)

Allegheny Energy

Allegheny Energy, previously called the Allegheny Power System (APS), is a Pennsylvania-based control area within RF that was integrated into the PJM footprint on April 1, 2002. APS is adjacent to the western portion of the PJM Mid-Atlantic (PJMMA) region. (http://www.alleghenyenergy.com/)

American Transmission System Incorporated (ATSI)

American Transmission System Incorporated is a subsidiary of the FirstEnergy Corporation. The control areas within this system include four major companies: Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company and Pennsylvania Power Company. ATSI has Ohio and Pennsylvania-based control areas within RF, which integrated into the PJM footprint on June 1, 2011. ATSI is adjacent to the western portion of the PJM Mid-Atlantic (PJMMA) region. (http://www.firstenergycorp.com/feconnect/index.html)

Available Transfer Capability (ATC)

Available Transfer Capability (ATC) is the amount of energy above base case conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM RTO under specified system conditions. ATC is the First Contingency Incremental Transfer Capability (FCITC) reduced by applicable margins.

BPS

The Bulk Power System (BPS) refers to all generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. The BPS also includes the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area. As defined by the Regional Reliability Organization, the BPS is the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BRC

The PJM Board of Managers' Board Reliability Committee (BRC) is made up of PJM board members who conduct activities to review and assess reliability issues to bring to the full board of managers. The BRC is one of the groups that review the RRS report in the process to establish a FPR.

Capacity

The amount of electric power (measured in megawatts) that can be delivered to both firm energy to load located electrically within the PJM Interconnection and firm energy to the border of the PJM Control Area for receipt by others. Installed capacity and Unforced capacity are related measures of this quantity.

Capacity Benefit Margin (CBM)

Capacity Benefit Margin (CBM), expressed in megawatts, is the amount of import capability that is reserved for the emergency import of power to help meet LSE load demands during peak conditions and is excluded from all other firm uses.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a sub area of PJM to satisfy the RF's resource adequacy requirement of loss of load expectation. This assessment is done in a coordinated and consistent manner with the annual RRS, but is an independent evaluation. The CETO value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the sub area's actual import capability as determined from power flow studies. The sub area satisfies the criteria if its CETL is equal to or exceeds its CETO. PJM's CETO/CETL analysis is typically part of the PJM's deliverability demonstration. See Manual 20 section 4, and Manual 14B, attachment C for details.

Capacity Performance (CP)

Capacity product created within the RPM framework for 2018/2019 DY and subsequent DYs. CP is a more robust product than the capacity products available in auctions for DYs prior to 2018/2019 since it is required to provide enhanced performance during peak conditions. Additional information on CP can be found at
http://www.pjm.com/directory/etariff/FercDockets/1368/20141212-er15-623-000.pdf

ComEd

Commonwealth Edison (ComEd) is an Illinois-based control area within the RF that was integrated into the PJM footprint on May 1, 2004. ComEd is located on the western edge of the PJM RTO region. (http://www.exeloncorp.com/)

Control Area (CA)

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- Match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- Maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- Provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Dayton

Dayton Power and Light (Dayton), is an Ohio-based control area within RF that was integrated into the PJM footprint on October 1, 2004. The Dayton control area is adjacent to the western portion of the AEP region. (http://www.dpandl.com/)

Delivery Year (DY)

The Delivery Year (DY) is the twelve-month period beginning on June 1 and extending through May 31 of the following year. As changing conditions may warrant, the Planning Committee may recommend other Delivery Year periods to the PJM Board of Managers. In prior studies, the DY was formerly referred to as the “Planning Period”.

Deliverability

Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver generation capacity from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) Generation Deliverability; and (2) Load Deliverability.

Demand Resource (DR)

A resource with the capability to provide a reduction in demand. DR is a component of PJM’s Load Management (LM) program. The DR is bid into the RPM Base Residual Auction (BRA). See Load Management (LM).

Demand Resource (DR) Factor

Ratio of LM aggregate Load Carrying Capability (LCC) to total amount of LM in PJM. The LM LCC is determined by modeling LM in the PJM reliability program. The DR Factor is reviewed and changed, if necessary, each planning period by the PJM Board for use in determining the capacity credit for DR and Interruptible Load for Reliability (ILR). The use of the DR Factor was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Demand

The rate at which electrical energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand is equal to load when integrated over a given period of time. See Load.

Diversity

Diversity is the difference of the sum of the individual maximum demands of the various subdivisions of a system, or part of a system, to the total connected load on the system, or part of the system, under consideration. The two regions modeled in the RRS are the PJM RTO and the surrounding World region. If the model has peak demand periods occurring at the same time, for both regions (PJM RTO and World), there is little or no diversity (PJM-World Diversity). The peak demand period values are determined as the Expected Weekly Maximum (EWM). A measure of diversity can be the amount of MWs that account for the difference between a Transmission Owner zone’s forecasted peak load at the time of its own peak and the coincident peak load of PJM at the time of PJM peak.

DLCO

Duquesne Light Company (DLCO) is a Pennsylvania-based control area within the RF that was integrated into the PJM footprint on January 1, 2005. The DLCO control area is adjacent to the western portion of the Allegheny Energy region. (http://www.duquesnelight.com/)

DomVP

Dominion Virginia Power (DomVP) is a Virginia-based control area within SERC that was integrated into the PJM RTO on May 1, 2005. The DomVP control area is adjacent to the southern portion of the Allegheny Energy region. (http://www.dom.com/)

Duke Energy Ohio – Kentucky (DEOK)

Duke Energy Kentucky, part of Duke Energy, is a Kentucky-based control area. Duke Energy has approximately 35,000 megawatts of electric generating capacity in the Carolinas and the Midwest, and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C, Duke Energy Kentucky was integrated into the PJM RTO on January 1, 2012. Duke Kentucky is adjacent to the western portion of the AEP region. (http://www.duke-energy.com/kentucky.asp)

Duke Energy Ohio, part of Duke Energy, is an Ohio-based control area. Duke Energy has approximately 35,000 megawatts of electric generating capacity in the Carolinas and the Midwest, and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C., Duke Energy Ohio is currently part of MISO with a target integration date into the PJM RTO on January 1, 2012. Duke Ohio is adjacent to the western portion of the AEP region. (http://www.duke-energy.com/Ohio.asp)

East Kentucky Power Cooperative (EKPC)

EKPC is a not-for-profit electric utility with headquarters in Winchester, Ky. EKPC generates and transmits wholesale energy to 16 owner-member cooperatives. The owner-member cooperatives distribute that energy to more than 1 million Kentucky citizens across 87 counties. EKPC was integrated into the PJM RTO on June 1, 2013.

Eastern Interconnection

The Eastern Interconnection refers to the bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, on the west by the Rocky Mountains, on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. The Eastern Interconnection is one of the three major interconnections within the NERC and includes the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), Southeast Reliability Corporation (SERC) and the Southwest Power Pool, Inc. (SPP).

EEFORd

The Effective Equivalent Demand Forced Outage Rate (EEFORd) is used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor. See manual 22, pages 14-15 (http://www.pjm.com/~/media/documents/manuals/m22.ashx)

EFORd

The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time that a generating unit is in demand, but is unavailable due to a forced outage.

eGADS

eGADS is PJM's Web-based Generator Availability Data System where generation data is collected to track and project unit unavailability – as required for PJM adequacy and capacity market calculations. eGADS is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762-2006 (March 15, 2007).

EMOF

The Equivalent Maintenance Outage Factor (EMOF). For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

EWM

The Expected Weekly Maximum (EWM) is the weekly peak load corresponding to the 50/50 load forecast, typically based on a sample of 5 weekday peaks. The EWM parameter is used in the PJM PRISM program. Also see PJM Manual 20 pages 19-23.

FEF

The Forecast Error Factor (FEF) is a value that can be entered in the PRISM program per Delivery Year to indicate the percent increase of uncertainty within the forecasted peak loads. As the planning horizon is lengthened, the FEF generally increases 0.5% per year. FEF is held constant at 1.0% for all delivery years in the RRS, per stakeholder agreement of the approved assumptions.

FERC

The Federal Energy Regulatory Commission (FERC) is the federal agency responsible with overseeing and regulating the wholesale electric market within the US. (http://www.ferc.gov/)

Forced Outage

Forced outages occur when a generating unit is forcibly removed from service, due to either: 1) availability of a generating unit, transmission line, or other facility for emergency reasons; or 2) a condition in which the equipment is unavailable.

Forced Outage Rate (FOR)

The Forced Outage Rate (FOR) is a statistical measurement as a percentage of unavailability for generating units and recorded in the GADS. FOR indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. It is important to note that there is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand (Load) representing an hourly integrated total in megawatts, measured over a given time interval (typically a day, month, season, or delivery year). This expected demand is a median demand value indicating there is a 50 % probability actual demand will be above or below the expected peak.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of “unforced capacity”.

GEBGE

GEBGE is a resource adequacy calculation program, used to calculate daily LOLE that was jointly developed in the 1960s/1970s by staff at General Electric (GE) and Baltimore Gas and Electric (BGE). The GEBGE program has since been largely superseded and replaced by PJM’s PRISM program in the conduct and evaluation of IRM studies at PJM. (See PRISM.) GEBGE does prove useful to measure reliability calculations and to increase PJM staff efficiency in some sensitivity assessments.

Generating Availability Data System (GADS)

GADS is a NERC-based computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

GORP is a computer program maintained by the PJM Planning staff that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM Office of Interconnection (OI).

Generator Planned Outage

A generator planned outage is the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair – with the approval of the PJM OI.

Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include practices, methods, or acts generally accepted in the region.

ICAP

For non-intermittent generators, installed capacity (ICAP) commonly refers to "iron in the ground" – or rated capacity of a generation unit prior to derating or other performance adjustments. For the purposes of this report, the ICAP of intermittent generators such as wind and solar refers to the capacity credit calculated for each such generator as per PJM's Manual 21.

ILR

Interruptible Load for Reliability (IRL) is a component of PJM's Load Management (LM) program. In the RPM program, just prior to the final incremental auction, load with verifiable existing interruptible capability may declare themselves an Interruptible Load for Reliability (ILR). This component will end for the 2012 delivery year RPM market place. See Load Management and Demand Resources.

Import Capability

Import Capability, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect the PJM Control Area to its neighboring regions are evaluated to determine this single value. (See SIL)

IRM

The Installed Reserve Margin (IRM) is the percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. IRM is expressed in units of installed capacity (ICAP). The PJM IRM is the level of installed reserves needed to meet the ReliabilityFirst criteria for a loss of load expectation (LOLE) of one day, on average, every 10 years

ISO-NE

The Independent System Operator of New England (ISO-NE) is an independent system operator (ISO) and not-for-profit corporation responsible for reliably operating New England's bulk electric power generation, transmission system and wholesale electricity markets. Created in 1997 and with headquarters in Holyoke, MA, the ISO-NE control extends throughout New England including Maine, New Hampshire, Vermont, Rhode Island, Massachusetts and Connecticut. (http://www.iso-ne.com/)

LDA

Locational Deliverability Areas (LDAs) are zones that comprise the PJM RTO as defined in the RAA schedule 10.1 and can be an individual zone, a combination of two or more zones, or a portion of a zone. There are currently 25 LDAs within the PJM footprint.

Load

Integrated hourly electrical demand, measured as generation net of interchange. Loads generally can be reported and verified to the tenth of a megawatt (0.1 MW) for this report.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that provides input to PJM on load related issues.

Load Management (LM)

Load Management, previously referred to as Active Load Management (ALM), applies to interruptible customers whose load can be interrupted at the request of PJM. Such a request is considered an emergency action and is implemented prior to a voltage reduction. This includes Demand Resources (DR), Energy Efficiency, and Interruptible Load for Reliability (ILR) – ILR is only applicable in RPM markets prior to the 2012/13 delivery year, with ILR an inherent piece of all forecast load management values.

LCC

Load Carrying Capability (LCC), typically expressed in megawatts, is the amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten years).

LOLE

Generation system Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days (occurrences) per year. This is a measure of how often, on average, the available capacity is expected to fall short of the restricted demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess Generation Adequacy is an internationally accepted practice.
Let's consider the difference between probability and expectation. Mathematical expectation [E (x)] for a model is based on a given probability for each outcome. An equation for the calculation of expectation is:

$$E(x) = P_1X_1 + P_2X_2 + P_3X_3 + \ldots + P_nX_n$$

$$E(x) = \sum_{i=1}^{n} P_iX_i$$

Where

$P = \text{probabilty of outcome}$

$X = \text{definded outcome (Example: on or off)}$

The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor. There is no implication that it is the most frequently occurring value or the most highly probable, in fact it might not even be possible. The expected value is not something that is "expected" in the ordinary sense but is actually the long term average as the number of terms (trials) increase to infinity.[2]

For generation Adequacy the focus of these calculations, the LOLE, can be expressed in terms of probability as:

$$LOLE = \sum_{i=1}^{260} LOLE_i = \sum_{i=1}^{260}\sum_{j=1}^{21} LOLP_j$$

Where

$LOLE_i$ = Loss of Load Expectation for daily peak distribution

$LOLP_j$ = Loss of Load Probabilty for two state outcome, generation value is less than demand or not.

