FILE

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EXHIBIT NO. _____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into Renewable Energy Purchase Agreements for Inclusion in the Renewable Generation Rider	)))))	Case No. 18-1392-EL-RDR
In the Matter of the Application of Ohio Power Company to Amend its Tariffs	))	Case No. 18-1393-EL-ATA

DIRECT TESTIMONY OF JOHN F. TORPEY ON BEHALF OF OHIO POWER COMPANY

Filed: Sep 27, 2018

INDEX TO DIRECT TESTIMONY OF
JOHN F. TORPEY

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
JOHN F. TORPEY
ON BEHALF OF
OHIO POWER COMPANY

PERSONAL DATA

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John F. Torpey, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as the Managing Director – Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting, planning, and advisory services to the eleven electric operating companies of American Electric Power (AEP), including Ohio Power Company (AEP Ohio or the Company).

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Engineering from the Cooper Union for the Advancement of Science and Art (New York) in 1979 and a Master of Business Administration from Saint John's University (New York) in 1984. In addition, in 1995, I completed the American Electric Power System Management Development Program at the Ohio State University, and in 2000, I completed the Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

In 1979, I was employed by AEPSC as a Design Engineer in the Structural Design Department. In 1985 I became the Project Controls Engineer for the Zimmer Conversion Project and then for the Gavin FGD Retrofit Project. I became Manager of the Controls Services Department in 1994, with responsibility for capital and expense budgeting, and maintenance outage planning for the AEP generating plants. I held various managerial positions in the AEPSC generation organization related to planning, budgeting, and cost control. In 2004, I became the Director of Corporate Budgeting in the Corporate Planning and Budgeting Department, and in 2007 became Director - Integrated Resource Planning. I assumed my current position in January 2018.

I am a Professional Engineer registered in the State of Ohio and a Certified Management Accountant. I have been an adjunct instructor at Franklin University (Ohio) since 2006 and have taught classes in the Accounting program and the Energy Management program.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR-RESOURCE PLANNING AND OPERATIONAL ANALYSIS?

A. I am primarily responsible for the supervision and administration of long-term generation resource planning and analysis for AEP. In such capacity, I coordinate the use of short and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for the Company and AEP. I regularly monitor actual performance and review the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. On behalf of AEP Ohio, I submitted testimony in Case No. 18-501-EL-FOR, the Amended Long-Term Forecast Report (Amended LTFR). I have testified or provided testimony on behalf of AEP Ohio affiliates Appalachian Power Company (APCo) and Wheeling Power Company before the Public Service Commission of West Virginia, and for APCo before the Virginia State Corporation Commission. I also testified on behalf of AEP Ohio affiliate Indiana Michigan Power Company before the Michigan Public Service and the Indiana Utility Regulatory Commissions.

Q. WHAT WAS THE PURPOSE OF YOUR TESTIMONY IN THE AMENDED LTFR CASE?

A. In addition to sponsoring the Integrated Resource Plan and Forecast Report Requirements for Electric Utilities sections of the Amended LTFR, my testimony in the Amended LTFR case explained the methodology used by AEP Ohio to develop its assumptions for renewable resource costs and presented the economic benefits associated with the addition of renewable resources for AEP Ohio. Specifically, I presented the economic benefits to AEP Ohio's customers of adding generic wind and solar projects, I calculated a break-even cost of renewable projects, and I performed a probabilistic simulation of renewable project benefits.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. The purpose of my testimony is to summarize the methodology used to evaluate two Renewable Asset Purchase Agreement (REPA) bids received in response to AEP Ohio's

recent Solar Energy Request for Proposals (RFPs). This evaluation identifies the benefits the REPAs bring to AEP Ohio and its customers, as compared to other available products in the market. In addition, I discuss how the REPAs will act as a hedge to market volatility. In summary, the REPAs result in a $332 million savings ($99.6 million on a net present value basis) when compared to market under the AEP Fundamental Analysis department's 2018 Fundamentals Forecast. Each project individually results in a net savings on a levelized cost, a nominal dollar, and a net present value basis under all pricing scenarios.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. I am supporting the following exhibits:

