STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
August 26, 2019
INDIANA UTILITY
REGULATORY COMMISSION

APPLICATION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF 20 MW_{AC} CLEAN ENERGY SOLAR PROJECT; FOR APPROVAL OF RELATED ACCOUNTING AND RATEMAKING INCLUDING: TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE PROJECT THROUGH I&M'S BASIC RATES OR A SOLAR POWER RIDER, APPROVAL OF DEPRECIATION PROPOSAL, AND AUTHORITY TO DEFER COSTS UNTIL SUCH COSTS ARE REFLECTED IN RATES; AND FOR APPROVAL OF SALE OF RENEWABLE ENERGY CREDITS.	)	CAUSE NO. 45245

SUBMISSION OF REBUTTAL TESTIMONY OF
<u>JOSEPH G. DeRUNTZ</u>

Applicant, Indiana Michigan Power Company (I&M), by counsel, respectfully submits the rebuttal testimony and attachment of Joseph G. DeRuntz in this Cause.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the forgoing was served by hand delivery and or email transmission upon the following this 26th day of August, 2019:

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I&M Exhibit ______

INDIANA MICHIGAN POWER COMPANY

CAUSE NO 45245

PRE-FILED VERIFIED REBUTTAL TESTIMONY

OF

JOSEPH G. DERUNTZ

PRE-FILED VERIFIED REBUTTAL TESTIMONY OF JOSEPH DERUNTZ
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain portions of testimony offered by the Office of Utility Consumer Counselor (OUCC) witnesses Lauren Aguilar and John Haselden. Specifically, I will address Ms. Aguilar's assertion that the status of the South Bend Solar Project (SBSP or Project) Engineering, Procurement, and Construction (EPC) contract was misrepresented. Additionally, I will address the portions of Mr. Haselden's testimony that discuss:

- the Project cost estimate, with respect to the timing of the EPC contract execution;
- the Project's cost and Levelized Cost of Energy (LCOE), including his incorrect treatment of property taxes, selective use of project cost and LCOE information from a Northern Indiana Public Service Company (NIPSCO) 2018 IRP presentation, and misuse of U.S. Energy Information Administration (EIA) and Lazard reports to characterize the Project's overall cost and LCOE as unreasonable;
- alleged "customer risks" associated with the Project's initial cost and ongoing operation and maintenance (O&M) expense; and
- the benefits of owning the SBSP versus entering into a power purchase agreement (PPA).

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I am sponsoring the following attachments:

- Attachment JGD-1R: I&M's Response to OUCC RFI 1-25
- Attachment JGD-2R: NIPSCO 2018 IRP Presentation, Appendix A, p. 338
- Attachment JGD-3R: National Renewable Energy Laboratory, Direct Normal Solar Resource of Indiana
- Attachment JGD-4R: National Renewable Energy Laboratory, Photovoltaic Solar Resource of the United States
- Attachment JGD-5R: NIPSCO 2018 IRP Presentation, Appendix A, p. 57
- Attachment JGD-6R: OUCC Attachment JEH-5, pp. 11-12
- Attachment JGD-7R: OUCC Attachment JEH-5, p. 22
- Attachment JGD-8R: OUCC Attachment JEH-5, p. 47
- Attachment JGD-9R: EPRI Technical Assessment Guide (TAG) for Power Generation and Storage Technologies; 2016 Topics; Table 2-9: Design and Cost Estimate Classification

II. EPC CONTRACT

Q. On page 10, lines 8-12, Ms. Aguilar states that you made misrepresentations regarding the status of negotiations with the selected Project bidder. How do you respond?

A. At the time I provided direct testimony, negotiation of all aspects of the EPC contract with the selected bidder were, in fact, completed. My direct testimony was based on those completed negotiations. As discussed in the rebuttal testimony of Company witness David Lucas, the EPC contract has since been fully-executed, with no change to the Project scope or costs as they were negotiated on May 2, 2019[1].

Q. On page 10, lines 16-18, Mr. Haselden infers that using the EPC contract costs prior to obtaining final signatures was premature. Do you agree?