260 = Number of weekdays in a delivery year

Daily peak = The integrated hourly average peak, or Demand.

The LOLEi for daily peak is calculated or convolved as:

$$LOLEi = \sum_{j=1}^{21} LOLP_j = \sum_{j=1}^{21} PD_j(XD_j) * PG_j(XG_j)$$

Where

$PG(XG)$ = Probabilty of generation at 1st generation value(outcome) less than demand

$PD(XD)$ = Probabilty at given Demand value(outcome)

21 = Discrete Distribution values to assess all likely values of Demand

Demand = The integrated hourly average peak, or Daily peak.

LOLP

The Loss of Load Probability (LOLP), which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0. See LOLE.

LSE

Load Serving Entity (LSE) is defined and discussed thoroughly at the following link. This is a PJM training class concerning requirements of an LSE, including: LSE Obligations, Who are LSEs?, PJM Membership, Capacity Obligations (RAA) for PJM, Agreements and Tariffs, Transmission Service, FTRs, Ways to supply Energy, Energy Load Pricing, Energy Market – Two Settlement, Ancillary Services, http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-req-lse.aspx .

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2 Power System Reliability Evaluation", Roy Billinton, 1970, Gordon and Breach, Science Publishers for further details on calculation methods.

MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a probabilistic analysis program using sequential Monte Carlo simulation to analyze the resource adequacy for multiple areas. MARS is used by ISOs, RTOs, and other organizations to conduct multi-area reliability simulations.

MC

The PJM Members Committee (MC) is reviews and decides upon all major changes and initiatives proposed by committees and user groups. The MC is the lead standing committee and reports to the PJM Board of Managers.

MIC

The PJM Market Implementation Committee (MIC) initiates and develops proposals to advance and promote competitive wholesale electricity markets in the PJM region for consideration by the Electricity Markets Committee. Along with the OC and the PC, the MIC reports to the MRC.

MISO

The Midcontinent Independent System Operator (MISO) is an independent, nonprofit regional transmission (RTO) organization that supports the constant availability of electricity in 15 U.S. states throughout the Midwestern U.S. and the Canadian province of Manitoba. The Midwest ISO was approved as the nation's first regional transmission organization (RTO) in 2001. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota. (http://www.midwestiso.org/home)

MRC

The PJM Markets and Reliability Committee (MRC) are responsible for ensuring the continuing viability and fairness of the PJM markets. The MRC also is responsible for ensuring reliable operation and planning of the PJM system. The MRC reports to the MC.

MRO

The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils that comprise the North American Electric Reliability Council (NERC). The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the north central region of North America. The MRO region is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba. (http://www.midwestreliability.org/)

NERC

The North American Electric Reliability Corporation (NERC) is a super-regional electric reliability organization whose mission is to ensure the reliability of the bulk power system in North America. Headquartered in Atlanta, GA, NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. (http://www.nerc.com/)

NPCC

The Northeast Power Coordinating Council (NPCC) is a regional electric reliability organization within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Northeast region comprising parts or all of: New York, Maine, Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts, and the Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island. (http://www.npcc.org/)

NYISO

The New York Independent System Operator (NYISO) operates New York State's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system. A not-for-profit corporation, the NYISO began operating in 1999. The NYISO is headquartered in Rensselaer, NY with an operation center in Albany, NY. (http://www.nyiso.com/public/index.jsp)

NYSRC

The New York State Reliability Council (NYSRC) a nonprofit, sub-regional electric reliability organization (ERO) within the NPCC. Working in conjunction with the NYISO, the NYSRC's mission is to promote and preserve the reliability of electric service on the New York Control Area (NYCA) by developing, maintaining and updating reliability rules which shall be complied with by the New York Independent System Operator (NYISO). (http://www.nysrc.org/)

OC

The PJM Operating Committee (OC) reviews system operations from season to season, identifying emerging demand, supply and operating issues. Along with the MIC and the PC, the OC reports to the MRC.

OI

The Office of the Interconnection (OI), typically referring to the PJM Operations staff.

OMC

Outside Management Control (OMC) events are a category of data events recorded in the eGADS data. This data category was implemented per the IEEE Standard 762 titled, "IEEE Standard for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity", approved September 15, 2006, available in March 2007. PJM staff, consistent with NERC staff efforts, adopted this new reporting category, starting in January of 2006. Annex D of the IEEE Standard 762 gives examples for these event types including; substation failure, transmission operation error, acts of terrorism, acts of nature such as tornadoes and ice storms, special environmental limitations, and labor strikes or disputes. OMC events are eliminated with the introduction of Capacity Performance in 2018/2019 DY.

PC

The PJM Planning Committee (PC) reviews and recommends planning and engineering strategies for the transmission system. Along with the MIC and the OC, the PC reports to the MRC. Technical subcommittees and working groups reporting to the PC include: Relay Subcommittee (RS), Load Analysis Subcommittee (LAS), Transmission and Substation Subcommittee (TSS), Relay Testing Subcommittee (RTS), Regional Planning Process Task Force (RPPTF), and the Resource Adequacy Analysis Subcommittee (RAAS).

pcGAR

NERC's personal computer based Generator Availability Report (pcGAR) is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

The Peak Load is the maximum hourly load over a given time interval, typically a day, month, season, or delivery year. See Forecast Peak Load.

Peak Load Ordered Time Series (PLOTS)

The Peak Load Ordered Time Series (PLOTS) load model is the result of the Week Peak Frequency application. This is one of the load model's input parameters. This is discussed in the load forecasting, Week Peak Frequency (WKPKFQ) parameters section of Part II – Modeling and analysis.

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday. Please note that the load forecast report used in this study define peak season as June, July and August.

PJM-MA

The PJM Mid-Atlantic region (PJM-MA) of the PJM RTO, established pursuant to the PJM Reliability Assurance Agreements dated August 1994 or any successor. A control area of the PJM RTO responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the PJM Mid-Atlantic Region through coordinated operations and planning of generation and transmission facilities. The PJM Mid-Atlantic Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia. The PJM-MA control area is the Eastern edge of the PJM RTO region.

PRISM

The Probabilistic Reliability Index Study Model (PRISM) is PJM's planning reliability program. PRISM replaced GEBGE, using the SAS programming language. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

RI

The Reliability Index (RI) is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years. A given value of reliability index is the reciprocal of the LOLE.

Reliability

In a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Bulk Power electric reliability cab be addressed be considering two basic and functional aspects of the bulk power system – adequacy and security.

ReliabilityFirst (RF)

ReliabilityFirst is a not-for-profit super-regional electric reliability organization whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Beginning operations on January 1, 2006, RF is composed of the former Mid-Atlantic Areas Council (MAAC), East Central Area Reliability Coordination Agreement (ECAR) and parts of the Mid-America Interconnected Network (MAIN). RF is one of the eight Regional Reliability Organizations under NERC in North America. RF is headquartered in Canton, OH with another office in Lombard, IL. The RF Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, Virginia, Illinois, Michigan, Wisconsin, Kentucky, West Virginia, Ohio, and Indiana. (http://www.rfirst.org/)

Reliability Assurance Agreement (RAA)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff, and the Transmission Owners Agreement.
(http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx)

Reliability Pricing Model (RPM)

PJM's Reliability Pricing Model (RPM) is the forward capacity market in the PJM RTO Control Area. PJM Manual 18 outlines many aspects of this market place. (http://www.pjm.com/markets-and-operations/rpm.aspx)

Reserve Requirement Study (RRS)

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the IRM and FPR, which represents the amount above peak load that must be maintained to meet the RF adequacy criteria. The RF adequacy criteria are based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years. Also referred to as the R-Study. (http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx)

Resource Adequacy Analysis Subcommittee (RAAS)

Reporting to the PC, the RAAS assists PJM staff in performing the annual Reserve Requirement Study (RRS) and maintains the reliability analysis documentation (http://pjm.com/committees-and-groups/subcommittees/raas.aspx). See Resource Adequacy Analysis Subcommittee web site.

Restricted Peak Load

For the given forecast period, the restricted peak load equals the forecasted peak load minus anticipated load management.

RTEP

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission enhancements to preserve regional transmission system reliability, the foundation for thriving competitive wholesale energy markets. PJM's FERC-approved, region-wide planning process provides an open, non-discriminatory framework to identify needed system enhancements. (http://www.pjm.com/planning/rtep-upgrades-status.aspx)

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components or switching operations. One part of the Reliability term.

SERC

The Southeastern Electric Reliability Council (SERC) is a regional electric reliability organization (ERO) within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems in all or portions of 16 central and southeastern states, including Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. SERC is headquartered in Charlotte, NC. (http://www.serc1.org/Application/HomePageView.aspx)

SIL

Simultaneous transmission Import Limit (SIL) study is a series of power flow studies that, per FERC order 697, assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability. FERC Order, 124 FERC 61,147, issued August 6, 2008; found that PJM's studies, as amended, met the requirements for a SIL study. The purpose is to assist our members in responding to FERC regarding their two Market Power Indicative screens and their Delivered Price Test Analysis.

SND

The Summer Net Dependable (SND) rating for a given generation unit is used in the summer period. All processes use the SND rating as the basis for evaluating a unit.

SPP

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Southwest U.S. region, including all or parts of: Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico. (http://www.spp.org/)

THI

The Temperature-Humidity Index (THI) reflects the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: $THI = Td – (0.55 – 0.55RH) * (Td - 58)$ where Td is the dry-bulb temperature and RH is the percentage of relative humidity.

Unrestricted Peak Load

The unrestricted peak load is the metered load plus estimated impacts of Load Management.

Variance

A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations. See PJM manual 22, page 12 and Section 3 Item C, (http://www.pjm.com/~/media/documents/manuals/m22.ashx).

Weather Normalized Loads

The weather-normalized loads are estimated seasonal peak assuming median peak day weather conditions. The weather-normalized loads are also referred to as 50 / 50 loads.

XEFORd

XEFORd is a statistic that results from excluding OMC events from the EFORd calculation. The use of the XEFORd was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Zone / Control Zone

An area within the PJM Control Area, as set forth in PJM's Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement (RAA). Schedule 10 and 15 of the RAA provide information concerning the distinct zones that comprise the PJM Control Area.

IV. Appendices

Appendix A
Base Case Modeling Assumptions for 2018 PJM RRS

Parameter	2017 Study Modeling Assumptions	2018 Study Modeling Assumptions	Basis for Assumptions
Load Forecast			
Unrestricted Peak Load Forecast	153,384 MW (2021/2022 DY)	152,887 MW (2022/2023 DY)	Forecasted Load growth per 2018 PJM Load Forecast Report, using 50/50 normalized peak.
Historical Basis for Load Model	2003-2012	TBD	Load model selection method approved at the June 7, 2018 PC meeting (see Attachment V).
Forecast Error Factor (FEF)	Forecast Error held at 1 % for all delivery years.	Forecast Error held at 1 % for all delivery years.	Consistent with consensus gained through PJM stakeholder process.
Monthly Load Forecast Shape	Consistent with 2017 PJM Load Forecast Report and 2016 NERC ES&D report (World area).	Consistent with 2018 PJM Load Forecast Report and 2017 NERC ES&D report (World area).	Updated data.
Daily Load Forecast Shape	Standard Normal distr bution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Consistent with consensus gained through PJM stakeholder process.
Capacity Forecast			
Generating Unit Capacities	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems.
New Units	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value. .	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	Consistent with CETO cases.

Parameter	2017 Study Modeling Assumptions	2018 Study Modeling Assumptions	Basis for Assumptions
Wind Resources	Derived from hourly wind data over summer peak hours. Units can use a capacity factor of 13% or actual performance once historic data is available.	A wind generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, February July 13, 2017 Planning Committee, Agenda Item 10.
Solar Resources	Derived from hourly solar data over summer peak hours. Units can use a capacity factor of 38% or actual performance once historic data is available.	A solar generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a solar unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, July 13, 2017 Planning Committee, Agenda Item 10.
Firm Purchases and Sales	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Match EIA-411 submission and RPM auctions.
Retirements	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Updated data available on PJM's web site, but model data frozen in May 2018.
Planned and Operating Treatment of Generation	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply:	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply:	Consistency with other PJM reporting and systems.

Parameter	2017 Study Modeling Assumptions	2018 Study Modeling Assumptions	Basis for Assumptions
	•Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Active generation projects in the PJM interconnection queues will be modeled in the PJM RTO after applying a suitable commercial probability.	•Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	
Unit Operational Factors			
Forced and Partial Outage Rates	5-year (2012-16) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2013-17) GADS data. (Those units with less than five years data will use class average representative data.).	Most recent 5-year period. Use PJM RTO unit fleet to form class average values.
Planned Outages	Based on eGADS data, History of Planned Outage Factor for units.	Based on eGADS data, History of Planned Outage Factor for units.	Updated schedules.
Summer Planned Outage Maintenance	In review of recent Summer periods, no Planned outages have occurred.	In review of recent Summer periods, no Planned outages have occurred.	Review of historic 2013 to 2017 unit operational data for PJM RTO footprint.