- Exhibit JFT-1: AEP Ohio Renewable Bid Net Cost of Energy Summary
- Confidential Exhibit JFT-2: Highland Solar Detailed Evaluation
- Confidential Exhibit JFT-3: Willowbrook Solar Detailed Evaluation

RFP ANALYSIS

Q. WOULD YOU FIRST PLEASE PROVIDE A BRIEF OVERVIEW OF THE METHODOLOGY USED IN YOUR ANALYSIS OF THE SOLAR ENERGY BIDS?

A. Yes. I performed an analysis on the short-listed bids that passed an initial screening assessing their suitableness for consideration as a resource within AEP Ohio. Company witness Bradley discusses this initial screening process. I evaluated each REPA based upon its levelized Net Cost of Energy (NCOE). NCOE takes into account the cost to procure energy from the owner per the REPA and the avoided cost of energy from the market. The equation below shows how Net Cost of Energy is calculated, where

Avoided Cost of Energy and Avoided Cost of Capacity are typically negative numbers.

$$Net\ Cost\ of\ Energy\ \left(\frac{\$}{MWh}\right) = REPA\ Price\ \left(\frac{\$}{MWh}\right) + \frac{Avoided\ Cost\ of\ Energy\ (\$) + Avoided\ Cost\ of\ Capacity\ (\$)}{Annual\ Generation\ (MWh)}$$

Q. PLEASE EXPLAIN WHY LEVELIZED COSTS ARE USED IN YOUR ANALYSIS.

A. As shown on Exhibit JFT-1, the NCOE changes each year due to increasing energy and capacity prices. By discounting the annual values to a present value in terms of the base year, 2021, and then levelizing those values over a 20-year period, I provide a metric that is readily comparable across project sizes. Other metrics that were calculated and presented on Confidential Exhibits JFT-2 and JFT-3 include the REPA net present value (NPV), and the levelized cost of energy (LCOE).

Q. PLEASE DESCRIBE HOW THE AVOIDED COST OF ENERGY WAS FACTORED INTO YOUR ANALYSIS.

A. For each REPA bid, the annual avoided cost of energy was calculated as the sum of the hourly-avoided energy costs for all 8,760 hours in a year. For each hour, the avoided cost of energy was calculated as the site's energy output multiplied by the forecasted hourly market price of energy.

Expected hourly site energy output values were provided with each bid for one calendar year, or 8,760 hours. Hourly market prices for energy were based upon the AEP Fundamental Analysis Department's 2018 Fundamentals Forecast, which were also used in the Amended LTFR. For this analysis, I calculated the levelized NCOE (LNCOE) and NPV for each REPA using the 2018 Fundamentals Forecast Base Band energy and capacity prices in addition to energy and capacity prices in three other scenarios – Low Band, High Band, and Status Quo. As the names indicate, the Low Band is a forecast of

market prices based on lower natural gas prices than in the Base Band. High Band uses higher natural gas prices, and Status Quo is derived from the Base Band but assumes no additional carbon regulations. The Base Band, Low Band, and High Band all include the assumption that a carbon burden would be in place beginning in 2028. In the Amended LTFR filing, Company witness Bletzacker describes the basis for these forecast scenarios. In this analysis, the avoided cost of energy is a savings compared to the PJM market. For example, if for a given hour, the cost of energy received through a REPA was $35/MWh, and the market price of energy was $40/MWh, AEP Ohio would realize an avoided cost of energy of $5/MWh.

Q. PLEASE DESCRIBE HOW AND WHY CAPACITY CREDIT WAS CONSIDERED IN YOUR ANALYSIS.

A. The capacity credit for the solar REPA sites equals 19% of their nameplate ratings. In these analyses, the monetary value of capacity is viewed as a savings versus the market. Each MW of PJM capacity credit obtained through a REPA represents capacity that could be offered into the PJM capacity auction. The monetary value of capacity resources was calculated using the AEP Fundamental Analysis Department's 2018 Fundamentals Forecast. This forecast utilizes capacity values which have been established through the PJM Base Residual Auction through 2021, and then incorporates forecasted values for each subsequent year. Capacity credit is evaluated in dollars per megawatt-day. To determine the annual capacity credit value each site's PJM capacity credit was multiplied by 365 and then multiplied by the monetary value of capacity.

