

**MONONGAHELA POWER COMPANY and)
THE POTOMAC EDISON COMPANY,) Case No. 17-0296-E-PC
Petition for Approval of a Generation Resource)
Transaction and Related Relief)
)**

Public Version

August 25, 2017

Table of Contents

I. INTRODUCTION	1
II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS	4
III. THE RATIONALE FOR THE PROPOSED TRANSACTION LACKS MERIT, BECAUSE THE COMPANIES DO NOT NEED TO PROCURE ADDITIONAL GENERATION CAPACITY.	7
IV. PURCHASING PLEASANTS WOULD EXPOSE THE COMPANIES' CUSTOMERS TO RISKS ASSOCIATED WITH SURPLUS ENERGY.....	18
V. PURCHASING PLEASANTS WILL LIKELY MEAN MUCH HIGHER RATES FOR THE COMPANIES' CUSTOMERS.	22
VI. THE COMPANIES' PROPOSED SHORT-TERM RATE DECREASE IS BASED ON UNREASONABLE ASSUMPTIONS.	66
VII. THE PROPOSED TRANSACTION'S PURCHASE PRICE APPEARS TO BE INFLATED.	68
VIII. CONCLUSION AND RECOMMENDATION.....	70

List of Figures and Tables

Figures

Figure 1: The Companies' Use of Winter Peak Loads Plus Reserve Margin Does Not Accurately Represent their Actual PJM Capacity Obligations

Figure 2: The Companies' Projected Energy Position With and Without Pleasants

Figure 3: Purchasing Pleasants Will Leave Ratepayers More Exposed to the Risk of Low Energy Market Prices

Figure 4: Past Prices and Future Price Curves for Henry Hub and the Dominion South Hub

Figure 5: ABB Natural Gas Price Forecast vs. Recent Prices and Futures Price Curve as of August 11, 2017 (Confidential)

Figure 6: ABB's Henry Hub Gas Price Forecasts, Fall 2014 to Fall 2016 (Confidential)

Figure 7: Henry Hub Natural Gas Futures Prices

Figure 8: ABB Forecast Henry Hub Natural Gas Prices vs. Futures Prices and Projections by Morgan Stanley and Moody's (Confidential)

Figure 9: Past and Forward Energy Market Prices for the PJM APS Zone

Figure 10: ABB's Projected APS Zone Energy Market Prices vs. Recent Zonal Prices and Current Forward Price Curve (Confidential)

Figure 11: ABB's Fall 2014 to Fall 2016 Projected APS Zone Energy Market Prices and Actual Prices in 2015 and 2016 (Confidential)

Figure 12: Recent APS Zone Energy Forward Price Curves

Figure 13: AE Supply vs. CRA Average Energy Revenue for Pleasants, 2018-2021 (Dollars per MWh) (Confidential)

Figure 14: AE Supply vs. CRA Pleasants' Energy Revenues for the Years 2018-2021 (Confidential)

Figure 15: Mon Power vs. CRA Pleasants' Energy Market Prices for the Years 2018-2020 (Confidential)

Figure 16: Pleasants Annual Generation, 1995 – May 2017

Figure 17: CRA's Projected Pleasants Generation 2018-2032 versus Historic Generation (Confidential)

Figure 18: Projected Pleasants Generation, 2018-2021 - CRA vs. AE Supply (Confidential)

Figure 19: ABB's Spring 2016 PJM Capacity Price Forecast (Confidential)

Figure 20: PJM 2016 and 2017 Load Forecasts

Figure 21: Projected PJM Capacity Prices by Delivery Year

Figure 22: Projected PJM Capacity Prices by Calendar Year

Figure 23: Energy Market Prices Used in CRA and Schlissel Technical Consulting (STC) Analyses (Confidential)

Figure 24: Future Pleasants Annual Generation Used in CRA and STC Analyses (Confidential)

Figure 25: Capacity Prices Used in CRA and STC Analyses (Confidential)

Figure 26: Annual Economic Results (Confidential)

Figure 27: CRA vs. Pleasants' Specific Coal Price Forecast (Confidential)

Tables

Table 1: Economics Results in Net NPV and Nominal Dollar

Table 2: Recent Dayton Power & Light Coal Plant Valuations

List of Exhibits

Exhibit DAS-1:	Schlissel Resume
Exhibit DAS-2:	Resp. to CAG-SUN-V-19
Exhibit DAS-3:	Resp. to CAG-SUN-I-11
Exhibit DAS-4:	Resp. to CAG-SUN-III-1
Exhibit DAS-5:	Resp. to CAG-SUN-III-17
Exhibit DAS-6:	Resps. to CAG-SUN-V-16 and Longview-I-2
Exhibit DAS-7:	Resp. to CAG-SUN-II-3
Exhibit DAS-8:	Resp. to CAG-SUN-II-8
Exhibit DAS-9:	Resp. to CAD-IV-B-9
Exhibit DAS-10:	Resp. to SC-II-7
Exhibit DAS-11:	Resp. to CAG-SUN-V-8
Exhibit DAS-12:	Resp. to CAG-SUN-V-12
Exhibit DAS-13:	Resp. to CAG-SUN-IV-13
Confidential Exhibit DAS-14: Resp. to CAG-SUN-II-36, Attachment C (Confidential – Competitively Sensitive)	
Exhibit DAS-15:	Resp. to WVEUG-IV-7
Exhibit DAS-16:	Resp. to CAG-SUN-IV-10
Exhibit DAS-17:	Resp. to SC-III-5
Confidential Exhibit DAS-18: Results of CRA’s NPV calculation (Confidential)	
Confidential Exhibit DAS-19: Results of STC Base Case, High Case, Low Case, and AE Supply Sensitivity (Confidential – Competitively Sensitive)	
Exhibit DAS-20:	Resps. to SC-II-6 and CAD-IV-B-16
Exhibit DAS-21:	Resps. to WVEUG-I-12, 13, and 24
Confidential Exhibit DAS-22: Resp. to CAD-III-A-26 (Confidential – Competitively Sensitive) and Supplemental Resp. to CAG-SUN-I-27 (Confidential)	

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is David A. Schlissel. I am the President of Schlissel Technical
4 Consulting, Inc., 45 Horace Road, Belmont, Massachusetts 02478.

5 **Q. On whose behalf are you testifying?**

6 A. I am testifying on behalf of West Virginia Solar United
7 Neighborhoods/Community Power Network (“WV SUN”) and the West Virginia
8 Citizen Action Group (“WVSUN/CAG”).

9 **Q. Please summarize your educational background and recent work experience.**

10 A. I graduated from the Massachusetts Institute of Technology in 1968 with a
11 Bachelor of Science Degree in Engineering. In 1969, I received a Master of
12 Science Degree in Engineering from Stanford University. In 1973, I received a
13 Law Degree from Stanford University. In addition, I studied nuclear engineering
14 at the Massachusetts Institute of Technology during the years 1983-1986.

15 Since 1983 I have been retained by governmental bodies, publicly-owned utilities,
16 and private organizations in 38 states to prepare expert testimony and analyses on
17 engineering and economic issues related to electric utilities. My recent clients
18 have included the U.S. Department of Justice, the Attorney General and the
19 Governor of the State of New York, state consumer advocates, and national and
20 local environmental and consumer organizations.

21 I have filed expert testimony before state regulatory commissions in Arkansas,
22 Arizona, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana,
23 Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota,
24 Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North
25 Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, South
26 Dakota, Texas, Vermont, Virginia, West Virginia, and Wisconsin and before an
27 Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

1 A copy of my current resume is included as Exhibit DAS-1. Additional
2 information about my work is available at www.schlissel-technical.com and at
3 www.ieefa.org.

4 **Q. Have you previously testified before the Public Service Commission of West**
5 **Virginia?**

6 A. Yes. I have filed testimony in Commission Case Nos. 97-1329-E-CN, 06-0033-E-
7 CN, 12-1571-E-PC, 12-1655-E-PC and 14-0546-E-PC.

8 **Q. What is the purpose of your testimony in this proceeding?**

9 A. I was asked to evaluate the proposed transaction in which Monongahela Power
10 Company (hereinafter, “Mon Power”) would acquire ownership (1,300 MW of
11 installed capacity) of the Pleasants Power Station from its merchant affiliate,
12 Allegheny Energy Supply Company (“AE Supply”). Under this proposal, the
13 customers of Mon Power and The Potomac Edison Company (collectively, “the
14 Companies”) would become financially responsible for Pleasants. This testimony
15 presents the results of my evaluation and analyses of the proposed transaction.

16 **Q. What materials have you reviewed in your preparation of this testimony?**

17 A. I have reviewed the testimony and exhibits filed by the Companies and their
18 responses to discovery requests submitted by the active parties to this proceeding,
19 as well as publicly available information on the Pleasants plant, natural gas prices,
20 and past, current, and future PJM loads, resources, and energy and capacity
21 market prices.

1 **Q. Please briefly describe the Companies' Petition and the proposed**
2 **transaction.**

3 A. The Companies are seeking Commission approval for Mon Power to purchase the
4 Pleasants plant from AE Supply for a price of \$195 million.¹ The plant would
5 then be added to Mon Power's rate base, where it would earn an assumed 10%
6 return on equity.² To cover these expenses until the next base rate case, the
7 Companies have asked the Commission to approve a Temporary Surcharge of
8 approximately \$148 million.³ The Companies nevertheless claim that, due to
9 their expectations of increased Expanded Net Energy Cost ("ENEC") revenues,
10 the proposed transaction would result in a short-term rate decrease.⁴ (As
11 explained in Section VI below, this claim is based on unrealistic energy price
12 assumptions.)

13 Mon Power's proposed acquisition of the plant from AE Supply, its corporate
14 affiliate, followed a request for proposals ("RFP") that was administered by
15 Charles River Associates ("CRA"). Among other restrictions, the RFP included a
16 strong geographic preference for generating facilities within the Allegheny Power
17 System ("APS") zone of PJM.⁵ In the RFP, Mon Power also excluded an array of
18 resources, including generators whose unforced capacity was less than 100 MW,
19 renewable resources such as wind and solar, and long-term power purchase
20 agreements ("PPAs").⁶ After reviewing the three conforming bids received
21 during the RFP process, CRA recommended Pleasants as the winning bid.⁷

¹ Petition for Approval of Generation Resource Transaction and Related Relief at page 7 (Mar. 7, 2017) (hereinafter, "Petition"). A portion of the purchase price could be satisfied assuming AE Supply's repayment obligations for \$142 million of pollution control bond debt. *Id.*

² Direct Testimony of Raymond E. Valdes at page 7 (hereinafter, "Valdes Direct").

³ Petition at page 8.

⁴ *Id.*

⁵ Direct Testimony of Robert J. Lee (hereinafter, "Lee Direct"), Ex. RJL-1 & Ex. RJL-2 (Mon Power RFP) at page 12 (Dec. 16, 2016). The RFP states that bids to sell a facility outside the APS zone "may" be considered if Mon Power does not receive at least three qualified bids from within the zone.

⁶ See Lee Direct, Ex. RJL-2 at page 12; Direct Testimony of Jay A. Ruberto at pages 9, 11 (hereinafter, "Ruberto Direct"). During the RFP process, Mon Power further stated that it would not entertain a long-term fixed-priced PPA instead of an acquisition even if "the fixed price would be significantly below the

1 To assess the economics of the plants bid into the RFP, CRA prepared net present
2 value (“NPV”) calculations.⁸ In performing these calculations, CRA relied on a
3 set of natural gas, capacity, and energy price forecasts from ABB Inc. Although
4 the NPV calculations were performed in February 2017, the underlying price
5 forecasts were completed in May 2016.⁹ CRA used the energy price forecast to
6 project Pleasants’ generation and energy market revenues over a 15-year period
7 (2018-2032).¹⁰ This projection was developed using a Microsoft Excel-based tool
8 that compared the forecasted prices to the plant’s variable (fuel and non-fuel
9 O&M) costs.¹¹ CRA then plugged the results of that projection into its NPV
10 spreadsheet to come up with a 15-year NPV calculation.

11
12 **II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

13 **Q. Please summarize your principal conclusions and findings.**

14 A. First, if FirstEnergy Corp. actually believed CRA’s overly optimistic forecasts of
15 future energy and capacity market revenues and the projection of significant
16 economic benefits from continued operation of the Pleasants plant, AE Supply
17 wouldn’t be selling the plant.

18 Second, the Companies create an artificial “need” for the capacity from Pleasants
19 by overstating their PJM capacity obligation using a forecast based on their winter

long term cost of an acquisition.” Mon Power RFP Q&A, GEN 00004 (Dec. 27, 2016), *available at* <http://monpower-rfp.com/FAQ>. Although Mon Power defended the exclusion of PPAs from the RFP by citing, among other things, a desire to “minimize against market risk and volatility,” Lee Direct at page 4, the Companies failed to produce any studies supporting their suggestion that PPAs involve market risks or volatility. Exhibit DAS-2 (resp. to CAG-SUN-V-19).

⁷ Lee Direct at page 9.

⁸ *Id.* at page 7; Lee Direct, Ex. RJL-2 at page 22. The NPV calculation, which has been designated confidential, was produced in discovery. See Exhibit DAS-3 (resp. to CAG-SUN-I-11(b)).

Note: much of the information that the Companies produced in discovery, and which is discussed in my testimony, has been variously designated as Confidential or Confidential-Competitively Sensitive. All exhibits and figures that reference such confidential information are labeled as “Confidential,” and have been redacted from the public version of my testimony.

⁹ See Exhibit DAS-4 (resp. to CAG-SUN-III-1(c)(i)).

¹⁰ Lee Direct, Ex. RJL-1 at page 1.

¹¹ Lee Direct at page 13.

1 peak loads. Contrary to the Companies’ approach here, PJM actually determines
2 capacity obligations on the basis of utilities’ coincident contributions to PJM’s
3 peak demand – which occurs in the summer, not the winter.

4 Third, the Companies’ claim that the proposed transaction will result in long-term
5 rate benefits to customers¹² is based on a severely flawed economic analysis. The
6 NPV calculation relied on by the Companies is at heart driven by the extremely
7 optimistic, unreasonable assumption that the future will be very different (and
8 much more favorable to the economics of coal-fired generation) than the recent
9 past. In particular, the Companies assume that, contrary to recent history:

- 10 1. Future natural gas and energy market prices will [[REDACTED]
11 [REDACTED]].
- 12 2. The amount of power generated by Pleasants will [[REDACTED]]
13 between 2016 and 2020 and, as a result, the plant will generate [[REDACTED]
14 [REDACTED]]
15 [REDACTED]].
- 16 3. Capacity prices will [[REDACTED]
17 [REDACTED]].
- 18 4. Pleasants’ future operating performance [[REDACTED]] and/or its
19 operating costs or capital expenditures (“capex”) [[REDACTED]
20 [REDACTED]] despite the aging of plant components, structures and
21 equipment.
- 22 5. Pleasants will not incur any compliance costs associated with U.S. EPA’s
23 Effluent Limitations Guidelines (“ELG”) rule, or with the closure of a

¹² See Ruberto Direct at page 21 (“the acquisition of the entire Pleasants plant is projected to produce a net present value of \$636 million over 15 years with an associated rate benefit to customers”); see also Petition at pages 15-17.

1 large coal ash impoundment that would be transferred to customers under
2 the proposed transaction.

3 The Companies' unreasonably optimistic assumptions were compounded by the
4 fact that the NPV calculation prepared by CRA merely looked at a single set of
5 future conditions through which it, not surprisingly, decided that the acquisition
6 of Pleasants would provide a substantial NPV benefit for the Companies'
7 ratepayers. CRA did not consider any sensitivities or alternative scenarios.

8 Fourth, CRA's NPV calculation reflects forecasts for future Pleasants generation
9 and energy market prices that are [[REDACTED]] than the plant's current owner, AE
10 Supply, has assumed in its recent income statements and cash flow projections.
11 CRA also forecasts [[REDACTED]] energy market prices than Mon Power has projected
12 in recent modeling of its Harrison and Fort Martin plants.

13 Fifth, the Companies' claim that the proposed purchase of the Pleasants plant will
14 result in a rate decrease in 2017 and 2018 is premised on the assumption that
15 energy market prices will be [[REDACTED]] than those in CRA's NPV
16 calculation.

17 Sixth, the \$150 per kW purchase price at which the Companies would acquire
18 Pleasants is inflated when compared to recent valuations of other coal plants in
19 western PJM.

20 **Q. Please summarize your recommendations.**

21 A. I am recommending that the Commission deny the Companies' proposed
22 transaction.

23 If the Commission does approve the transaction, however, the Companies – not
24 customers – should be required to bear the market risks of the Pleasants plant, *i.e.*,
25 that the revenues they receive from selling Pleasants' energy and capacity into the
26 PJM markets do not fully recover the future costs of producing power at the plant.
27 Ratepayers should not be forced to bear all of these significant risks. This is

1 especially so given that the Companies are basing their economic analyses on
2 such a drastic change in future circumstances from what we have seen in recent
3 years.

4

5 **III. THE RATIONALE FOR THE PROPOSED TRANSACTION LACKS**
6 **MERIT, BECAUSE THE COMPANIES DO NOT NEED TO PROCURE**
7 **ADDITIONAL GENERATION CAPACITY.**

8 **Q. The Companies contend that the proposed transaction provides a “solution”**
9 **to a purported capacity shortfall.¹³ What capacity shortfall have the**
10 **Companies projected?**

11 A. In their Petition, the Companies claimed that they would face a capacity shortfall
12 of 1,005 MW of unforced capacity by 2020, growing to 1,439 MW by 2027.¹⁴
13 When the Companies presented these figures, they anticipated selling their
14 16.25% share of the Bath County pumped storage facility.¹⁵

15 **Q. Does Mon Power still plan to sell the Bath County plant?**

16 A. No. Although Mon Power previously planned to sell its share of Bath County
17 through an RFP process, the Companies now state that Mon Power has no plans
18 to dispose of its ownership share.¹⁶ The decision not to sell Bath County means
19 that Mon Power will own about 220 MW more capacity than the Companies
20 assumed in the Petition. In effect, the Companies are now claiming that they will

¹³ Petition at pages 4, 5, 15.

¹⁴ *Id.* at pages 2, 4, 15; Ruberto Direct at page 7. In the PJM capacity market, a utility’s capacity obligations, and a generating unit’s capacity, is measured in MW of unforced capacity, or “UCAP.” PJM distinguishes between UCAP and installed capacity, or ICAP. “Installed capacity represents the maximum generating capacity of a given facility. Unforced capacity represents the amount of installed capacity that is actually available at any given time after discounting for time that the facility is unavailable due to outages such as repairs.” Capacity Market/RPM FAQs, at Q3, available at <https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets/capacity-markets-faqs.aspx> (last visited Aug. 24, 2017). Unforced capacity is therefore lower than installed capacity.

¹⁵ Petition at pages 3-4.

¹⁶ Exhibit DAS-5 (Companies’ resp. to CAG-SUN-III-17).

1 face a shortfall of 779 MW of unforced capacity by 2020, growing to 1,213 MW
2 by 2027.¹⁷

3 **Q. Does the existence of a capacity shortfall mean that the Companies “need” to**
4 **purchase a generation asset?**

5 A. No.

6 **Q. Please explain.**

7 A. The Companies participate in the PJM capacity market (called the Reliability
8 Pricing Model, or “RPM”), which is designed to ensure that there is enough
9 capacity to meet customer load throughout the region.¹⁸ Through the RPM, PJM
10 purchases sufficient capacity, through auctions, to meet the reliability
11 requirements of its system. PJM then assigns a daily unforced capacity obligation
12 to participating utilities to charge them, based on their contribution to the overall
13 system peak, for their share of the total capacity purchased.¹⁹ Under PJM rules,
14 there is no requirement that the Companies – or any other utility – own as much
15 unforced capacity as their PJM capacity obligation. Consequently, the Petition’s

¹⁷ The Companies provided their capacity calculation, both with and without Bath County, in a spreadsheet produced in discovery. See CAG-SUN-1-8 Attachment A. This spreadsheet assumes that Mon Power’s share of Bath County will have a UCAP of 226 MW starting with the 2020/21 delivery year. (In PJM’s capacity market, capacity obligations and prices are determined based on the delivery year, which runs from June 1-May 31. For example, the 2020/21 delivery year runs from June 1, 2020, through May 31, 2021.)

¹⁸ “The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid.” PJM Manual 18: PJM Capacity Market, Revision 38, at page 4 (July 27, 2017) (hereinafter, “PJM Manual 18”), available at <http://www.pjm.com/-/media/documents/manuals/m18.ashx>. In their integrated resource plan, the Companies acknowledged that “PJM determines what constitutes sufficient capacity to maintain overall reliability for each zone through its annual load forecast and reserve margin guidelines.” Case No. 15-2002-E-IRP, 2015 Integrated Resource Plan at page 18 (Dec. 30, 2015) (hereinafter, the “2015 IRP”).

¹⁹ See PJM Manual 18 at pages 5-6 (“Under RPM, each [load serving entity] that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone.”). The only exception is where a utility elects to be a Fixed Resource Requirement (“FRR”) entity. FRR entities effectively opt out of the PJM capacity auction process, and must procure their own generation capacity. *Id.* at page 208. The Companies are not FRR entities, and there is no evidence that they have considered selecting the FRR option.

1 repeated references to the Companies’ “capacity needs,”²⁰ which they cite as a
2 rationale for this proposed transaction, is misleading.

3 Put differently, there is a difference between a capacity *need* and a capacity
4 *shortfall*. Even if the Companies’ PJM capacity obligation were greater than the
5 UCAP of Mon Power’s current generating fleet (such that it had a “capacity
6 shortfall”), Mon Power would not need to procure additional capacity. Because
7 the Companies participate in the PJM capacity market, the RPM ensures that
8 customers will have reliable electric service. Accordingly, the Petition is wrong in
9 suggesting that generation capacity is “needed to serve West Virginia
10 customers.”²¹ Although the Companies’ proposed purchase of Pleasants would
11 have a significant financial impact on customers (and, as discussed in Section V
12 below, would likely increase costs to customers), the transaction is not necessary
13 to ensure reliability.

14 **Q. How does Mon Power’s ownership of generation capacity affect the**
15 **Companies’ customers?**

16 A. The impact is financial. In PJM, a utility is not required to own any generating
17 capacity to meet its capacity obligation – a utility such as Mon Power satisfies its
18 capacity obligation by paying locational reliability charges to PJM. Meanwhile,
19 Mon Power bids the unforced capacity of its generation assets into the PJM
20 auctions, where they receive capacity payments for whatever amount of their
21 capacity clears in the auction. Thus, to the extent a utility, such as Mon Power,

²⁰ See, e.g., Direct Testimony of Holly C. Kauffman at pages 10, 11 (hereinafter, “Kauffman Direct”);
Ruberto Direct at page 3.

²¹ Petition at page 1. It is also worth noting that the Pleasants plant’s energy and capacity would not be
“earmarked” for the Companies’ customers. As the Companies have acknowledged, “Mon Power bids all
of the energy and capacity from its power plants into the PJM energy and capacity markets.” Exhibit DAS-
6 (resps. to CAG-SUN-V-16 and Longview-I-2).

Note: WVSUN/CAG served discovery request CAG-SUN-V-16 under seal, but the Companies
subsequently determined that this question, and their response, were not confidential. Letter from G. Jack,
FirstEnergy, to E. Pepper, WVCAG (Aug. 14, 2017).

1 owns generation facilities, the capacity revenues earned from those facilities can
2 offset the capacity payments being paid to PJM.²²

3 **Q. How is the cost of capacity reflected in rates?**

4 A. The amount that customers ultimately pay for capacity is the difference between
5 the Companies' capacity payments to PJM (i.e., the locational reliability charge)
6 and the capacity revenues Mon Power's power plants receive for however much
7 of their UCAP clears in the PJM auction. This means that, all else being equal,
8 customers would receive a net capacity credit if Mon Power's generation fleet
9 earned more capacity revenue than the amount of the charges the Companies must
10 pay to satisfy their capacity obligation.²³ Conversely, customers would pay a net
11 capacity charge if the Companies' capacity payments to PJM exceeded the
12 capacity revenues earned by Mon Power's generation fleet. Because the cost of
13 capacity is tied to the Companies' PJM capacity obligation, the only definition of
14 "capacity shortfall" that has any meaning for ratepayers is the amount by which
15 the Companies' PJM capacity obligation exceeds the UCAP of Mon Power's
16 generation fleet that clears the auction.

17 **Q. Do you agree with the Companies' claim that it will face a 779 MW capacity**
18 **shortfall by 2020?**

19 A. No, I do not. This capacity shortfall claim contradicts the Companies' prior
20 representations to this Commission, and does not reflect how their actual PJM
21 capacity obligations will be determined, which will be based on their contribution
22 to PJM's coincident peak demand – which occurs in the summer.

²² As stated on page 6 of PJM's Manual 18, "[load serving entities] may choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Incremental Auctions or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction. Such action may wholly or partially offset an LSE's Locational Reliability Charges during the Delivery Year depending upon how the clearing prices of the resources compare to the Final Zonal Capacity Prices that apply to their unforced capacity obligations."

²³ The bills that customers ultimately pay not only reflect capacity charges, but also (among other things) energy costs and revenues, and the costs of owning generation facilities.

1 **Q. Please explain how the Companies' claim is inconsistent with their prior**
2 **representation.**

3 A. The Companies' capacity shortfall claim relies on a forecast which projects a 384
4 MW shortfall during the 2019/20 delivery year, growing to a 779 MW shortfall in
5 2020/21.²⁴ But in a September 2016 filing with the Commission, the Companies
6 stated that their estimated PJM capacity obligation for the 2019/20 delivery year
7 was 3,229 MW of unforced capacity, while the Companies projected that they
8 would own 3,399 MW of unforced capacity.²⁵ In other words, far from claiming a
9 384 MW unforced capacity *shortfall*, the Companies have previously admitted
10 that they will have an estimated capacity *surplus* of 170 MW during 2019/20.
11 This large discrepancy demonstrates that the Companies' claims of an imminent
12 shortfall, including the claimed 779 MW shortfall in 2020/21, are not credible.

13 **Q. Please explain how the Companies developed the capacity shortfall**
14 **calculation reflected in Mr. Ruberto's testimony.**

15 A. The Companies first created a load forecast, which they created by forecasting
16 future energy consumption (GWh) and inputting that forecast into a regression
17 model to arrive at forecasts of summer and winter peak demand (MW).²⁶ The
18 Companies then added a reserve margin to the forecast.²⁷ The capacity shortfall
19 graphically represented on page 20 of Mr. Ruberto's testimony was calculated by
20 taking the Companies' forecast of winter peak demand, plus the PJM installed
21 reserve margin, and comparing those figures to Mon Power's currently owned
22 capacity (measured in MW of unforced capacity).

23 **Q. Do you agree with the approach taken by the Companies to calculate their**
24 **capacity position?**

25 A. No. The Companies failed to follow PJM's methodology when they projected
26 their future capacity position. PJM establishes utilities' capacity obligations using

²⁴ Ruberto Direct at page 20; *see also* CAG-SUN-I-8 Attachment A.

²⁵ Case No. 16-1074-E-P, Companies' Response and Motion to Dismiss at page 2 (Sept. 6, 2016).

²⁶ Direct Testimony of Bradley Eberts at pages 3-5.

²⁷ *Id.* at page 3.