Parameter	2017 Study Modeling Assumptions	2018 Study Modeling Assumptions	Basis for Assumptions
Gas Turbines, Fossil, Nuclear Ambient Derate	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Operational history and Operations Staff experience indicates unit derates during extreme ambient conditions. Summer Verification Test data confirms this hypothesis.
Generator Performance	Peak period generator performance is consistent with year-round generator performance	For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2017/18) RTO-aggregate outage data (data from DY 2013/14 will be dropped and replaced with data from DY 2014/15).	New methodology to develop winter peak week capacity model to better account for the risk caused by the large volume of concurrent outages observed historically during the winter peak week.
Class Average Statistics	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience.
Uncommitted Resources	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Consistency with other PJM reporting and systems.
Generation Owner Review	Generation Owner review and sign-off of capacity model.	Generation Owner review and sign-off of capacity model.	Annual review to insure data integrity of principal modeling parameters.
Load Management and Energy Efficiency			
Load Management and Energy Efficiency	**PJM RTO load management modeled per the January 2017 PJM Load Forecast Report (Table B7)**	PJM RTO load management modeled per the January 2018 PJM Load Forecast Report (Table B7)	Model latest load management and energy efficiency data. Based on Manual 19, Section 3 for PJM Load Forecast Model.

Parameter	2017 Study Modeling Assumptions	2018 Study Modeling Assumptions	Basis for Assumptions
Emergency Operating Procedures	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	Consistent reporting across historic values.
Transmission System			
Interface Limits	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW.	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW.	Reliability Assurance Agreement, Schedule 4, Capacity Benefit Margin definition.
New Transmission Capability	Consistent with PJM's RTEP as overseen by TEAC.	Consistent with PJM's RTEP as overseen by TEAC.	Consistent with PJM's RTEP as overseen by TEAC.
Modeling Systems			
Modeling Tools	ARC Platform 2.0	ARC Platform 2.0	Per recommendation by PJM Staff. Latest available version.
Modeling Tools	Multi-Area Reliability Simulation (MARS) Version 3.16	Multi-Area Reliability Simulation (MARS) Version 3.16	Per recommendation by PJM Staff and General Electric Staff. Latest available version.
Outside World Area Models	Base Case world region include: NY, MISO, TVA and VACAR.	Base Case world region include: NY, MISO, TVA and VACAR.	Updated per publicly available data and by coordination with other region's planning staffs.

Appendix B

Description and Explanation of 2018 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2017 Base Case IRM in percentage points (pp)
	Individual and New Modeling Characteristic Sensitivity Case	
	The first six sensitivities use the previous 2017 reserve requirement study Base Case as the reference. For the sensitivity cases in red (Case No. 1-6), all differences are with respect to the 2017 Base Case result (2021 DY PJM RTO IRM = 15.77%).	
1	**Load model update – Weekly shape (#56692 2Area)**	**Decrease by 0.02** *
	Modeling characteristics from the Weekly Peak distributions, or 52 mean and standard deviation values, were impacted by updated historical data. The 2018 weekly load model for PJM and the World is based on the same historical time period as in the 2017 study (2003 to 2012).	
2	**Load model update – Monthly Forecast shape (#56695 2Area)**	**No Impact** *
	Impact of using the monthly forecast from the 2018 PJM Load Forecast Report in place of the 2017 version. The monthly forecast for the World is also included in this sensitivity.	
3	**Load model update – Both weekly and monthly shape (#56696 2Area)**	**Decrease by 0.02** *
	Impact of using both the 2018 PJM Load Forecast Report and the updated weekly parameters simultaneously. This is a combination of Case No. 1 and Case No. 2.	
4	**PJM Capacity Model update**	**Decrease by 0.04** *
	Impact of using updated PJM RTO capacity model and associated unit characteristics.	
5	**World Capacity Model update**	**No Impact** *
	Impact of using updated World region capacity model.	
6	**PJM RTO and World Capacity Model update**	**Decrease by 0.03** *
	Impact of using both the updated PJM RTO Capacity Model and the updated World Capacity Model simultaneously. This is a combination of Case No. 4 and Case No. 5.	

Case No.	Description and Explanation	Change in <u>2018</u> Base Case IRM in percentage points (pp)
Load Model Sensitivity Cases		
	Sensitivity numbers 7 and higher are based on the 2018 Base Case. All differences are with respect to the 2018 Base Case result (2022 DY).	
7	**No Load Forecast Uncertainty (LFU) (#56697)**	**Decrease by 4.92**
	This scenario represents "perfect vision" for forecast peak loads, i.e., forecast peak loads for PJM RTO and the Outside World areas have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and economic uncertainties on IRM requirements. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
8	**Vary the Forecast Error Factor (#56677 and 56678)**	**See Below**
	This two-area sensitivity gauges the impact of the FEF on the IRM. When the FEF is decreased to 0% compared to the 1% used in the base case, the IRM falls by 0.16pp. When instead the FEF is increased to 2.5%, the IRM rises by 0.83pp. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
9	**Number of Years in Load Model (#56679-56680)**	**See below**
	These two-area sensitivity cases replace the time period used for the load model in the base case of 2003 to 2012 with other candidate load models considered in the selection process by RAAS.	

PRISM #	Time Period	PJM LM #	World LM #	2022 IRM %	Difference (PP)
56552	2003-2012 (10 Year LM)	51753	51842	15.66	-
56679	2004-2012 (9 Year LM)	51763	51841	16.08	0.41
56680	2004-2014 (11 Year LM)	51824	51843	16.50	0.84

10	Truncated Normal Distribution Shapes (#56686-56689, 56698-56699)	See below

These two-area sensitivity cases reduce the bound of sigma in the 21 point curve representation of the Normal distribution, which is applied to the 52 weekly means and standard deviations of the load models. The base case uses bounds of +/- 4.2 sigma. The truncated normal distributions are used for both PJM and World load models.

# of Standard Deviations	2022 IRM	Difference from base case
2.36	14.80	-0.86
2.50	15.02	-0.65
2.90	15.33	-0.33
3.20	15.55	-0.12
3.60	15.64	-0.02
3.90	15.68	0.02
4.20	15.66	-

This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.

11	PJM Monthly Load Shape (#56700 and #56701)	See below

These two-area sensitivity cases test the impact of making adjustments to the PJM monthly load profile relative to the base case assumption in Table II-1. In the base case, the August peak is 97% of the annual peak. Increasing this August ratio by one percentage point (to 98%) increases the IRM to 16.12%, or 0.46 pp higher than the base case. Reducing this August ratio by one percentage point (to 96%) decreases the IRM to 15.35%, or 0.31 pp lower than the base case.

12	World Monthly Load Shape (#56702)	See below

This two-area sensitivity case tests the impact of making adjustments to the World monthly load profile relative to the base case assumption in Table II – 1. In the base case, the World peaks in July while its August peak is 99.6% of the annual (July) peak. Switching the World's annual peak to August and making its July peak to be 99.6% of the annual peak reduces the IRM by 0.04 pp to 15.62%.

	Generation Unit Model Sensitivity Cases	
13	**High Ambient Temperature Unit Derating (#56703 2Area)**	**Decrease by 1.37**
	Assessment of performance of PJM RTO units on high ambient temperature conditions indicated that some units cannot produce their summer net dependable rating on these days. This type of derating is per PJM's Operations rules and is not considered a GADS derated outage event. This assessment assumes that all units are not affected by high ambient temperature conditions and that they can produce their full summer net dependable rating. This sensitivity removes the 2500 MW on planned outage for the peak summer period (weeks 6-15)	
14	**Replace the EEFORd values with EFORd values for all units in the model. (#56704 2Area)**	**Decrease by 0.97**
	This case replaces the EEFORd statistic with the EFORd statistic, for all units. It assumes that EMOF is not included in the EEFORd computation.	
15	**Impact of change in EEFORd: F-Factor (#56705 1Area)**	**Increase by 1.42**
	There is a direct correlation to the forced outage rate of the PJM RTO units vs. the PJM IRM. This sensitivity increases the (EEFORd) by 1 percentage point.	
16	**Perfect performing units : (#56706 1Area)**	**Decrease by 8.86**
	Adjust the performance characteristics for all base units to approximate perfect performing units i.e., each unit has a FOR of zero, planned outages of zero and zero maintenance outages.	
	Capacity Benefit Margin Sensitivity Cases	
17	**Various values of Capacity Benefit Margins**	**See Figure I-7**
	Figure I-7 shows the impact to IRM as the value of Capacity Benefit Margin (CBM) is increased. CBM is a measure of transfer assistance available from the outside neighboring region. This graph indicated what value PJM's interconnected ties have on the calculated IRM, and where the value of CBM saturates (becomes constant).	
	Reserve Modeling Sensitivity Cases	

18	**PJM RTO at cleared RPM auction (#56081)**	**RI = 56.3**
	In this sensitivity, PJMRTO reserves are modeled as per the most recent RPM auction while the World is solved to meet the 1 in 10 criterion. The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%. This reserve margin was achieved at clearing prices that are between approximately 44% to 82% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in Demand Response and Energy Efficiency resources, additional wind and solar resources, and one new combined cycle gas resource The full report can be found at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en	
19	**PJM RTO IRM Vs. World Reserves (#56628-56643)**	**See below**
	For a two area study, World Reserves were varied from the calculated requirement (1 day in 10) to the forecasted reserves. The runs are made by solving the World for a fixed load (corresponding to an installed reserve level) and PJM RTO is solved to its criterion (1 day in 10). The results are in Figure I-6. The valid range of world reserves is determined through consideration of different load management assumptions. Within this valid range of world reserves, as the reserves of the world increase, the IRM requirement for PJM RTO declines at a decelerating rate.	
20	**PJM RTO RI Vs. PJM RTO Reserves (#56662-56676)**	**See below**
	A two area study when PJM RTO reserves were varied from the calculated requirement (1 day in 10). The runs are made by solving the PJM RTO for a fixed load (corresponding to an installed reserve level) and World is at its 1D/10 YR level. As the PJM RTO reserves increase, the reliability Index (measured by the LOLE value) increases exponentially. See Figure II-5.	

Topological Modeling Sensitivity Cases		
21	**Single Area PJM RTO Model (#56553)**	**Increase 1.51**
	This models only the PJM RTO in a single area case. The solution is for a Reliability Index (RI) of 10, or once every 10 years. When compared to the official case results, this represents the value of the interconnected ties, or Capacity Benefit Of Ties (CBOT). The difference between the base run and this sensitivity in the load carrying capability (LCC), multiplied by the reserve requirement, yields an approximate 2,969 MW of capacity that does not need to be inside the PJM RTO. This megawatt amount represents the value of the 3,500 MW CBM that is specified in Schedule 4 of the PJM Reliability Assurance Agreement (RAA).	
22	**Two Area Model with Ambient Derates for World Area -xxxx MW out on PO for World area**	**xxxx**
	This sensitivity models the Base Case with ambient derates for the World region too. The same proportion of impact of ambient conditions on the World fleet of units is modeled as are modeled for the PJM generation fleet. The impact of ambient conditions on the generation fleet affects several generation categories as shown in Table II-6. Ambient conditions are modeled as Planned outages over the ten week Summer period, similar to the 2,500 MW derating used in the PJMRTO area.	
23	**Relationship between IRM and ambient impact on unit performance**	**See Below**
	This sensitivity adjusts the total amount of ambient derates, for the appropriate generation categories affected by high ambient (THI) conditions (See Table II-6 for categories). Ambient derates are modeled as planned outages over the high LOLE summer period. The range of impact to the unit fleet due to high ambient conditions, for the entire PJM RTO fleet of units, was 2,500 – 8,500 megawatts. The increase in the IRM for every additional 1000 megawatts of ambient derates, on average, was xxxpp.	

Appendix C
Resource Adequacy Analysis Subcommittee (RAAS)

RAAS Main Deliverables and Schedule

There are 3 primary deliverables of the RAAS.

1. The assumptions letter for the upcoming RRS

   Per the below time line, this activity is scheduled to start in February and be completed in May.

2. The IRM, FPR Analysis Report

   Per the below time line, this activity is scheduled to start in June and be completed in September.

3. The Winter Weekly Reserve Target in the Report

   Per the below time line, this activity is shown as item number thirteen, scheduled to be completed in September, for the upcoming winter period.