These capacity credits reflect the conservative capacity value AEP Ohio would place on intermittent resources under PJM's Capacity Performance requirement, which

goes into full effect in June 2020. PJM publishes class-average capacity values for renewable energy projects. The latest values, published June 1, 2017, were 60% for solar with ground mounted tracking, and 38% for solar with "other than ground mounted" tracking. As a point of comparison, if the REPA analysis used the full 60% for solar over the 20-year REPA period, compared to the 19% capacity value used in this analysis, the NPV of savings versus market for the two REPAs would increase by $73 million. Although the Company acknowledges that using a higher capacity value would introduce a higher risk of non-performance, the key takeaway is that there is significant additional upside potential associated with the REPAs that this analysis conservatively did not take into account.

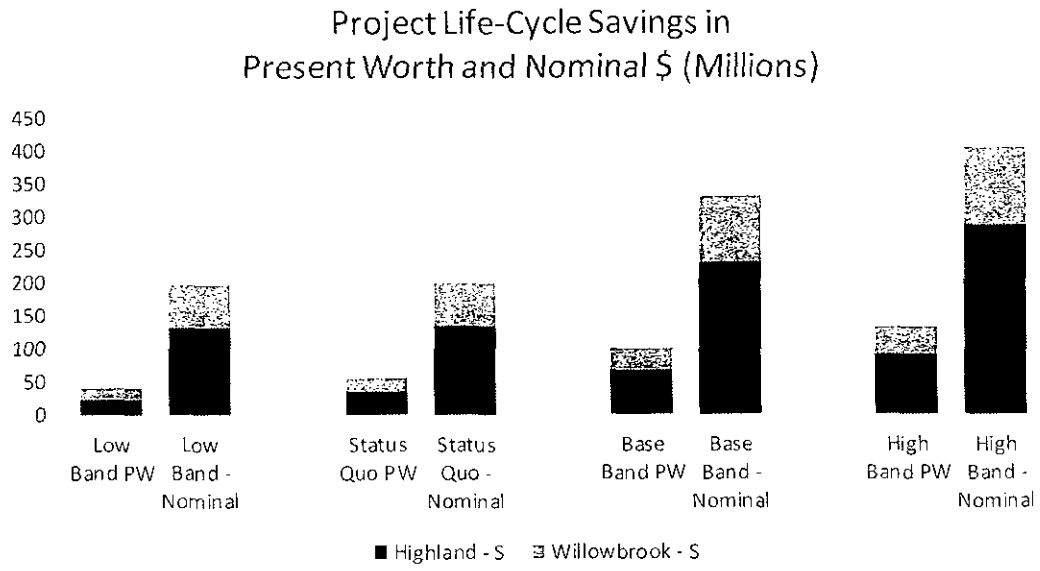
Q. PLEASE DESCRIBE HOW YOUR ANALYSIS ADDRESSED RENEWABLE ENERGY TAX CREDITS.

A. Renewable energy tax credits were not included as a direct benefit to AEP Ohio in the REPA analysis. Any available tax credits would accrue to the owner of the site, and the REPA bid prices factored in the value of these credits.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A. As shown in Exhibit JFT-1, in all pricing scenarios, the two solar REPAs result in net cost savings over the lives of the projects when compared to other like products available in the market. The change in net revenue requirements on a wholesale basis for the two REPAs results in a nominal savings of $332 million (or $99.6 million on a net present worth basis) under Base Band pricing assumptions. The chart below shows the wholesale savings for both projects under all pricing scenarios. The benefits range from a high savings on a nominal dollar basis of $404 million ($133 million on a net present worth

basis) to a low savings of $196 million nominally ($41 million on a net present worth basis) over the REPA period.



Confidential Exhibits JFT-2 through JFT-3 present the full analysis of the REPA Bids.