1 a particular methodology. Specifically, a utility’s capacity obligation is based on
2 summer peak load coincident with the PJM peaks.²⁸ In their Petition, however,
3 the Companies calculated their capacity position using winter peak load, a value
4 which is greater than summer peak load within the Companies’ service territory.²⁹
5 By using these higher winter peaks, and departing from the PJM methodology, the
6 Companies significantly increased the size, and hastened the timing, of their
7 purported capacity shortfall.³⁰

8 **Q. But aren’t the Companies generally winter-peaking utilities?**

9
10 A. Yes, but that is not relevant to the Companies’ PJM capacity obligation. The
11 Companies participate in the PJM capacity market and the PJM system as a whole
12 is summer peaking. Therefore, because PJM procures sufficient capacity to cover
13 its overall system peak, it ensures that there will be sufficient capacity at all times
14 of the year, including the winter period when the Companies experience their
15 peak.³¹ (In fact, PJM is currently experiencing a capacity surplus – there is

²⁸ PJM Manual 19: Load Forecasting and Analysis, Revision 31, at page 27 (June 1, 2016), *available at* <https://www.pjm.com/~media/documents/manuals/m19.ashx>. PJM determines capacity obligations by, first, considering zonal weather-normalized summer peak loads and then calculating the contribution of each wholesale and retail customer to those peaks. *Id.* The resulting Peak Load Contribution serves as the basis for determining the capacity obligation.

²⁹ 2015 IRP at page 16; *see also* Ruberto Direct at pages 5-6.

³⁰ In response to discovery, the Companies admit that their winter peak demand is not used in setting the Companies’ PJM capacity obligation, and that the PJM capacity obligation is based on the Companies’ summer peak coincident with the PJM peak. Exhibit DAS-7 (resp. to CAG-SUN-II-3). The Commission Staff has similarly observed that, “[b]ecause PJM peaks in the summer, for PJM planning purposes, the adequacy of MPC [Mon Power Company] capacity is measured during the summer months.” Public Service Commission of West Virginia, 2016 Management Summary Report, Appendix C, at p. 88 (Feb. 2017), *available at* http://www.psc.state.wv.us/Mgmt_Sum/MSR2016_Report.pdf.

³¹ Although PJM does have a winter reserve target, it does not impose any obligation on the Companies (or any other utilities) in acquiring capacity to meet this target. Instead, as explained in PJM’s most recent Reserve Requirements Study, “With this [winter reserve margin] recommendation, the PJM Operations Department will coordinate generator maintenance scheduling over the winter period to seek to preserve a 27% margin after units on planned and maintenance outages are removed. This margin is a guide to be used by PJM Operations and is not an absolute requirement.” 2016 PJM Reserve Requirement Study at page 43 (Oct. 6, 2016) (emphasis removed), *available at* <http://www.pjm.com/~media/committees-groups/subcommittees/raas/20160927/20160927-2016-pjm-reserve-requirement-study.ashx>.

1 significantly more existing and planned generation in PJM than is needed to
2 satisfy PJM's reserve margin requirements.³²⁾

3 **Q. Are you aware of any instance in the past in which the Companies have**
4 **claimed that they need to own enough capacity to meet their winter peak**
5 **loads plus a reserve margin?**

6
7 A. No. In the last proceeding in which the Companies sought approval to purchase a
8 generation asset (the Harrison plant), they based their capacity shortfall projection
9 on their summer peak.³³

10 **Q. Does the Companies' forecast of their winter peak plus reserve margin**
11 **provide an accurate representation of the Companies' actual PJM capacity**
12 **obligation?**

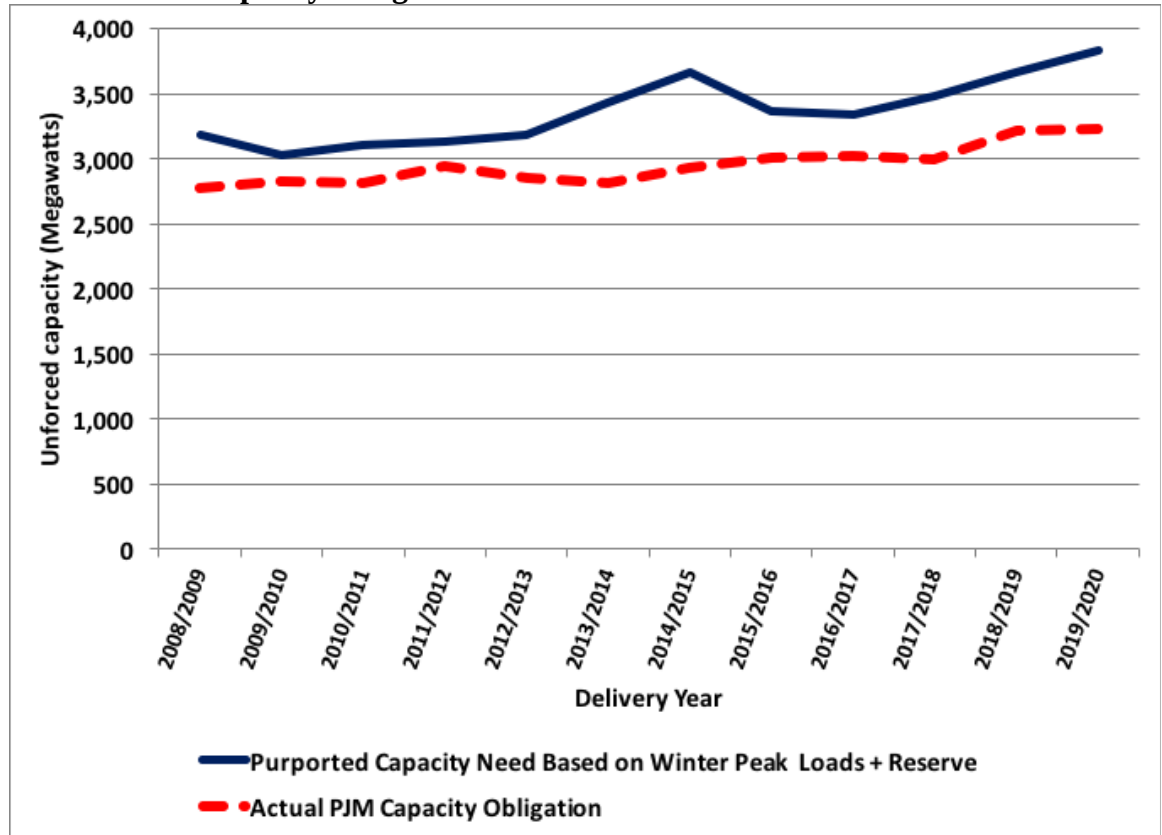
13
14 A. Not at all. In fact, as shown by Figure 1, below, if the approach that the
15 Companies have taken to projecting their capacity requirements in this case were
16 applied retroactively, they would have dramatically overstated their actual PJM
17 capacity obligations for the last decade.

³² See PJM, Forecasted Reserve Margin, available at <http://www.pjm.com/-/media/planning/res-adeq/20170705-forecasted-reserve-margin-graph.ashx?la=en>.

³³ Case No. 12-1571-E-PC, Direct Testimony of Michael B. Delmar at page 8, Figure 1 (Nov. 16, 2012).

1
2
3

Figure 1: The Companies' Use of Winter Peak Loads Plus Reserve Margin Does Not Accurately Represent their Actual PJM Capacity Obligations



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7

Q. Please explain.

8

A. The solid dark line in Figure 1 is the Companies' purported capacity need using the approach presented in their Petition (*i.e.*, winter peak load plus reserve margin). For 2008 through 2015, this line reflects the Companies' actual winter peak loads plus reserve margin; from 2016 onward, it shows the forecast winter peak loads plus reserve presented by witness Eberts in this case.

9

10

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1 The dashed red line in Figure 1 represents the Companies' actual capacity
2 obligation for PJM delivery years 2008/09 through 2016/17 and the Companies'
3 own estimate of its PJM capacity obligation for 2017/18 through 2019/20.³⁴

4 For the historical period from PJM delivery years 2008/09 through 2016/17, the
5 Companies' purported capacity needs based on winter peak loads plus reserve
6 margin would have exceeded their actual PJM capacity obligations by an average
7 of nearly 400 MW each year. For the next three years (that is, delivery years
8 2017/2018 through 2019/2020), use of the Companies' winter peak load plus
9 reserve margin methodology would overstate their projected PJM capacity
10 obligation by over 500 MW each year.

11 **Q. Is there any reason to expect that the Companies' winter peak loads +**
12 **reserve margin will become an accurate predictor of their PJM capacity**
13 **obligations in the future?**

14
15 A. No. The Companies' future capacity obligations will be based on their share of
16 the coincident PJM peak load which will be in the summer, not on its own winter
17 peak loads. Remarkably, the Companies have chosen to present a methodology
18 for determining their capacity shortfall that does not resemble how their actual
19 PJM capacity obligation – which, as explained above, is what ratepayers are
20 actually charged for – is determined.

21 **Q. Aside from identifying this critical flaw in the Companies' claimed need for**
22 **the capacity from the Pleasants plant, have you evaluated the validity of the**
23 **Companies' underlying energy requirements forecast?**

24 A. No, I have not evaluated those aspects of the forecast.

³⁴ The Companies have not forecasted their capacity obligation past 2019/20. See Exhibit DAS-7 (resp. to CAG-SUN-II-3).

1 **Q. Most of the Companies’ testimony focused on the Companies’ capacity**
2 **position as the justification for the proposed transaction. Have the**
3 **Companies articulated any “need” for purchasing a coal plant on the basis of**
4 **a need for more energy?**

5 A. No. In fact, the available evidence shows that the Companies are already long on
6 energy, and that this surplus would balloon if Mon Power purchases Pleasants.

7 **Q. Please explain.**

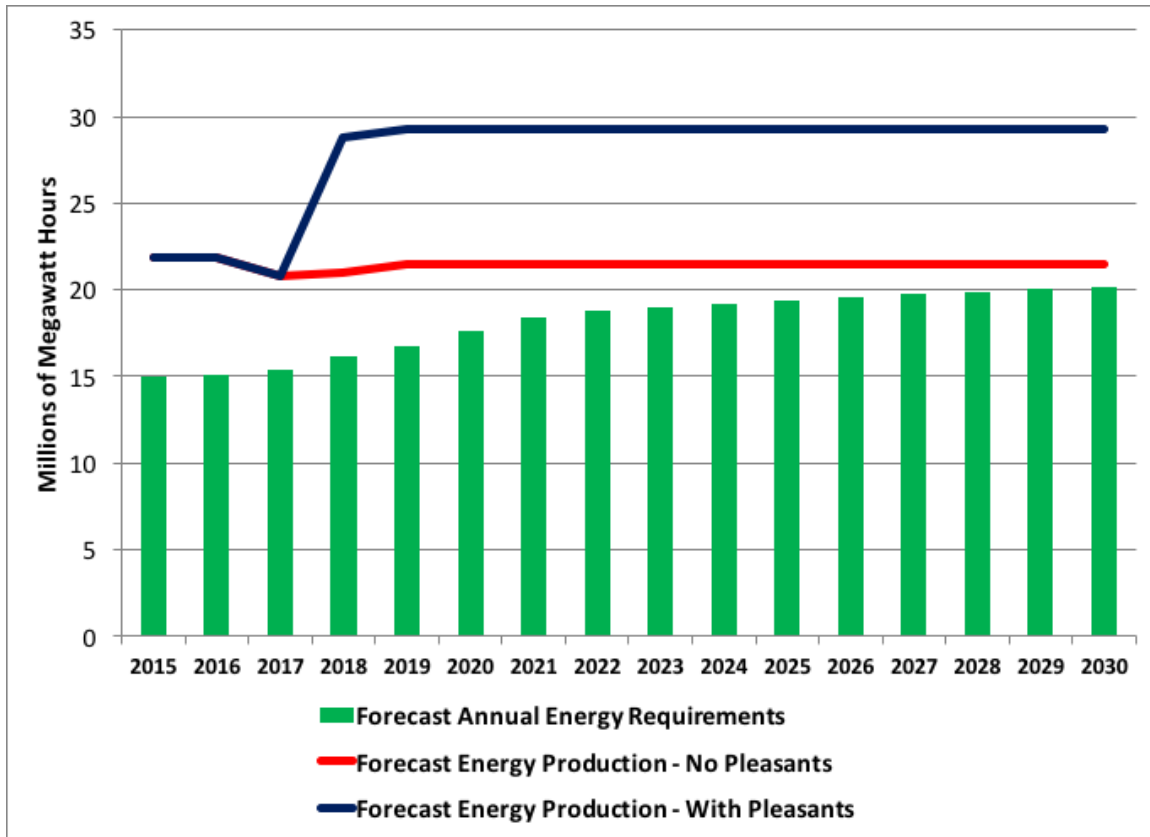
8 A. The forecasts presented in the Companies’ 2015 IRP show that, with no additional
9 generating capacity, Mon Power’s fleet will produce far more energy than the
10 Companies will purchase to meet customer requirements through 2030.³⁵ In 2030,
11 the Companies will generate 14% more electricity than their customers demand,
12 without the purchase of any additional generation. Purchasing the Pleasants plant
13 would significantly increase this surplus, as shown in Figure 2. Assuming a
14 realistic capacity factor for the plant,³⁶ the Companies would have 78% more
15 energy than they require in 2018, and would still have 45% more than they need
16 in 2030. In other words, in order to eliminate the few peak hours per year in
17 which the Companies’ demand exceeds generation from Mon Power’s units, the
18 Companies are proposing to generate 45-78% more energy than they need to meet
19 annual energy demands.³⁷ The economic risks to ratepayers of owning this much
20 excess energy will be detailed in the next section.

³⁵ 2015 IRP at page 22.

³⁶ Figure 2 is based on a projected 68% capacity factor for Pleasants. That amount represents the plant’s average capacity factor over the past five years. If the plant ended up operating at more than the 68% capacity factor assumed here, the Companies would have even more excess energy.

³⁷ The Companies purchase all of their energy to serve their load from PJM and sell into PJM all of the energy produced by plants. There is no reliability concern if the Companies are net purchasers of energy from PJM for a few hours per year.

1 **Figure 2: The Companies’ Projected Energy Position With and Without**
2 **Pleasants³⁸**



3

4

5 In short, not only have the Companies dramatically overstated the capacity
6 shortfall by not producing an accurate representation of their PJM capacity
7 obligation, but they have also proposed a “solution” that will result in the
8 Companies having an extreme surplus energy position for the short- and long-
9 term future.

10

³⁸ Sources: 2015 IRP, Figure 7, page 22 for “Forecast energy production - no Pleasants”; Exhibit BDE-2 for “Forecast Annual Energy Requirements”; and assumed an 68% capacity factor for Pleasants.

1 **IV. PURCHASING PLEASANTS WOULD EXPOSE THE COMPANIES’**
2 **CUSTOMERS TO RISKS ASSOCIATED WITH SURPLUS ENERGY.**

3 **Q. In the previous section, you discussed the Companies’ current surplus energy**
4 **position and the fact that the energy surplus will become much larger as a**
5 **result of the proposed transaction. What benefits do the Companies allege**
6 **from a surplus energy position?**

7 A. The Companies generally assert two benefits. The first is that having an energy
8 surplus is beneficial because it provides the Companies with more energy to sell,
9 with the revenues credited to ratepayers.³⁹

10 The second is that owning Pleasants will provide a “hedge” against price volatility
11 in the energy and capacity markets. Although the Companies have made no effort
12 to quantify the risk of energy or capacity price volatility or the potential impact of
13 such volatility on ratepayers, they have repeatedly asserted the value of Pleasants
14 as a “hedge.”⁴⁰

15 **Q. Do you agree with these alleged benefits?**

16 A. No.

17 **Q. Why not?**

18 A. First, it is not true that having surplus energy to sell is inherently beneficial to the
19 Companies’ ratepayers. It is only beneficial if the revenues obtained from the
20 sales of Pleasants’ energy into the PJM market more than offset the fixed and
21 variable costs of generating that power and owning the plant.

22 Under the Pleasants plant’s current ownership structure, the risk that market
23 revenues are insufficient to cover the fixed and variable operating costs of the
24 plant is borne by the shareholders of the Companies’ parent company, FirstEnergy
25 Corp. If Mon Power purchases the plant from AE Supply, those market risks
26 would be transferred to Mon Power and Potomac Edison ratepayers. The

³⁹ See Petition at page 16; Kauffman Direct at page 10.

⁴⁰ See, e.g., Petition at pages 15-16; Ruberto Direct at pages 24-25; Kauffman Direct at pages 5, 9-10, and 14.

1 Companies would recover all of the plant's costs, plus a return on equity, from
2 ratepayers, while ratepayers would be exposed to the risk that the revenues
3 received from market sales do not cover those costs. In essence, Mon Power's
4 customers would be taking on the market risks that AE Supply, FirstEnergy
5 Corp., and its shareholders are seeking to shed through this proposed affiliate
6 transaction. As I will discuss in the next section of testimony, I believe that Mon
7 Power's assertion, that ownership of the plant will provide a net benefit to
8 ratepayers for the next fifteen years, is not based on reasonable energy and
9 capacity price forecasts. There is a high risk that the plant will not be profitable
10 and will not produce a net benefit to ratepayers. In fact, if there was not such a
11 high risk, AE Supply and FirstEnergy would not be looking to offload the
12 Pleasants plant to begin with.

13 **Q. What about the alleged benefit of owning excess energy as a “hedge” against**
14 **energy market price volatility?**

15 A. There is no reason to think that purchasing Pleasants will provide any kind of
16 hedge against any purported future price volatility. First, the Companies have
17 offered no credible evidence that, in the absence of the proposed transaction,
18 customers would face retail price volatility, and they have not conducted any
19 studies of the issue.⁴¹ Second, the Companies ignore the fact that the large surplus
20 energy position resulting from the transaction would leave the Companies
21 exposed to the risk of significant energy market price volatility.

22 **Q. Please explain.**

23 A. The Companies assert that there is a risk to ratepayers when there is an energy
24 shortfall that leaves ratepayers exposed to energy market price volatility.⁴² If
25 energy market prices increase, then Mon Power must pay more for the energy it
26 purchases from the PJM market. This is offset by the revenue Mon Power's plants

⁴¹ See Exhibit DAS-8 (resp. to CAG-SUN-II-8(c)(i)).

⁴² Kauffman Direct at page 14.

1 earn from the energy they sell – but when Mon Power has a shortfall, the net
2 effect would, all else equal, be higher costs passed on to ratepayers.

3 The Companies fail to mention, however, that ratepayers are also exposed to
4 energy market price volatility when there is an energy surplus. If energy market
5 prices decrease, Mon Power receives less revenue from its plants. This is offset by
6 Mon Power also paying less for the energy it purchases – but when Mon Power
7 has an energy surplus, the net effect would be a reduction in revenues and higher
8 costs that are passed on to ratepayers.

9 **Q. Has this scenario ever occurred?**

10 A. Yes. One of the driving factors behind Mon Power’s 2015 ENEC rate increase
11 was low wholesale energy prices.⁴³ Mon Power’s expected revenues from sales of
12 surplus energy into the energy market did not materialize, leading to a need to
13 recover the loss in ENEC rates. (In that case, Companies’ witness Raymond
14 Valdes stated, “Since more energy can be generated by Mon Power’s power
15 plants than is needed for the Companies’ load obligation, a decrease in PJM
16 energy market prices typically causes net energy costs to increase.”⁴⁴ This is in
17 contrast to Companies’ witness Holly Kauffman’s claim in this proceeding that
18 purchasing Pleasants will allow the Companies “to take advantage of low energy
19 prices on behalf of customers when they occur.”⁴⁵)

20 **Q. By how much would the proposed transaction increase the Companies’**
21 **surplus energy position?**

22 A. As discussed above in Section III, and as shown in Figure 3 below, the
23 Companies will have an energy surplus through 2030 in the absence of the
24 Pleasants purchase. That energy surplus already exposes the Companies’

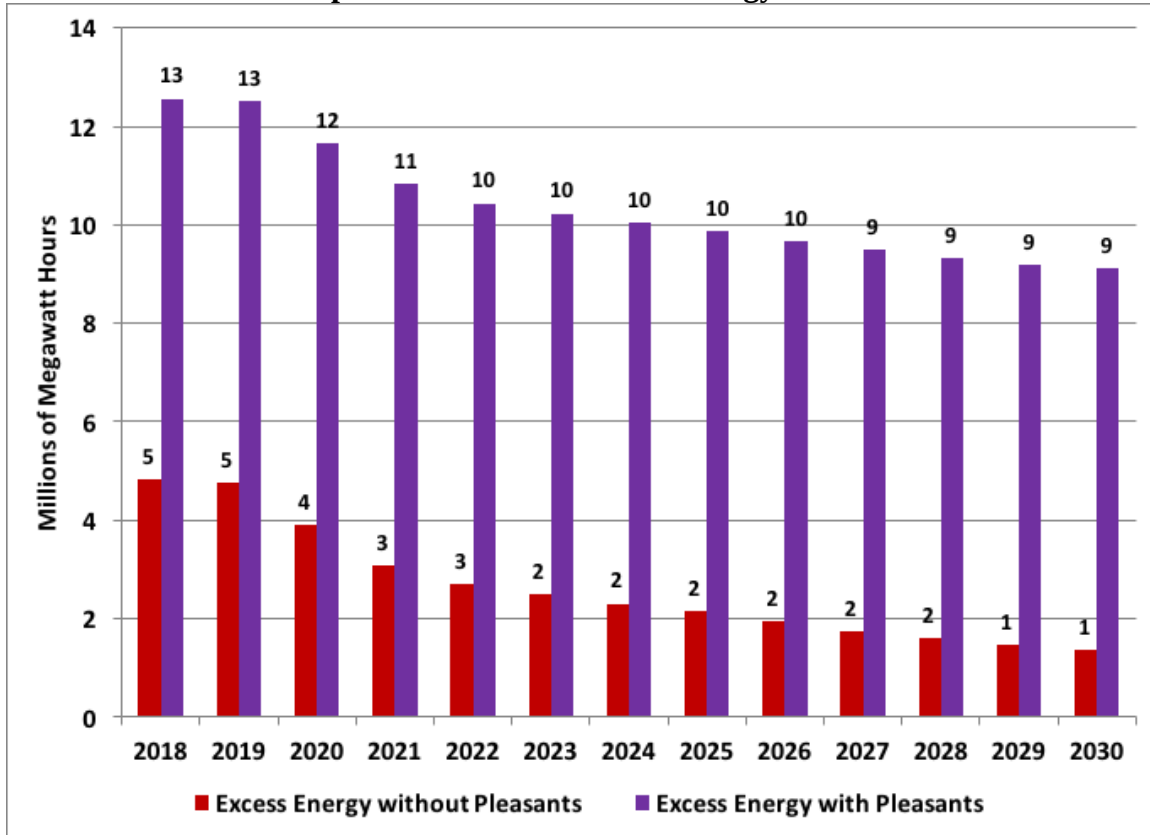
⁴³ See Case No. 15-1351-E-P, Direct Testimony of Raymond E. Valdes at page 8 (Aug. 14, 2015) (“The primary reason for the increased ENEC under-recovery balance is lower than forecasted energy market prices (which reduced generation energy sales revenue).”).

⁴⁴ *Id.* at page 9.

⁴⁵ Kauffman Direct at page 10.

ratepayers to the risk that energy market prices will be lower than forecast. The addition of Pleasants would mean that the Companies' energy surplus would be several times larger over the next fifteen years.

Figure 3: Purchasing Pleasants Will Leave Ratepayers More Exposed to the Risk of Low Energy Market Prices



Effectively, the Companies' ratepayers would become speculators in the PJM energy market, selling Pleasants' output on the wholesale market and hoping that the revenues are sufficient to cover the plant's costs.

1 **V. PURCHASING PLEASANTS WILL LIKELY MEAN MUCH HIGHER**
2 **RATES FOR THE COMPANIES’ CUSTOMERS.**

3 **Q. What are the key factors which determine whether the acquisition of the**
4 **Pleasants plant will produce a positive net benefit or a negative net cost for**
5 **the Companies’ ratepayers?**

6 A. Although there are a substantial number of factors that can influence whether
7 Mon Power’s acquisition of the Pleasants plant will produce net benefits or costs
8 for ratepayers, the key factors are: (1) the acquisition price; (2) future natural gas
9 and energy market prices; (3) future capacity market prices; and (4) future plant
10 generation and fuel and non-fuel operating & maintenance (“O&M”) costs.

11 **Q. Are all of these factors reasonably certain?**

12 A. No. The only factor that is certain is the proposed acquisition price. The
13 remaining factors cannot be forecasted with certainty, and any reasonable analysis
14 of Pleasants’ future costs and revenues would need to account for uncertainty by
15 evaluating a range of potential future market scenarios.

16 **Q. Did CRA consider this uncertainty in its calculation of the NPV for the**
17 **Pleasants acquisition?**

18 A. No. CRA simply used a single set of assumptions which allowed for no
19 uncertainty.⁴⁶

20 **Q. Was this reasonable?**

21 A. No. CRA should have a run a number of scenarios that assumed different natural
22 gas and energy market prices, capacity market prices, and future plant generation
23 and O&M costs. This is especially true because its NPV calculation assumes that
24 the future economic environment for the Pleasants plant will be dramatically
25 different from its recent past.

⁴⁶ Exhibit DAS-9 (resp. to CAD-IV-B-9) (stating, in response to a discovery request seeking CRA’s sensitivity analyses, that “[t]he CRA analysis included only a base case and did not perform sensitivity analyses”); Exhibit DAS-10 (resp. to SC-II-7) (“CRA did not perform additional scenario analyses.”).

1 **Q. Have you seen other utilities run multiple resource scenarios when**
2 **considering plant acquisitions or major capital investments?**

3 A. Yes. Utilities routinely look at a range of future scenarios when considering major
4 investments in building or acquiring capacity or making expensive upgrades to
5 existing plants. For example, in 2016, Indianapolis Power & Light (“IPL”)
6 requested permission from the Indiana Utility Regulatory Commission (“IURC”)
7 to spend approximately \$100 million on environmental upgrades at its Petersburg
8 plant. In support of its application, IPL ran what it described as a “full life cycle
9 production cost simulation” for 32 scenarios that used the “reference,” “low,” and
10 “high” natural gas price forecast provided by ABB Inc., the same company that
11 has provided the price forecasts that CRA used for its NPV analysis here.⁴⁷ At
12 least eight of these scenarios evaluated the economics of making the proposed
13 upgrades using ABB’s Fall 2015 low gas price forecast. IPL also modeled some
14 scenarios that included a range of possible future CO₂ prices.

15 **Q. Could the Companies have required CRA to evaluate the economics of**
16 **acquiring Pleasants under a range of possible scenarios?**

17 A. Yes. ABB prepares high and low gas price sensitivities,⁴⁸ so the Companies could
18 have purchased more than one pricing scenario from ABB. The Companies also
19 could have asked ABB to model Pleasants’ future performance using ABB’s
20 dispatch model. This is what ABB did in the IURC case discussed above; ABB
21 actually performed the modeling for IPL. And because of those different natural
22 gas price scenarios, IPL’s modeling of the proposed Petersburg environmental
23 upgrades included a range of possible energy market prices. Other key factors for
24 the analysis also varied because a range of natural gas prices was being
25 considered – unit generation, for example.

⁴⁷ Direct Testimony of Joan M. Soller in IURC Cause No. 44794 (May 31, 2016).

⁴⁸ Exhibit DAS-11 (resp. to CAG-SUN-V-8).

1 **A. NATURAL GAS PRICES**

2 **Q. Why are the projected natural gas prices used in CRA’s economic analysis of**
3 **Pleasants important?**

4 A. The level of natural gas prices affects the cost of generating power at natural gas-
5 fired plants which, in turn, determines the market clearing prices in the PJM
6 wholesale energy market during many peak- and off-peak hours of the year.⁴⁹ At
7 the same time, when modeling a power plant’s future performance, the forecasted
8 natural gas prices will impact the plant’s projected generation because, in
9 scenarios with lower gas prices, generation from a coal-fired plant like Pleasants
10 will be displaced in the model in more hours of the year. Thus, lower natural gas
11 prices adversely impact the economics of a generating plant like Pleasants in two
12 ways: (i) by reducing the revenue that the plant owner would receive from selling
13 the plant’s generation into the PJM energy market and (ii) by decreasing the
14 amount of power (in MWh) that the plant would generate. Consequently, when
15 modeling a coal plant’s future revenues, it is important not to use an inflated
16 forecast of natural gas prices, as this will bias the analysis in favor of the plant.