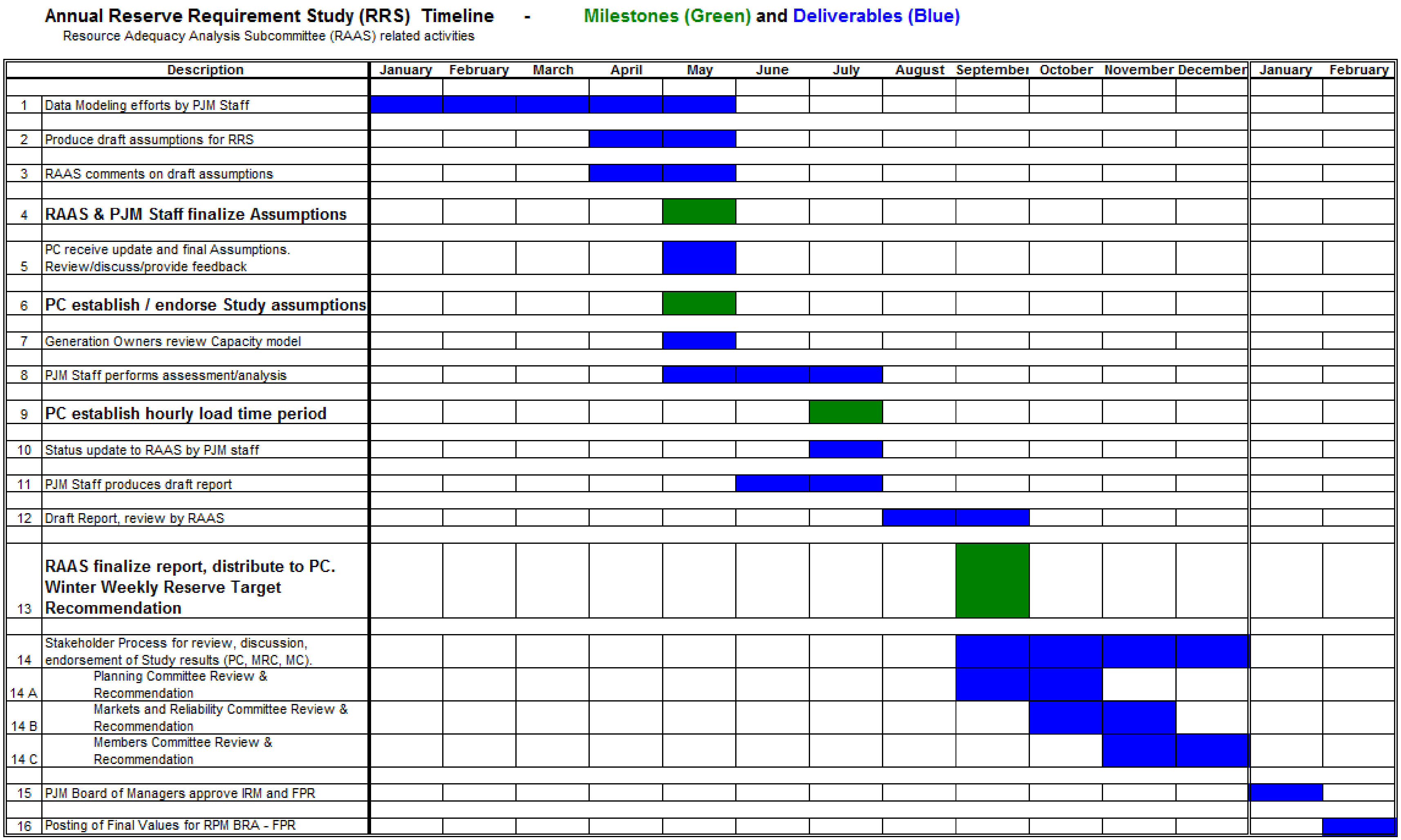
This technical working group was established by and reports to the PJM Planning Committee.

The activities of the PJM RAAS are shown at the following web link:

http://pjm.com/committees-and-groups/subcommittees/raas.aspx

Timeline for 2018 Reserve Requirement Study

Figure IV-1: Timeline for 2018 RRS



The 2018 Study activities last for approximately 14 months. Some current Study activities, shown in items 1 and 2, overlap the previous Study timeframe. The posting of final values occurs on or about February 1st.

Appendix D
ISO Reserve Requirement Comparison

Appendix E
RAAS Review of Study - Transmittal Letter to PC

October 10, 2018

Steven R. Herling
Chairman Planning Committee
PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Dear Mr. Herling,

The Resource Adequacy Analysis Subcommittee (RAAS) has completed its review of the 2018 PJM Reserve Requirement Study (RRS) report.

The review efforts are in accordance with the RAAS Charter, as approved by the Planning Committee and posted at: http://pjm.com/committees-and-groups/subcommittees/~/media/committees-groups/subcommittees/raas/postings/charter.ashx

The review included the following efforts:

- Development and completion of the Study assumptions, including an activity timeline
- Participation in subcommittee meetings to discuss and review PJM staff progress in developing the Study model
- Identification of modeling improvements for incorporation into the analysis and report, as described in the June 2018 RRS Study Assumptions letter
- Participation in subcommittee meetings to discuss and review preliminary analysis results
- Verification that all base case study assumptions are fully and completely adhered to
- Review of a draft version of the study report

After review and discussion of the study results, the subcommittee unanimously endorsed the PJM recommendation shown in the table below.

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2018	2019 / 2020	15.97%	**16.0%**	6.08%	**1.0895**
2018	2020 / 2021	15.89%	**15.9%**	6.04%	**1.0890**
2018	2021 / 2022	15.84%	**15.8%**	6.01%	**1.0884**
2018	2022 / 2023	15.66%	**15.7%**	5.90%	**1.0887**

PJM will be requesting Planning Committee endorsement of the recommendations detailed above at your October 10, 2018 meeting.

The review efforts of the RAAS will be concluded upon acceptance of this report by the Planning Committee.

Respectfully,

Thomas A Falin
RAAS Chair

Appendix F
Discussion of Assumptions

This appendix's intent is to document assumptions and modeling items that affect the calculated IRM for the base case run. The following considerations were included in the modeling and analysis

- Trends observed over several Study models are significant and are considered at the time of validating the recommendations resulting from this report.

- Historically significant drivers of the Study results include the overall unit forced outage rates, forecasted monthly load profile, load model diversity, forecast reserve for both Area1 (PJM RTO) and Area2 (World), size of the neighboring region modeled, and time period used in the hourly load model to create the weekly statistical parameters.

- The sensitivities presented in Appendix B provide an important tool for validating assumptions and results of the study.

- Mitigating uncertainty to the forward capacity market is an important consideration.

A discussion of the assumptions considered in the study is presented below,

Independence of Unit Outage Events (no recognition of common cause failures): Historically, this has been an assumption widely used throughout the industry. All production grade commercial applications used to perform probabilistic reliability indexes use this assumption. However, changes in the makeup of the industry, such as the current trend to build mostly units that rely on the shared gas transmission system, could invalidate this assumption for some units that do have a correlation for outages due to the shared gas transmission pipeline.

Forecast Error Factor (FEF): The RRS models a 1% Forecast Error Factor for all delivery years. This modeling, which began in the 2005 Study, represents a switch from the previous practice of increasing the FEF as the planning horizon lengthens.

Intra-World Load Diversity: The diversity values used are from an assessment of 18 years of historic hourly data. See Table II-3 for further details. In 11 of the 18 historic years, the diversity was lower than the average. Using the average of the historic diversity values was considered to be a reasonable assumption (as opposed to using the minimum of the values which was deemed to be very conservative).

Assistance from World area: The value of the outside world's assistance is associated with two modeling characteristics: the timing of PJM's need for assistance and the ability of the World to supply assistance at this time of need. The assumption that the outside world adjacent to PJM will help PJM avoid Loss-of-Load events is based on historic operating experience.

Modeling all External NERC Regions in a Single Area: PRISM is limited to a 2-area model: PJM and the World Area. Thus, all external NERC regions are modeled in a single area, ignoring the transmission constraints between the areas. This approach assumes that all external NERC regions share loss-of-load events which are not the case in practice. Furthermore, PRISM solves the World to collectively be at a 1 in 10 reliability level whereas, in practice, each external NERC Region is at 1 in 10 and hence the World is collectively at a level worse than 1 in 10.

Units out on planned maintenance over summer peak period due to ambient conditions: The moving of planned outage events to the summer peak period is an assumption that has been used since 1992. This is consistent with what has been observed by Operations over the summer period and reflects PJM's experience with a control region that includes about 1,300 units. Currently, 2,500 MW are modeled out to reflect reduced unit output during high ambient conditions (hot and humid). Verification of this quantity was performed in early 2016 using Summer Verification Test data from 2013-2015.

Holding World at known reserve requirement level rather than forecast reserves: The World is modeled at the reserve requirement known for each of the surrounding individual sub-regions that make up the World region. This assumption ensures that PJM does not depend on World “excess” reserves that may be committed to other regions. Any excess reserves, however, may be uncommitted and actually available to serve PJM under a capacity emergency. Thus, this assumption may understate the amount of assistance available to PJM from the World area.

Normally-distributed load model: The uncertainty in the daily peak load model is assumed to be normally distributed. The normal distribution is approximated using a histogram with 21 points ranging from -4.2 to +4.2 standard deviations from the mean. This 21-point approximation is used in all weeks (and in each of the 5 days within a week) of the analysis. The means and standard deviations vary from week to week and are computed by a separate program. This program uses historic weekly load data, magnitude ordered within a season, to compute the mean and standard deviation for each of the 52 weeks in the model. The 21 point daily peak distribution is defined by each week’s mean and standard deviation in the calculation of loss of load expectation.

PJM and World regions load diversity: The value of the Capacity Benefit Margin (CBM) is associated with the timing of PJM load model peaks relative to the timing of the World load model peaks. This difference in timing is assessed by the PJM-World Diversity. The PJM-World Diversity is a measure of the World’s load value at the time of PJM’s annual peak. This measure is expressed as a percentage of the World’s annual peak. Currently, this value is computed by using 17 years of historical hourly peak loads for the World (see Table II-3). Note that the greater the diversity, the more capacity assistance the World can provide at PJM’s peak (or other PJM high load events). The value of PJM-World diversity might change depending on the dataset of historical hourly peaks considered.

Perfect correlation between two load models: As mentioned earlier in the report, PJM’s load is assumed to be normally distributed (approximated via a 21-point histogram). The World’s load model is modeled in the same way. When PJM is assumed to be facing a particular load level (for instance, load level 2, the second highest load level), the World is assumed to be facing the corresponding magnitude-ordered load level (i.e. the second highest out of the 21 load levels for the World). In other words, there is a perfect correlation between the two load models. In practice though, the World could be facing any other of the 20 remaining load levels.

World Load Management: The criteria to select the World reserve level stipulates that the World will be assumed to be at the higher of the following two reserve levels: 1) the reserve level that satisfies 1 in 10 (as found by PRISM) or 2) the composite reserve level as a percentage of the World peak (see Table I-5) excluding load management as an available resource. In the event that reserve level 1) is selected, then implicitly some load management is being assumed as an available resource in the World. On the other hand, when reserve level 2) is selected, no load management is assumed as available.

**OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY'S
DISCOVERY REQUEST
PUCO CASE NO. 18-501-EL-FOR, 18-1392-EL-RDR, AND 18-1393-EL-ATA
SECOND SET**

INTERROGATORY

IGS-INT-2-001 The Amendment to the Long Term Forecast Report states (at p. 4), "R.C. 4928.143(B)(2)(c) permits the Commission to make a finding of need for new generation plants owned or operated by the EDU. The General Assembly deliberately created this option as part of a post-corporate separation 'wires utility' function and it does not require a traditional analysis of integrated resource planning 'need.'" Regarding this statement::

a. Identify and explaining the meaning of a "traditional analysis of integrated resource planning 'need'.":

b. Explain why AEP is not required to demonstrate "need" based upon a traditional analysis of integrated resource planning need.

RESPONSE

The Company objects to this request as seeking a legal conclusion or opinion that is not attributable to a witness and is more appropriate for briefing and argument by counsel, and which the Company reserve the right to further address in those contexts. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows. The Company's views, however, do not limit or restrict the Commission's exercise of its jurisdiction or pursuit of options it may have in this regard and the ESP statute speaks for itself. But a traditional analysis of integrated resource planning need would be one performed for an integrated utility, which would be prior to enactment of SB 3 and SB 221 in Ohio. AEP Ohio is not an integrated utility and cannot perform integrated resource planning. And the ESP statute uses the phrase "resource planning" -- not "integrated resource planning" -- which is a concept that has meaning in the context of post-corporate separation and in the context of an electric distribution utility as an RTO member. Thus, the "resource planning" concept in the ESP statute is distinctly different from integrated resource planning in the context of traditional regulation.