Q. HOW DO THE REPAS ACT AS A PRICE HEDGE TO THE MARKET?

A. The REPAs are fixed-priced contracts and as such, offer a hedge against volatile market prices. In addition, the contracts offer physical energy supply for reasonable arrangements, and renewable energy credits for green tariffs, as explained by Company witnesses Allen and Williams, respectively. As the PJM market price for energy fluctuates over the next 20 years, the REPAs will maintain a level of stability relative to a portion of AEP Ohio customers' energy costs. Energy prices may spike upward during severe weather events or periods of high forced outage rates among other generators. During these periods, AEP Ohio, through the REPAs, will have a degree of certainty for a portion of its energy costs.

Q. ARE THESE RESULTS CONSISTENT WITH THE 2018 AEP OHIO INTEGRATED RESOURCE PLAN FILING MADE IN CASE NO. 18-501-EL-FOR?

A. Yes. The 2018 AEP Ohio Integrated Resource Plan included generic solar resources and showed the benefit to AEP Ohio from adding solar projects that had similar cost and performance characteristic to those found in the REPAs that are the subject of this case.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

AEP Ohio Renewable Bids Net Cost of Energy (NCOE)

HIGHLAND SOLAR 300 MW

YEAR	HIGH NCOE ($/MWh)	BASE NCOE ($/MWh)	STATUS_QUO NCOE ($/MWh)	LOW NCOE ($/MWh)
2021	$1.11	$5.11	$5.58	$10.31
2022	$0.67	$4.42	$5.13	$10.20
2023	($1.28)	$2.60	$3.66	$9.16
2024	($3.29)	$0.81	$1.94	$7.86
2025	($4.78)	($0.96)	$0.23	$6.47
2026	($6.58)	($2.45)	($1.54)	$5.47
2027	($8.01)	($3.67)	($2.88)	$4.17
2028	($20.20)	($15.26)	($5.26)	($7.07)
2029	($22.64)	($17.44)	($7.33)	($9.09)
2030	($27.40)	($21.62)	($10.61)	($12.99)
2031	($29.88)	($24.32)	($12.91)	($15.25)
2032	($33.00)	($27.13)	($15.52)	($17.33)
2033	($36.48)	($29.52)	($18.57)	($20.44)
2034	($37.10)	($31.86)	($19.54)	($21.78)
2035	($40.80)	($35.28)	($22.54)	($25.59)
2036	($42.34)	($37.48)	($24.09)	($28.23)
2037	($44.53)	($40.25)	($25.80)	($29.57)
2038	($47.72)	($44.93)	($27.62)	($32.57)
2039	($50.42)	($45.84)	($30.03)	($34.48)
2040	($53.33)	($49.31)	($32.60)	($38.20)
Levelized	($16.75)	($12.22)	($6.26)	($4.29)

WILLOWBROOK SOLAR 100 MW

YEAR	HIGH NCOE ($/MWh)	BASE NCOE ($/MWh)	STATUS_QUO NCOE ($/MWh)	LOW NCOE ($/MWh)
2021	($3.33)	$0.67	$1.12	$5.83
2022	($3.82)	($0.09)	$0.62	$5.65
2023	($6.09)	($2.17)	($1.14)	$4.35
2024	($7.74)	($3.63)	($2.51)	$3.35
2025	($9.33)	($5.50)	($4.33)	$1.85
2026	($10.83)	($6.70)	($5.82)	$1.10
2027	($12.32)	($8.00)	($7.24)	($0.27)
2028	($24.47)	($19.54)	($9.56)	($11.52)
2029	($27.16)	($21.96)	($11.87)	($13.72)
2030	($31.60)	($25.78)	($14.85)	($17.35)
2031	($34.21)	($28.68)	($17.24)	($19.75)
2032	($37.13)	($31.24)	($19.70)	($21.62)
2033	($40.61)	($33.65)	($22.74)	($24.79)
2034	($41.61)	($36.39)	($24.03)	($26.50)
2035	($45.21)	($39.58)	($26.90)	($30.04)
2036	($46.40)	($41.48)	($28.14)	($32.49)
2037	($48.14)	($43.89)	($29.49)	($33.51)
2038	($51.43)	($48.68)	($31.40)	($36.53)
2039	($54.14)	($49.66)	($33.81)	($38.48)
2040	($57.30)	($53.33)	($36.53)	($42.34)
Levelized	($21.09)	($16.56)	($10.63)	($8.75)