A. No, I do not. As I explained above, and in the Company's response to OUCC RFI 1-25[2], the contract was agreed to in principle. Negotiation of the costs included in the EPC contract were final, when the Project estimate was provided to the Commission in the Company's application. As I also previously mentioned, the EPC contract has been fully executed, with no changes to scope or costs being made.

III. SBSP LCOE

Q. On page 4, lines 14-16, Mr. Haselden disputes the Project's LCOE, and provides his own calculated value. Please explain why the LCOE he provides is incorrect.

A. Mr. Haselden's calculated LCOE of $90/MWh, an increase of approximately $8/MWh to the Company's calculated LCOE of $82.38/MWh, is due to his incorrect application of property tax, as discussed in the rebuttal testimony of Company witness Brent Auer.

Q. On page 16, lines 12-14, Mr. Haselden compares the cost of the SBSP to the cost of solar projects in a 2018 NIPSCO IRP presentation (NIPSCO

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[1] Executed public and confidential versions of the EPC contract, provided as Attachments DAL-2C and DAL-2R, to the rebuttal testimony of Company witness David Lucas.

[2] I&M's response to OUCC RFI 1-25, included as Attachment JGD-1R.

Presentation). Please explain why a direct comparison of costs between solar projects does not always yield meaningful results.

A. In general, capital costs are influenced by the generating capacity of solar projects, with economies of scale being achieved with larger projects. Additionally, a solar project's LCOE is highly dependent on the amount of solar radiation reaching a given geographical area (insolation), making the geographical location of a solar project a major influence on a generating unit's capacity factor. Neglecting to consider the differences in generating capacity and geographical location, when comparing costs between solar projects, can lead to inaccurate conclusions.

Q. On page 16, lines 12-14, Mr. Haselden compares the SBSP cost of $1,838.54/kW to a solar project cost of $1,151.01/kW, which he obtained from the NIPSCO Presentation. Is this comparison appropriate?

A. No. As I previously discussed, capital costs are influenced by the scale of a solar project. The $1,151.01/kW cost Mr. Haselden uses from the NIPSCO Presentation was an average bid price for utility-scale solar build projects. The $1,151.01/kW bid price was for five projects with a total capacity of 669 MW[3], while the SBSP is a much smaller 20 MW facility. A direct comparison of multiple projects totaling 669 MWs to a single 20 MW project is inappropriate, because the larger projects are less expensive due to the economies of scale. Additionally, the information he references is taken from a document labeled "Preliminary - Subject to Due Diligence". Clearly, this information had not yet been fully vetted. In contrast, the SBSP has been fully vetted, and has secured final EPC contract pricing.

[3] NIPSCO 2018 IRP Presentation Appendix A, p. 338, included as Attachment JGD-2R .

Q. On page 17, lines 15-21, Mr. Haselden criticizes the SBSP for having a lower capacity factor than "similar projects." Please respond.

A. As I previously mention, insolation at the location of a solar project has a significant impact on a generating unit's capacity factor. In response to the Company's DR 1-09, which requested Mr. Haselden provide evidence to support his claim that "The SBSP is estimated to have a capacity factor of 20.6% compared to similar projects at this latitude of 23-24%", he provided examples of projects that were located in areas with much higher insolation[4,5]. Comparison of capacity factors between solar generating units with different degrees of insolation, as Mr. Haselden does, is inappropriate and does not yield meaningful results.

Additionally, Mr. Haselden does not provide the total cost or LCOE for the projects he provides in response to the Company's DR 1-09. Selective comparison of individual solar project attributes, as is the case with his comparison of capacity factors, does not lead to reliable conclusions. Even when insolation is equal between two solar projects, capacity factor remains dependent on the number of solar panels installed. Additional panels increase capacity factor, but also increase project costs and the resulting LCOE. As I discuss in more detail later, there are tradeoffs between project costs and capacity factor.

[4] National Energy Renewable Laboratory, Direct Normal Solar Resource of Indiana, included as Attachment JGD-3R.
[5] National Energy Renewable Laboratory, Photovoltaic Solar Resource of the United States, included as Attachment JGD-4R.