17 **Q. What is the source of the natural gas prices used for CRA’s analysis of the**
18 **proposed Pleasants purchase?**

19 A. CRA used ABB’s Spring 2016 reference (that is, middle or base) case forecast
20 which Mon Power had purchased in mid-October 2016.

21 **Q. When did CRA prepare its NPV analysis?**

22 A. According to information provided in discovery, CRA prepared the NPV
23 calculation for Pleasants in February 2017.⁵⁰

⁴⁹ Companies’ witness Thomas Sweet, who sponsored the ABB market price forecasts used in CRA’s analysis, has acknowledged that “the forecasted increase in natural gas prices is a key driver of the forecasted increase in electricity prices.” Exhibit DAS-12 (resp. to CAG-SUN-V-12).

⁵⁰ Companies’ Resp. to CAG-SUN-V-10.

1 **Q. Had ABB issued a new forecast by that time?**

2 A. Yes. The ABB Fall 2016 forecast had been released in November 2016.⁵¹

3 **Q. Have the Companies or CRA provided a credible reason for why it did not**
4 **use the most up-to-date ABB forecast when it prepared its NPV analysis?**

5 A. No. The Companies have merely said they purchased the ABB Spring 2016
6 forecast on October 13, 2016, which was before the ABB Fall 2016 forecast was
7 available.⁵² But that does not explain why Mon Power could not have waited a
8 few weeks and acquired the later (and more recent) Fall 2016 forecast.

9 **Q. Is the NPV calculation discussed in the testimony of Companies' witnesses**
10 **Lee and Ruberto based on a reasonable range of projected natural gas**
11 **prices?**

12 A. No. CRA's analysis used a single electricity price forecast, which was based on a
13 single set of very high natural gas prices. This reliance on an unreasonably high
14 gas price forecast biased the analysis in favor of the proposed Pleasants purchase.

15 **Q. Please explain why you have concluded that the single set of natural gas**
16 **prices that CRA relied on is unreasonably high.**

17 A. There are several reasons why this single set⁵³ of gas price forecasts (from ABB's
18 spring 2016 reference case) is unreasonably high. First, ABB's forecasts, [[REDACTED]
19 [REDACTED]], are inconsistent with
20 recent market trends, including actual gas prices. Second, ABB's price forecasts
21 in recent years [[REDACTED]
22 [REDACTED]].
23 Third, [[REDACTED]] than gas futures prices, which indicate
24 that gas prices will remain relatively flat in coming years. In contrast to ABB's
25 predictions, these futures prices are consistent with recent market history and with

⁵¹ Exhibit DAS-4 (resp. to CAG-SUN-III-1).

⁵² Companies' Resp. to CAG-SUN-V-13.

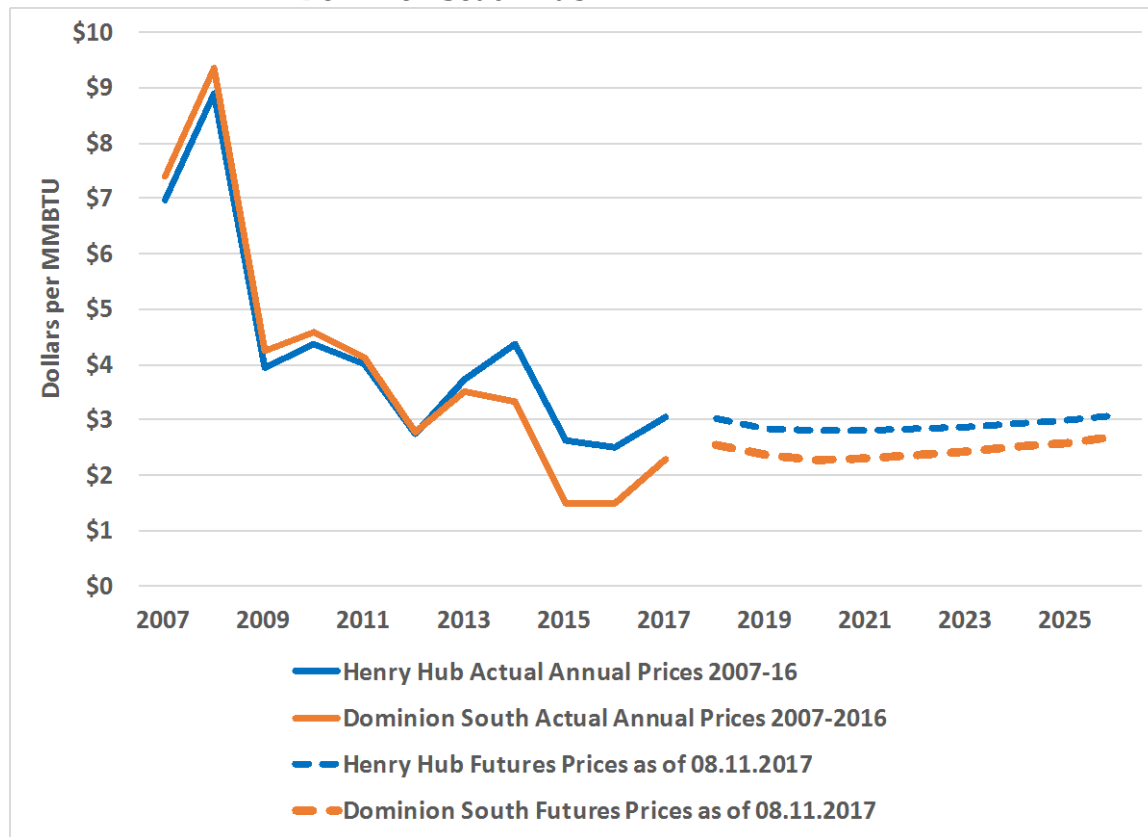
⁵³ The reference case includes forecasts at several natural gas pricing hubs.

1 recent market analyses, which conclude that regional gas prices are likely to
2 remain low in coming years.

3 **Q. Please briefly summarize the recent trend in gas prices.**

4 A. As shown in Figure 4, below, natural gas prices collapsed between 2008 and 2009
5 as a result of increased supplies due to the production from shale gas formations,
6 and have remained low since then except for a temporary uptick in early 2014.
7 Current natural gas futures prices (which represent the market's view of future
8 natural gas prices) reflect the market's expectation that gas prices will remain low
9 in coming years.

1 **Figure 4: Past Prices and Future Price Curves for Henry Hub and the**
2 **Dominion South Hub**⁵⁴



3

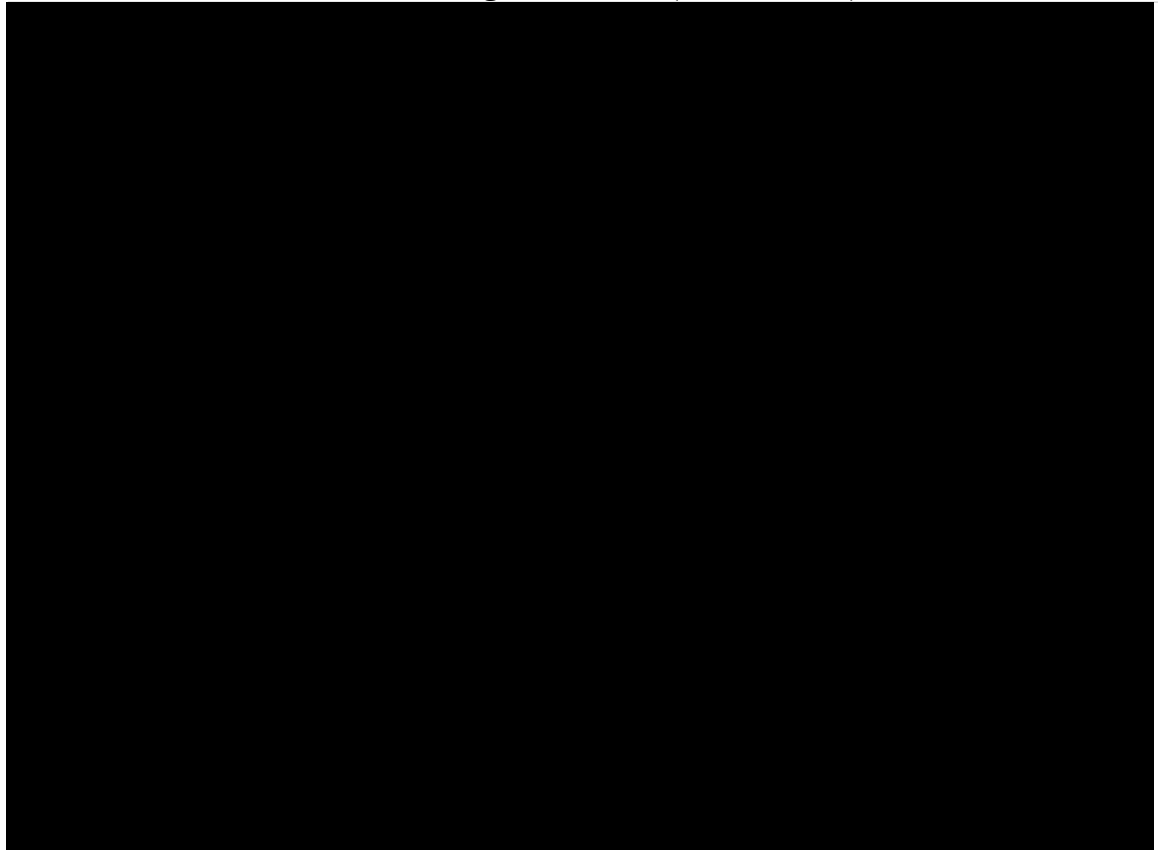
4 **Q. Are the natural gas prices that CRA relied on for its NPV analysis of**
5 **Pleasants consistent with recent gas price history and the market’s**
6 **expectations for future natural gas prices?**

7 **A. No.** As shown in Confidential Figure 5, below, the ABB natural gas prices that
8 CRA relied on assume [[REDACTED]] from recent (and current) natural
9 gas prices. ABB’s forecast is also [[REDACTED]] than the futures prices presently
10 available in the market.

⁵⁴ Historic and future natural gas prices from OTC Global Holdings, downloaded from SNL Financial on August 13, 2017.

Note: unless otherwise stated, the graphs throughout my testimony present market prices in nominal dollars.

1 **Figure 5: ABB Natural Gas Price Forecast vs. Recent Prices and Futures**
2 **Price Curve as of August 11, 2017 (Confidential)**⁵⁵



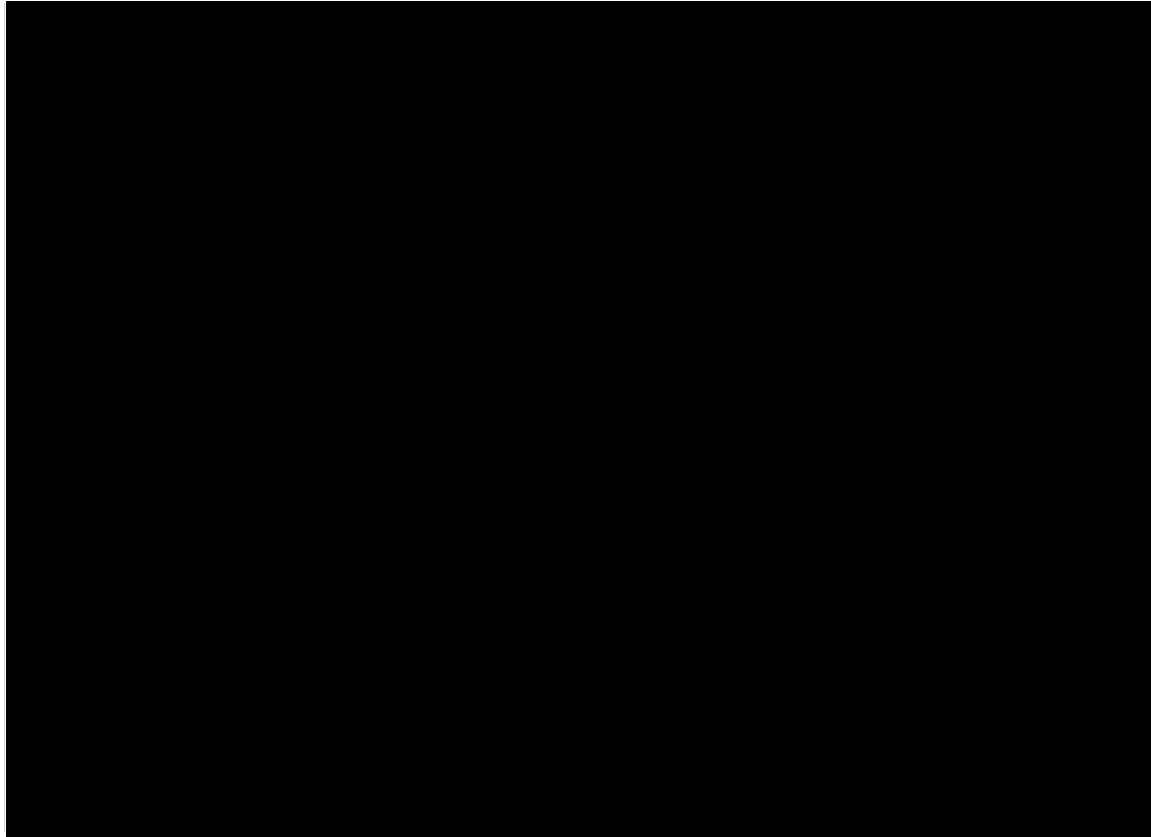
3

4 **Q. Have ABB’s projections of future natural gas prices [REDACTED]**
5 **over time?**

6 **A. Yes.** ABB issues forecasts of natural gas and energy market prices and capacity
7 prices every six months. Confidential Figure 6, below, shows the reference (or
8 base) case Henry Hub natural gas price forecasts issued by ABB from the fall of
9 2014 through the fall of 2016.

⁵⁵ The ABB gas price forecasts presented in this figure were produced in response to discovery request CAG-SUN-I-15.

1 **Figure 6: ABB’s Henry Hub Gas Price Forecasts, Fall 2014 to Fall 2016**
2 **(Confidential)**⁵⁶



3
4

5 Confidential Figure 6 reveals several critical points:

- 6 1. Starting in the Fall of 2014, and with some exceptions in specific years,
7 ABB’s natural gas price forecasts [[REDACTED]
8 [REDACTED]
- 9 2. [REDACTED]] For example, in the Fall of
10 2014 ABB projected that the average Henry Hub natural gas price [[REDACTED]
11 [REDACTED]] By the
12 Fall of 2016, ABB was projecting that [[REDACTED]

⁵⁶ The ABB forecasts presented in this figure, which were responsive to discovery requests CAG-SUN-III-4 and -5, were produced following the settlement of WVSUN/CAG’s July 17, 2017 motion to compel.

⁵⁷ *Id.*

1 [REDACTED].]] This represented
2 [[REDACTED].]]

3 3. Although actual Henry Hub prices have generally declined since 2014, as
4 shown in Figure 4 above, ABB continues to forecast [[REDACTED]
5 [REDACTED]
6 .]] However, the [[REDACTED]
7 [REDACTED] has not yet
8 happened. [[REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED].]]

13 4. Actual natural gas prices since the beginning of 2015 have been [[REDACTED]]
14 ABB's projected prices, as can be seen in Confidential Figure 6.

15 **Q. Do these same points apply to ABB's forecasts of future natural gas prices at**
16 **other key hubs?**

17 A. Yes. The same key points apply to ABB's forecast of natural gas prices at other
18 hubs, such as the Dominion South Hub.

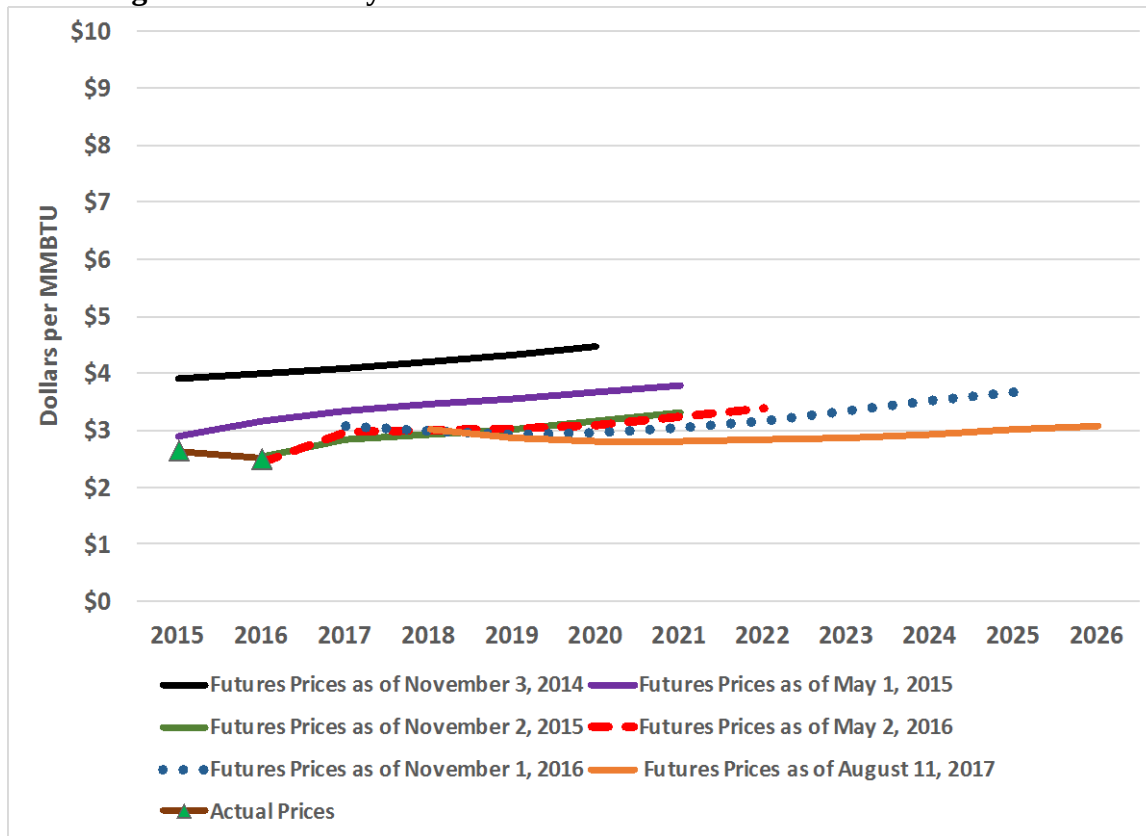
19 **Q. How have ABB's forecasts of natural gas prices changed since the Spring**
20 **2016 forecast that CRA relied on for its analysis of the proposed Pleasants**
21 **purchase?**

22 A. As shown in Confidential Figure 6, above, ABB's Fall 2016 forecasts of natural
23 gas prices [[REDACTED]] the Spring 2016 forecasts. And ABB's June 7, 2017
24 webcast for its Spring 2017 forecast suggested that its current forecast of natural
25 gas prices has declined since its Fall 2016 forecast.

1 **Q. Have there been major changes in recent years in the futures prices for**
2 **natural gas?**

3 A. Not really. As shown in Figure 7, below, futures prices have generally been
4 declining since the fall of 2014. However, the general expectation of the market
5 that gas prices will remain low, with little escalation, has remained the same.

6 **Figure 7: Henry Hub Natural Gas Futures Prices⁵⁸**



⁵⁸ OTC Global Holdings, downloaded from SNL Financial.

1 **Q. Why did you choose to present the May and November natural gas futures**
2 **price in Figure 7?**

3 A. ABB releases its forecasts in the spring and fall. I chose to look at the natural gas
4 futures prices on the first weekday of the spring and fall months of May and
5 November.

6 **Q. Have the natural gas futures prices since 2015 been higher than actual gas**
7 **prices?**

8 A. Yes. [[REDACTED]] and the natural gas futures prices have been
9 higher than actual gas prices.

10 **Q. Have natural gas futures prices been extremely volatile?**

11 A. Because they reflect market transactions and do not have periodic release dates
12 like ABB forecasts, futures prices can and have changed from day-to-day.
13 However, looking at futures prices over a longer period (as in Figure 7 above)
14 shows that the generally flat trend has remained the same over time. From this
15 perspective, futures prices for natural gas have not been more volatile over the
16 long term than ABB's forecasts.

17 **Q. Do these natural gas futures prices offer a more reasonable picture of future**
18 **gas prices than ABB's Spring 2016 gas price forecast?**

19 A. Yes, they do. Although, as shown in Figure 7, above, futures have also
20 overestimated gas prices, in recent years they have been [[REDACTED]] to actual
21 prices than ABB's forecasts.

22 **Q. What about the argument that futures prices can sometimes reflect periods**
23 **when there are only a very small number of transactions?**

24 A. Although that is a concern, the question here is whether the ABB forecasts –
25 which underlie the Companies' claims that Pleasants will provide net benefits to
26 ratepayers – are reasonable. Given the choice between a history of ABB forecasts

1 that are repeatedly projecting [[REDACTED]] that have
2 never happened [[REDACTED]] and
3 a set of futures prices that have accurately predicted that prices would remain low,
4 I have concluded that the futures prices are more reliable. This is especially true
5 where, as here, ABB already has [REDACTED] its forecast of natural gas prices, at
6 least once, since the forecast that CRA used in its NPV calculation.

7 **Q. Have you seen any other forecasts that project that natural gas prices will**
8 **remain low or evidence that supports that observation?**

9 A. Yes. It is recognized that natural gas prices can be expected to remain low for the
10 foreseeable future for a combination of demand-side and supply-side factors. For
11 example:

- 12 • On the supply side, Morgan Stanley argues that technology improvements
13 have pushed the break-even price of natural gas below \$3 per MMBTU –
14 and even lower in Appalachia.⁵⁹ Morgan Stanley recently said that “\$2-
15 3/MMbtu natural gas, not \$3-4, is the new normal,” and, consequently,
16 reduced its 2017-2018 price forecast and cut its long-term outlook for
17 Henry Hub prices by 27 percent to \$2.75 per MMBTU with even lower
18 prices (\$2.25-\$2.50) across Appalachia.
- 19 • Significant efficiency gains in the production of shale gas were achieved
20 in 2016. According to an analysis by Sanford Bernstein & Co., the fact
21 that these efficiency gains were achieved amid a supply glut was
22 “terrifying.”⁶⁰ Bernstein said that that “[t]hese gains, coming when drillers
23 were already overproducing, “is even more bearish for our view of gas
24 price”⁶¹
- 25 • On the demand side, electricity demand around the U.S. is forecasted to be
26 basically flat, and, despite the planned addition of approximately 20 GW
27 of new natural gas-fired combined cycle capacity in PJM, the growing
28 penetration of renewables is competing directly with natural gas in major

⁵⁹ Morgan Stanley Research, *Don't Bet Against Innovation: Sub-\$3 is the New Normal* (Mar. 28, 2017),
available at
https://fa.morganstanley.com/hillgroup/mediahandler/media/41640/Natural%20Gas_Don%27t%20Bet%20Against%20Innovation_Sub-%243%20Is%20the%20New%20Normal.pdf.

⁶⁰ SNL Financial, Bernstein calls shale gas efficiency gains ‘terrifying’ amid supply glut (Aug. 7, 2017).

⁶¹ *Id.*

1 markets in the West, the Great Plains States and Texas. The hoped-for big
2 growth opportunity for natural gas is LNG exports. However, while the
3 U.S. is on track to become the third largest exporter of LNG (after Qatar
4 and Australia), this is creating a global glut of LNG. In other words, there
5 is not enough global demand for LNG to soak up the U.S. excess and drive
6 prices up.⁶² As a result, based on a review of natural gas supplies and
7 demand, Deloitte has concluded that “there will likely be continued record
8 levels of production combined with historically low prices for the near-to-
9 medium term.”⁶³

- 10 • Moody’s Investors Service does not expect natural gas prices to increase
11 over the next three years – thus it assumes that Henry Hub natural gas
12 prices over the 2017-2019 period will remain around \$3 per MMBTU or
13 below.⁶⁴

⁶² Deloitte, *Seeking Growth: What will drive US natural gas demand* (2017), available at <https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/us-natural-gas-consumption-demand.html>.

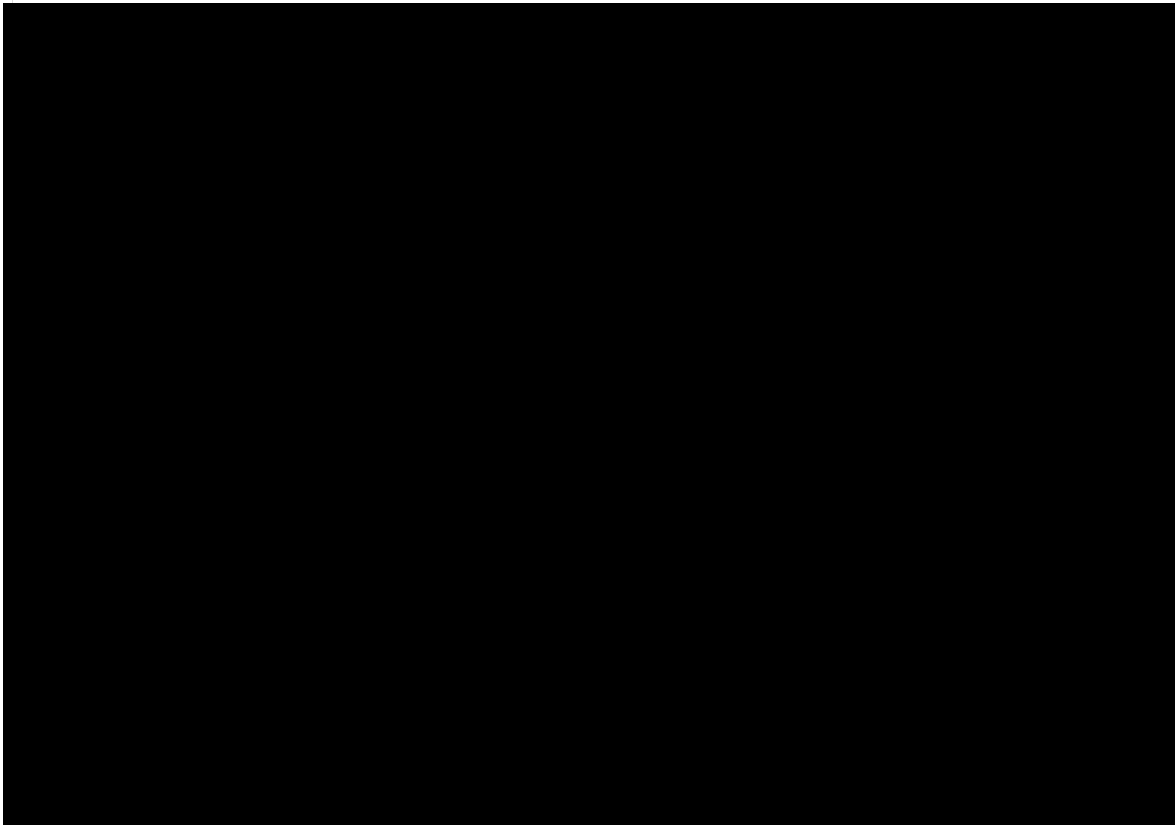
⁶³ *Id.* at page 5.

⁶⁴ Moody’s Investors Service, *PJM Merchant Generation Facing Refinancing Risk* at page 4 (Apr. 21, 2017).

1 **Q. How does ABB's Spring 2016 forecast of natural gas prices compare with**
2 **Moody's and Morgan Stanley's price projections for 2019?**

3 A. As shown in Confidential Figure 8 below, the Henry Hub natural gas prices in
4 ABB's Spring 2016 Forecast for the years 2019 and 2020 are [REDACTED]
5 [REDACTED]] the prices projected by Moody's and Morgan Stanley and current
6 futures prices.