Prepared by: Counsel

Exhibit JAL-9

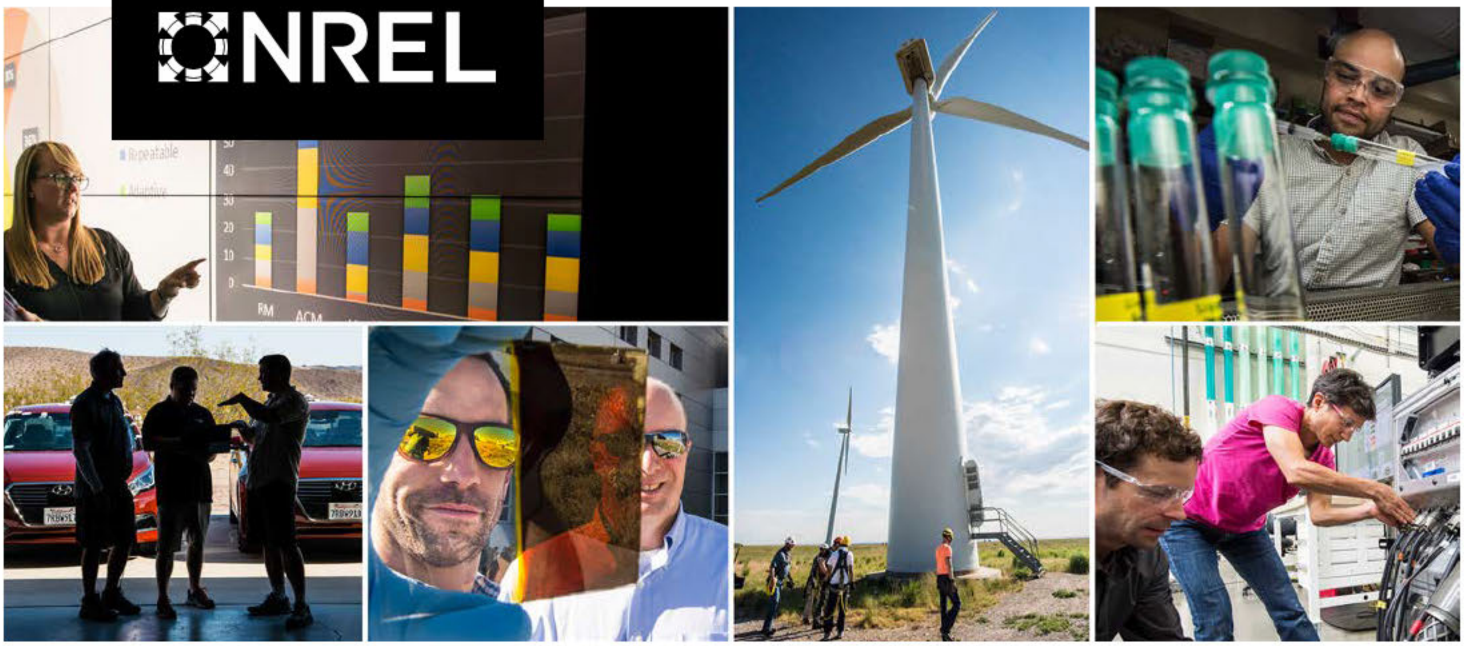
CONFIDENTIAL

Intentionally Omitted

Exhibit JAL-10

CONFIDENTIAL

Intentionally Omitted



Status and Trends in the U.S. Voluntary Green Power Market (2017 Data)

Eric O'Shaughnessy, Jenny Heeter, and Jenny Sauer

National Renewable Energy Laboratory

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Office of Energy Efficiency & Renewable Energy
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Technical Report
NREL/TP-6A20-72204
October 2018

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Technical Report
NREL/TP-6A20-72204
October 2018

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Golden, CO 80401
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NOTICE

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Executive Summary

Most renewable energy procurement in the United States falls into one of two categories. Compliance-based purchasing refers to renewable energy procurement by load-serving entities to comply with state renewable energy mandates. Voluntary purchasing or voluntary "green power," for the purposes of this report, refers to voluntary renewable energy procurement by retail electricity customers in excess of state renewable energy mandates. In this report, we present data and key trends for voluntary green power markets, except for a small portion of voluntary purchasing where no data are available.

In 2017, about 5.5 million retail electricity customers procured about 112 million megawatt-hours (MWh) of green power, representing about 26% of all U.S. renewable energy sales (excluding large hydropower) (Figure ES-1) or about 3% of all U.S. retail electricity sales. For comparison, compliance-based procurement accounted for about 57% of renewable energy procurement.

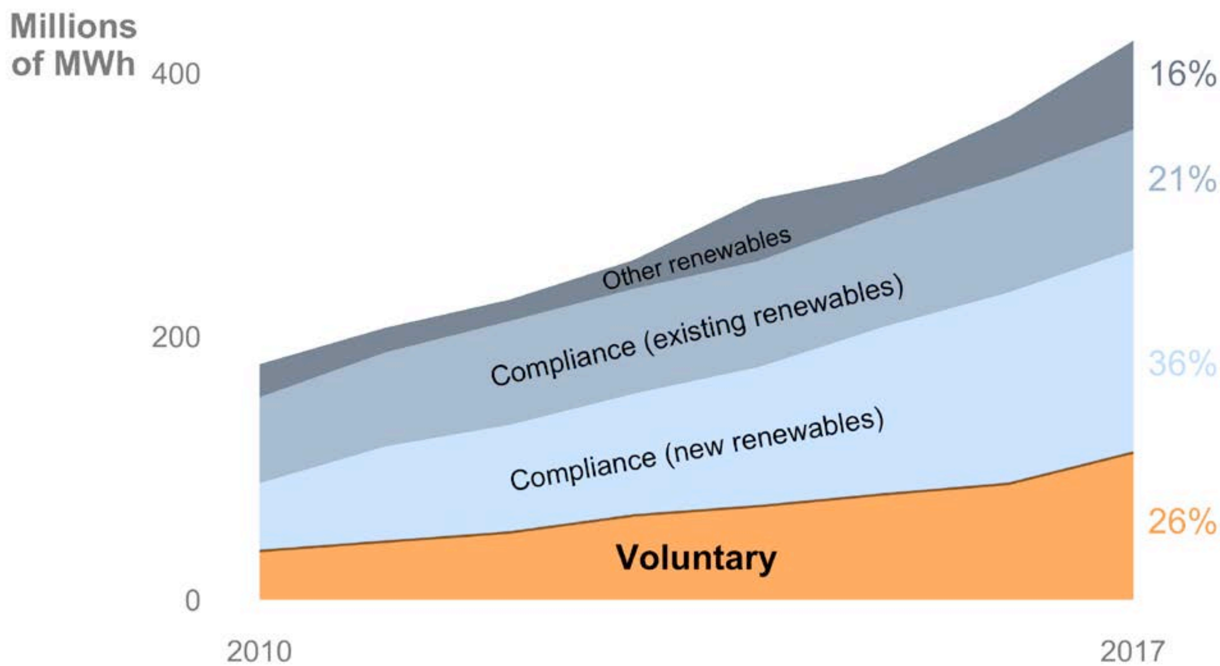

Figure ES-1. Voluntary green power sales (MWh), 2010–2017

This report summarizes the status and trends of sales of seven ways that customers can obtain green power. These options, described here as green power products, are utility green pricing programs, utility renewable contracts, unbundled renewable energy certificates, competitive suppliers, community choice aggregations, power purchase agreements, and community solar. Key trends include:

- Utility green pricing programs, which have generally relied on wind, are increasing their procurement of solar energy, especially among the 10 largest programs.

- Unbundled renewable energy certificates—which are primarily purchased by large nonresidential customers—continue to account for the majority of voluntary green power sales (about 46%) (Figure ES-2).
- Green power sales through power purchase agreements exhibited the strongest year-over-year growth in absolute terms, increasing by about 12.7 million MWh from 2016 to 2017.
- Community choice aggregations—which primarily serve residential and small commercial customers—account for about half of green power customers.
- Green power sales through community solar programs exhibited the strongest year-over-year growth in relative terms, increasing eightfold from 2016 to 2017 mostly due to the implementation of new utility-administered community solar green power programs.

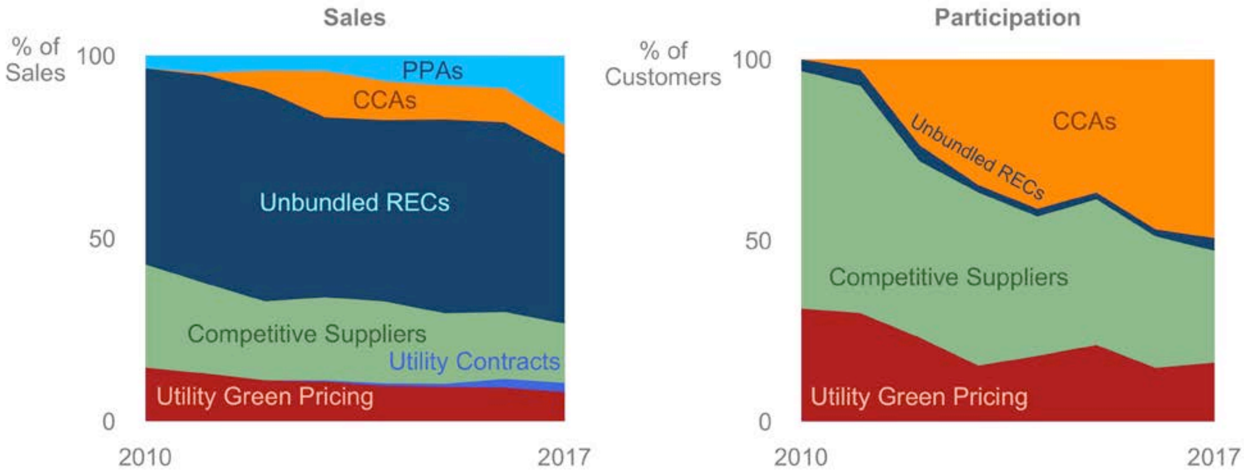

Figure ES-2. Voluntary green power market shares of different products in terms of sales (left) and customers (right), 2010–2017

PPA = power purchase agreement; CCA = community choice aggregation; REC = renewable energy certificates

The ongoing growth of the U.S. voluntary green power market is driven primarily by increased sales of existing products, especially unbundled renewable energy certificates—which grew by 32 million MWh from 2010 to 2017, but also the expansion of new products like community choice aggregations and power purchase agreements—which together grew by 29 million MWh from 2010 to 2017. As these new products expand, there is the potential for customer confusion and for customers to misunderstand the impact of their purchase. Measures to increase product transparency, particularly for new products like community choice aggregations and community solar, could help customers better understand the impact of their purchasing decisions.

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1 Introduction

Most renewable energy procurement in the United States falls into one of two categories. Compliance-based purchasing refers to renewable energy procurement by load-serving entities to comply with state renewable energy mandates known as renewable portfolio standards (RPS). Voluntary green power, for the purposes of this report, refers to voluntary renewable energy procurement by retail electricity customers in excess of RPS.[1] Both types of procurement are verified through renewable energy certificates (RECs), accounting mechanisms that represent the clean energy attributes of one megawatt-hour (MWh) of renewable electricity. When a REC is "retired" on behalf of a specific user, that user has the sole right to claim the use of the renewable energy represented by that REC, thus preventing the double counting of renewable energy use claims.[2] For more information on RECs and their role in voluntary green power markets, see NREL (2015) and EPA (2018). The report summarizes data on the various ways in which retail electricity customers—including residential, commercial & industrial (C&I), and institutional (e.g., government) customers—purchase voluntary green power. For similar data from compliance-based markets, see Barbose (2017).

Table 1 on the following page summarizes the seven ways that customers can buy green power, which we refer to as green power products. For each green power product, RECs are retired on behalf of retail electricity customers to allow those customers to make valid claims to renewable energy use. The inclusion of RECs in all seven green power products ensures that the associated renewable energy use cannot be double counted and claimed by a utility for RPS compliance. In other words, all sales through the green power products are above and beyond sales that would have occurred anyway due to state RPS. The availability of the seven green power products varies geographically based on state electricity market structure, laws, and regulations.

For the purposes of this report, the term green power refers exclusively to renewable energy procurement that exceeds RPS obligations. For example, competitive suppliers and community choice aggregations (CCAs) are subject to RPS compliance in states with RPS, and therefore a fraction of their sales is used to meet their compliance obligations. All voluntary green power sales estimates (MWh) reported here for competitive suppliers and CCAs exclude the portion of renewable energy sales used toward RPS compliance.

This report does not include green power use where no explicit REC transaction occurs and therefore no usage data are available. This lack of data/absence of REC transaction occurs when customers own on-site systems and "retain" the RECs, so that RECs are never sold or recorded in one the seven green power products defined in Table 1. Data from the U.S. EPA's Green Power Partnership suggest that on-site green power consumption by nonresidential customers may amount to about 4% of the green power market summarized in the report, or about four million MWh annually. Additional on-site green power, not accounted for in this report, is

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[1] This definition is consistent with the definition used by the U.S. Environmental Protection Agency. See EPA (2018) for more information about voluntary green power.

[2] RECs are formally recognized as a valid basis for making renewable energy use claims by the Federal Trade Commission, the U.S. Environmental Protection Agency, the U.S. Federal Energy Regulatory Commission, the U.S. Federal Energy Management Program, the American Bar Association, and at least 35 U.S. states and territories. See Jones, Quarrier, and Kelty (2015) for a more complete discussion of the legal basis of RECs.

occurring through residential installations and organizations that are not part of the Green Power Partnership. Further, this report does not discuss potential costs of integrating voluntary green power resources into the grid or the technical impacts of voluntary green power markets on electric grids.