Q. While Mr. Haselden only references a single page out of the NIPSCO Presentation, was there other relevant information he did not include?

A. Yes. In the same presentation, research produced a range of utility-scale solar build project costs from $1,155/kW - $2,370/kW. At $1,838.54/kW, the SBSP cost falls well within this range.[6]

Q. On page 16, line 16 through page 17, line 2, Mr. Haselden quotes the EIA and Lazard to show the Project's LCOE is unreasonable. Is the analysis he provides accurate?

A. No. Mr. Haselden incorrectly applies information from the EIA and Lazard as follows:

- He quotes a range of solar project LCOE costs taken from EIA tables that represent costs for projects going into service in 2023.[7] From the same report, the correct information for projects going into service in 2021 provides a range of solar project LCOE costs from $32.60/MWh - $82.80/MWh.[8] The SBSP's LCOE of $82.38/MWh falls within this range.
- The Lazard analysis Mr. Haselden references clearly states in its assumptions[9] that the LCOE calculation is based on a 50 MW system in a high insolation area. His use of this information neglects to take into account the disparity between the higher insolation for the projects in the Lazard data and the relatively low degree of insolation for the SBSP. He further disregards the difference in capacity between the 50 MW Lazard project and the 20 MW SBSP. As I previously discuss, both insolation and generating capacity impact

[6] NIPSCO 2018 IRP Presentation Appendix A, p. 57, included as Attachment JGD-5R.
[7] OUCC Attachment JEH-5, pp. 11-12, included as Attachment JGD-6R.
[8] OUCC Attachment JEH-5, p. 22, included as Attachment JGD-7R.
[9] OUCC Attachment JEH-5, p. 47, included as Attachment JGD-8R.

the calculation of a solar project's LCOE and cannot be ignored when comparing one project LCOE to another.

IV. SBSP COST

Q. Does Mr. Haselden offer any criticism of the Company's use of a competitive bidding process for the SBSP?

A. No, he does not. In fact, the $1,151.01/kW solar project cost he references from the NIPSCO presentation is the result of a competitive bidding process.

Q. On page 17 line 16 through page 18 line 5, Mr. Haselden suggests that the SBSP has not been optimized for energy output. How do you respond?

A. Mr. Haselden is correct in his observation of the tradeoffs between the cost of additional solar panels and a facility's capacity factor. The Company was mindful of this tradeoff when it structured the Project's RFP. By providing the desired nameplate capacity of the facility, with no restrictions on capacity factor or equipment configuration, the bidders were free to optimize their proposals to balance the cost of the facility with the energy output. Evaluating the proposals based on LCOE resulted in the most cost effective solution for optimizing energy output.

Q. On page 17, lines 4-5, Mr. Haselden claims the cost of the facility's interconnection is a significant portion of the total Project cost. Is this true?

A. No. In fact, the interconnection cost is less than five percent of the total Project cost.[10]

[10] Attachment JGD-1C to Company witness DeRuntz's direct testimony.

Q. On page 10, lines 16-19, Mr. Haselden discusses the Project cost, with respect to the EPC contract and interconnection cost. Please explain the level of certainty for these two estimated Project costs.

A. The EPC contract is fixed, removing uncertainty for the majority of the total Project cost. At less than five percent of the total Project cost, the interconnection is based on a Class V estimate, which by definition, includes some uncertainty.

Q. On page 10, lines 18-19, Mr. Haselden emphasizes the uncertainty associated with the interconnection's Class V cost estimate. How do you respond?

A. Although the interconnection estimate does not have the same level of certainty as the remaining Project costs, the Company is confident, based on its experience and expertise in this area, that the Project will be completed within the total estimated cost, including the contingency.

Q. Mr. Haselden mentions the Company's inclusion of a $1.2 million Project contingency, on page 11, lines 1-2, as support for his concern about project cost. Can you elaborate on this?