7 **Figure 8: ABB Forecast Henry Hub Natural Gas Prices vs. Futures**
8 **Prices and Projections by Morgan Stanley and Moody's**
9 **(Confidential)**



10

11

12

13

1 **Q. Have the Companies been able to provide any credible evidence that they**
2 **attempted to verify the reasonableness and accuracy of ABB’s natural gas**
3 **price forecasts?**

4 A. No. Although Mr. Ruberto claimed that the Companies verified the
5 reasonableness and accuracy of ABB’s Spring 2016 forecasts, there is no
6 documentation to confirm that this review was more than cursory.⁶⁵

7 **Q. What is your conclusion concerning the natural gas prices underlying CRA’s**
8 **NPV calculation of Pleasants?**

9 A. Rather than relying on ABB’s unreasonably high forecast of natural gas prices,
10 CRA’s NPV analysis should have been based on the natural gas future prices
11 available at the time it prepared its analysis. If CRA was concerned about
12 volatility it could have averaged the futures prices over a period of time. CRA
13 also should have considered high and low gas price sensitivity studies of $\pm 10\%$
14 around that base case forecast. This would have been more than reasonable given
15 that ABB’s Spring 2016 gas price forecast was [[REDACTED]] both the then-
16 current natural gas futures prices and ABB’s Fall 2016 forecast.

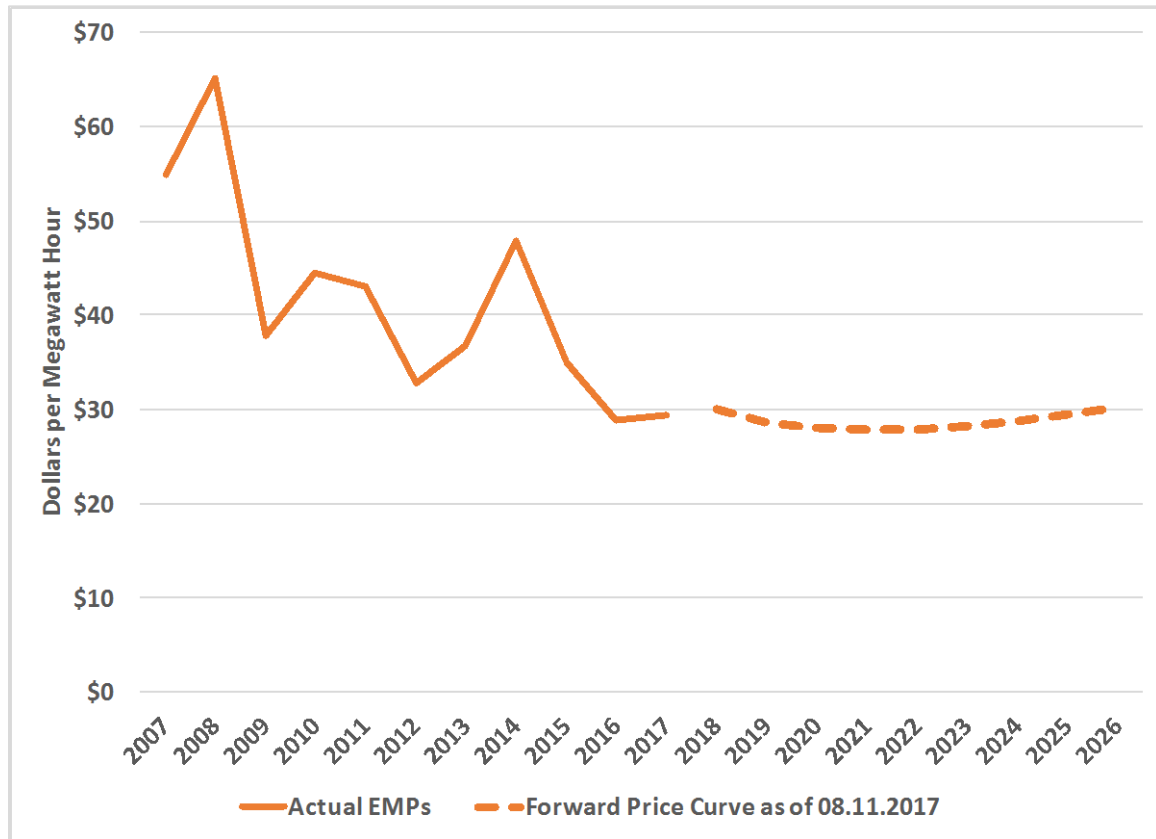
17 **B. ENERGY MARKET PRICES**

18 **Q. What is the recent history of energy market prices in the APS Zone of PJM?**

19 A. The energy market prices (“EMPs”) in the competitive PJM markets dropped
20 significantly after natural gas prices collapsed in 2009. As shown in Figure 9,
21 below, the annual energy market prices in the APS Zone of PJM have, on
22 average, remained low since then, except for an uptick during 2014 as a result of
23 the polar vortex event. Current forward price curves suggest EMPs will remain
24 low for the coming years.

⁶⁵ Exhibit DAS-13 (resp. to CAG-SUN-IV-13).

Zone⁶⁶



Q. What is the source of the energy market prices that CRA used in its analysis of the proposed Pleasants purchase?

A. As with natural gas prices, CRA used a single energy market price forecast from ABB's Spring 2016 reference case in calculating Pleasants' NPV.

Q. Did ABB's Spring 2016 Forecast contain additional energy market price projections?

A. Yes. ABB developed energy market prices from its low and high gas price scenarios.⁶⁷

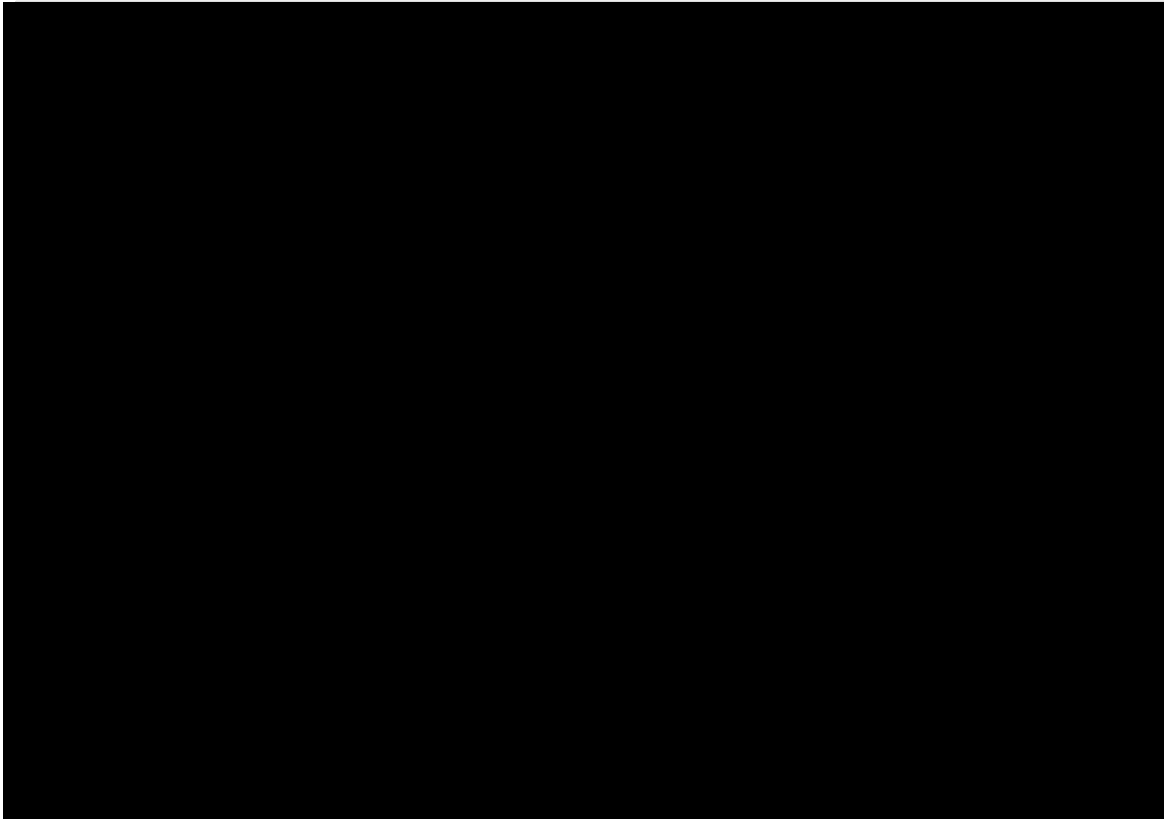
⁶⁶ Historic APS Zone prices downloaded from PJM website. OTC Global Holdings forward prices were downloaded from SNL Financial.

⁶⁷ Exhibit DAS-11 (resp. to CAG-SUN-V-8).

1 **Q. How do the ABB Spring 2016 energy market prices compare to recent prices**
2 **and forward energy market price curves?**

3 A. As shown in Confidential Figure 10, the average annual EMPs forecast by ABB
4 [[REDACTED]] in coming years, [[REDACTED]] the recent EMPs and
5 current forward energy market prices suggest are reasonable to expect.

6 **Figure 10: ABB's Projected APS Zone Energy Market Prices vs. Recent**
7 **Zonal Prices and Current Forward Price Curve (Confidential)**

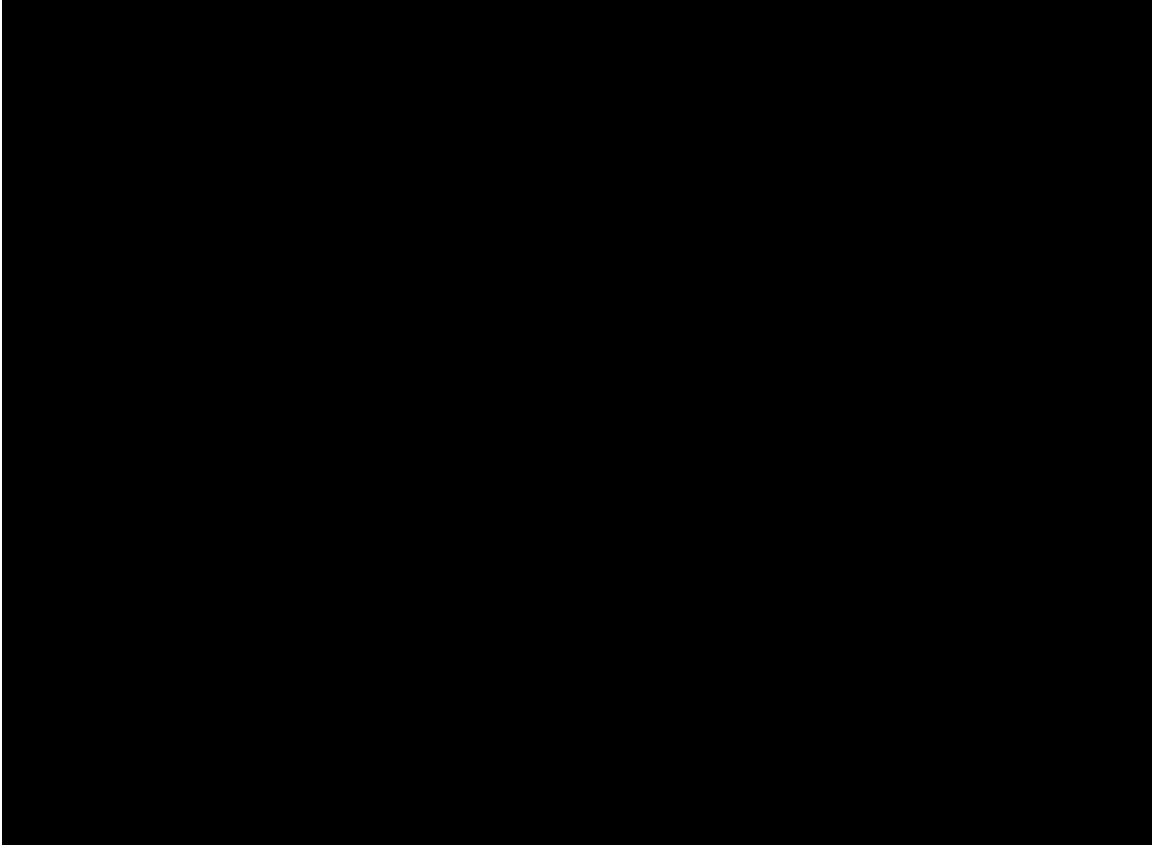


8

9 **Q. Have ABB's forecasts of future energy market prices [[REDACTED]]**
10 **in recent years?**

11 A. Yes. As with natural gas, ABB issues forecasts of energy market prices every six
12 months. Confidential Figure 11, below, shows ABB's reference case energy
13 market price forecasts from the Fall of 2014 through the Fall of 2016.

1 **Figure 11: ABB’s Fall 2014 to Fall 2016 Projected APS Zone Energy**
2 **Market Prices and Actual Prices in 2015 and 2016**
3 **(Confidential)**⁶⁸



4

5 Confidential Figure 11 reveals a number of critical points:

- 6 1. Starting in the Fall of 2014, ABB’s APS Zone energy market price
7 forecasts have [[REDACTED]]
- 8 2. [[REDACTED]].]] For example, in the Fall of
9 2014 ABB projected that the average energy market price in the APS Zone
10 of PJM [[REDACTED]].]] By the Fall of 2016,
11 ABB’s projection for the average energy market price in the APS Zone
12 [[REDACTED]]
13 [[REDACTED]]
14 [[REDACTED]].]]

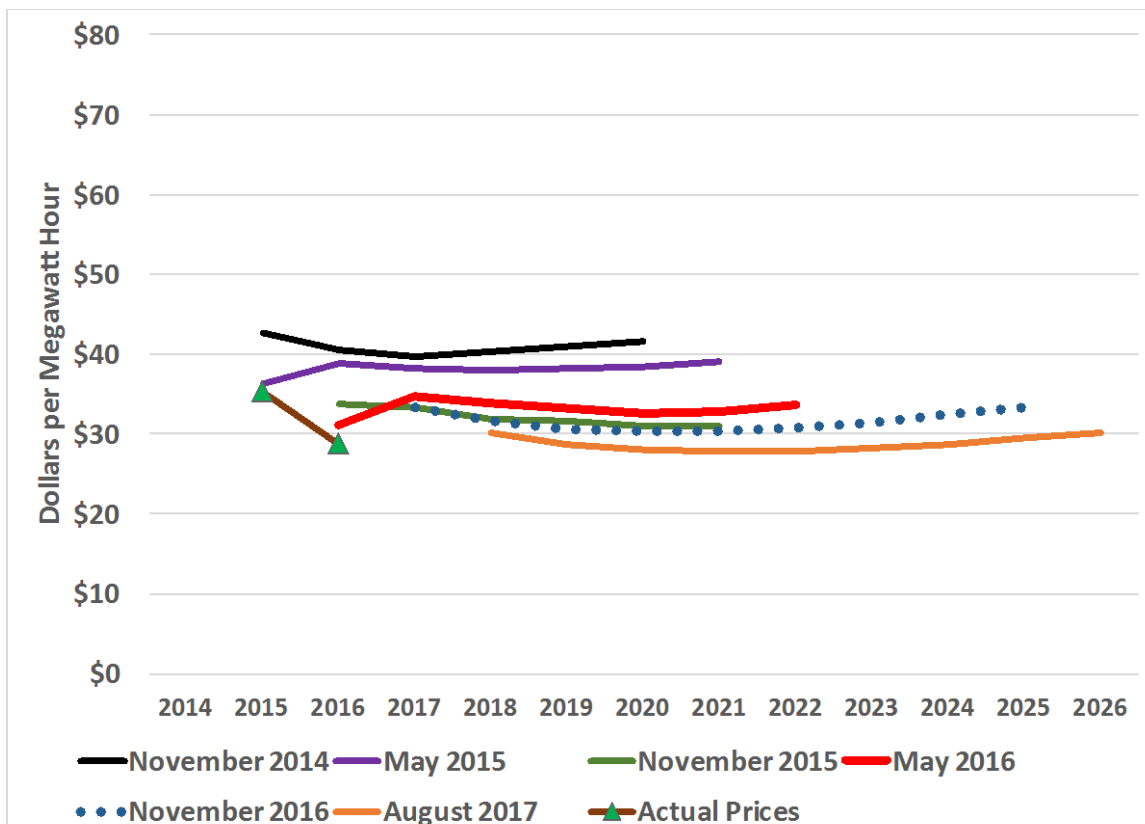
⁶⁸ ABB Reference Case forecasts responsive to discovery requests CAG-SUN-III-4 and -5, which were produced following the settlement of WVSUN/CAG’s July 17, 2017 motion to compel.

1 3. Actual 2015 and 2016 energy market prices have been [REDACTED]
2 ABB’s projected prices.

3 **Q. Have there been any major changes in recent years in the forward curves for**
4 **energy market prices?**

5 A. Not really. As shown in Figure 12, below, although forward curves for energy
6 market prices have declined in recent years, the general expectation of the market
7 – that energy prices will trend up slowly, if at all – has remained the same.

8 **Figure 12: Recent APS Zone Energy Forward Price Curves⁶⁹**



9
10 **Q. What about the argument that futures prices can sometimes reflect periods**
11 **when there are only a very small number of transactions?**

⁶⁹ Source: Forward Energy Market Prices downloaded from SNL Financial.

1 A. As I explained with respect to gas price futures, that may be a potential concern.
2 But again, the key question is whether energy forwards are more reliable than the
3 ABB price forecast relied on by the Companies. Given that ABB's forecasts have
4 repeatedly projected [REDACTED] that have not
5 happened [REDACTED],
6 while forward price curves have accurately predicted that prices would remain
7 low, the futures prices are more reliable in estimating Pleasants' NPV.
8 Furthermore, Figure 12, above, shows that even the energy forward price curves
9 have been above actual energy market prices in the APS Zone. This should give
10 the Commission more confidence that use of the forward energy market prices to
11 evaluate the proposed transaction is appropriate and conservative.

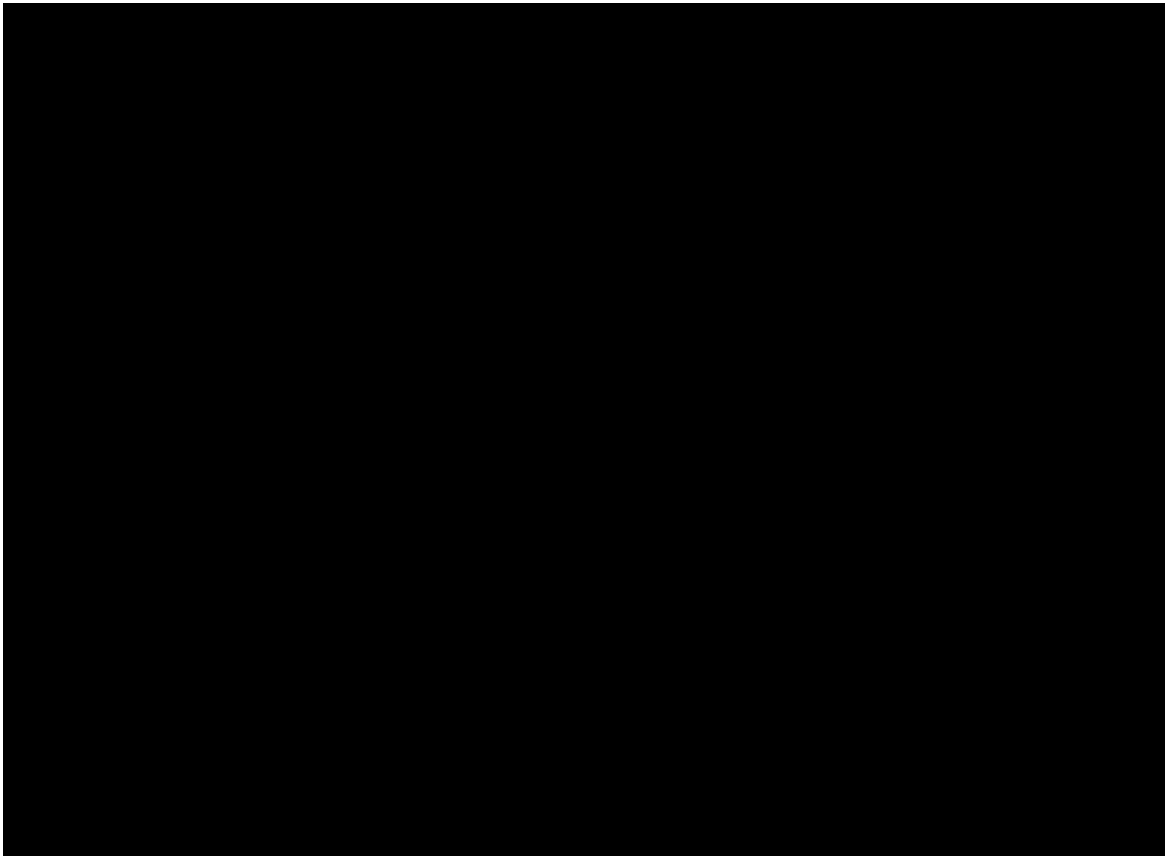
12 **Q. Have you seen any energy market price forecasts by Mon Power or affiliated**
13 **companies that conflict with the ABB Spring 2016 Forecast used to evaluate**
14 **the proposed Pleasants purchase?**

15 A. Yes. AE Supply's 2017 forecasts of Pleasants' Income States and Cash Flows for
16 the years 2017 through 2021 include projections for the plant's annual generation
17 and energy revenues (both in dollars and dollars per MWh) for the years 2017
18 through 2021.⁷⁰ The differences between AE Supply's projections and CRA's are
19 startling, as shown in Confidential Figures 13 and 14 below.

⁷⁰ Confidential Exhibit DAS-14 (CAG-SUN-II-36 Attachment C) (Confidential – Competitively Sensitive).

1 First, Confidential Figure 13 compares AE Supply’s projected energy revenue for
2 Pleasants, on a dollar per MWh basis, with realized energy prices, again on a
3 dollar per MWh basis, from CRA’s NPV analysis of Pleasants. (“Realized prices”
4 are the average revenue per MWh earned by the plant during the year).

5 **Figure 13: AE Supply vs. CRA Average Energy Revenue for Pleasants,**
6 **2018-2021 (Dollars per MWh) (Confidential)**⁷¹



7
8 Thus AE Supply clearly expects energy market prices to be [[REDACTED]]
9 in these years than does CRA.

10 In addition, as I will discuss in the next section of my testimony, CRA projects
11 [[REDACTED]] from Pleasants during the years 2018-2021 than

⁷¹ AE Supply Average Revenue per MWh from the Companies response to CAG-SUN-II-36 Attachment C (Confidential – Competitively Sensitive).

1 AE Supply. As a result of both the [[REDACTED]] energy prices and the
2 [[REDACTED]] generation, CRA projects [[REDACTED]] energy revenues for
3 Pleasants for these years, as shown in Confidential Figure 14, below.

4 **Figure 14: AE Supply vs. CRA Pleasants' Energy Revenues for the Years**
5 **2018-2021 (Confidential)**⁷²

6

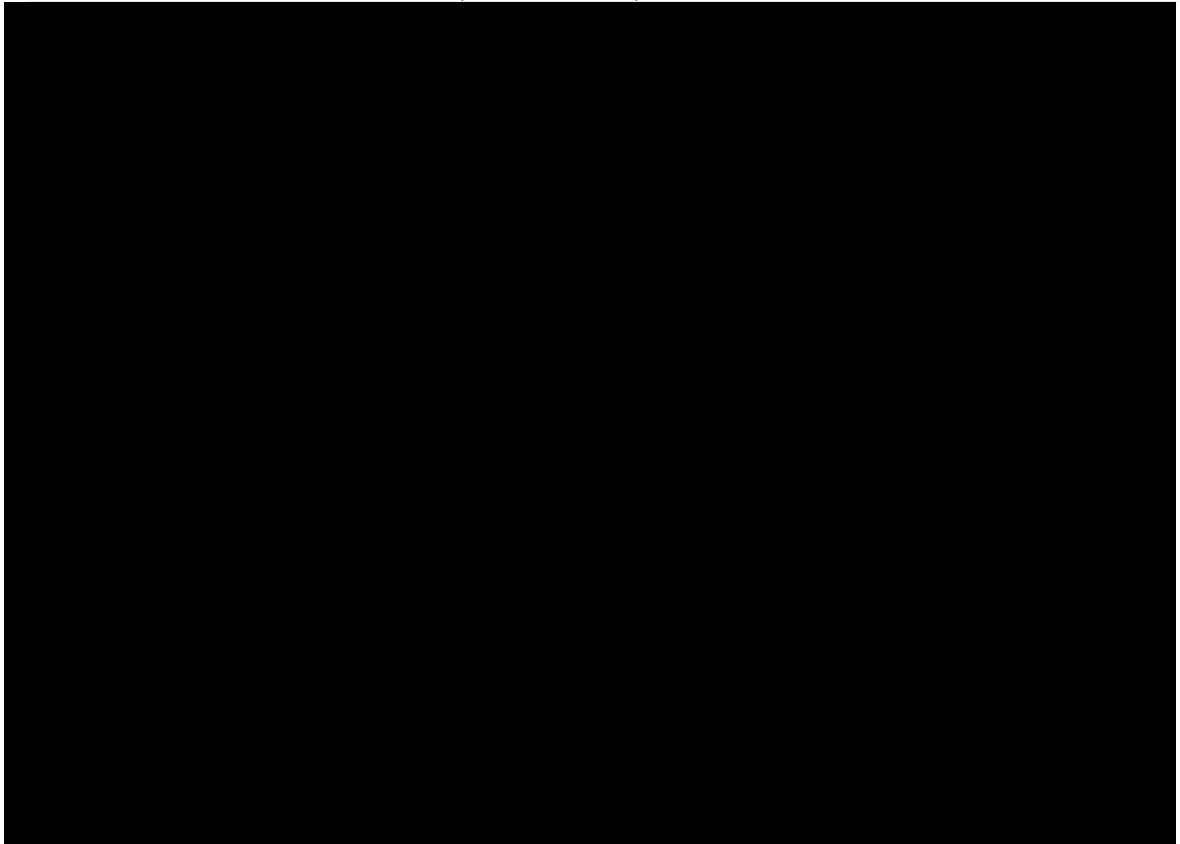
7 Thus, AE Supply has projected approximately [[REDACTED]] energy
8 revenues from Pleasants during the years 2018-2021 than CRA.

9 **Q. Has Mon Power provided any internal projections of future energy market**
10 **prices?**

⁷² See Confidential Exhibit DAS-14 (CAG-SUN-II-36 Attachment C) (Confidential – Competitively Sensitive). The Companies provided some additional information about these financial statements in response to WVEUG-IV-7. See Exhibit DAS-15.

1 A. Yes. Mon Power has used energy market price forecasts for the years 2017-2020
2 to project the generation of its currently owned Harrison and Fort Martin units. As
3 shown in Confidential Figure 15, below, the energy market prices used by Mon
4 Power for its analysis of its existing generation are [[REDACTED]] than
5 those used by CRA to evaluate the proposed transaction.

1 **Figure 15: Mon Power vs. CRA Pleasants' Energy Market Prices for the**
2 **Years 2018-2020 (Confidential)**⁷³



3

4 **Q. Have you seen any independent assessments of future PJM energy market**
5 **prices?**

6 A. Yes. Moody's Investor Service released a report in early May of this year titled
7 "US Marcellus Shale Gas Buildout Wreaks Havoc on PJM Market." In this report,
8 Moody's concluded that with the expected addition in PJM of some 23 GW of
9 new efficient natural gas-fired plants, a "glut in supply" will drive down market
10 prices.⁷⁴

11 As Moody's explains:

⁷³ Mon Power's forecasted prices for Fort Martin and Harrison were produced in discovery. See Exhibit DAS-16 (resp. to CAG-SUN-IV-10).