Table 1. Green Power Products

Product	Description	Customer Classes
Utility green pricing	Utility customers procure green power on a month-to-month basis through an added fee on their utility bill	Residential, small commercial
Utility renewable contracts	Utility customers procure green power from their utility through a special tariff or bilateral contract, typically on a long-term basis sourced from a new renewable energy generator	Large C&I
Unbundled RECs	Retail customers buy RECs separated or "unbundled" from the underlying electricity. This category refers only to sales of unbundled RECs directly to retail customers, it excludes sales of unbundled RECs through other green power products (e.g., utility green pricing) to avoid double counting.	All, mostly C&I and institutional
Competitive suppliers	Customers in competitive electricity markets may select a green power option from an alternative retail electricity supplier	All
Community choice aggregations (CCA)	Communities aggregate their loads to collectively procure green power as a bulk purchaser through an alternative electricity supplier	All, mostly residential and small commercial
Power purchase agreements (PPA)	Customers procure green power through a long-term contract with an off-site renewable energy project	C&I, institutional*
Community solar	Customers buy a subscription in a shared solar project and accrue green power in proportion to their subscription	All, mostly residential and small commercial

* Residential customers also sign PPAs, however RECs are typically owned by the project owner rather than the end-use customer. Residential PPAs are excluded from this report.

Data Sources and Limitations

Green power market data are based on figures provided to the National Renewable Energy Laboratory (NREL) by utilities and independent renewable energy marketers and publicly available data (Table 2). The data on voluntary market trends presented in this report build on data presented in *Status and Trends in the U.S. Voluntary Green Power Market (2016 Data)* (O'Shaughnessy et al. 2017).

Table 2. Methodologies, Resources, and Data Limitations

Product	Methodology, Resources, and Limitations
Utility green pricing	National estimate extrapolated from data collected from 46 utility programs. NREL estimates that the data sample represents over 80% of utility green pricing sales
Utility renewable contracts	Estimates based on data from WRI (2018); Heeter, Cook, and Bird (2017); and data collected by NREL
Unbundled RECs	National estimate extrapolated from data provided by the Green-e national certification program (Leschke 2018) and NREL survey data.
Competitive suppliers	Estimates based on survey data, data from EIA Form-861 (EIA 2018a), and competitive supplier websites
Community choice aggregations	Estimates for Massachusetts and Ohio based on data collected from CCAs; estimates for California based on Trumbull (2018); estimates for Illinois based on information from ICC (2018a; 2018b) and Homefield Energy (2018); estimates for New York based on Westchester Power (2018).
Power purchase agreements	Based on data obtained from BNEF (2018) and S&P Global Market Intelligence (2018).
Community solar	Based on data on operational community solar projects compiled from various sources (O'Shaughnessy et al. 2018), state-level solar capacity factors, and assumed average subscription sizes per customer; REC treatment is unknown for most projects. Community solar sales and participation figures are therefore excluded from green power market totals, except for sales and participation from programs administered by MCE, Pacific Gas & Electric, Rocky Mountain Power, and Sacramento Municipal Utility District (where by design customers retain RECs).

Structure of this Report

Section 2 provides an overall summary of the status of the green power market with national totals of sales (MWh) and participation (number of customers). We provide state-level estimates of green power sales and participation in the Appendix. Sections 3–9 summarize the status and trends for each of the green power procurement mechanisms. Section 10 analyzes how the expansion of new retail electricity products may affect voluntary green power markets. Section 11 concludes the report.

2 Summary of Voluntary Green Power Participation and Sales

About 5.5 million U.S. electricity customers purchased about 112 million MWh of green power in 2017 (Table 3), which represents about a 27% increase in green power sales from 2016 to 2017.[3]

Table 3. Voluntary Green Power Participation and Sales in 2017

Green Power Option	Sales (MWh)	Participants
Utility green pricing	8,850,000	885,000
Utility renewable contracts	2,788,000	15
Competitive suppliers	18,133,000	1,691,000
Unbundled RECs	51,744,000	192,000
CCAs	8,882,000	2,726,000
PPAs	21,271,000	273
Community solar	80,400	4,700
Total	111,748,000	5,499,000

PPAs, unbundled RECs, and utility renewable contracts tend to be purchased in large quantities by larger nonresidential electricity customers. As a result, these products account for about 68% of green power sales but only account for about 4% of customers (Figure 1). In contrast, CCAs, competitive suppliers, and utility green pricing programs primarily serve small electricity buyers such as residential and small commercial customers. These products account for about 96% of green power customers but only about 32% of green power sales.

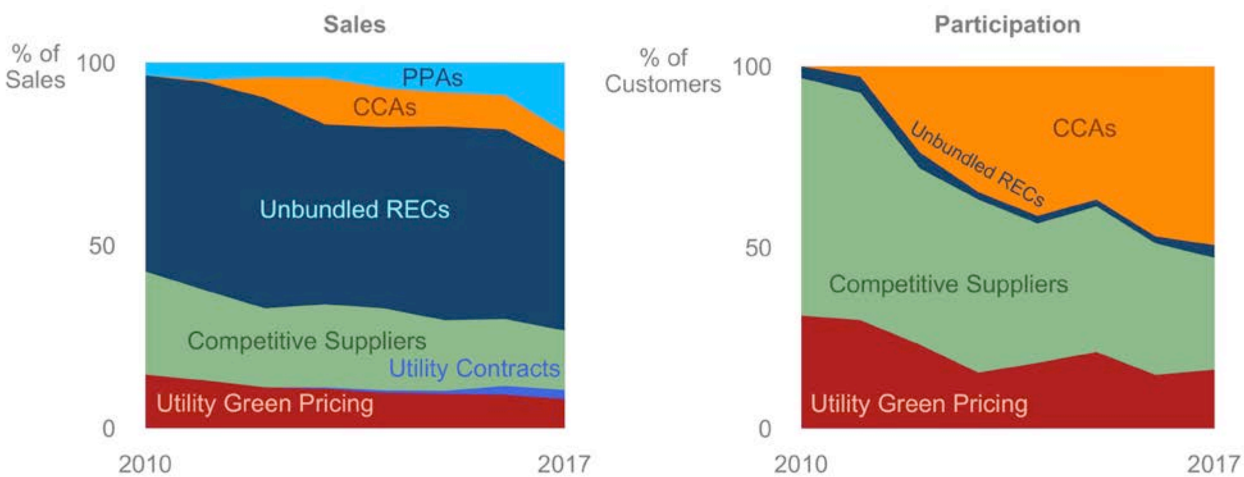


Figure 1. Shares of green power sales (left) and customers (right) over time by product

Community solar, PPAs, and utility contracts collectively account for less than 1% of customers.

[3] All of the data in this section and data behind certain figures in this report are available in a spreadsheet format at https://data.nrel.gov/submissions/98 ("U.S. Voluntary Green Power Market Data 2017," NREL).

For the first time, U.S. voluntary green power sales broke 100 million MWh in 2017, reaching about 112 million MWh (Table 4). Unbundled RECs continue to account for nearly half (46%) of the green power market in terms of sales. Green power sales through PPAs more than doubled from 2016 to 2017, accounting for more than half of the increase in market wide green power sales (Figure 2).

Table 4. Estimated Green Power Sales (millions of MWh), 2012–2017[a]

Green Power Option	2012	2013	2014	2015	2016	2017
Utility green pricing	6.0	6.9	7.0	7.5	8.0	8.9
Utility contracts	0	0.2	0.5	0.7	2.1	2.8
Competitive suppliers	11.6	14.5	16.2	15.4	16.0	18.1
Unbundled RECs	31.0	31.4	36.0	42.5	45.5	51.7
CCAs	3.0	8.1	7.7	7.4	8.1	8.9
PPAs	2.2	2.7	5.1	6.6	7.9	21.3
Community solar	0	0	0	0	0.01	0.08
Total	**54**	**64**	**73**	**80**	**88**	**112**

[a] We continuously update historical results based on improved data and methods; some historical results differ from results provided in previous versions of this report.

Figure 2. Green power sales by mechanism, 2010–2017

Plots are on different scales.

We estimate that green power participation remained relatively stable from 2016 to 2017, as increases in participation through most products were offset by an estimated reduction in competitive supplier customers (Table 5, Figure 3). Over that period, CCAs accounted for about half of all green power customers.

Table 5. Estimated Green Power Participation (×1,000 customers[a]), 2012–2017[b]

Green power option	2012	2013	2014	2015	2016	2017
Utility green pricing	570	706	743	789	816	885
Utility contracts	0	0.001	0.001	0.001	0.001	0.002
Competitive suppliers	1,200	2,200	1,584	1,506	2,011	1,691
Unbundled RECs	110	95	89	70	108	192
CCAs	580	1,600	1,700	1,380	2,600	2,726
PPAs	0.15	0.17	0.18	0.20	0.21	0.27
Community solar	0	0	0	0	1.5	4.7
Total	**2,460**	**4,601**	**4,117**	**3,745**	**5,537**	**5,500**

[a] Includes all customer types: residential, C&I, institutional
[b] We continuously update historical results based on improved data and methods; some historical results differ from results provided in previous versions of this report.

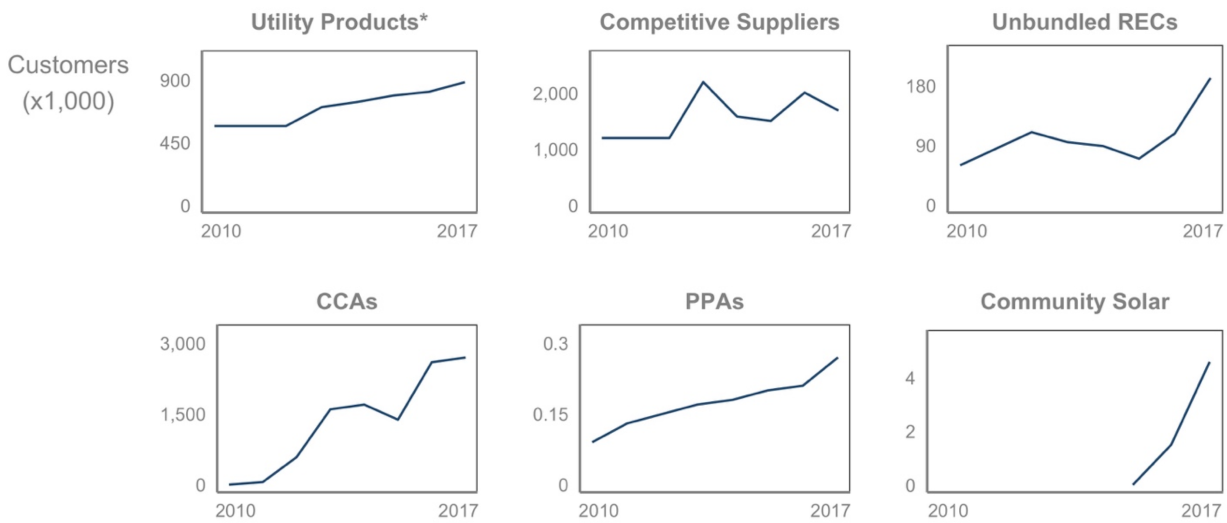


Figure 3. Green power participation by mechanism (2010–2017)

Plots are on different scales.
* Equal to sum of utility green pricing and utility renewable contracts

Figure 4 places the voluntary green power market in the context of the broader renewable energy market, excluding large hydropower. Most U.S. renewable energy sales are used to comply with state RPS programs. In 2017, compliance-based sales in state programs that require regulated entities to procure RECs from "new" projects accounted for about 36% of renewable energy sales, while compliance-based sales from existing projects accounted for about 21% of renewable energy sales. The voluntary market accounted for about 26% of all U.S. nonlarge-hydro renewable energy sales in 2017. The "other renewables" group in Figure 4 includes utility renewable energy purchasing beyond RPS requirements and on-site generation. The other category may also include some renewable energy that was generated in 2017 for which the RECs will be sold in a future year. Compliance-based REC sales are based on data compiled by the Lawrence Berkeley National Laboratory (LBNL 2017). Total U.S. renewable energy sales are based on retail electricity sales data from the U.S. Energy Information Administration (EIA 2018b).