Net Cost of Energy
Highland Solar (300 MW)
2018H2 Fundamentals Base Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	300	[redacted]				37.8	[redacted]	50.8	57.0	(1.1)	[redacted]	5.11
2022	0.8495	300					39.2		30.1	57.0	(0.6)		4.42
2023	0.7829	300					40.5		44.2	57.0	(0.9)		2.60
2024	0.7216	300					41.8		58.7	57.0	(1.2)		0.81
2025	0.6650	300					43.0		73.6	57.0	(1.5)		(0.96)
2026	0.6129	300					44.0		88.9	57.0	(1.8)		(2.45)
2027	0.5649	300					44.6		104.7	57.0	(2.2)		(3.67)
2028	0.5207	300					55.6		120.9	57.0	(2.5)		(15.26)
2029	0.4799	300					57.2		137.6	57.0	(2.9)		(17.44)
2030	0.4423	300					60.7		154.8	57.0	(3.2)		(21.62)
2031	0.4076	300					62.7		172.2	57.0	(3.6)		(24.32)
2032	0.3757	300					64.9		190.1	57.0	(4.0)		(27.13)
2033	0.3463	300					66.5		208.5	57.0	(4.3)		(29.52)
2034	0.3191	300					68.1		227.3	57.0	(4.7)		(31.86)
2035	0.2941	300					70.8		246.5	57.0	(5.1)		(35.28)
2036	0.2711	300					72.2		266.3	57.0	(5.6)		(37.48)
2037	0.2499	300					74.2		286.5	57.0	(6.0)		(40.25)
2038	0.2303	300					78.0		307.1	57.0	(6.4)		(44.93)
2039	0.2122	300					78.1		328.6	57.0	(6.8)		(45.84)
2040	0.1956	300					80.7		350.6	57.0	(7.3)		(49.31)
Present Worth	9.4633										(25.4)	(67.3)	
Levelized							52.3		129.0	57.0	(2.7)	(7.1)	(12.22)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Base Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Base Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. *Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.*