A. Yes. As I discuss on page 12 of my direct testimony, with any large project there are risks. Inclusion of a project contingency is standard industry practice, as no project is void of uncertainty and risk. The more developed a project's scope and procurement plan, the lesser the risk and need for contingency. With a fully-executed, fixed-price EPC contract and completed land purchase, the SBSP risk is significantly reduced. Based on established industry standards[11] for quantifying contingency costs, a range of 5 - 10 percent is recommended for estimates with

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[11] EPRI Technical Assessment Guide (TAG®) for Power Generation and Storage Technologies; 2016 Topics. EPRI, Palo Alto, CA: 2016. 3002008947; Table 2-9: Design and Cost Estimation Classification, included as Attachment JGD-9R.

the highest level of certainty. At 3 percent, the Project's $1.2 million contingency is very low compared to the industry standard 5 - 10 percent.

Q. On page 10, beginning on line 13, Mr. Haselden warns against Project "cost overruns". Please discuss the Company's process for managing project costs, including the approval and use of contingency funds.

A. As I discuss on page 12 of my direct testimony, the use of project contingency funds requires American Electric Service Power Corporation (AEPSC) management approval. AEPSC's standard work practice is to track and project costs on a monthly basis. If there is a change to a project's cost or schedule, the change is documented, reviewed and approved before any contingency is allocated. This process ensures project changes and costs are closely monitored and controlled, and reviewable by regulators.

V. ALLEGED "CUSTOMER RISKS"

Q. Beginning on page 11, line 11, Mr. Haselden uses a cost comparison of the transformer replacements at the Company's Deer Creek solar facility and the O&M estimate provided for the SBSP as justification for recommending a cap on the Project's O&M. Is this an appropriate comparison?

A. No. The transformer replacement at the Company's Deer Creek facility was an isolated capital expenditure. The type of transformer that failed at Deer Creek will not be used for the SBSP. The Company's Clean Energy Pilot Project (Pilot) has provided valuable experience with owning solar generation, including lessons learned from Deer Creek's transformer failures. By installing a variety of equipment and technology at the four different Pilot facilities, the Company gained the experience needed to make an informed decision to replace the unreliable transformer at Deer Creek with the type installed at the remaining three Pilot facilities, where the equipment has been reliable. With the exception of the transformer failure at Deer Creek, the Company has only invested $29,000 in its four Pilot facilities since the first unit went into service in December 2015. The use of an isolated historical capital expenditure to justify limiting future O&M expense is not appropriate. See the rebuttal testimony of Company witness Auer, for discussion of Mr. Haselden's recommendation to place a cap on O&M.

VI. BENEFITS TO OWNING THE SBSP

Q. On page 10, beginning on line 5, Mr. Haselden makes the argument that entering into a PPA is more beneficial to the Company's customers than owning the SBSP. Do you agree?

A. No, I do not. There are many advantages to owning solar generation versus entering into PPAs, including the Company's ability to:

- have control over operations over the life of the facility and be able to respond to market changes, which may not be possible under a PPA (market conditions, frequency regulation, ancillary services, reactive/voltage needs, etc.);
- have control over determining whether the facility's expected useful life could be extended or the site repowered; and
- take advantage of new or existing generation technologies (e.g., battery storage), when economically beneficial.

VII. CONCLUSION

Q. Does this conclude your pre-filed verified rebuttal testimony?

A. Yes, it does.

VERIFICATION

I, Joseph G. DeRuntz, Project Director American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Dated: August 26, 2019.

Joseph G. DeRuntz

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-25

REQUEST

Mr. Joseph DeRuntz;

Referencing page 10, please submit the EPC Contract and the scoring summary.