⁷⁴ Press Release, Moody's Investor Service, Moody's: Marcellus Shale Gas Buildout Wreaks Havoc on PJM Power Market (May 8, 2017), available at https://www.moody's.com/research/Moodys-Marcellus-Shale-Gas-Buildout-Wreaks-Havoc-on-PJM-Power--PR_366337?yptr=yahoo.

1 Moody's estimates that new high-efficiency gas plants coming online
2 between 2016 and 2020 will produce approximately 100 terawatt
3 hours (TWh) per year of additional on-peak power compared to 2015
4 levels, resulting in a 25% increase in supply during on-peak hours.
5 According to the report, however, the growth in supply will occur at a
6 time with little or no growth in demand.

7 "According to PJM's latest forecast, load growth and peak demand
8 have declined over the last ten years," says Toby Shea, a vice president
9 and senior credit officer at Moody's. "The market imbalance will drive
10 down prices and pose challenges to generators operating on thin
11 margins."

12 Moody's predicts on-peak equivalent power prices in PJM to fall by
13 about \$7/megawatt-hour (MWh), and around-the-clock prices to fall
14 by about \$3.5/MWh, starting in 2021. The scenario would represent
15 15% and 10% declines, respectively."⁷⁵

16 Thus Moody's expectation of declining energy market power prices beginning in
17 2021, after being flat through then, contrasts directly with the vision pushed by
18 ABB in which energy market prices [REDACTED]
19 [REDACTED]].⁷⁶

20 **Q. What is your recommendation concerning the energy market prices that the**
21 **Commission should use to evaluate whether the proposed transaction would**
22 **provide benefits for the Companies' ratepayers?**

23 A. As I explain below, the proposed Pleasants purchase should be evaluated using
24 recent forward peak and off-peak prices, with a $\pm$ 10 percent range for sensitivity
25 studies.

⁷⁵ *Id.*

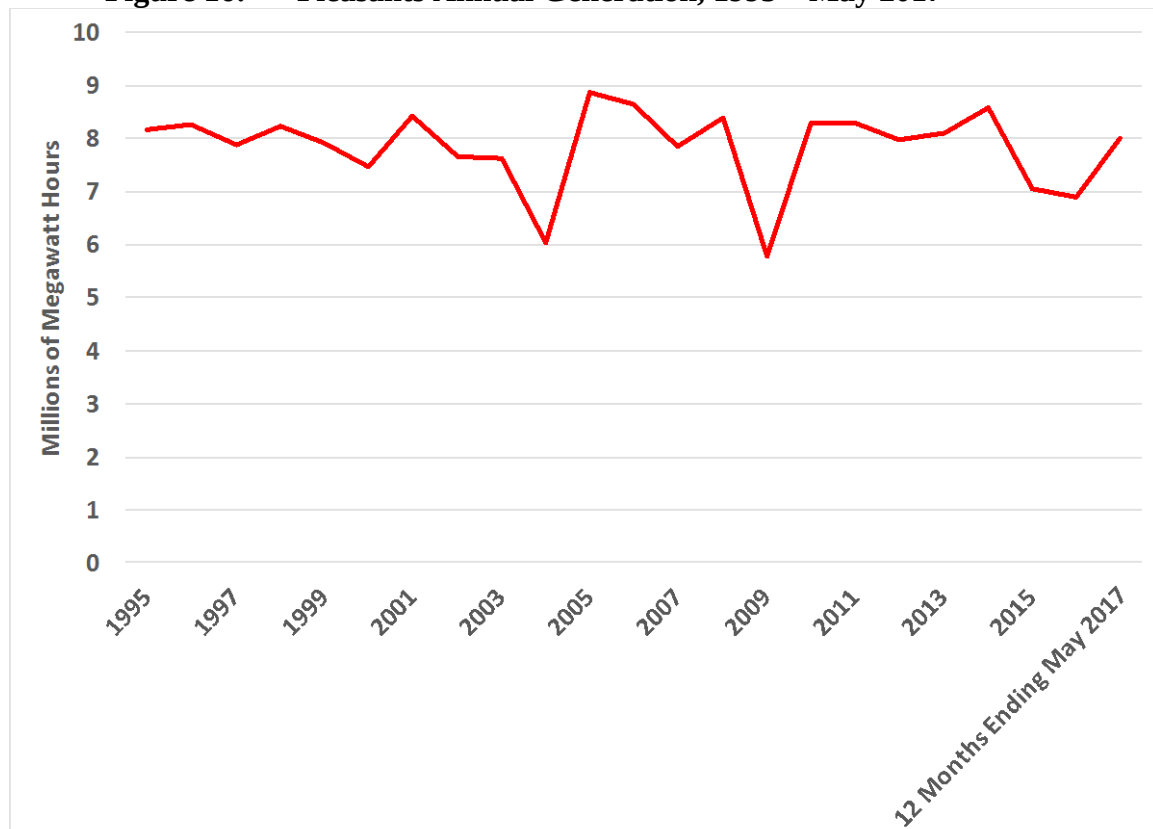
⁷⁶ See Confidential Figure 10, above.

1 **C. PLEASANTS' FUTURE OPERATING PERFORMANCE**

2 **Q. How much power has Pleasants generated in recent years?**

3 A. As can be seen in Figure 16, below, Pleasants' generation has been up and down
4 for at least the last 22 years, with a high of 8.85 million MWh in 2005 and a low
5 of 5.8 million MWh in 2009. Annual generation declined by 20 percent from
6 2014 through 2016 before experiencing an uptick in late 2016 and early 2017.

7 **Figure 16: Pleasants Annual Generation, 1995 – May 2017**



8

9

10 **Q. What does CRA project for Pleasants' future operating performance in its**
11 **analysis of the proposed acquisition?**

12 A. CRA projects that Pleasants generation will [[REDACTED]]
13 [[REDACTED]], as shown in Confidential Figure 17,
14 below.

1 A. No. While the plant's generation will almost certainly fluctuate from year to year,
2 it is reasonable to expect that its average annual production will decline in coming
3 years due to (1) increased competition from efficient natural gas-fired generators
4 and continued low natural gas prices, (2) the impact of plant aging, and (3)
5 increased competition from renewable wind and solar resources in PJM.

6 **Q. How old are Pleasants Units 1 and 2?**

7 A. Pleasants Unit 1 is 38 years old. Unit 2 is 37 years old.

8 **Q. Do you think it is reasonable to expect that the operating performance of the**
9 **Pleasants units will deteriorate as they age?**

10 A. Yes. It is reasonable to expect that the operating performance of the Pleasants
11 units will deteriorate as they age and/or that the cost of continuing to operate the
12 units will increase due to age-related degradation or the need to replace degraded
13 plant equipment.

14 Babcock & Wilcox, an experienced designer and builder of fossil-fuel-fired and
15 nuclear electric generating units, including coal-fired plants, has identified the
16 following consequences of plant aging:

17 **Power Plant Aging**

18 At the beginning of power plant life there is a period in which the
19 operators and maintenance crews learn to work with the new system
20 and minor problems are resolved. This period may be marked with a
21 high forced outage rate, but this quickly declines as the system is
22 broken in.

23 As the plant matures, the personnel adapt to the new system, and any
24 shortcomings are overcome or better understood. During this phase the
25 forced outage rate remains low, availability is high, and the operating
26 and maintenance costs are minimal. This mature phase normally lasts
27 25 to 30 years, depending on the design and use of the unit. The power
28 plant is usually operated near rated capacity during this period.

29 Following this phase, the aging process becomes noticeable. Forced
30 outages and maintenance costs increase and availability declines.
31 Component end of life usually causes the higher forced outage rate.
32 Occasional operational error and the degradation of boiler components
33 due to erosion, corrosion, creep and fatigue lead to localized failures.

1 The forced outage rate steadily increases during this phase unless
2 major overhauls or component replacements are instituted.⁷⁸

3 * * * *

4 **Traditional Roles of the Aging Plant**

5 As the aging plant becomes less reliable, its role is often changed.
6 Newer, more reliable plants are less costly to maintain and are
7 generally more efficient to handle the base power load. The older
8 plants become auxiliary units or are designated for peaking service.
9 Older plants with higher heat rates, i.e., lower efficiencies, or with low
10 capacity may be retired. Prior to the 1980s, it was assumed that older
11 plants would be torn down to make room for the newer, larger, more
12 efficient units. It was common to retire a plant after 35 to 40 years of
13 service.

14 This planned obsolescence began to change in the early 1980s. The
15 cost of newer, more efficient plants became more than most boiler
16 operators could readily finance. As a result, new construction was
17 delayed and plans to retire the older plants were put on hold. The need
18 to keep the older units running brought about a new strategy of life
19 extension. This is a strategy that delays the plant retirement while
20 maintaining acceptable availability. The strategy requires the
21 replacement of some components to keep the plant running with
22 acceptable forced outage rates and maintenance costs. These
23 replacements or repairs expand upon those traditionally incorporated
24 in a plant maintenance program. Significant capital expenditures are
25 normally required to affect the availability rate.”⁷⁹

26 **Q. Have you seen any evidence that the Companies have considered the**
27 **potential adverse impact of aging on Pleasants’ operating performance?**

28 A. No. In fact, CRA’s NPV analysis assumes that there would be [[REDACTED]
29 [REDACTED]] at any time between
30 2018 and 2032, a period when it will be 38 to over 50 years old. And although
31 CRA mathematically reduced the plant’s generation output to account for outages,
32 CRA’s model otherwise assumes that it would be economic for the plant to
33 operate continuously for years at a time.⁸⁰

⁷⁸ Babcock & Wilcox, *Steam, Its Generation and Use*, 40th Edition, (1992), Chapter 46, at pages 46-1 et seq.

⁷⁹ *Id.* at pages 46-1 and 46-2.

⁸⁰ See Exhibit DAS-17 (resp. to SC-III-5 Confidential).

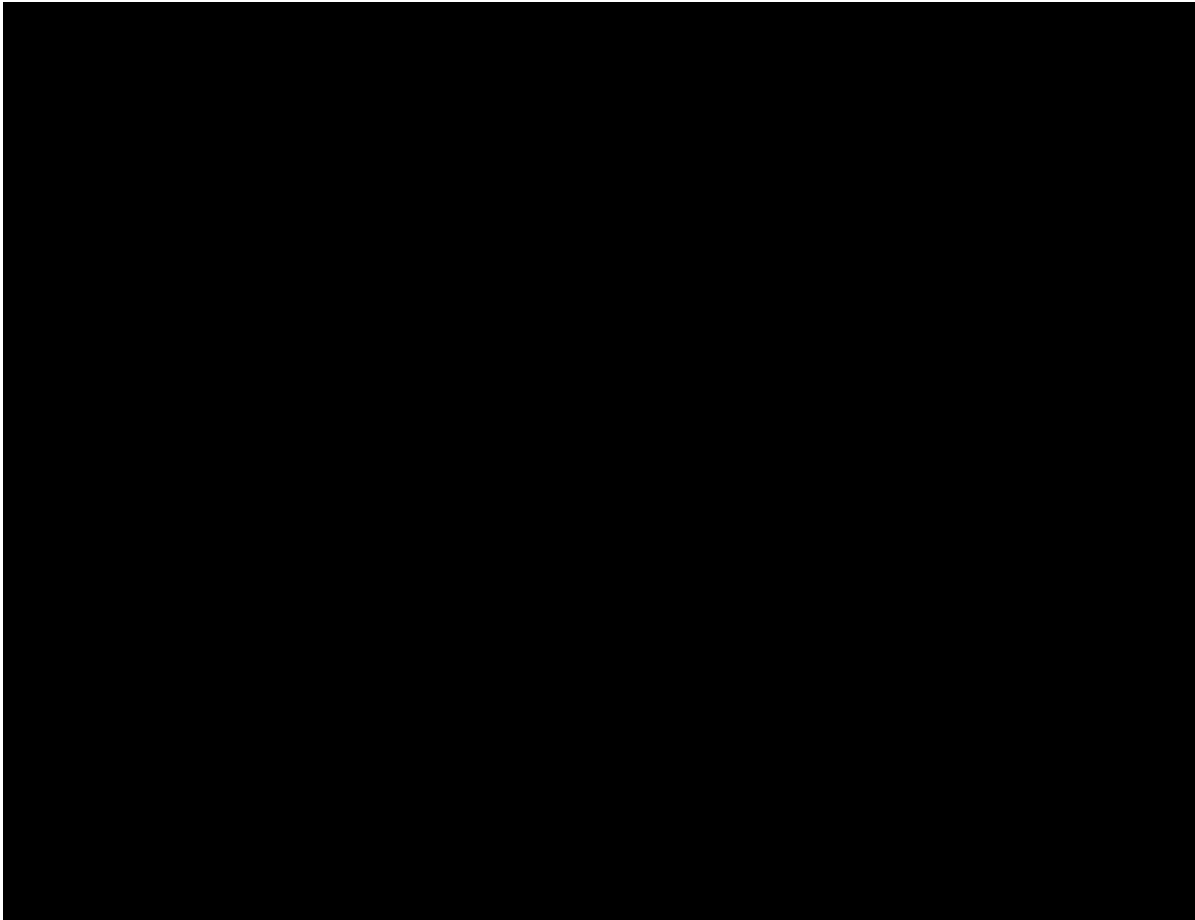
1 **Q. Has AE Supply projected how much power Pleasants will generate in coming**
2 **years?**

3 A. Yes. AE Supply has projected [[REDACTED]
4 [REDACTED].]]

5 **Q. How do CRA's projections of future Pleasants generation compare to those**
6 **prepared by AE Supply?**

7 A. [[REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED].]]

1 **Figure 18: Projected Pleasants Generation, 2018-2021 - CRA vs. AE**
2 **Supply (Confidential)**⁸¹



3
4 It is clear from Confidential Figure 18 that while AE Supply [[REDACTED]
5 [REDACTED]
6 [REDACTED]].

7 **D. CAPACITY PRICES**

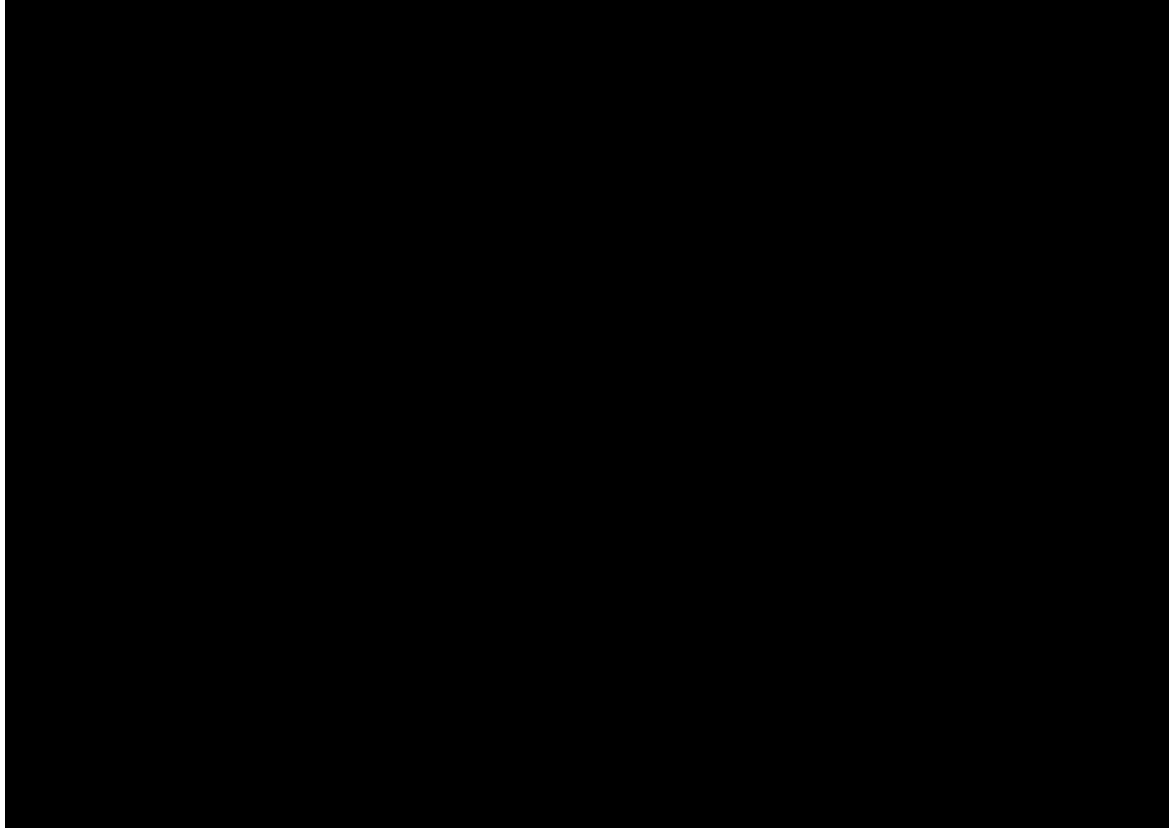
8 **Q. What assumptions concerning future capacity prices did CRA use in its NPV**
9 **analysis of the proposed Pleasants purchase?**

10 A. CRA used capacity prices from ABB’s Spring 2016 forecast. These capacity

⁸¹ AE Supply projections from Confidential Exhibit DAS-14 (CAG-SUN-II-36 Attachment C) (Confidential – Competitively Sensitive).

1 prices are shown in Confidential Figure 19, below, and reflect ABB’s projection
2 that future capacity prices would [[REDACTED]
3 [REDACTED] [REDACTED] [REDACTED].]]

4 **Figure 19: ABB’s Spring 2016 PJM Capacity Price Forecast⁸³**
5 **(Confidential)**



6
7 ABB’s forecast included the actual results of PJM’s capacity auctions through the
8 2019/2020 Delivery Year and then projected that the capacity price in the next
9 auction (for the delivery year 2020/2021) would [[REDACTED]] from \$100 per MW-day
10 to [[REDACTED]] per MW-day.

⁸² [[REDACTED]]
[REDACTED] Companies’ Confidential Resp. to CAG-SUN-I-11b, “11b
MonPower_RFP_Evaluation_Model_011117 Allegheny_20170207,” “Capacity Price” tab.
⁸³ See *id.*

Q. What was the actual result of the PJM auction for the delivery year 2020/2021?

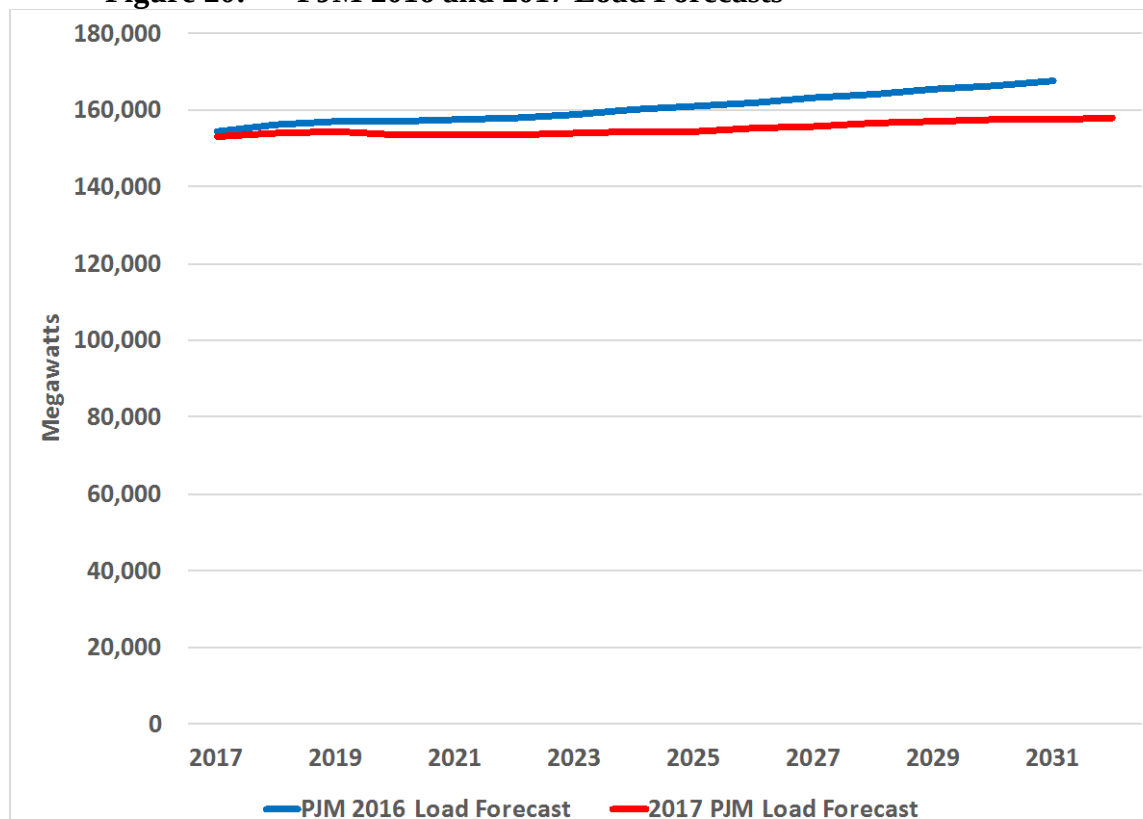
A. As reflected in Confidential Figure 19, above, the capacity price for the PJM RTO Zone, which includes the APS zone, was only \$76.53 per MW-day or [REDACTED] of the price that ABB had predicted.

Q. Is it reasonable to expect that capacity prices will [REDACTED] beginning in next year's PJM auction for the delivery year 2021/2022?

A. No. There are a number of factors which I believe will keep capacity prices relatively low for the foreseeable future.

1. PJM peak loads are stagnant, showing very little growth from 2017 through 2032, as shown in Figure 20, below.

Figure 20: PJM 2016 and 2017 Load Forecasts



1 2. PJM acquired enough capacity in the May 2017 auction for the 2020/2021
2 delivery year to provide a 23.3 reserve margin, or 6.7 percent above the
3 target reserve margin of 16.6 percent. Still, approximately 16,000 MW of
4 capacity failed to clear in the auction. The existence of this excess
5 capacity while PJM loads remain stagnant will mean that capacity prices
6 are likely to remain low.

7 **Q. Do the [REDACTED] capacity prices used by CRA affect the results of its**
8 **analysis of the proposed Pleasants purchase?**

9 A. Yes. The annual capacity prices are a critical input to the NPV calculation. If
10 future capacity prices are [REDACTED] the ABB Spring 2016 Forecast
11 that CRA used in its analysis, and the plant's annual energy revenues are below
12 what CRA projects, continued operation of Pleasants would be uneconomic for
13 the Companies' ratepayers, who would bear the burden of paying for all of the
14 plant's fixed costs.

15 **Q. What do you currently estimate that future capacity prices will be in PJM?**

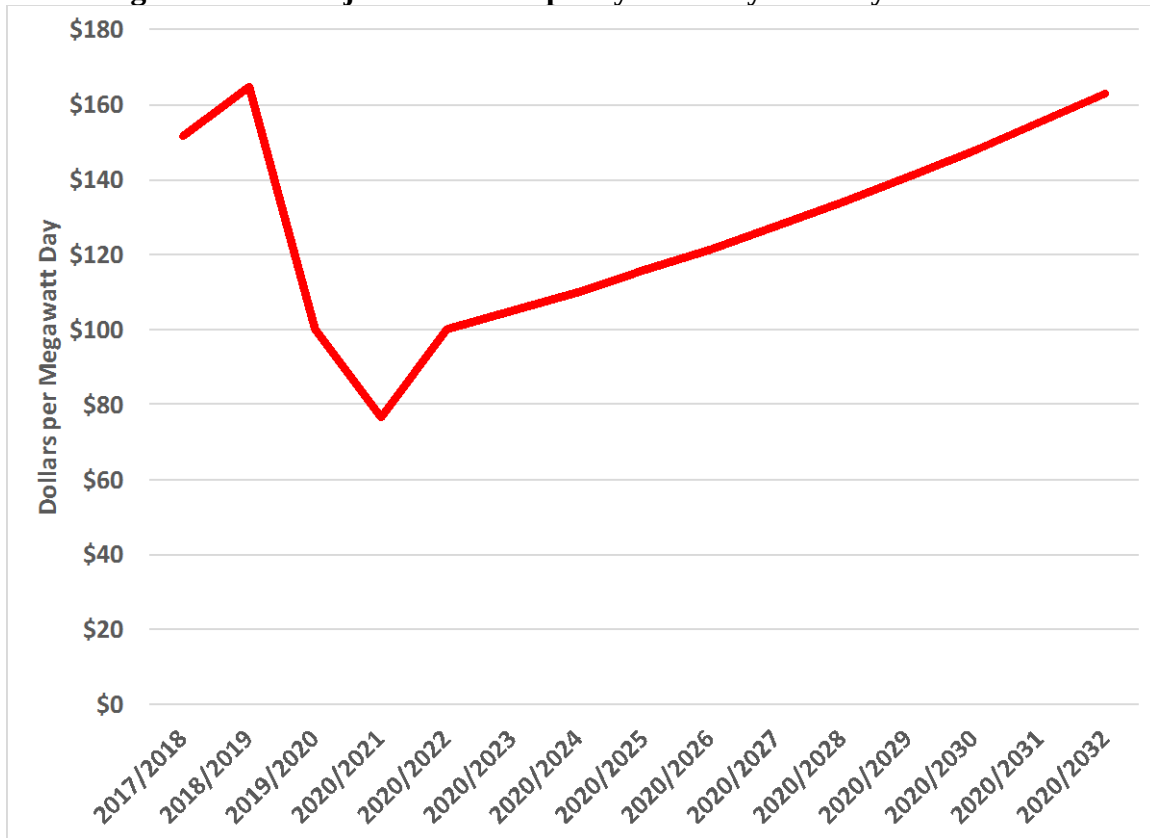
16 A. Capacity prices in PJM have ridden a roller-coaster, up and down, for years, and
17 have been far below the calculated Costs of New Entry ("CONE") values. Plus, as
18 I discussed earlier, there will be a capacity glut in PJM for years, especially given
19 the projected load stagnation.

20 Given these factors, I have conservatively assumed that there will be minor
21 growth in capacity prices long-term; that capacity prices will increase to about
22 \$100 per MW-day in the next PJM BRA auction (for the 2021/2022 delivery
23 year); and that there will be minor (5 percent, on average) growth in capacity
24 prices in subsequent years. However, given the way the market has behaved there
25 may be a continued pattern of ups-and-downs over a period of years with jumps in
26 some years followed by declines in others.