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Highland Solar (300 MW)
2018H2 Fundamentals Low Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	300					32.8		46.5	57.0	(1.0)		10.31
2022	0.8495	300					33.6		25.0	57.0	(0.5)		10.20
2023	0.7829	300					34.6		25.2	57.0	(0.5)		9.16
2024	0.7216	300					35.8		29.3	57.0	(0.6)		7.86
2025	0.6650	300					36.9		36.5	57.0	(0.8)		6.47
2026	0.6129	300					37.6		44.4	57.0	(0.9)		5.47
2027	0.5649	300					38.6		53.2	57.0	(1.1)		4.17
2028	0.5207	300					49.5		62.9	57.0	(1.3)		(7.07)
2029	0.4799	300					51.1		73.4	57.0	(1.5)		(9.09)
2030	0.4423	300					54.6		84.9	57.0	(1.8)		(12.99)
2031	0.4076	300					56.4		97.3	57.0	(2.0)		(15.25)
2032	0.3757	300					58.0		110.8	57.0	(2.3)		(17.33)
2033	0.3463	300					60.5		125.3	57.0	(2.6)		(20.44)
2034	0.3191	300					61.3		141.0	57.0	(2.9)		(21.78)
2035	0.2941	300					64.4		157.8	57.0	(3.3)		(25.59)
2036	0.2711	300					66.3		175.9	57.0	(3.7)		(28.23)
2037	0.2499	300					66.9		195.3	57.0	(4.1)		(29.57)
2038	0.2303	300					69.1		216.3	57.0	(4.5)		(32.57)
2039	0.2122	300					70.1		238.7	57.0	(5.0)		(34.48)
2040	0.1956	300					72.9		262.7	57.0	(5.5)		(38.20)
Present Worth	9.4633										(15.7)	(23.6)	
Levelized							46.1		79.9	57.0	(1.7)	(2.5)	(4.29)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Low Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Low Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Highland Solar (300 MW)
2018H2 Fundamentals High Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	300	[redacted]				42.0	[redacted]	46.5	57.0	(1.0)	[redacted]	1.11
2022	0.8495	300					43.1		27.1	57.0	(0.6)		0.67
2023	0.7829	300					44.7		36.3	57.0	(0.8)		(1.28)
2024	0.7216	300					46.2		50.0	57.0	(1.0)		(3.29)
2025	0.6650	300					47.2		64.2	57.0	(1.3)		(4.78)
2026	0.6129	300					48.5		78.9	57.0	(1.6)		(6.58)
2027	0.5649	300					49.3		94.2	57.0	(2.0)		(8.01)
2028	0.5207	300					60.9		110.1	57.0	(2.3)		(20.20)
2029	0.4799	300					62.8		126.6	57.0	(2.6)		(22.64)
2030	0.4423	300					66.9		143.6	57.0	(3.0)		(27.40)
2031	0.4076	300					68.7		161.2	57.0	(3.4)		(29.88)
2032	0.3757	300					71.1		179.4	57.0	(3.7)		(33.00)
2033	0.3463	300					73.9		198.2	57.0	(4.1)		(36.48)
2034	0.3191	300					73.7		217.7	57.0	(4.5)		(37.10)
2035	0.2941	300					76.7		237.8	57.0	(4.9)		(40.80)
2036	0.2711	300					77.4		258.6	57.0	(5.4)		(42.34)
2037	0.2499	300					78.7		280.2	57.0	(5.8)		(44.53)
2038	0.2303	300					81.0		302.6	57.0	(6.3)		(47.72)
2039	0.2122	300					82.8		325.9	57.0	(6.8)		(50.42)
2040	0.1956	300					84.7		350.0	57.0	(7.3)		(53.33)
Present Worth	9.4633										(23.8)	(92.3)	
Levelized							57.1		121.0	57.0	(2.5)	(9.7)	(16.75)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - High Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - High Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Highland Solar (300 MW)
2018H2 Fundamentals Status Quo Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	300					37.5		46.5	57.0	(1.0)		5.58
2022	0.8495	300					38.7		25.0	57.0	(0.5)		5.13
2023	0.7829	300					39.9		33.0	57.0	(0.7)		3.66
2024	0.7216	300					41.1		46.9	57.0	(1.0)		1.94
2025	0.6650	300					42.3		61.3	57.0	(1.3)		0.23
2026	0.6129	300					43.5		76.4	57.0	(1.6)		(1.54)
2027	0.5649	300					44.3		92.1	57.0	(1.9)		(2.88)
2028	0.5207	300					46.0		108.4	57.0	(2.3)		(5.26)
2029	0.4799	300					47.5		125.4	57.0	(2.6)		(7.33)
2030	0.4423	300					50.1		143.0	57.0	(3.0)		(10.61)
2031	0.4076	300					51.7		161.1	57.0	(3.4)		(12.91)
2032	0.3757	300					53.6		180.0	57.0	(3.8)		(15.52)
2033	0.3463	300					55.9		199.6	57.0	(4.2)		(18.57)
2034	0.3191	300					56.1		219.9	57.0	(4.6)		(19.54)
2035	0.2941	300					58.3		240.9	57.0	(5.0)		(22.54)
2036	0.2711	300					59.0		262.7	57.0	(5.5)		(24.09)
2037	0.2499	300					59.8		285.3	57.0	(5.9)		(25.80)
2038	0.2303	300					60.7		308.9	57.0	(6.4)		(27.62)
2039	0.2122	300					62.1		333.5	57.0	(6.9)		(30.03)
2040	0.1956	300					63.6		359.0	57.0	(7.5)		(32.60)
Present Worth	9.4633										(23.8)	(34.5)	
Levelized							46.6		120.6	57.0	(2.5)	(3.6)	(6.26)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Status Quo Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Status Quo Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