RESPONSE

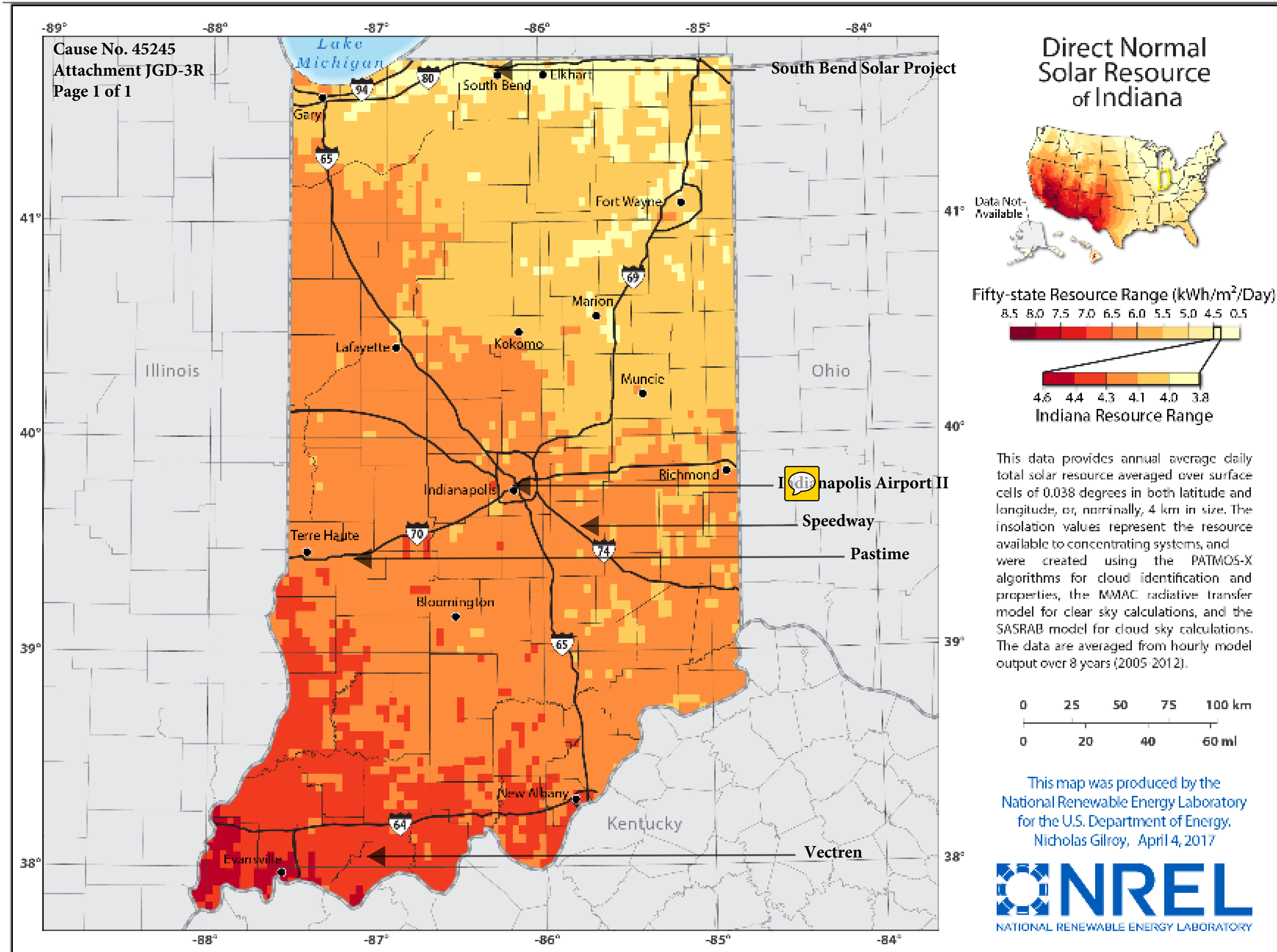
I&M objects to the request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Subject to and without waiver of the foregoing objection, I&M provides the following response.

Please see "OUCC 1-25_Confidential_Attachment_1.pdf", for the SBSP bid evaluation matrix. The EPC contract, while agreed to in principle, remains under negotiations between the Parties and is not yet available at this time. Once the agreement is fully executed, I&M will supplement this response subject to confidentiality considerations.