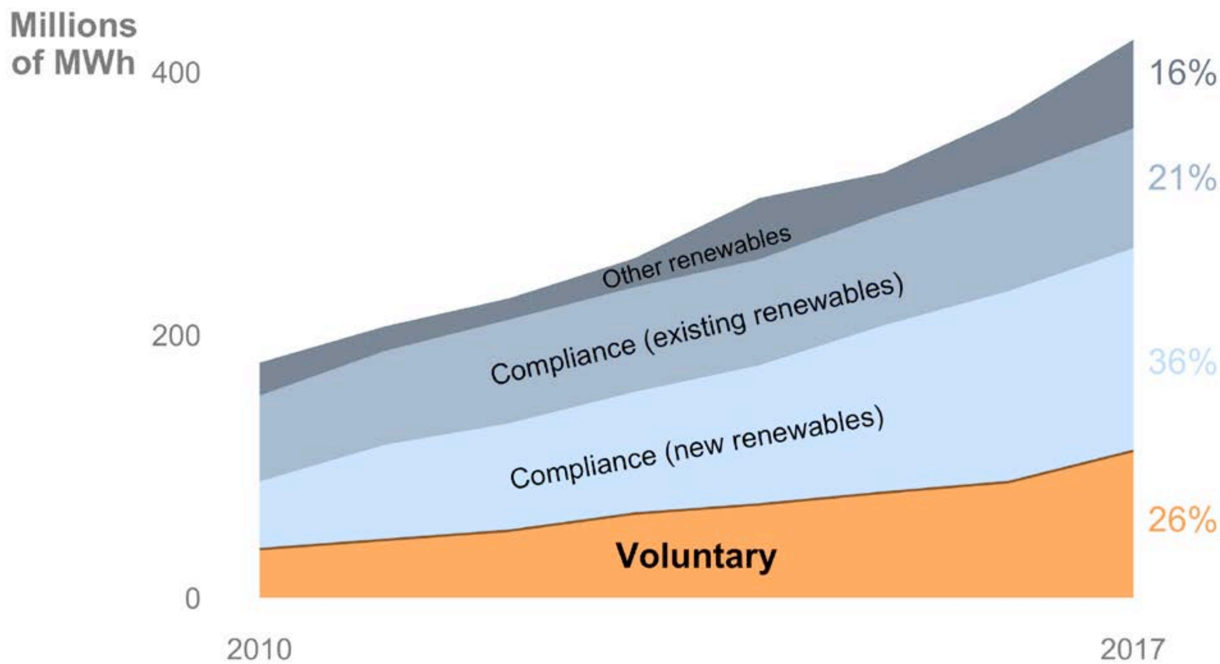


Figure 4. Renewable energy sales in voluntary, compliance, and other markets, 2010–2017

Based on data from EIA (2018b) and LBNL (2017)

The category of "other renewables" has expanded in recent years, in part because some utilities are exceeding RPS requirements as renewable energy costs fall. For instance, California's investor-owned utilities were on track to meet the state's previous RPS about 10 years ahead of schedule (Gattaciecca, Trumbull, and DeShazo 2018), and recent changes to the California RPS may prompt California utilities to further increase renewable energy procurement. Increased above-RPS renewable energy procurement by utilities could have implications for voluntary green power markets. We explore these questions as part of a larger discussion in Section 10.

3 Utility Green Pricing

Many utilities sell green power to residential and nonresidential customers through utility green pricing programs (Figure 5).[4] In a green pricing program, the utility retires RECs on behalf of the customer in proportion to the quantity of green power purchased by the customer. Green pricing customers generally pay for the green power through an additional line item on their utility bill. Green pricing sales and participation data in this report are based on survey data gathered by NREL.

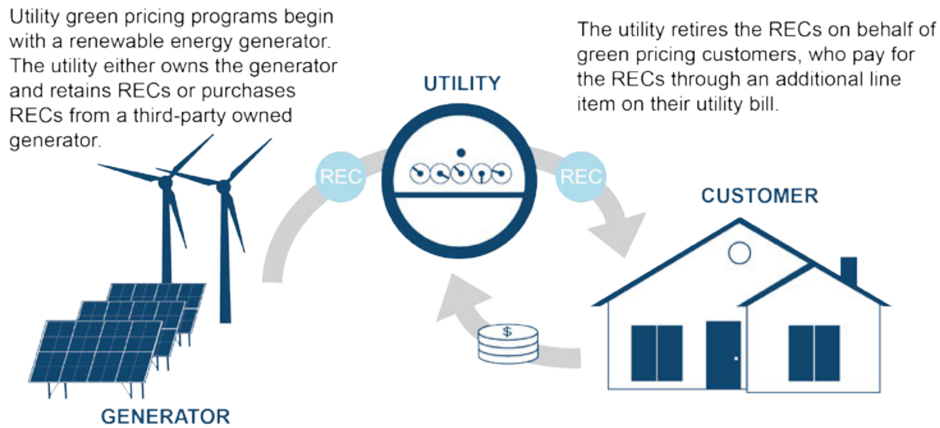


Figure 5. How utility green pricing programs work

The figure provides a simplified schematic for visualization purposes. Specific program structures vary.

3.1 Status of Utility Green Pricing Programs

In 2017, about 885,000 customers bought about 8.9 million MWh of green power through utility green pricing programs (Figure 6).

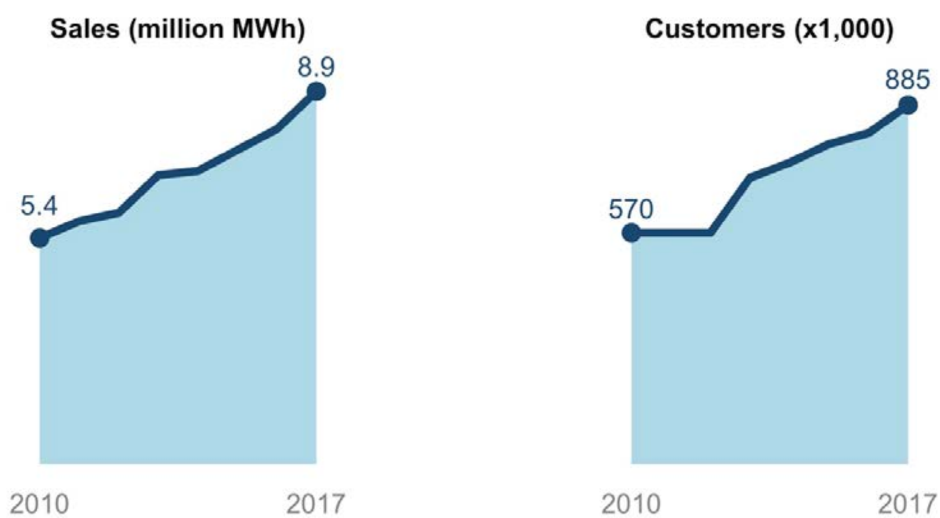


Figure 6. Utility green pricing program sales and participation, 2010–2017

[4] A list of active utility green pricing programs is available at https://www.nrel.gov/analysis/green-power.html ("Voluntary Green Power Procurement," NREL).

3.2 Trends in Utility Green Pricing Programs

Utility green pricing sales continue to steadily increase. A few key trends have emerged alongside this steady increase in sales: growth continues to be driven by a few large programs; utility green pricing programs are increasing the solar content of their green power portfolios; green pricing premiums correlate with program size and renewable energy content; and programs continue to procure primarily unbundled RECs.

Overall growth was driven by success in the largest programs

Large green pricing programs steered overall sales and participation growth in 2017, consistent with previous years, overshadowing ongoing retraction of smaller programs. We estimate that the 10 largest utility green pricing programs accounted for about 90% of overall sales in 2017. These large programs achieve their size, in part, because of high participation rates (i.e., the percentage of eligible customers that enroll in green pricing). For instance, Portland General Electric (PGE), the largest green pricing program in the country, reached a customer participation rate of over 19%. The participation rate among the remaining top 10 programs averaged about 4% (NREL 2018), while participation rates outside the top 10 averaged around 2%.

Residential and nonresidential sales both increased from 2016 to 2017 in the top 10 programs, while sales in both sectors stabilized in the remaining programs (Figure 7). After several years of decline, residential enrollment and sales in programs outside the top 10 programs remained steady over the course of 2017. Similarly, outside the top 10, nonresidential enrollment continued to decline but at a slower rate than previous years. The drivers behind the ongoing decline in nonresidential sales in the non-top 10 programs is unclear. Possible explanations include nonresidential customers shifting toward other green power products such as unbundled RECs, shifting toward other electricity products such as community solar that do not necessarily meet the definition of green power, or simply losing interest in green power.

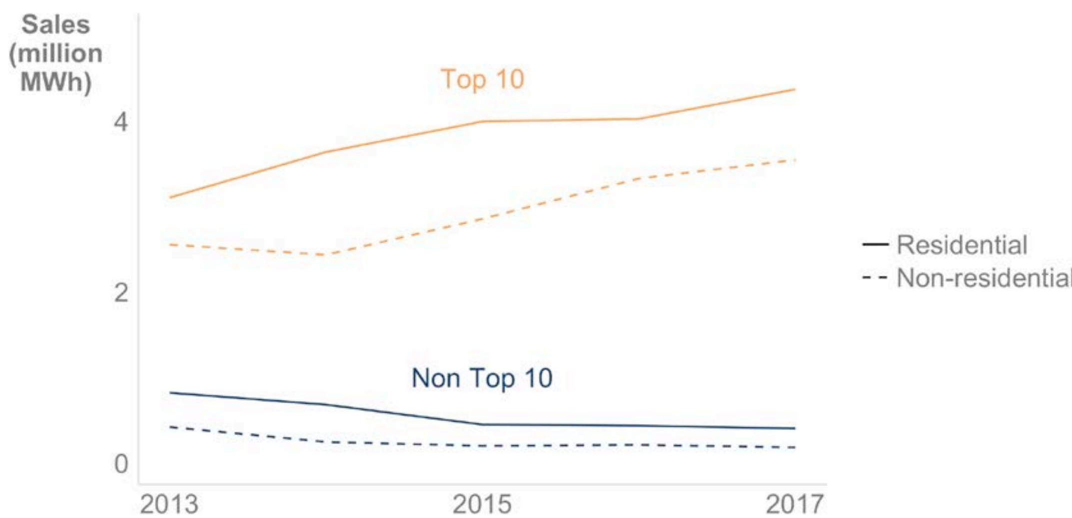


Figure 7. Residential and nonresidential utility green pricing sales in top 10 and other programs

Solar content continues to increase in green pricing portfolios

Solar is increasing in its share of the power mix of green pricing programs, though wind remains the primary generation resource. This trend is largely driven by a few large programs that are beginning to increase procurement of solar resources. Emerging green pricing programs that feature solar procurement allow customers to purchase solar-generated RECs at a premium. Unlike utility-administered community solar, green pricing programs do not provide customers with bill credits for PV system output. Notably, several large utilities that offer green pricing programs initiated new solar programs in 2017 that provide both bill credits and RECs to customers. Though these programs blur the lines between green pricing and community solar, we define them here as community solar and summarize these projects in Section 9.2.2.

To our knowledge, PGE's Green Future Solar program, launched in 2015, remains the only green pricing program fueled entirely by solar. Green Future Solar customers purchase 1-kW "blocks" of solar energy for an additional $5 per month on top of basic service. This program exhibited growth in both sales and enrollment from 2016 to 2017. Several other large programs increased the solar content of their green power portfolios in 2017, including PacifiCorp's Blue Sky Block, Xcel Energy's Renewable*Connect, the Tennessee Valley Authority's Green Power Switch Program, and Avista's Buck-A-Block program.

An increase in solar sales is particularly prominent among the top 10 utilities: the contribution of solar to green power sales in the top 10 programs reached 14% in 2017, compared to 6% for other programs. However, the solar share in non-top 10 programs is increasing rapidly, growing from 1% in 2016 to 6% in 2017. Most remaining non-wind renewable generation outside the top 10 is sourced from landfill gas, which has remained steady at about 13% share of generation.

Figure 8. Percentage of solar in green power portfolios of top 10 and other utility green pricing programs

Green pricing premiums correlate with program size and solar content

Green pricing programs charge customers for their RECs through premiums over the standard rates paid by utility customers. These premiums are generally higher than prices for unbundled RECs (see Section 6) because green pricing programs must also recoup various program and administrative costs. Large green pricing programs generally offer green power at lower price premiums than other programs. The average residential premium among the top 10 programs was about $0.016/kWh, while the average premium among other programs was $0.022/kWh. Overall, residential rate premiums ranged from $0.002/kWh to $0.08/kWh, with an overall average premium of $0.019. The average nonresidential premium among top 10 programs was about $0.013/kWh, while the average premium in smaller programs was about $0.022. The ability of larger programs to offer lower green power premiums, possibly through economies of scale, helps explain why large green pricing programs have been able to sustain high participation rates, while smaller programs continue to exhibit losses in sales. Interestingly, utility green pricing premiums have remained relatively stable in recent years even as renewable energy costs have declined. Stable premiums may reflect stagnant utility administration and marketing costs that, unlike renewable energy costs, have not declined over time.

In addition to correlating with program size, green power premiums exhibit a slight correlation with the percentage of solar in the green power portfolio. Specifically, green power premiums are higher in green pricing programs that use more solar (Figure 9). This correlation is to be expected: solar is generally costlier per watt installed than wind, thus solar RECs are generally more expensive than wind-based RECs (see Section 6.2). The fact that some utility green pricing programs have been able to integrate more solar—despite its typically higher cost—may demonstrate customer interest in and willingness to pay for solar green power products.