Net Cost of Energy
Willowbrook Solar (100 MW)
2018H2 Fundamentals Base Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	100					37.6		50.8	19.0	(0.4)		0.67
2022	0.8495	100					39.0		30.1	19.0	(0.2)		(0.09)
2023	0.7829	100					40.7		44.2	19.0	(0.3)		(2.17)
2024	0.7216	100					41.6		58.7	19.0	(0.4)		(3.63)
2025	0.6650	100					43.0		73.6	19.0	(0.5)		(5.50)
2026	0.6129	100					43.7		88.9	19.0	(0.6)		(6.70)
2027	0.5649	100					44.4		104.7	19.0	(0.7)		(8.00)
2028	0.5207	100					55.4		120.9	19.0	(0.8)		(19.54)
2029	0.4799	100					57.2		137.6	19.0	(1.0)		(21.96)
2030	0.4423	100					60.5		154.8	19.0	(1.1)		(25.78)
2031	0.4076	100					62.7		172.2	19.0	(1.2)		(28.68)
2032	0.3757	100					64.6		190.1	19.0	(1.3)		(31.24)
2033	0.3463	100					66.4		208.5	19.0	(1.4)		(33.65)
2034	0.3191	100					68.4		227.3	19.0	(1.6)		(36.39)
2035	0.2941	100					70.9		246.5	19.0	(1.7)		(39.58)
2036	0.2711	100					72.1		266.3	19.0	(1.9)		(41.48)
2037	0.2499	100					73.7		286.5	19.0	(2.0)		(43.89)
2038	0.2303	100					77.7		307.1	19.0	(2.1)		(48.68)
2039	0.2122	100					77.9		328.6	19.0	(2.3)		(49.66)
2040	0.1956	100					80.7		350.6	19.0	(2.4)		(53.33)
Present Worth	9.4633										(8.5)	(32.3)	
Levelized							52.2		129.0	19.0	(0.9)	(3.4)	(16.56)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Base Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Base Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Willowbrook Solar (100 MW)
2018H2 Fundamentals Low Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	100					32.6		46.5	19.0	(0.3)		5.83
2022	0.8495	100					33.5		25.0	19.0	(0.2)		5.65
2023	0.7829	100					34.8		25.2	19.0	(0.2)		4.35
2024	0.7216	100					35.6		29.3	19.0	(0.2)		3.35
2025	0.6650	100					36.9		36.5	19.0	(0.3)		1.85
2026	0.6129	100					37.4		44.4	19.0	(0.3)		1.10
2027	0.5649	100					38.4		53.2	19.0	(0.4)		(0.27)
2028	0.5207	100					49.3		62.9	19.0	(0.4)		(11.52)
2029	0.4799	100					51.2		73.4	19.0	(0.5)		(13.72)
2030	0.4423	100					54.4		84.9	19.0	(0.6)		(17.35)
2031	0.4076	100					56.4		97.3	19.0	(0.7)		(19.75)
2032	0.3757	100					57.8		110.8	19.0	(0.8)		(21.62)
2033	0.3463	100					60.4		125.3	19.0	(0.9)		(24.79)
2034	0.3191	100					61.5		141.0	19.0	(1.0)		(26.50)
2035	0.2941	100					64.5		157.8	19.0	(1.1)		(30.04)
2036	0.2711	100					66.3		175.9	19.0	(1.2)		(32.49)
2037	0.2499	100					66.6		195.3	19.0	(1.4)		(33.51)
2038	0.2303	100					68.8		216.3	19.0	(1.5)		(36.53)
2039	0.2122	100					69.9		238.7	19.0	(1.7)		(38.48)
2040	0.1956	100					72.9		262.7	19.0	(1.8)		(42.34)
Present Worth	9.4633										(5.2)	(17.0)	
Levelized							46.0		79.9	19.0	(0.6)	(1.8)	(8.75)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Low Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Low Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Willowbrook Solar (100 MW)
2018H2 Fundamentals High Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	100	[redacted]				41.8	[redacted]	46.5	19.0	(0.3)	[redacted]	(3.33)
2022	0.8495	100					42.9		27.1	19.0	(0.2)		(3.82)
2023	0.7829	100					44.8		36.3	19.0	(0.3)		(6.09)
2024	0.7216	100					46.0		50.0	19.0	(0.3)		(7.74)
2025	0.6650	100					47.1		64.2	19.0	(0.4)		(9.33)
2026	0.6129	100					48.1		78.9	19.0	(0.5)		(10.83)
2027	0.5649	100					49.1		94.2	19.0	(0.7)		(12.32)
2028	0.5207	100					60.7		110.1	19.0	(0.8)		(24.47)
2029	0.4799	100					62.8		126.6	19.0	(0.9)		(27.16)
2030	0.4423	100					66.7		143.6	19.0	(1.0)		(31.60)
2031	0.4076	100					68.6		161.2	19.0	(1.1)		(34.21)
2032	0.3757	100					70.9		179.4	19.0	(1.2)		(37.13)
2033	0.3463	100					73.7		198.2	19.0	(1.4)		(40.61)
2034	0.3191	100					74.0		217.7	19.0	(1.5)		(41.61)
2035	0.2941	100					76.8		237.8	19.0	(1.6)		(45.21)
2036	0.2711	100					77.3		258.6	19.0	(1.8)		(46.40)
2037	0.2499	100					78.2		280.2	19.0	(1.9)		(48.14)
2038	0.2303	100					80.6		302.6	19.0	(2.1)		(51.43)
2039	0.2122	100					82.5		325.9	19.0	(2.3)		(54.14)
2040	0.1956	100					84.7		350.0	19.0	(2.4)		(57.30)
Present Worth	9.4633										(7.9)	(41.1)	
Levelized							57.0		121.0	19.0	(0.8)	(4.3)	(21.09)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. *Based on 2018 H2 AEP Fundamental Forecast - High Case.*