Overall Summary and Pricing Received

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Preliminary – Subject to Due Diligence


Direct Normal Solar Resource of Indiana
South Bend Solar Project
Indianapolis Airport II
Speedway
Pastime
Vectren
Lake Michigan
Gary
South Bend
Elkhart
Fort Wayne
Marion
Kokomo
Lafayette
Muncie
Indianapolis
Richmond
Terre Haute
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69
70
74
64
-89°
-88°
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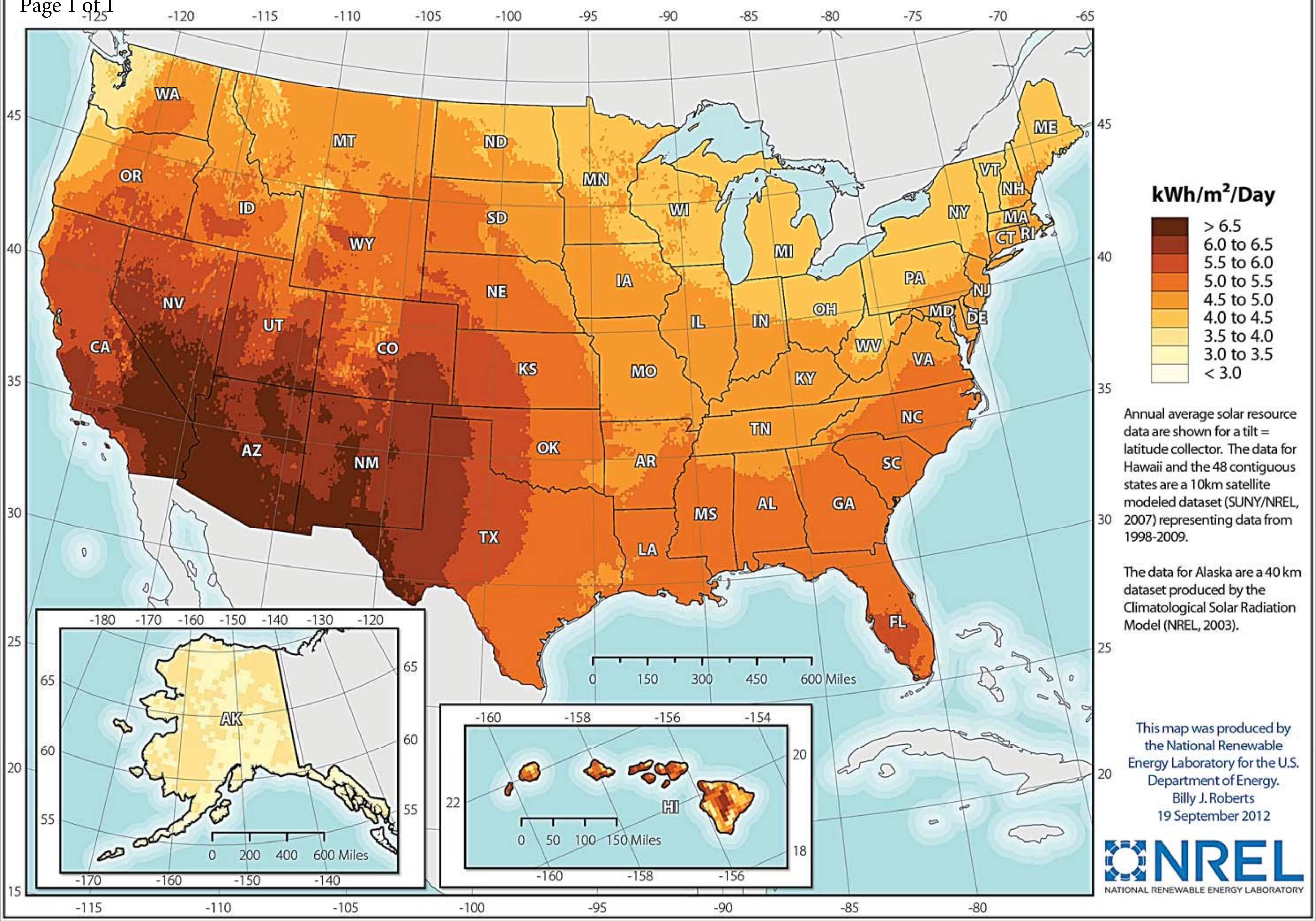
-86°
-85°
-84°
41°
40°
39°
38°
Data Not-Available
Fifty-state Resource Range (kWh/m²/Day)
8.5 8.0 7.5 7.0 6.5 6.0 5.5 5.0 4.5 0.5
4.6 4.4 4.3 4.1 4.0 3.8
Indiana Resource Range
This data provides annual average daily total solar resource averaged over surface cells of 0.038 degrees in both latitude and longitude, or, nominally, 4 km in size. The insolation values represent the resource available to concentrating systems, and were created using the PATMOS-X algorithms for cloud identification and properties, the MMAC radiative transfer model for clear sky calculations, and the SASRAB model for cloud sky calculations. The data are averaged from hourly model output over 8 years (2005-2012).
0 25 50 75 100 km
0 20 40 60 mi
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Nicholas Gilroy, April 4, 2017
NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Photovoltaic Solar Resource of the United States