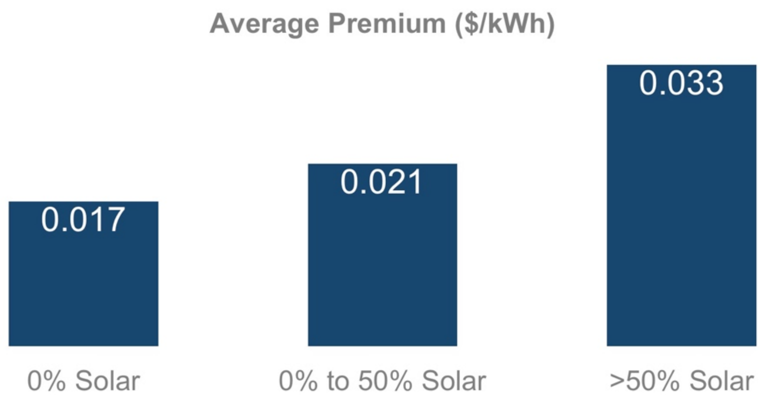


Figure 9. Average green pricing premium for programs offering different percentages of solar

Green Pricing Programs Continue to Procure Primarily through Unbundled RECs

Unbundled RECs remain the leading method for green power procurement in utility green pricing programs.[5] Across all utilities, about 52% of power is procured through unbundled REC contracts of five years or less. More utilities procured power through long-term bundled REC contracts in 2016 than 2017; in 2017, programs procured about 30% of green power through long-term (≥11 years) bundled REC contracts, compared to 18% of power in 2016. Green power procured through utility-or customer-owned generation is marginal and shows a decrease compared to prior years.

[5] As noted in the introduction, unbundled RECs that are bought and sold by an intermediary like a utility green pricing program are excluded from the sales estimates for unbundled RECs summarized in Section 6.

Table 6. Contract Length by Type of Utility Green Power Procurement (MWh), 2017

Contract Length	Unbundled RECs (%)	RECs Bundled with Electricity (%)	Projects Owned by Utility (%)	RECs Produced by Utility Consumers (%)
≤1 year	28	0	0	0
2–5 years	24	0	0	0
6–10 years	3	6	0	~0
≥11 years	4	30	5	0
Percent of total procurement	59	36	5	0

4 Utility Renewable Contracts

Some utilities offer to procure renewable energy on behalf of large nonresidential customers through a one-off bilateral contract or through programs known as utility green tariffs. In both cases, the utility moves the customer to a new rate structure to reflect the costs of the renewable energy project and retires RECs on behalf of the customer. A key difference between utility renewable contracts and utility green pricing is that customers may use utility renewable contracts to support and procure green power from a new generator. Also, the long-term price predictability of utility renewable contracts may yield economic benefits that do not accrue through utility green pricing programs.

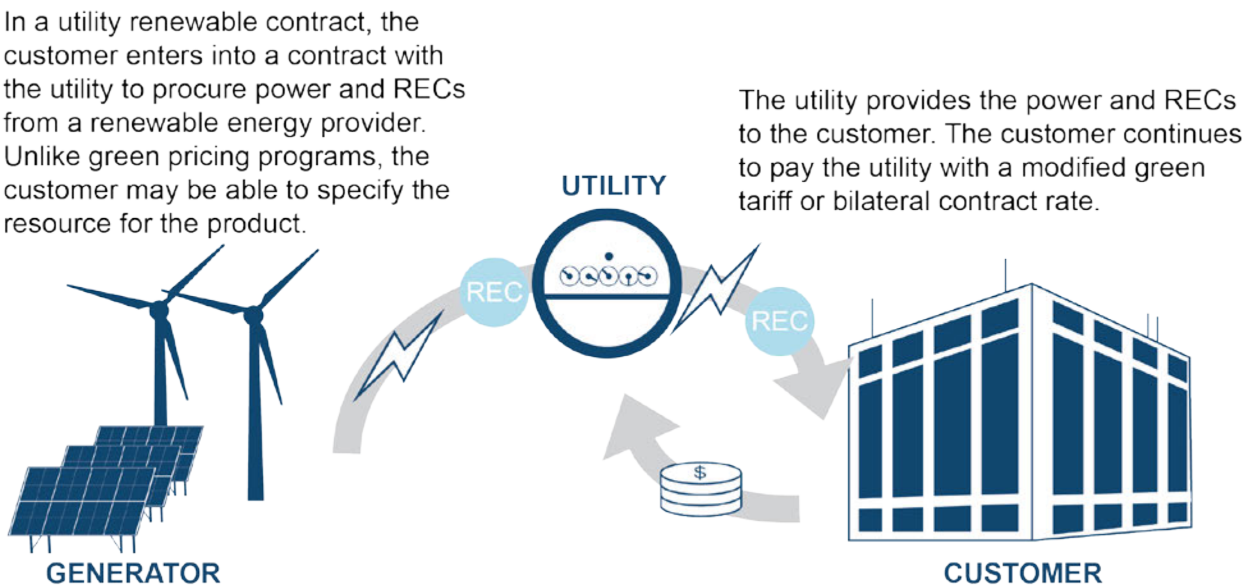


Figure 10. How utility renewable contracts work

The figure provides a simplified schematic for visualization purposes. Specific program structures may vary; tariff structures may also vary within programs on a case-by-case basis.

4.1 Utility Bilateral Agreements

In a bilateral agreement, a utility procures renewable energy on behalf of a single nonresidential customer through a one-off contract. The terms of bilateral agreements are generally unavailable to other customers; hence, bilateral agreements may vary from project to project even within the same utility. Bilateral agreements can be difficult to track, because capacity may not be publicly disclosed. Based on data compiled in Heeter, Cook, and Bird (2017) and on subsequent NREL research, we estimate that at least 15 utility bilateral agreements have been signed in nine states: Alabama, Arizona, Georgia, Iowa, Kentucky, Nebraska, Oklahoma, Oregon, and Tennessee. We estimate that about 741 MW of capacity in six agreements had come online by the end of 2017 and that they generate about 2.2 million MWh of green power per year (Figure 11). Most bilateral agreements to date have been made by information technology companies (e.g., Google and Microsoft), allowing these companies to power data centers with green power located in their utility's service territory. Iowa is the state leader in terms of bilateral contract capacity due to two relatively large wind contracts totaling to about 546 MW of capacity.

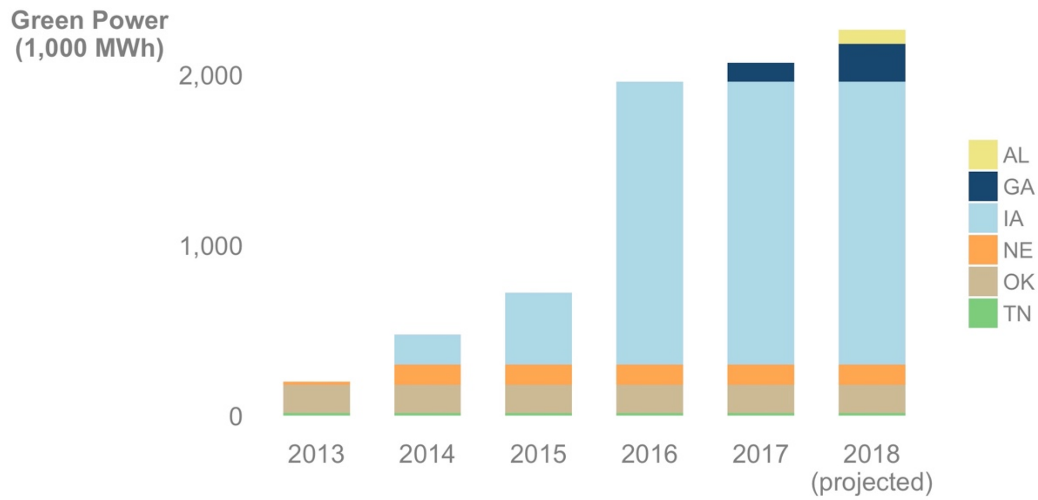


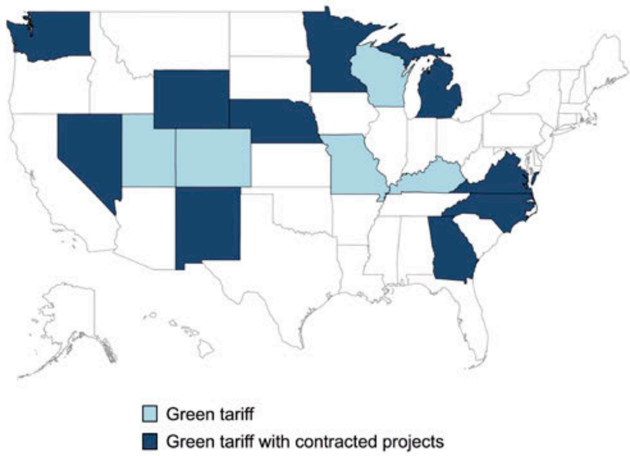
Figure 11. Annual green power sales through utility bilateral contracts

Based on data from Heeter, Cook, and Bird (2017) and data collected by NREL

4.2 Utility Green Tariff Programs

Utility green tariff programs allow customers to switch to new tariff rates to procure renewable energy via the utility. Utility green tariffs are available to any customer in an eligible customer class, whereas bilateral contracts are one-off arrangements with a single customer. Much like a utility green pricing program, this is a program run through the utility but typically involves a larger customer purchase. Further, most utility green pricing customers remain on the same rate structure and pay an additional line-item premium to reflect their participation in green pricing. In contrast, utility green tariff customers switch to a new rate structure to reflect their participation in the green tariff.

Fourteen utilities currently offer green tariff programs, though customers have only used the green tariffs under 10 of these programs (WRI 2018) (Figure 12). By the end of 2018, 21 green tariffs are expected to be offered by 16 utilities in 17 states (Bonugli et al. forthcoming). Some programs are limited to new load, meaning that customers can only use the green tariffs to procure electricity for new facilities or operations (e.g., New Mexico, North Carolina). Some programs place restrictions on the use of green tariffs for existing customers. For instance, the Madison Gas & Electric program in Wisconsin only allows existing customers to use green tariffs for projects no larger than 25 MW in capacity but places no restrictions on new customers (Tawney, Barua, and Bonugli 2017).



CO: Xcel Energy – Renewable*Connect

GA: Georgia Power – Renewable Energy Development Initiative Schedule

KY: Kentucky Power – Renewable Power Option Rider

MI: Consumers Energy Company – Voluntary Large Customer Program

MN: Xcel Energy – Renewable*Connect

MO: Ameren Missouri – Renewable Choice Program

NC: Duke Energy – Green Source Rider

NE: Omaha Public Power District – Schedule No. 261

NM: Public Service Company of New Mexico – Green Energy Rider

NV: NV Energy – Green Energy Rider

UT: Rocky Mountain Power – Service from Renewable Energy Facilities

VA: Dominion Virginia Power – Renewable Energy Supply Service

WA: Puget Sound Energy – Long Term Renewable Energy Purchase Rider

WI: Madison Gas & Electric – Renewable Energy Rider

WY: Black Hills Energy – Large Power Contract Service

Figure 12. Utility green tariff programs

Map based on information from WRI (2018)

By the end of 2017, 770 MW of PV projects had been contracted for through green tariff programs, with about 540 MW of that capacity in nine projects online by the end of 2017. We estimate these projects generated about 716,000 MWh of green power in 2017. We project that green power output will increase to 1,037,000 MWh in 2018 (Figure 13), both because projects that came online in the middle of 2017 will produce for the entire calendar year, and also because three additional projects are slated to come online in 2018 (WRI 2018). Nevada is currently the state leader in terms of green power output from utility green tariffs, in part because NV Energy's program is the longest-running utility green tariff in the country, implemented in September 2013.

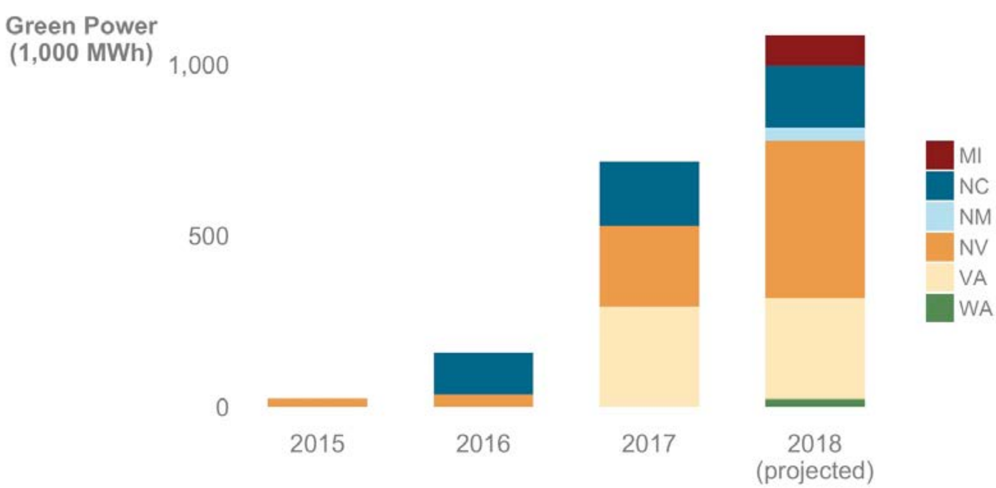


Figure 13. Annual green power sales through utility green tariff programs

Based on data from WRI (2018)