27 Figures 20 and 21, below, shows the capacity prices I believe are reasonable to
28 use to evaluate the proposed transaction. Figure 21 presents these prices by June 1
29 – May 31 delivery years and Figure 22 by calendar years. The prices in both these

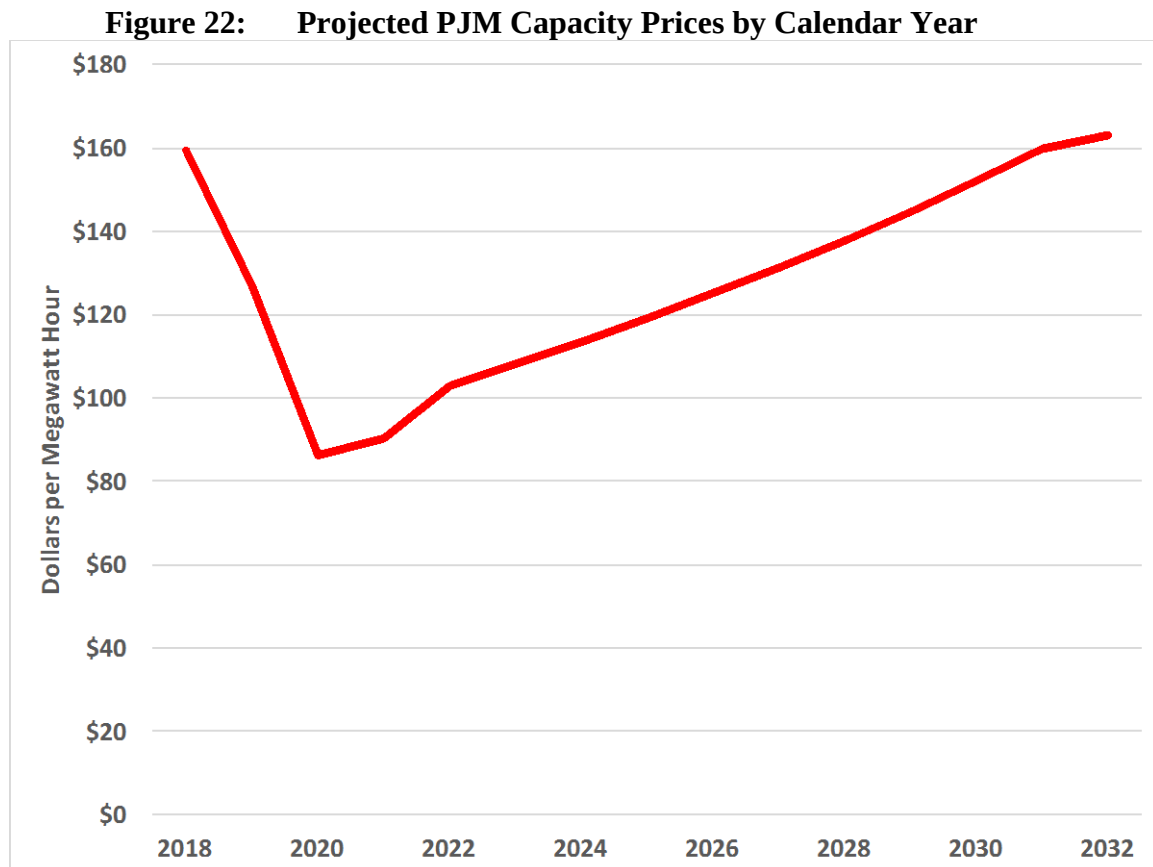
1 figures reflect the actual results of the PJM auction through the 2020/2021
2 delivery year.

3 **Figure 21: Projected PJM Capacity Prices by Delivery Year**



1

2



3

4

5 **E. ECONOMIC ANALYSIS**

6 **Q. Should the Public Service Commission give any weight to CRA's NPV**
7 **calculation of the Pleasants plant?**

8 A. No. CRA's analysis is heavily biased in favor of Mon Power's acquisition of
9 Pleasants and its results are simply not credible.

10 **Q. Please explain.**

11 A. As I have shown above, CRA used very high natural gas prices and energy market
12 prices in its analysis. It also assumed that the amount of power generated at
13 Pleasants will [REDACTED]

1 [REDACTED], or
2 later. Moreover, CRA has used [[REDACTED]] annual capacity market
3 prices that are simply not credible in light of (1) the actual results of PJM auction
4 for the 2020/2021 delivery year and (2) the levels of new generating supplies that
5 are currently being projected to be added in PJM.

6 **Q. Have you completed an economic analysis that you believe reflects more**
7 **reasonable assumptions as to future energy and capacity market prices and**
8 **Pleasants' generation?**

9 A. Yes. I have completed an economic analysis that has a Base Case that is based
10 upon current energy market price forward curves, Pleasants' generation for the
11 last twelve months for which I have data (June 2016-May 2017), and capacity
12 price assumptions that reflect the results of May's PJM base residual auction for
13 the 2020/2021 delivery year and the projected glut of generating capacity in PJM.

14 **Q. Why did you use Pleasants' generation for the twelve months ending May**
15 **2017 in your Base Case?**

16 A. I used this twelve-month period to be conservative, as the plant generated more in
17 these months than it did in either calendar year 2016 or calendar year 2015.

18 **Q. What other scenarios have you examined?**

19 A. I have analyzed both a High Case and a Low Case.

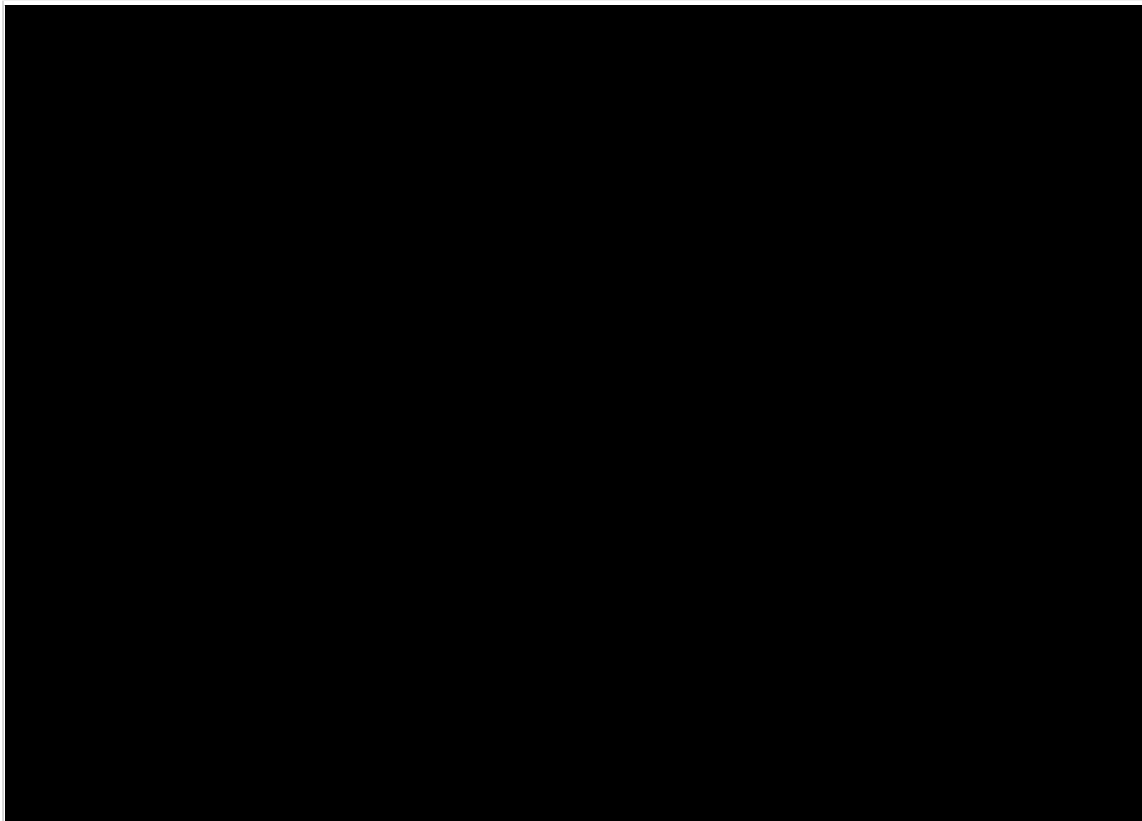
20 The High Case assumes that energy market prices and Pleasants' annual
21 generation are 10 percent higher than they are in the Base Case. Capacity prices
22 are assumed to be 10 percent higher than in the Base Case beginning in 2021.

23 The Low Case assumes that energy market prices and Pleasants' annual
24 generation are each 10 percent lower than in the Base Case. Capacity market
25 prices are assumed in this case to be 10 percent lower than in the Base Case
26 beginning in 2021.

1 **Q. How do the energy market prices used in your analysis compare with the**
2 **prices used by CRA?**

3 A. The peak and off-peak energy market prices I have used in my analyses are
4 [[REDACTED]] than those used by CRA. I selected these prices based on
5 my assessment of the PJM market and current forward power price curves.

6 **Figure 23: Energy Market Prices Used in CRA and Schlissel Technical**
7 **Consulting (STC) Analyses (Confidential)**



8

9

10 **Q. Are all of the STC energy market prices shown in Confidential Figure 23,**
11 **above, taken from the forward market price curve for August 11, 2017?**

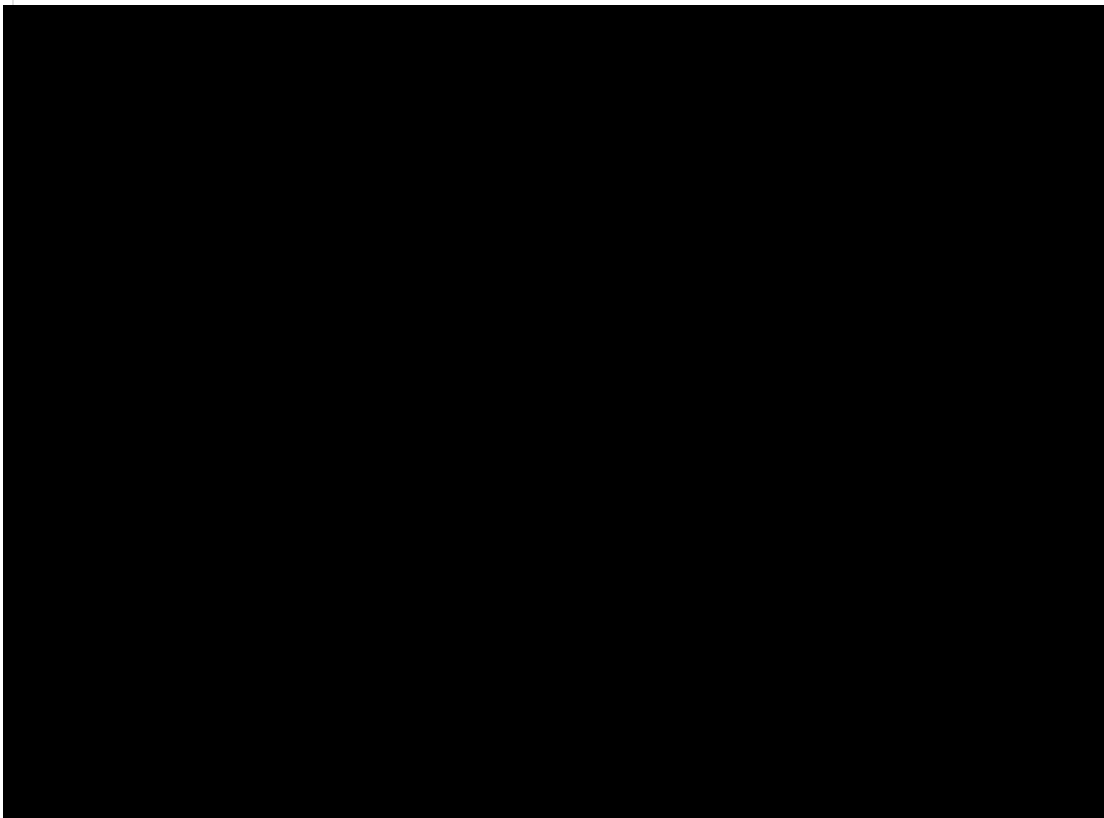
12 A. No. The forward prices I had went through 2026. To develop the prices for later
13 years I escalated the 2026 peak and off-peak prices by 2.7 percent per year. This

1 was the annual rate at which the forward prices for 2026 had increased over the
2 same prices in 2025.

3 **Q. How do your expectations for annual Pleasants generation differ from the**
4 **results of CRA's analysis?**

5 A. Based on Pleasants' operating history over the past 20 years, and the market's
6 expectations for future energy prices, I believe that Pleasants will generate
7 [REDACTED] power each year than assumed in CRA's NPV calculation.

8 **Figure 24: Future Pleasants Annual Generation Used in CRA and STC**
9 **Analyses (Confidential)**



10

11 **Q. Do you really believe that Pleasants will generate precisely the same amounts**
12 **of power every year?**

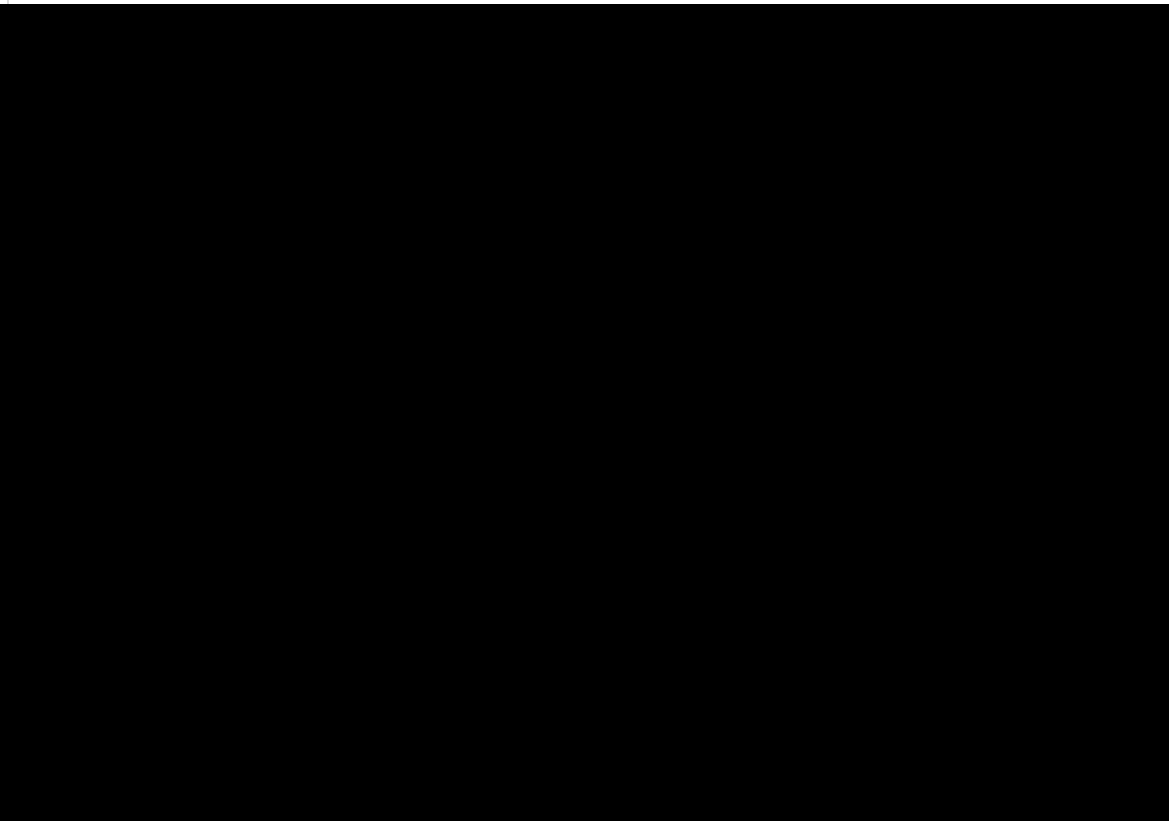
13 A. Of course not. However, there is no way to predict the exact amount of power the
14 plant actually will generate in any particular year. That will depend on plant-

1 specific conditions and costs, and market conditions such as the generation from
2 other plants that are selected for dispatch instead of Pleasants. Thus, my estimate
3 of future generation at Pleasants is an average annual generation over a number of
4 years.

5 **Q. How do the capacity prices in your analysis compare to the ABB forecast**
6 **used by CRA?**

7 A. As shown in Confidential Figure 25, below, the capacity prices I used in my
8 analysis are [[REDACTED]] than the unrealistically high capacity prices in
9 CRA's analysis.

10 **Figure 25: Capacity Prices Used in CRA and STC Analyses (Confidential)**



11

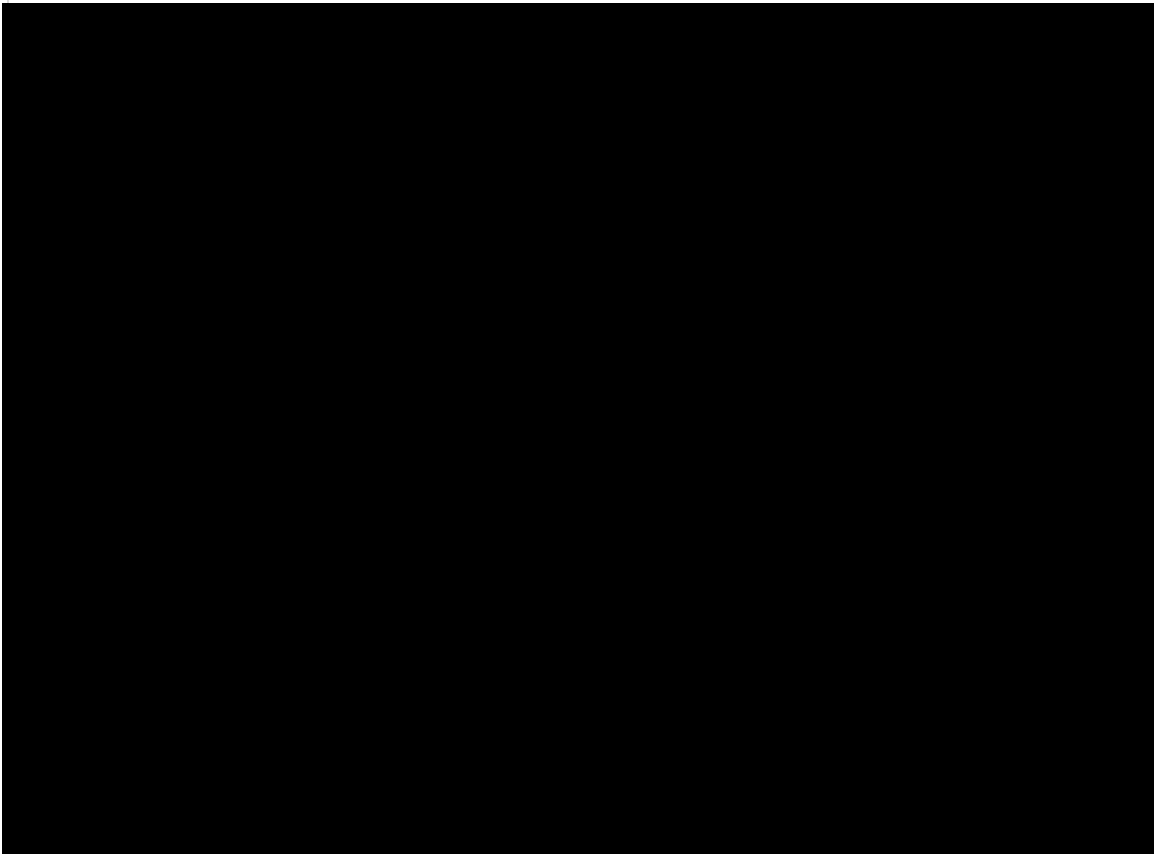
12 **Q. Did you also prepare a sensitivity analysis using any of FirstEnergy's own**
13 **price forecasts?**

1 A. Yes. I prepared a final sensitivity analysis that (a) used AE Supply’s forecasts for
2 energy market prices and Pleasants’ generation through 2021 and (b) assumed
3 that, for the remaining years of the 15-year period (that is, 2022-2032), (i) energy
4 market prices would escalate at the same rate projected by ABB in its Spring 2016
5 forecast and (ii) Pleasants would generate 8.8 million MWh per year, which is the
6 same annual generation as in my High Case. I also assumed that capacity prices
7 in this AE Supply Sensitivity would be the same as in my High Case.

8 **Q. What are the results of your economic analyses?**

9 A. The results of my NPV Base, High and Low Cases, and AE Supply Sensitivity
10 economic analyses are presented in Confidential Figure 26 and Table 1 below:

1 **Figure 26: Annual Economic Results (Confidential)**⁸⁴



2

3 **Table 1: Economics Results in Net NPV and Nominal Dollar**

4

	NPV Millions of Dollars
CRA NPV Calculation	\$636
STC Base Case	-\$470
STC High Case	-\$266
STC Low Case	-\$640
STC AE Supply Sensitivity	-\$249

5

6 As these results demonstrate, the Pleasants plant’s 15-year NPV is negative when
7 using more reasonable assumptions. This means that, far from providing a “rate

⁸⁴ Compare Confidential Exhibit DAS-18 (results of CRA’s NPV calculation) with Confidential Exhibit DAS-19 (results of STC Base Case, High Case, Low Case, and AE Supply Sensitivity).

1 benefit to customers,”⁸⁵ acquiring Pleasants would likely saddle the Companies’
2 customers with higher costs.

3 **Q. Are there any other costs that the Pleasants plant will likely face that were**
4 **not reflected in CRA’s NPV calculation?**

5 A. Yes. There are a number of potential costs and operational risks facing Pleasants
6 that would make the acquisition of Pleasants even more uneconomic for the
7 Companies’ customers. These costs and risks include the following:

- 8 • ELG compliance costs - Pleasants may need to incur significant capital
9 expenditures to comply with the Effluent Limitation Guidelines
10 (“ELGs”). According to one of the Companies’ witnesses, Kurt
11 Leutheuser, the compliance costs are estimated to be \$80-120 million.⁸⁶
12 Mr. Leutheuser described this as a “likely potential cost[] in the future
13 that should be planned for.”⁸⁷ But CRA’s NPV calculation did not
14 include such costs.⁸⁸
- 15 • Coal ash impoundment closure costs - Under the proposed transaction,
16 financial responsibility for the McElroy’s Run coal ash impoundment
17 would pass to the Companies.⁸⁹ Mr. Leutheuser noted that the cost of
18 closing this impoundment is estimated to be \$45 million.⁹⁰ Here again,
19 these costs were not factored into CRA’s NPV analysis.
- 20 • Plant aging - There is no evidence that CRA has accounted for the
21 adverse impact of aging on Pleasants’ operating performance. Indeed,
22 CRA assumes that there would be []
23 [REDACTED]
24 []].

⁸⁵ Ruberto Direct at page 21.

⁸⁶ Direct Testimony of Kurt P. Leutheuser, Ex. KPL-1 at pages 3-9, 3-11 (hereinafter, “Leutheuser Direct”).

⁸⁷ *Id.*

⁸⁸ Exhibit DAS-20 (resp. to SC-II-6) (“Compliance costs for ELG were not included in the NPV analysis.”); *id.* (resp. to CAD-IV-B-16) (“Effluent limitations guideline expenses were not included in the NPV analysis.”).

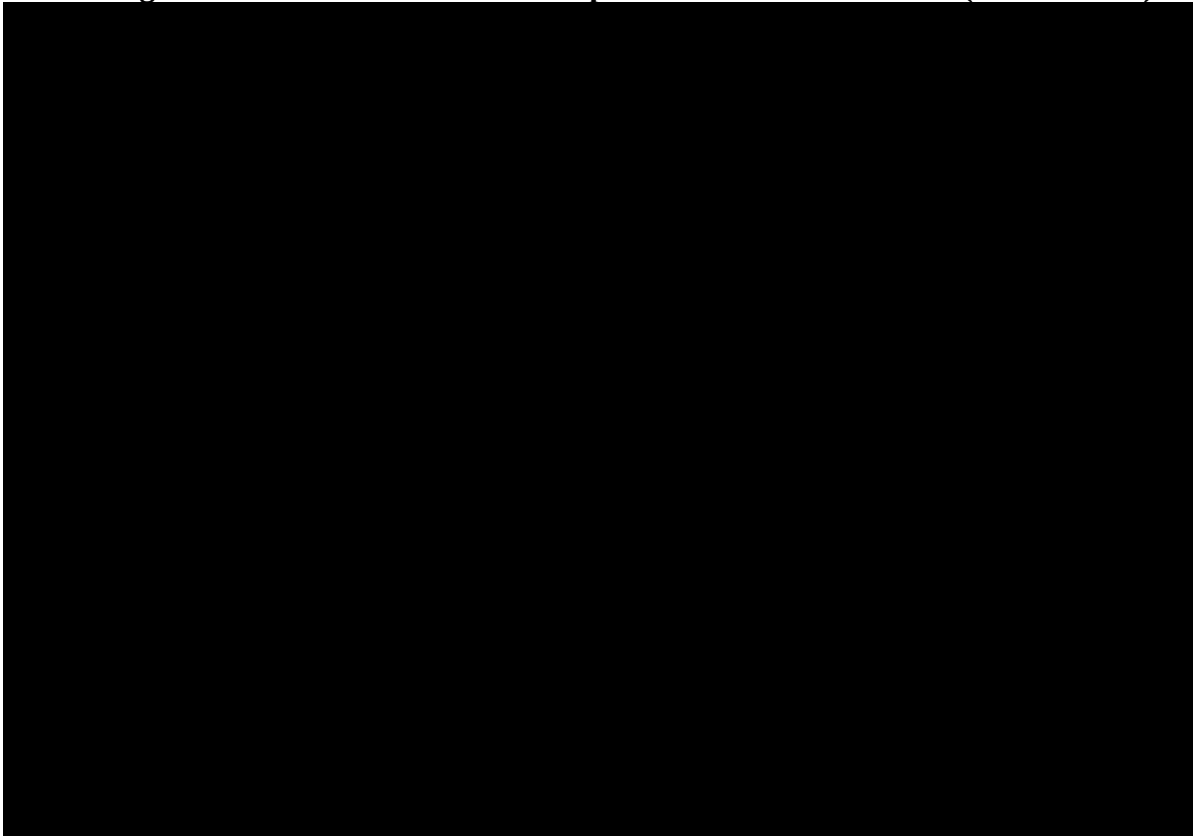
Despite the magnitude of the potential ELG compliance and CCR closure costs, the Companies produced hardly any documentation supporting their cost estimates. See Exhibit DAS-21 (resps. to WVEUG-I-12, 13, & 24).

⁸⁹ Petition, Ex. 9A, Asset Purchase Agreement, at page 2 (Mar. 6, 2017).

⁹⁰ Leutheuser Direct, Ex. KPL-1 at pages 3-10, 3-11.

- CO₂ costs - Although utilities regularly consider for potential CO₂ costs when estimating the economics of fossil fuel generating units, CRA did not include any such costs in its NPV calculation.
- Pleasants' Unforced Capacity - CRA's capacity revenue projection assumes that [[REDACTED]] of UCAP clears the PJM auction each year throughout the 15-year period 2018-2032. This assumption has already been proven wrong for the 2020/21 delivery year [[REDACTED]] and is highly questionable for the remaining years given that Pleasants [[REDACTED]] in the past six auctions.⁹¹
- Pleasants fuel costs - In its Spring 2016 Reference Case, ABB developed a plant-specific forecast of Pleasants' fuel costs. As shown in Confidential Figure 27, below, ABB's plant-specific cost forecast [[REDACTED]] the costs assumed in CRA's calculation.

Figure 27: CRA vs. Pleasants' Specific Coal Price Forecast (Confidential)



⁹¹ Confidential Exhibit DAS-22 (resp. to CAD-III-A-26 and supplemental resp. to CAG-SUN-I-27) (Confidential – Competitively Sensitive).

1 **Q. Did you include the costs listed above in your NPV analyses?**

2 A. No. Although Pleasants will likely face many of these costs in coming years, I
3 did not factor them into the NPV analyses I developed. Because I did not include
4 these potential costs, my analysis is conservative.

5 **Q. Does the Low Case represent a worst-case analysis?**

6 A. No. It's certainly possible that one or more of the Pleasants units could generate
7 less energy than I've assumed in the Low Case, or that energy market or capacity
8 prices could be even lower than I've assumed. Coal prices also could be higher.
9 Power production costs also could be higher, especially as the units age.

10

11 **VI. THE COMPANIES' PROPOSED SHORT-TERM RATE DECREASE IS**
12 **BASED ON UNREASONABLE ASSUMPTIONS.**

13 **Q. Have the Companies estimated the impact of the proposed transaction on**
14 **rates?**

15 A. Yes. The Companies originally estimated that the transaction would result in a
16 \$31.5 million rate decrease (1.6%) for the 16-month period from September 2017
17 through December 2018. This rate decrease was comprised of a \$148.6 million
18 increase in rates to pay for the transaction surcharge (to begin recovering the fixed
19 costs of the transaction) and a \$180 million decrease in ENEC rates as a result of
20 increased revenues from energy and capacity sales to PJM.⁹² The projected ENEC
21 rate decrease would be subject to true-up during the next ENEC proceeding.