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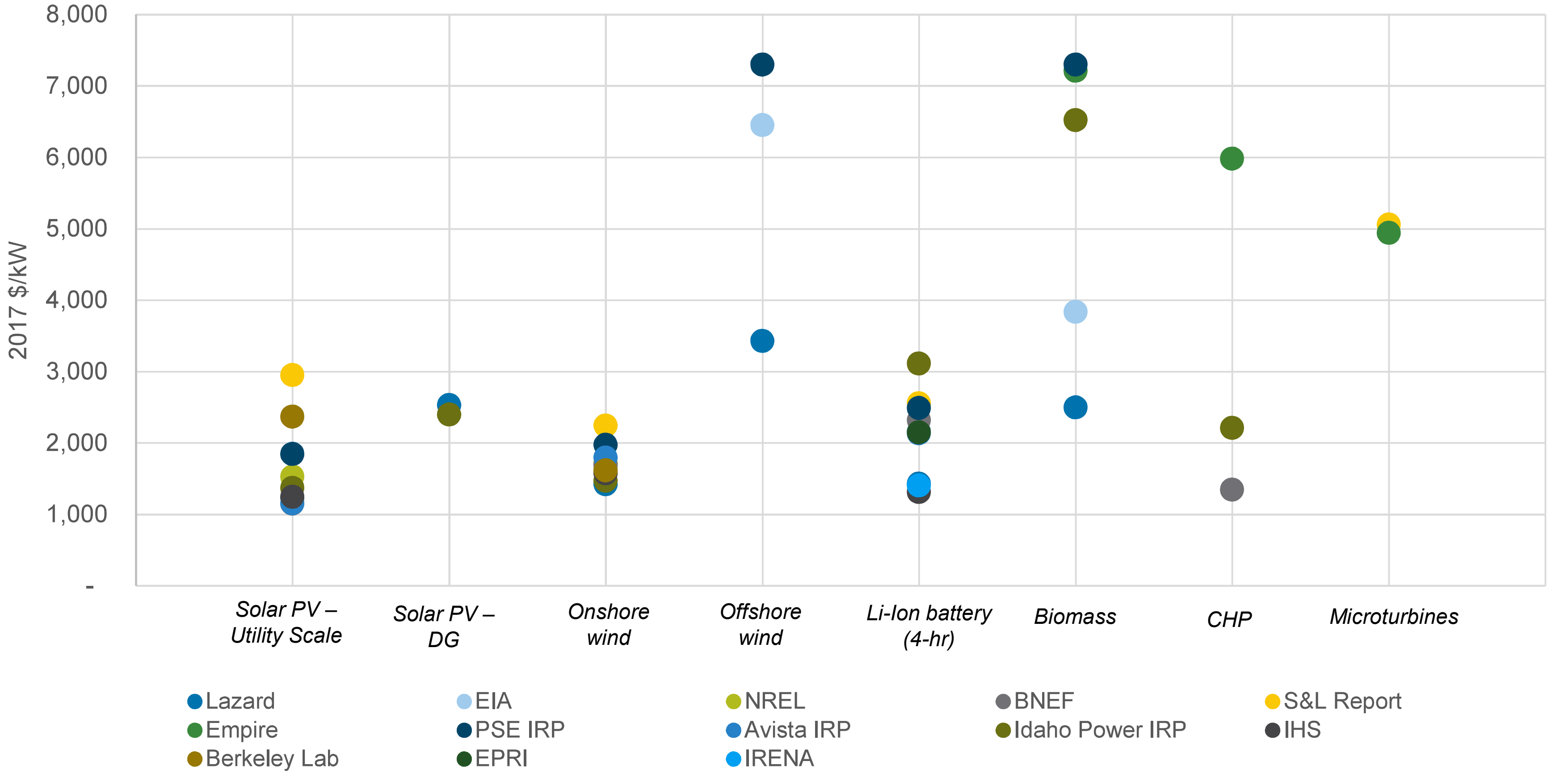