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - High Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D

OPCo
Net Cost of Energy
Willowbrook Solar (100 MW)
2018H2 Fundamentals Status Quo Case
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	$/MW-Day	(MW)	($M)	($M)	($/MWh)
2021	0.9217	100	[redacted]				37.3	[redacted]	46.5	19.0	(0.3)	[redacted]	1.12
2022	0.8495	100					38.5		25.0	19.0	(0.2)		0.62
2023	0.7829	100					40.0		33.0	19.0	(0.2)		(1.14)
2024	0.7216	100					40.9		46.9	19.0	(0.3)		(2.51)
2025	0.6650	100					42.2		61.3	19.0	(0.4)		(4.33)
2026	0.6129	100					43.2		76.4	19.0	(0.5)		(5.82)
2027	0.5649	100					44.1		92.1	19.0	(0.6)		(7.24)
2028	0.5207	100					45.8		108.4	19.0	(0.8)		(9.56)
2029	0.4799	100					47.6		125.4	19.0	(0.9)		(11.87)
2030	0.4423	100					49.9		143.0	19.0	(1.0)		(14.85)
2031	0.4076	100					51.7		161.1	19.0	(1.1)		(17.24)
2032	0.3757	100					53.4		180.0	19.0	(1.3)		(19.70)
2033	0.3463	100					55.8		199.6	19.0	(1.4)		(22.74)
2034	0.3191	100					56.3		219.9	19.0	(1.5)		(24.03)
2035	0.2941	100					58.4		240.9	19.0	(1.7)		(26.90)
2036	0.2711	100					58.9		262.7	19.0	(1.8)		(28.14)
2037	0.2499	100					59.4		285.3	19.0	(2.0)		(29.49)
2038	0.2303	100					60.4		308.9	19.0	(2.1)		(31.40)
2039	0.2122	100					61.9		333.5	19.0	(2.3)		(33.81)
2040	0.1956	100					63.6		359.0	19.0	(2.5)		(36.53)
Present Worth	9.4633										(7.9)	(20.7)	
Levelized							46.5		120.6	19.0	(0.8)	(2.2)	(10.63)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.

C. Total nameplate capacity of the REPA.

D. Total estimated energy output of the REPA.

E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.

F. REPA price.

G. REPA cost based on estimated energy and REPA price.

H. Weighted average of hourly market price of energy displaced by hourly incremental solar purchase. Based on 2018 H2 AEP Fundamental Forecast - Status Quo Case.

I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).

J. Based on 2018 H2 AEP Fundamental Forecast - Status Quo Case

K. Based on 19 percent PJM Capacity Credit.

L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years

M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L, i.e., the cost of the REPA, plus the solar energy impact on market sales/purchase, plus the capacity credit value.

N. The net cost of energy for the REPA, Column M x 1000 ÷ Column D