22 The Companies did not project the rate impact of the transaction beyond
23 December 2018. The Companies also have not re-calculated their estimated near-

⁹² Petition at page 8.

1 term rate decrease to reflect the fact that the transaction, if approved, would not
2 close before September 2017.⁹³

3 **Q. Do you find it significant that the Companies did not estimate the rate impact**
4 **of the transaction beyond 2018?**

5 A. Yes. According to my base case scenario, which makes assumptions about future
6 energy and capacity prices that I believe to be more reasonable than ABB's, [[REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED].]]]

11 **Q. Do you believe that the Companies have overstated the projected ENEC rate**
12 **decrease?**

13 A. It seems likely.

14 **Q. Why?**

15 A. The Companies used a market price forecast for their ENEC rate decrease
16 analysis that was [[REDACTED]] the forecast used by CRA in their dispatch model
17 and [[REDACTED]] higher than market future prices. The average 2018 price used in the
18 ENEC rate analysis was \$32.53/MWh, [[REDACTED]] than the average market
19 price used by CRA in their dispatch modeling and 9.2% higher than market
20 futures.⁹⁴

21 It is inexplicable why Mon Power would use a different set of numbers to
22 calculate the projected near-term rate impact of the transaction than the numbers it
23 provided to its consultant to calculate the overall net present value of the
24 transaction.

⁹³ See Companies' Resp. to WVEUG-V-22.

⁹⁴ Companies' Resp. to CAG-SUN-V-3; Confidential File "CAG SUN I-11 Dispatch_Model_Pleasants
CONFIDENTIAL" tab "Energy_Price", column R; and OTC Global Holdings futures price as of 8/1/2017.

1 **VII. THE PROPOSED TRANSACTION’S PURCHASE PRICE APPEARS TO**
2 **BE INFLATED.**

3 **Q. At what price does Mon Power propose to purchase the Pleasants plant?**

4 A. Mon Power proposes to pay \$150/kW, or \$195 million, to acquire Pleasants.⁹⁵

5 **Q. What justification does Mon Power provide for this price?**

6 A. Companies’ witness Ruberto claims that this price compares favorably to the
7 market for generation capacity because it is significantly cheaper than the other
8 two bids received for Mon Power’s RFP and the price at which Mon Power sold
9 its share of Pleasants four years ago.⁹⁶ Witness Ruberto also relies on CRA’s
10 NPV calculation to contend that acquiring Pleasants at this price is a good deal.⁹⁷

11 **Q. How was the price of \$150/kW arrived at?**

12 A. \$150/kW was the price at which AE Supply, the plant owner and corporate
13 affiliate of Mon Power, offered Pleasants into the RFP. No information has been
14 provided on why AE Supply offered Pleasants at this price.

15 **Q. How does this price of \$150/kW compare to the value of other coal-fired**
16 **power plants located in western PJM?**

17 A. It is higher. There have been significant write-downs in the value of merchant
18 coal assets in western PJM in the last year. These devaluations are a direct result
19 of the financial difficulties faced by merchant coal plants in the current
20 environment of low wholesale electricity market prices in PJM. For example,
21 Dayton Power & Light wrote down the value of all of its merchant coal plants in
22 Ohio in the fourth quarter of 2016, as shown in the following table:

⁹⁵ Kauffman Direct at page 5.

⁹⁶ Ruberto Direct at page 24.

⁹⁷ *Id.*.

1 **Table 2: Recent Dayton Power & Light Coal Plant Valuations**⁹⁸
2

Plant	MW Owned	Value after Impairment (\$/kW)
Stuart	807.8	\$70.56
Killen	400	\$107.50
Miami Fort	367.2	\$98.04
Zimmer	377.664	\$63.55
Conesville	128.631	\$7.77

3

4 In the third quarter of 2016, American Electric Power wrote down the value of all
5 of its Ohio coal plants (Cardinal Unit 1, a 43.5% interest in Conesville Unit 4,
6 Conesville Units 5-6, a 26% interest in Stuart, and a 25.4% interest in Zimmer
7 Unit 1) plus its share of a Texas coal plant (Oklaunion) to \$0. AEP explained that
8 it did so because its ten-year discounted cash flow model resulted in projected
9 negative cash flows under AEP’s expected future energy and capacity prices.⁹⁹

10 Also in the third quarter of 2016, FirstEnergy Solutions wrote down the value of
11 its merchant coal assets in Ohio and Pennsylvania to \$435 million, or an average
12 of \$88/kW.¹⁰⁰ All of the merchant coal assets in Ohio and Pennsylvania that have
13 been written down by American Electric Power, Dayton Power & Light and
14 FirstEnergy Solutions in the past year have been valued significantly lower than
15 the purchase price proposed here for Pleasants (\$150/kW).

⁹⁸ Notes to Financial Statements: Asset Impairment Expenses, available at https://www.sec.gov/cgi-bin/viewer?action=view&cik=874761&accession_number=0000874761-17-000003&xbrl_type=v# (“The Stuart, Killen, Miami Fort, Zimmer, Conesville and the gas-fired peaking plant asset groups were determined to have a fair value of \$57 million, \$43 million, \$36 million, \$24 million, \$1 million and \$2 million, respectively.”).

⁹⁹ Notes to Financial Statements: Dispositions, Assets and Liabilities Held for Sale and Impairments, available at https://www.sec.gov/cgi-bin/viewer?action=view&cik=4904&accession_number=0000004904-16-000102&xbrl_type=v#.

¹⁰⁰ Notes to Financial Statements: Asset Impairments, available at https://www.sec.gov/cgi-bin/viewer?action=view&cik=1031296&accession_number=0001031296-17-000015&xbrl_type=v#. FirstEnergy Solutions owns a total of 4,964 MW of coal-fired generation in Ohio and Pennsylvania. See FirstEnergy 2016 10-K, page 48, available at <http://investors.firstenergycorp.com/file/Index?KeyFile=38163065&Output=2&OSID=9>.

1 **Q. How does AE Supply, as Pleasants’ owner, view the plant’s financial**
2 **outlook?**

3
4 A. Consistent with the impairments of other older coal-fired plants within PJM, AE
5 Supply’s internal revenue projection predicts that [[REDACTED]

6 [REDACTED]
7 [REDACTED]
8 [REDACTED]

9
10 **VIII. CONCLUSION AND RECOMMENDATION**

11 **Q. Should the Commission approve or reject the Companies’ proposed**
12 **purchase of the Pleasants plant?**

13 A. The Commission should reject the Company’s proposed purchase.

14 **Q. If the Commission approves the proposed transaction, are there any**
15 **conditions that the Commission should apply to its approval?**

16 A. Yes. As I have explained, CRA’s economic analysis showing that Pleasants
17 would produce a net benefit is premised on unreasonable projections for future
18 natural gas prices, energy market prices, plant generation, and capacity market
19 prices, each of which represent significant departures from the recent past. For
20 this reason, the Companies’ proposal exposes ratepayers to the significant risk
21 that the future costs of owning and operating Pleasants will exceed, perhaps by a
22 substantial margin, the revenues it will be able to earn from selling the plant’s
23 energy, capacity, and ancillary services into the PJM markets.

24 Therefore, if the Commission approves the acquisition, it should, at a minimum,
25 adopt a mechanism ensuring that the Companies (and their parent company) bear
26 the risks that their revenue projection is not accurate. More specifically, this risk-
27 sharing mechanism would provide that, in any year in which the total revenues

¹⁰¹ See Confidential Exhibit DAS-14 (CAG-SUN-II-36 Attachment C, “2017 2+10F” tab) (Confidential – Competitively Sensitive).

1 from selling Pleasants' energy, capacity and ancillary services into the PJM
2 markets do not fully cover the total costs of owning and operating Pleasants –
3 including fuel, non-fuel O&M (both variable and fixed), emissions costs
4 (including any future CO₂ costs), capital expenditures, depreciation, interest,
5 taxes, and Mon Power's return on equity – the Companies, not ratepayers, would
6 bear the net shortfall.

7 **Q. Does this complete your testimony at this time?**

8 A. Yes.

9

David A. Schlissel

President

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SUMMARY

I have worked since 1974 as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

PROFESSIONAL EXPERIENCE

Electric Resource Planning - Analyzed the financial and economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the financial, economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO₂ and CO₂. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Electric System Reliability - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Nuclear Power – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Electric Industry Regulation and Markets - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Montana Public Service Commission (Docket Nos. D2013.5.33 and D2014.5.46) – May 2015

The circumstances surrounding the extended outage of Colstrip Unit 4 from July 1, 2013 through January 23, 2014.

Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 12 & 13) – December 2014

Whether Duke Energy Indiana's Edwardsport IGCC Project was in service between June 7, 2013 and March 31, 2014 and the Project's current operational performance and cost status and future prospects.

Public Service Commission of West Virginia (Case No. 14-0546-E-PC) – August 2014

The reasonableness of American Electric Power's proposed transfer of 50 percent of the Mitchell Coal Plant to its regulated affiliates in West Virginia.

Mississippi Public Service Commission (Docket No. 2013-UN-189) – March and June 2014

The prudence of Mississippi Power Company's management of the planning for the Kemper County IGCC Plant.

Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 8, 10, and 12) – June 2012, April 2013 and April 2014

Startup and pre-operational testing delays at Duke Energy Indiana's Edwardsport IGCC Project.

Public Service Commission of West Virginia (Case No. 12-1655-E-PC) – June 2013 and July 2013

The reasonableness of Appalachian Power Company's proposed acquisition of 2/3 of Unit 3 of the John E. Amos power plant and 1/2 of the two unit Mitchell power plant.

Public Service Commission of West Virginia (Case No. 12-1571-E-PC) – April 2013

The reasonableness of Monogahela Power Company's proposed acquisition of 80 percent of the Harrison Power Station.

Virginia State Corporation Commission (Case No. PUE-2012-00128) – March 2013

Whether Dominion Virginia Power's proposed Brunswick Project natural gas-fired combined cycle power plant is needed and in the public interest.

Arizona Corporation Commission (Docket No. E-01922A-12-0291 – December 2012

Reasonableness of Tucson Electric Power's proposed Environmental Compliance Adjustor mechanism.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR and 50-286-LR) – June 2012

Reply to testimony filed by Entergy Nuclear and NRC Staff concerning the relicensing of Indian Point Units 2 and 3.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – March 2012

Petition to Reopen the docket for the Kemper County IGCC Plant based on changed circumstances.

Mississippi Public Service Commission (Docket No. 2009-UA-279) – February 2012

The financial and economic risks of retrofitting Mississippi Power Company's Plant Daniel Coal Plant.

Georgia Public Service Commission (Docket No. 34218) – November 2011

The reasonableness of Georgia Power Company's proposed fossil plant decertification/retirement plan.

Missouri Public Service Commission (Case No. EO-2011-0271) – October 2011

Reasonableness of Ameren Missouri's 2011 Integrated Resource Plan filing.

Maryland Public Service Commission (Case No. 9271) – October 2011

The reasonableness of Constellation Energy Group's proposed divestiture of three coal-fired power plants as mitigation for market power concerns arising from its proposed merger with Exelon Corporation.

Minnesota Public Utilities Commission (Docket No. E017/M-10-1082) – August and September 2011

Whether the proposed addition of the Big Stone Plant Air Quality Control System is a lower cost alternative for the ratepayers of Otter Tail Power Company than retirement of the Plant and replacement by a natural gas-fired combined cycle unit possibly combined with new wind capacity.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – June, July, and October 2011 and June 2012

Duke Energy Indiana's imprudence and gross mismanagement of Edwardsport IGCC Project.

Kansas State Corporation Commission (Docket No. 11-KCPE-581-PRE) – June 2011

The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

Arizona Corporation Commission (Docket No. E-01345A-10-0474) – May 2011

The reasonableness of Arizona Public Service Company's proposed acquisition of Southern California Edison's share of Four Corners Units 4 and 5.

Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010

The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July, November and December 2010

The reasonableness of Duke Energy Indiana's new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

Oregon Public Utility Commission (Docket LC 48) – May and August 2010

Comments and Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan.

South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010

The reasonableness of Black Hills Power Company's 2007 Integrated Resource Plan and the Company's decision to build the Wygen III coal-fired power plant.

Michigan Public Service Commission (Docket No. U-16077) – April 2010

Comments on the City of Holland Board of Public Works' 2010 Power Supply Study.

Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010

Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010

The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009

The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010

The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009

The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Public Service Commission of Michigan (Docket No. U-15996) – July 2009

Comments on Consumer Energy's Electric Generation Alternatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

Public Service Commission of Michigan (Docket No. U-16000) – July 2009

Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008

The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and September 2008

The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008

The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008

The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007

AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009

The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007

Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007

Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007

Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007

The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007

The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008

Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007

The appropriate carbon dioxide (“CO₂”) emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana’s proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007

Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007

Florida Light & Power Company’s need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006

The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008

Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007

Duke’s need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006

Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006

Whether APS’s acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006

Quantification of plaintiff’s business losses during an extended power plant outage and plaintiff’s business earnings due to the shortening and delay of future plant outages.
[Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006

Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006

Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006

The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006

Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005

The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005

The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005

The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005

Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005

Joint testimony with Peter LanzaLotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004

Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004

Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004

Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004

Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

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Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

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Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004

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The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

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The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

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Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003

Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

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The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003

Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

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Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003

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New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002

Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003

Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

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Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

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The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001

Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001

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Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

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The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

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Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998

The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998

Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997

The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996

Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996

Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994

Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994

Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994

The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994

Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994

Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994

Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993

Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993

Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995

Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

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United Illuminating Company off-system capacity sales. [Confidential Testimony]

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Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992

Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993

Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - June 1991

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Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989

Boston Edison's corporate management of the Pilgrim Nuclear Station.

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Kansas State Corporation Commission (Case 164,211-U) - April 1989

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Public Utility Commission of Texas (Docket 8425) - March 1989

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Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988

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Illinois Commerce Commission (Docket 87-0695) - April 1988

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The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues during Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2012- Director of Resource Planning Analysis, Institute for Energy Economics and Financial Analysis
2010 - President, Schlissel Technical Consulting, Inc.
2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.
1994 - 2000: President, Schlissel Technical Consulting, Inc.
1983 - 1994: Director, Schlissel Engineering Associates
1979 - 1983: Private Legal and Consulting Practice
1975 - 1979: Attorney, New York State Consumer Protection Board
1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,
1973: Stanford Law School,
Juris Doctor
1969: Stanford University
Master of Science in Astronautical Engineering,
1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fifth Request for Information**

The following response to CAG-SUN-V-19 of the Fifth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	August 14, 2017

CAG-SUN-V-19

19. Refer to page 4, lines 17-20 of the Lee Testimony.

- a. Provide any correspondence in which Mon Power informed CRA of its desire to procure capacity resources through an RFP process rather than purchasing power through a contractual arrangement.
- b. Produce all documentation in which Mon Power or CRA evaluated the market risks and potential volatility that would be associated with the Mon Power's purchase of power through a contractual arrangement.

Response:

- a. All non-privileged communication was produced in response to CAG-Sun-I-14a.
- b. CRA is not aware of any such documentation.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
First Request for Information**

The following response to CAG-SUN-I-11 of the First Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on March 28, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	April 17, 2017

CAG-SUN-I-11

Refer to page 7, lines 15-21 of the Direct Testimony of Robert J. Lee.

- a. Describe and produce a copy of the dispatch model referenced in this portion of Mr. Lee's testimony.
- b. Produce each and every net present value ("NPV") calculation prepared during the RFP evaluation stage.
- c. Produce, in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in preparing the NPV calculations referenced in subpart (b).
- d. Did CRA conduct any sensitivities or alternative modeling runs on these NPV calculations?
 - i. If so:
 - (a) Produce those sensitivity or alternative modeling analyses, including any workpapers and modeling input and output files (in electronic format with formulas intact).
 - (b) Explain the purpose of each sensitivity or alternative modeling run, and why CRA conducted that sensitivity or modeling run.
 - ii. If not, explain why not.
- e. Confirm that the NPV calculations referenced in this portion of Mr. Lee's testimony provided the basis for Mr. Ruberto's testimony (page 25, lines 3-4) that "CRA calculated an NPV for the Pleasants facility of \$636M, which effectively represents its value above market purchases."
 - i. If not confirmed, produce, in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in preparing the NPV calculation referenced on page 25, lines 3-4 of Mr. Ruberto's testimony.

Response:

- a. To develop an outlook on expected future operation of plants that were offered in response to the RFP, particularly commodity sales revenue and associated variable costs, CRA used a proprietary dispatch model. The tool used was a Microsoft Excel-based dynamic dispatch model that evaluates future capacity factors, energy revenues, fuel costs, and energy margins on a unit-specific basis. In addition to plant-specific characteristics, inputs include future fuel and electricity prices from a forecast from a third party provider (in this case, purchased from ABB/Ventyx). For each hour during the analysis period, the model compares the market price of electricity to the marginal cost of operating the unit to determine the most profitable dispatch over time. The dispatch algorithm observes relevant constraints, such as forced outage rate, maintenance rate, minimum up time, minimum down time, and startup costs.
- b. Please refer the confidential files attached to CAD I-5:
- c. Please see CAG-SUN-I-11 CONFIDENTIAL on the attached CD:
 - 1. Dispatch_Model_1 CONFIDENTIAL
 - 2. Dispatch_Model_2 CONFIDENTIAL
 - 3. Dispatch_Model_3 CONFIDENTIAL
- d. No. CRA did not do alternative modeling runs.
 - 1. A single forecast was selected that was expected to provide middle-of-the-road results and serve the primary purpose of the calculation to allow accurate ranking of the alternative proposals.
- e. This is confirmed.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Third Request for Information**

The following response to CAG-SUN-III-1 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on June 6, 2017 has been prepared under the supervision of the person identified below.

Name: Thomas Sweet

Title: Director, Global Reference Case, Enterprise Software
Company: ABB

Date: June 19, 2017

CAG-SUN-III-1

Refer to page 5, lines 15-20 and page 7, lines 3-7 of the Direct Testimony of Thomas Sweet.

- a. Confirm that the natural gas, capacity, and electricity price forecasts referenced in this portion of Mr. Sweet's testimony were taken from ABB's Spring 2016 Reference Case.
 - i. If confirmed, explain why Mr. Sweet did not use price forecasts from the Fall 2016 Reference Case. In your answer, please identify each and every reason why those forecasts were not used.
 - ii. If not confirmed, produce a complete copy of the Reference Case from which the forecasts were taken.
- b. Identify the date(s) on which the natural gas, capacity, and electricity price forecasts for ABB's Fall 2016 Reference Case were completed.
- c. With regards to each natural gas, capacity, and electricity price forecast sponsored by Mr. Sweet in this proceeding:
 - i. Identify the date on which the price forecast was completed.
 - ii. Identify the date on which the price forecast was provided to CRA.
- d. For his testimony in this case, did Mr. Sweet make any updates or other modifications to the gas, capacity, and electricity price forecasts presented in the ABB Spring 2016 Reference Case?
 - i. If so, please identify each update or modification that Mr. Sweet made, and for each such update or modification:
 - (a) Explain why Mr. Sweet made the update or modification;
 - (b) Identify the date on which the update or modification was made; and
 - (c) Produce all workpapers and other documents associated with the update or modification.
 - ii. If not, confirm that the price forecasts that the Companies are relying on in this case are more than a year old.

- (a) If not confirmed, explain why not.
- e. As of this month (*i.e.*, June 2017), does Mr. Sweet believe that his natural gas, capacity, and electricity price forecasts are an accurate representation of future gas, capacity, and electricity prices?
 - i. If yes, explain the complete factual basis for his belief.
 - ii. If not:
 - (a) Explain why not, and identify each reason why Mr. Sweet believes such natural gas, capacity, and/or electricity price forecast(s) is no longer an accurate representation of future prices.
 - (b) Identify and produce any natural gas, capacity, and/or electricity price forecast(s) developed or relied on by Mr. Sweet which he believes to be an accurate representation of future prices as of June 2017.

Response:

- a. The natural gas, capacity, and electricity price forecasts referenced in this portion of Mr. Sweet's testimony were not taken from ABB's Spring 2016 Reference Case but erroneously provided from ABB's Fall 2016 Reference Case.
 - i. Not applicable.
 - ii. Refer to ABB's Midwest Spring 2016 Reference Case Report, and the Natural Gas Prices tab, Electric Prices tab, and Capacity Prices tab of the attachment to CAG-SUN I-15.
- b. November 4, 2016.
- c.
 - i. May 6, 2016.
 - ii. ABB does not know the date the price forecast was provided to CRA.
- d. No. The natural gas, capacity, and electricity price forecasts referenced in Mr. Sweet's testimony were not taken from ABB's Spring 2016 Reference Case but erroneously provided from ABB's Fall 2016 Reference Case. Therefore, ABB's Midwest Spring 2016 Reference Case Report and the attachment to CAG-SUN I-15 containing price forecasts for natural gas, capacity, and electricity have been provided to correct the error.
 - i.
 - (a) Not applicable.
 - (b) Not applicable.
 - (c) Not applicable.
 - ii. Yes.

- (a) Not applicable.
- e. Yes.
 - i. ABB's Midwest Spring 2016 Reference Case was used for natural gas, capacity, and electricity price forecasts which are an accurate representation of future natural gas, capacity, and electricity prices. Differences between actual prices and forecasted prices do not render use of a forecast inaccurate. The underlying tools are consistent from one forecast period to another. Also, the long-term implied heat rate, which depicts the marginal unit, hasn't changed significantly between ABB's Midwest Spring 2016 Reference Case and June 2017.
 - ii.
 - (a) Not applicable.
 - (b) Not applicable.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Third Request for Information**

The following response to CAG-SUN-III-17 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on June 6, 2017 has been prepared under the supervision of the person identified below.

Name:	Holly C. Kauffman
Title:	President, West Virginia Operations
Company:	Monongahela Power Company
Date:	June 16, 2017

CAG-SUN-III-17

Does Mon Power anticipate attempting to sell its share of the Bath County plant in the future? If so, when?

Response:

Mon Power has no current plans to sell its share of the Bath County plant.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fifth Request for Information**

The following response to CAG-SUN-V-16 CONFIDENTIAL of the Fifth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods has been prepared under the supervision of the person identified below.

Name:	Jay A. Ruberto
Title:	Director, Regulated Generation and Dispatch
Company:	FirstEnergy Service Company
Date:	August 14, 2017

CAG-SUN-V-16 CONFIDENTIAL

[[Confirm that Mon Power bids all of the energy and capacity from its power plants into the PJM energy and capacity markets.

- a. If not confirmed, please explain which plants are not bid into the markets and why.]]

Response:

Confirmed.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Longview Power, LLC's First Request for Information**

The following response to Longview-I-2 of the First Request for Information of Longview Power, LLC received on April 28, 2017 has been prepared under the supervision of the person identified below.

Name:	Raymond E. Valdes
Title:	Director, Rates & Regulatory Affairs
Company:	FirstEnergy Service Company
Date:	May 8, 2017

Longview-I-2

Reference Valdes Testimony, Exhibit REV-10. Please provide the following:

- a) With respect to the itemized Fuel Expense (501) and Allowances (509) expenditures totaling \$239.422M and the PJM Spot Market Energy revenues of \$355.090M for the indicated period 9/1/17 through 12/31/18, please provide a monthly breakdown of these expenditures, and the MWH production (on a monthly basis) associated with these allocated expenditures
- b) Please indicate what proportion of each month's Pleasants Power Station total output the MWH total indicated in response to a) above represents for that period of time.
- c) Please indicate on a month-by-month basis what portion of the plant output is dedicated to MonPower's load and what represents off system sales.
- d) With respect to the PJM-RPM Auction revenues totaling \$83.941M for the indicated period 9/1/17 through 12/31/18, what amount of Pleasants Power Station capacity (MW) is associated with those capacity revenues.

Response:

- a) See Attachment A to this response.
- b) Objection as the question is unclear as to the information requested and is vague and ambiguous. However, the forecasted MWh output for the September 1, 2017 through December 31, 2018 period is provided in response to part (a) above.
- c) Since Mon Power bids on a daily basis all of its generation resources into the PJM market and buys all of the power needed to serve its West Virginia retail load from the PJM market, it is not possible to determine which portion of Mon Power's generation resources are consumed by its retail load and which portion represents off system sales.
- d) See the response to Staff 1.40.

Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Second Request for Information

The following response to CAG-SUN-II-3 of the Second Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on May 11, 2017 has been prepared under the supervision of the person identified below.

Name: Jay Ruberto
Title: Director Regulated Generation
Company: MP
Date: May 22, 2017

CAG-SUN-II-3

Refer to the page 5, lines 1-4 of the Direct Testimony of Jay Ruberto.

- a. Please describe what Mon Power's "capacity requirements" are, and which entit(ies) establish those requirements.
- b. Confirm that the sole reason Mon Power uses winter peak to identify its capacity shortfall is because Mon Power "determined that its peak occurs during the winter months."
 - i. If not confirmed, please identify each and every reason why Mon Power uses winter peak to identify its capacity shortfall.
- c. Admit that the Companies' winter peak load is not used in determining the Companies' PJM capacity obligation.
 - i. If not admitted, explain your understanding of how winter peaks are used in determining a Load Serving Entity's PJM capacity obligation.
- d. Admit that the Companies' PJM capacity obligation is based on their summer peak load coincident with the PJM peaks, and is determined using the methodology set forth in *PJM Manual 19: Load Forecasting and Analysis*.
 - i. If not admitted, please explain your understanding of how the Companies' PJM capacity obligation is determined.
- e. Identify the Companies' PJM capacity obligation for each delivery year from 2007/2008 through the 2017/2018 delivery year.
- f. Provide the Companies' most recent forecast of its PJM capacity obligation beyond the 2017/2018 delivery year. If Companies do not forecast their capacity obligation, please explain why not.

Response:

- a. For purposes of determining its PJM capacity obligations, Mon Power's current capacity requirement is its Unforced Capacity MW value (UCAP) as established by PJM for each June 1 to May 30 planning year. Mon Power's UCAP is premised on its capacity Peak Load Contribution (PLC), a fixed value for the PJM planning year that Mon Power calculates and reports to PJM annually. This calculation follows the

PJM protocol which uses the average of the Mon Power load coincident with the PJM five peak hours plus any qualified demand response addback MWs, which are also provided by PJM. An APS zone-specific PLC adjustment factor, determined as the ratio of the APS zone capacity target to the total APS average 5CP with addbacks, is then applied to all PLCs in the APS Zone (including the Mon Power PLC) such that the sum of all PLCs established in the APS zone equates to the zone capacity target as determined by PJM. This adjustment factor was 1.002225 for the 2017/18 planning year.

The reference at page 5, lines 1-4 of Mr. Ruberto's direct testimony is to the capacity obligation calculation used in the 2015 IRP, as discussed at pages 3-4 of that testimony. Mon Power was obligated to present peak demand in the IRP on the basis of "peak demand during the PJM peak demand period and peak demand for the utility if that occurs at different time." See General Order No. 184.35 dated March 19, 2015.

- b. The Companies neither confirm nor deny this statement. Mon Power used the winter peak to measure its capacity resources and capacity needs in the 2015 IRP because the Companies' overall peak demand occurs during the winter months. However, Mon Power's peaks for any given year can be in either the summer or winter, while PE-WV's and West Virginia Power's peaks are always in the winter.
- c. Confirmed.
- d. Confirmed.
- e. The Companies' PJM Daily UCAP Obligations for each delivery year from June 1, 2007 through May 31, 2017 are shown below. The actual capacity obligation for 2017/2018 will not be posted by PJM until the start of the delivery year on or near June 1, 2017.

Delivery Year	Daily UCAP Obligation (MW)
2007/2008	2,969.185
2008/2009	2,782.257
2009/2010	2,823.672
2010/2011	2,817.824
2011/2012	2,944.636
2012/2013	2,851.136
2013/2014	2,812.114
2014/2015	2,931.406
2015/2016	3,014.633
2016/2017	3,024.495

- f. The forecasted annual PJM capacity obligation for the Companies for the time period of June 1, 2017 through May 31, 2020 is shown below. PJM auction result reports are only prepared at the zonal level. The actual UCAP obligation at the PJM account level for the current delivery year is posted just prior to the start of the delivery year on or near June 1 of that delivery year. For budget purposes, a ratio of the current UCAP obligation by PJM load account to the zone is used to calculate the projected UCAP obligation for each load account. Therefore, the UCAP obligation for the 2017/2018 delivery year is projected and the actual will not be known until approximately June 1, 2017.

Delivery Year	Forecasted Daily UCAP Obligation (MW)
2017/2018	2,999.015
2018/2019	3,223.507
2019/2020	3,228.584

Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Second Request for Information

The following response to CAG-SUN-II-8 of the Second Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on May 11, 2017 has been prepared under the supervision of the person identified below.

Name:	Jay A. Ruberto
Title:	Director, Regulated Generation and Dispatch
Company:	FirstEnergy Service Company
Date:	May 22, 2017

CAG-SUN-II-8

Refer to page 24, lines 16-20 of the Ruberto Testimony.

- a. Confirm that the reference to “market prices” in line 17 is referring to wholesale prices, not retail prices. If not confirmed:
 - i. Produce any documents supporting Mr. Ruberto’s contention that retail prices “can vary significantly from hour to hour.”
 - ii. Produce any documents supporting Mr. Ruberto’s contention that retail prices “can vary significantly . . . from year to year.”
- b. Have the Companies evaluated whether their customers would face volatility in retail prices in future years?
 - i. If so, please identify and produce all studies conducted by or on behalf of the Companies of future retail price volatility. Please produce any workpapers, modeling files, and other documentation associated with such studies.
 - ii. If not, please explain why not.
- c. Have the Companies evaluated whether their customers would face increases in retail prices in future years?
 - i. If so, please identify and produce all studies conducted by or on behalf of the Companies of future retail price increases. Please produce any workpapers, modeling files, and other documentation associated with such studies.
 - ii. If not, please explain why not.
- d. Please identify and produce all energy price forecasts, studies, or other documents that Mr. Ruberto relied on in concluding that “the market price for energy . . . [is] expected to increase in the coming years.”
- e. Please identify and produce all capacity price forecasts, studies, or other documents that Mr. Ruberto relied on in concluding that “capacity prices are expected to increase in the coming years.”

Response:

- a. The market prices refer to PJM LMP prices and not retail prices. These are the prices Mon Power pays to PJM, which impact retail customers through the annual ENEC adjustment.
 - i. Not applicable
 - ii. Not applicable
- b. The costs to purchase power from PJM at LMP prices are ultimately reflected in ENEC adjustments. Like other ENEC components, purchased power costs are variable. These variations can and do result in adjustments to retail rates.
 - i. Not applicable
 - ii. No specific study has been conducted.
- c. The Companies' customers may experience future retail price increase.
 - i. See the direct testimony of Mr. Thomas Sweet for energy forecasts. The Companies have not conducted any other specific studies of future retail price increases.
 - ii. A rate study is not needed to predict that increasing energy and capacity prices will affect customer retail rates. However, there is value in owning generation to insulate customers from volatile and increasing market prices.
- d. See the energy price forecast discussed in Mr. Thomas Sweet's direct testimony.
- e. See the capacity price forecast discussed in Mr. Sweet's direct testimony.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Consumer Advocate Division's Fourth Request for Information**

The following response to B-9 of the Fourth Request for Information of the Consumer Advocate Division received on June 12, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	June 22, 2017

B-9.

CRA did not include the results of any sensitivity analyses in its fairness opinion. In other words, no NPV numbers were produced assuming different capacity needs, capacity rates and/or lower natural gas prices. Did CRA perform any such sensitivity analyses? If so, please provide all sensitivity analyses performed including the dispatch results associated with lower natural gas prices. If not, was this at the direction of Mon Power?

Response:

No, The CRA analysis included only a base case and did not perform sensitivity analyses. There was no discussion recalled by either CRA or Mon Power about performing sensitivity analyses.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Sierra Club's Second Request for Information**

The following response to SC-II-7 CONFIDENTIAL of the Second Request for Information of the Sierra Club received on June 26, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	July 6, 2017

SC-II-7

Please refer to CAD A-4 Confidential Attachments A, B, and C.

- a. Please explain why these analyses were conducted for a fifteen-year period.
- b. Did CRA evaluate the bids over different time periods?
 - i. If so, please provide such analyses.
 - ii. If not, please explain why not.
- c. Did CRA estimate penalties from PJM for unavailability under its Capacity Performance policy?
 - i. If so, please identify the annual penalties assumed and where those are accounted for in the workbook. Please also provide supporting analyses and/or documentation for these costs.
 - ii. If not, please explain why not.
- d. Did CRA conduct any other analyses of the risks of owning these assets after the end of the fifteen-year period?
 - i. If so, please provide such analyses.
 - ii. If not, please explain why not.
- e. Please provide the date that these analyses were provided by CRA to the Companies.
- f. Are there any more up-to-date versions of these analyses?

- i. If so, please provide all updated versions of these analyses.
 - ii. If not, please explain why not.
- g. Have either CRA or the Companies re-evaluated any of these bids given changes in market conditions-e.g., the latest PJM RPM auction results?
 - i. If so, please provide such analyses.
 - ii. If not, please explain why not.
- h. Please provide the source for the electricity and capacity prices used by CRA.
- i. Please explain why the electricity and capacity prices used by CRA do not match those provided in the Direct Testimony of Witness Sweet.

Response:

We assume the question is directed towards CAD A-5 competitively sensitive confidential attachments A-C and not CAD A-4 attachments since the later are the RFP submittals and do not include any analysis done by CRA.

- a. The 15 year period was selected to capture and understand the fundamental economics of each bid.
- b. CRA did not perform additional scenario analyses. The base case analysis provides a reasonable estimate of expected economic performance.
- c. CRA's analysis did not include special considerations for PJM Capacity Performance penalties or bonuses beyond what would be included implicitly in the ABB capacity price forecast.
- d. Please refer to the response to (b) above.
- e. The results of the CRA analysis were provided to Mon Power in an Opinion Letter dated February 27, 2017.
- f. Please refer to the response to (b) above.
- g. Please refer to the response to (b) above.
- h. Please refer to the response provided to CAG-SUN-I (11c).
- i. The file referenced in response to (h) was provided to CRA by Mon Power. The file contains ABB Spring 2016 Reference Case forecast data converted into a standard template by CRA. Certain adjustments were made by CRA to the data as follows:

- a. Prices were restated in nominal dollars based on Moody's GDP deflator and the ABB forecast.
- b. Capacity prices were updated to reflect the most recent BRA auction clearing prices.
- c. Realignment of annual capacity prices to PJM calendar year prices.
- d. ABB calculates zonal capacity prices. For the AD Hub, PJM-AEP was used. For FirstEnergy's West Hub, PJM-WPA was used.
- e. Assigned Tetco M1 price to the Columbia Gas Appalachia price estimate. ABB's forecast provided to FirstEnergy did not include Columbia Gas Appalachia.

Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fifth Request for Information

The following response to CAG-SUN-V-8 CONFIDENTIAL of the Fifth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods has been prepared under the supervision of the person identified below.

Name: Tom Sweet
Title: Manager
Company: ABB
Date: August 14, 2017

CAG-SUN-V-8

Refer to page 3-23 of CAG-SUN-I-15 Attachment B CONFIDENTIAL.

- a. [[Please produce the source data for Figure 3-16 (*i.e.*, produce the annual Low Case, Base Case, Nuclear Life Extension Case, and High Case forecasts of natural gas prices shown in this Figure).
- b. Please confirm that the natural gas price forecasts sponsored by Mr. Sweet in this proceeding are based on the Spring 2016 Base Case. If confirmed:
 - i. Please explain why the Companies did not use the Low Case for purposes of their Petition.
 - ii. Please explain why Mr. Sweet did not provide any sensitivities or alternative cases when he supplied the gas price forecasts used in this proceeding.
- c. Please produce the monthly and annual electricity price forecast for the APS zone of PJM that is based on the Low Case natural gas price forecast shown in Figure 3-16.
 - i. If an hourly peak and off-peak electricity price forecast based on the Low Case exists, please produce that hourly forecast.]]

Response:

- a. Please see attached file. These include the Low and High gas scenarios. Prices here are in real 2016\$, so must be escalated using Moody's GDP deflator.
 - i. The source data for Figure 3-16 can be found in the FirstEnergy_CAG-SUN-V-08_081017.xlsx file.
- b.
 - i. ABB provided a base case forecast needed to run the analysis. Additionally, ABB provided sensitivities (upward and downward) from the base case. However, the high and low gas prices sensitivities are not fully functioning forecast scenarios since they do not include alternative coal price, load, emissions allowance price, capacity price, or other

drivers, which would all be impacted by lower or higher gas prices. The only fully integrated scenario provided by ABB is the Base Case.

- ii. Mr. Sweet's testimony was to provide an overview of the 2016 energy and capacity forecasts provided to Charles River Associates (CRA) for their use in modeling the dispatch of various generation resources in order to conduct the net present value analysis of the submitted bids as part of a Request for Proposal. Only the Base Reference Case forecast and not sensitivities were used by CRA and is the only fully integrated scenario.
- c. See attached. ABB did not provide hourly data for the low or high case, but CRA did hourly shaping of the Base Case for its models. Hourly data for other forecasts is not available. Additionally, as with the Base Case, ABB only provides prices in Real 2016\$, so they must be inflated to nominal using an appropriate price deflator. I have included a file "ABB S2016 Monthly High & Low Energy Prices - Nominal\$.xlsx" that contains the nominal values and I have included Moody's GDP price deflator.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fifth Request for Information**

The following response to CAG-SUN-V-12 of the Fifth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods has been prepared under the supervision of the person identified below.

Name:	Thomas Sweet
Title:	Director, Global Reference Case, Enterprise Software
Company:	ABB
Date:	August 14, 2017

CAG-SUN-V-12

Refer to page 4, line 4 through page 7, line 7 of the Sweet Revised Testimony.

- a. Identify and explain the basis for any correlation that Mr. Sweet and/or ABB assumed between any of the following factors in projecting electricity or capacity prices for this proceeding:
 - i. Natural gas prices.
 - ii. Carbon prices.
 - iii. Coal prices.
 - iv. Energy prices.
 - v. Load
- b. Further refer to the ABB electricity price forecast graphically represented on page 2 of Exhibit TS-1 (and discussed on page 7, lines 3-7), which projects a long-term increase in prices within the APS zone.
 - i. Please confirm that the forecasted increase in natural gas prices (shown on page 1 of Exhibit TS-1, and referenced on page 4, lines 13-18) is a key driver of the forecasted increase in electricity prices.
 - (a) If not confirmed, explain why not.
 - ii. Please explain why Mr. Sweet believes that electricity prices will increase over the long term, and identify each of the key drivers of that increase in prices.

Response:

- a. ABB utilizes a fundamental forecasting methodology for Natural gas prices, Coal prices and Energy prices. Carbon prices, depending on the sensitivity, are either fundamentally forecast or directly inputted. Load is directly inputted.

There was no correlation assumed between any of the following factors: natural gas prices, carbon prices, coal prices, energy prices, and load.

- b.
 - i. Yes, the forecasted increase in natural gas prices is a key driver of the forecasted increase in electricity prices.
 - ii. Electricity prices will increase over the long term due to increasing natural gas prices. Factors that put downward pressure on electricity prices, such as lower load forecasts due to energy efficiency and distributed generation, and increasing amounts of renewable generation, do not offset the upward pressure due to increasing natural gas prices.

From a national perspective increasing natural gas prices increases electricity prices. On a local basis declining reserve margins increase electricity prices.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fourth Request for Information**

The following response to CAG-SUN-IV-13 of the Fourth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on July 14, 2017 has been prepared under the supervision of the person identified below.

Name:	Jay A. Ruberto
Title:	Director, Regulated Generation and Dispatch
Company:	FirstEnergy Service Company
Date:	July 24, 2017

CAG-SUN-IV-13

Has Mon Power, or any of Mon Power's corporate affiliates, evaluated the reasonableness and/or accuracy of ABB's forecasts of electricity prices, capacity prices, natural gas prices, or coal prices?

- a. If so:
 - i. Describe with specificity the steps that have been taken to evaluate the reasonableness or accuracy of ABB's price forecasts.
 - ii. Identify each individual that was involved in performing such evaluation.
 - iii. Produce all documents that were reviewed, created, or relied on in performing such evaluation.
- b. If not, explain why not.

Response:

Yes, Mon Power evaluated the reasonableness of the ABB Spring 2016 forecast.

- a.
 - i. The details of the report were reviewed, including its extensive analysis, and was found to be comprehensive and reasonable.
 - ii. Jay A. Ruberto
 - iii. No such documents exist
- b. Not applicable

Resp. to CAG-SUN-II-36, Attachment C (Confidential – Competitively Sensitive)

Redacted

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Energy Users Group Fourth Request for Information**

The following response to WVEUG-IV-7 of the Fourth Request for Information of the West Virginia Energy Users Group received on June 30, 2017 has been prepared under the supervision of the person identified below.

Name:	Jay Ruberto
Title:	Director
Company:	MP
Date:	July 12, 2017

WVEUG-IV-7

Reference Attachments A, B, and C to the Companies' response to CAG-SUN-II-36 and the information provided to WVEUG by counsel on June 29, 2017.

- (a) Please confirm that the columns identified as “10+2F” represent a forecast of spending through year end, prepared in March of each year, and based on two months of actual costs for January and February of each year.
- (b) Please confirm that the items listed as “Cost of Revenue” represent the normal fuel costs, including the cost of coal, gas, oil, reagents, fuel handling, allowances, and purchased power that appear in the Companies’ annual ENEC.
- (c) Please confirm that the items identified as “Fixed Price Revenue” refer to the budgeted megawatt hours of the Pleasants plant multiplied by the budgeted forward price, and that this figure represents a distribution of revenue to each power station in the FirstEnergy Generation system on a pro forma basis for comparison purposes.
- (d) Please confirm that the items identified as “Plant Support” represents support provided to the Pleasants plant from FES or FirstEnergy Generation plant technical services and administration.
- (e) Please confirm that the expense items listed as “Unplanned Outages” and “Scheduled Outages” refer only to costs related to outside service, material, and rentals, and do not include internal labor costs.
- (f) Please confirm that the items listed as “Associate Company Expenses” (Attachment C) refer to allocated lease and/or rental company building costs.
- (g) Please confirm that the category identified as “AFUDC/Capitalized Interest” simply refers to normal AFUDC of capital expenditures.

- (h) Please confirm that the item categorized as “FFO” refers to Funds for Operations, factoring net income and adding back any costs related to income tax expense, AFUDC, sale lease-backs, and depreciation expense.
- (i) Please confirm that depreciation, as appearing in these attachments, is calculated on plant balance appearing in FERC accounts 101 and 108.
- (j) Please provide any supplemental information necessary to augment or clarify these responses.

Response:

- (a) “10+2F” is shown on the Dec 2015 and Dec 2016 reports. A 10+2F (forecast) represents 10 months of actual costs and 2 months of reforecasted costs. A “2+10F” was used in the March 2017 report and that represents 2 months of actual costs and 10 months of reforecasted costs.
- (b) “Cost of Revenues” include the cost of coal, gas, oil, reagents, fuel handling, allowances, and purchased power which are part of the MP annual ENEC.
- (c) “Fixed Price Revenue” is budgeted megawatt hours multiplied by the budget forward price in an effort to distribute revenue to each station on a pro forma basis for P&L comparison purposes
- (d) “Plant Support is support provided by plant technical services and administration.
- (e) “Unplanned Outage” and “Scheduled Outage” costs include outside services, material, and rental costs. They do not include internal labor.
- (f) “Associate Company Expenses” relate to allocated lease/rental company building cost.
- (g) “AFUDC/Capitalized Interest” is normal AFUDC of capital expenditures.
- (h) FFO is Funds from Operations. FFO takes net income and adds back any costs related to income tax expense, AFUDC, sale lease-backs, and depreciation expense.
- (i) Depreciation in the reports is related to depreciation of asset retirement cost, amortization, and accretion expense on ARO. All depreciation and amortization expenses are related to net plant balances in FERC accounts 101 and 108. Accretion expenses are in FERC account 411 and the liability is recorded in FERC account 230.

Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Citizen Action Group and Solar United Neighborhoods
Fourth Request for Information

The following response to CAG-SUN-IV-10 of the Fourth Request for Information of the West Virginia Citizen Action Group and Solar United Neighborhoods received on July 14, 2017 has been prepared under the supervision of the person identified below.

Name:	Jay Ruberto
Title:	Director, Regulated Generation & Dispatch
Company:	FirstEnergy Service Company
Date:	July 24, 2017

CAG-SUN-IV-10

Refer to the Companies' response to CAG-SUN-II-32, which asked for the Companies' "projection of Mon Power's annual generation capacity (MW) and energy production (MWh or GWh) for each of the years 2017-2032, both (a) with Pleasants, and (b) without Pleasants. Please include a breakdown of this projection by generating unit, and please include all PURPA contract purchases." Given your response that "[n]o such projection meeting all these criteria has been made," please provide the following information:

- a. Provide the Companies' projection of Mon Power's annual generation capacity (MW) from (i) owned units and (ii) PURPA contract purchases, for as many years as the Companies has made a forecast.
 - i. For the projection provided in response to subpart (a) of this request, produce all workpapers, modeling files (including input and output files),

and other documents created, used, or relied on in projecting Mon Power's annual generation capacity. Please produce all such workpapers and modeling files in machine-readable electronic format (preferable Excel) with formulas intact.
 - ii. If you are unable to provide any projection of Mon Power's future annual generation capacity, explain why not.
- b. Provide the Companies' projection of Mon Power's annual energy production (MWh) from (i) owned units and (ii) PURPA contract purchases, for as many years as the Companies has made a projection.
 - i. For the projection provided in response to subpart (b) of this request, produce all workpapers, modeling files (including input and output files), and other documents created, used, or relied on in projecting Mon Power's annual energy production. Please produce all such

workpapers and modeling files in machine-readable electronic format (preferable Excel) with formulas intact.

- ii. If you are unable to provide any projection of Mon Power's future annual energy production, explain why not.

Response:

We do not have forecasts that include Pleasants. Forecasts without Pleasants are provided in CAG-SUN-IV-10 Attachment A CONFIDENTIAL. The information is provided on a total basis and not on a unit by unit basis which is objected to on grounds of relevancy and competitive purposes.

- a. See CAG-SUN-IV-10 Attachment A CONFIDENTIAL for the annual Mon Power forecasted MW and MWH for 2017-2021 which are the only years available. Please note, Attachment A contains CONFIDENTIAL and Competitively Market Sensitive information and is being provided pursuant to the terms of the Protective Agreement executed by CAG-SUN in this proceeding.
- b. See a above.

Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Sierra Club's Third Request for Information

The following response to SC-III-5 CONFIDENTIAL of the Third Request for Information of the Sierra Club received on July 21, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	July 31, 2017

SC-III-5 CONFIDENTIAL

Please refer to CAG-SUN-I-11 Attachment 11a Dispatch_Model_Pleasants
CONFIDENTIAL.xls.

- a. Please identify and describe all operational constraints assumed in the dispatch model.
- b. Please explain why the dispatch model assumes **[BEGIN CONFIDENTIAL INFORMATION] [END CONFIDENTIAL INFORMATION]**
- c. Please confirm that the dispatch model assumes that **[BEGIN CONFIDENTIAL INFORMATION] [END CONFIDENTIAL INFORMATION]**
- d. Please explain why the coal prices assumed in the dispatch model **[BEGIN CONFIDENTIAL INFORMATION] [END CONFIDENTIAL INFORMATION]**
- e. Please explain how maintenance outages were incorporated into the dispatch model.
- f. Please explain how forced outages were incorporated into the dispatch model.
- g. Please provide supporting analyses and documentation for the coal prices used in the dispatch model.

Response:

- a. Operational constraints in the CRA dispatch model include the following:
 - Capacity: Maximum operating capacity for the plant
 - Minimum capacity: Minimum operating capacity for the plant
 - Minimum up time: The minimum number of hours that the plant may be dispatched for.
 - Minimum down time: The minimum number of hours that must elapse between operational periods.
 - Startup costs: The cost of starting up the plant prior to a period of generation, which may include startup fuel costs separately or as part of the overall startup costs. The plant will not be dispatched if the total margin from a dispatch period does not exceed the startup costs.
- b. After 2018, the dispatch model logic – considering fuel and power price forecasts – observes that it is always economic to have Pleasants in operation. Zero starts is not an assumption, but is an output of the model. Note that “zero starts” presumes the plant is in operation when the year begins, and thus does not need to start at the beginning of the year.
- c. The dispatch model assumes that it will always be economic to run Pleasants under the fuel and power price forecast scenario run through the model. This is not a prediction that Pleasants will never shut down in practice, but a reflection of the plant economics in the forecasted commodity price environment. Forced and planned outages are still considered, but the model output does not represent them as the plant turning off (as described below).
- d. CRA was not provided the file produced in response to Longview-I-09 and could not have used it in our modeling. However, the data included in that file would not be appropriate for the dispatch analysis even if it had been made available. The delivered coal prices in that file do not reflect any specific coal rank or quality. Rather, the prices are a blend based on ABB modeling of commodity costs, estimated transportation costs and assumptions about coal choices or blending at individual facilities. In practice, coal switching or blending may be limited by plant design, and/or coal yard configuration and may require certain capital expenditures. In addition, at the time of the RFP design, neither CRA nor Mon Power could know which plants would submit bids and could not know whether the set of prices from the file would cover all potential bidders. As a result, coal price inputs were derived from the ABB coal price series produced in response to CAG-SUN-I-11c.
- e. Maintenance outages are presumed to take place in shoulder months (March, April, October, November). Provided annual plant maintenance rates are divided among the months with maintenance outages on a pro rata basis. During those months, the total plant maximum capacity is reduced by the maintenance rate. In this manner, the dispatch model accounts for reduced generating capability during maintenance periods.

- f. Forced outages are reflected in a reduction in available maximum capacity across all hours by reducing the total plant capacity by the provided forced outage rate. In this manner, the dispatch model accounts for reduced generating capability during forced outage periods.
- g. Coal prices used in the analysis were provided in response to CAG-SUN-11c. Additional details of the ABB forecast and its use in CRA modeling was provided in response to CAG-SUN-IV-14. Documentation for the ABB forecasts is included in the ABB Coal Forecast previously produced.

Results of CRA's NPV calculation (Confidential)

Redacted

**Results of STC Base Case, High Case, Low Case,
and AE Supply Sensitivity (Confidential – Competitively Sensitive)**

Redacted

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Sierra Club's Second Request for Information**

The following response to SC-II-6 CONFIDENTIAL of the Second Request for Information of the Sierra Club received on June 26, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	July 6, 2017

SC-II-6

Please refer to CAD A-5 Confidential Attachment A.

- a. Please explain whether costs for compliance with ELG were included in this analysis.
 - i. If so, please identify the annual costs for compliance and where those costs are accounted for in the workbook. Please also provide supporting analyses and/or documentation for these costs.
 - ii. If not, please explain why not.
- b. Please explain if costs for compliance with CCR were included in this analysis.
 - i. If so, please identify the annual costs for compliance and where those costs are accounted for in the workbook. Please also provide supporting analyses and/or documentation for these costs.
 - ii. If not, please explain why not.

Response:

- a. Compliance costs for ELG were not included in the NPV analysis. Costs related to ELG were excluded due to uncertainty on the magnitude and timing of compliance expenditures. See response to WVEIG-II-8.
- b. Costs for compliance with CCR were not included in the NPV analysis. RFP responses for all of the applicable bidders affected by CCR indicated that the facilities were currently compliant with CCR. See response to WVEUG II-6.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
Consumer Advocate Division's Fourth Request for Information**

The following response to B-16 of the Fourth Request for Information of the Consumer Advocate Division received on June 12, 2017 has been prepared under the supervision of the person identified below.

Name:	Robert Lee
Title:	VP
Company:	CRA
Date:	June 22, 2017

B-16.

Please confirm no costs associated with the now-stayed Effluent Limitation Guidelines are included in CRA's analysis.

Response:

Effluent limitations guideline expenses were not included in the NPV analysis.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Energy Users Group First Request for Information**

The following response to WVEUG-I-12 of the First Request for Information of the West Virginia Energy Users Group received on March 24, 2017 has been prepared under the supervision of the person identified below.

Name:	Kurt Leutheuser
Title:	Project Manager
Company:	Black & Veatch
Date:	April 12, 2017

WVEUG-I-12

Regarding the "\$80 to \$120 million" estimated cost of Effluent Limit Guidelines ("ELG") compliance referenced in the Black & Veatch report, Section 3.8, please provide the following:

- a) A complete copy of the analysis that Black & Veatch performed to develop its cost estimate. This would include, but not be limited to, reports, excel spreadsheet analyses, memoranda, and supporting workpapers.
- b) A breakdown of the amounts expected to be capitalized and the amounts that would be expensed.

Response:

- a) Black & Veatch performed no cost estimate work nor was one included in the scope of work associated with Effluent Limit Guideline (ELG) compliance. The \$80 to \$120 million figure mentioned in report section 3.8.1 was supplied by the Respondent in Reference 2 "Response to Monongahela Power Company Request for Proposals for Power Supply Generation Facilities and/or Demand Resources."
- b) An analysis has not been performed on what is expected to be capitalized and what may be expensed.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Energy Users Group First Request for Information**

The following response to WVEUG-I-13 of the First Request for Information of the West Virginia Energy Users Group received on March 24, 2017 has been prepared under the supervision of the person identified below.

Name:	Jay Ruberto
Title:	Director, Regulated Generation
Company:	MP
Date:	April 12, 2017

WVEUG-I-13

Please provide any additional studies and/or analysis available to the Companies regarding the cost of ELG compliance.

Response:

There are no additional studies and/or analysis available regarding ELG compliance associated costs.

**Monongahela Power Company and The Potomac Edison Company
Case No. 17-0296-E-PC
West Virginia Energy Users Group First Request for Information**

The following response to WVEUG-I-24 of the First Request for Information of the West Virginia Energy Users Group received on March 24, 2017 has been prepared under the supervision of the person identified below.

Name:	Kurt Leutheuser
Title:	Project Manager
Company:	Black & Veatch
Date:	April 12, 2017

WVEUG-I-24

Please provide a complete copy of the analysis that Black & Veatch performed to develop its \$45 million cost estimate to meet the Coal Combustion Residual ("CCR) requirements for McElroy's Run. This would include, but not be limited to, reports, excel spreadsheet analyses, memoranda, and supporting workpapers. Also provide the amounts expected to be capitalized and the amounts that would be expensed.

Response:

- a) Black & Veatch performed no cost estimate work nor was one included in the scope of work associated with Coal Combustion Residual (CCR) compliance. The \$45 million figure mentioned in the report section 3.8.4 was supplied by AE Supply in Reference 2 "Response to Monongahela Power Company Request for Proposals for Power Supply Generation Facilities and/or Demand Resources."
- b) An analysis has not been performed on what is expected to be capitalized and what may be expensed.

**Resp. to CAD-III-A-26 (Confidential – Competitively Sensitive)
and Supplemental Resp. to CAG-SUN-I-27 (Confidential)**

Redacted

CERTIFICATE OF SERVICE

I hereby certify that on this date I served a copy of the foregoing CONFIDENTIAL VERSION of the Direct Testimony of David Schlissel upon the following parties via U.S. Mail, first class, postage prepaid:

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I further certify that on this date I served a copy of the foregoing PUBLIC VERSION of the Direct Testimony of David Schlissel upon the following parties via U.S. Mail, first class, postage prepaid:

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Date: August 25, 2017

Michael C. Soules

Michael Soules