2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

Table 1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CC	87	8.1	1.5	32.3	0.9	42.8	NA	42.8
Advanced CC	87	7.1	1.4	30.7	1.0	40.2	NA	40.2
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NB	NB
Advanced CT	30	17.2	2.7	54.6	3.0	77.5	NA	77.5
Advanced nuclear	NB	NB	NB	NB	NB	NB	NB	NB
Geothermal	90	24.6	13.3	0.0	1.4	39.4	-2.5	36.9
Biomass	83	37.3	15.7	37.5	1.5	92.1	NA	92.1
Non-dispatchable technologies								
Wind, onshore	44	27.8	12.6	0.0	2.4	42.8	-6.1	36.6
Wind, offshore	45	95.5	20.4	0.0	2.1	117.9	-11.5	106.5
Solar PV[4]	29	37.1	8.8	0.0	2.9	48.8	-11.1	37.6
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2021–2023. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.

[2]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2023 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table 1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	61.3	9.7	32.2	1.1	104.3	NA	104.3
Coal with 90% CCS[2]	85	50.2	11.2	36.0	1.1	98.6	NA	98.6
Conventional CC	87	9.3	1.5	34.4	1.1	46.3	NA	46.3
Advanced CC	87	7.3	1.4	31.5	1.1	41.2	NA	41.2
Advanced CC with CCS	87	19.4	4.5	42.5	1.1	67.5	NA	67.5
Conventional CT	30	28.7	6.9	50.5	3.2	89.3	NA	89.3
Advanced CT	30	17.6	2.7	54.2	3.2	77.7	NA	77.7
Advanced nuclear	90	53.8	13.1	9.5	1.0	77.5	NA	77.5
Geothermal	90	26.7	12.9	0.0	1.4	41.0	-2.7	38.3
Biomass	83	36.3	15.7	39.0	1.2	92.2	NA	92.2
Non-dispatchable technologies								
Wind, onshore	41	39.8	13.7	0.0	2.5	55.9	-6.1	49.8
Wind, offshore	45	107.7	20.3	0.0	2.3	130.4	-12.9	117.5
Solar PV[3]	29	47.8	8.9	0.0	3.4	60.0	-14.3	45.7
Solar thermal	25	119.6	33.3	0.0	4.2	157.1	-35.9	121.2
Hydroelectric[4]	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2023 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[2]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

EIA evaluated LCOE and LACE for each technology based on assumed capacity factors, which generally correspond to the high end of their likely utilization range. This convention is consistent with the use of LCOE to evaluate competing technologies in baseload operation such as coal and nuclear plants. Some technologies, such as combined-cycle (CC) plants, while sometimes used in baseload operation, are also built to serve load-following or other intermediate dispatch duty cycles. Simple conventional or advanced combustion turbines (CT) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor, which reflects the upper end of their typical economic utilization range. The duty cycle for intermittent resources is not operator controlled, but rather, it depends on weather that will not necessarily correspond to operator-dispatched duty cycles. As a result, LCOE values for wind and solar technologies are not directly comparable with the LCOE values for other technologies that may

Table A2. Regional variation in levelized cost of electricity for new generation resources entering service in 2021 (2018 $/MWh)

	Range for total system levelized costs				Range for total system levelized costs with tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Conventional CC	42.6	46.8	46.7	55.7	42.6	46.8	46.7	55.7
Advanced CC	38.1	41.6	40.5	48.5	38.1	41.6	40.5	48.5
Conventional CT	84.4	89.9	84.6	100.5	84.4	89.9	84.6	100.5
Advanced CT	74.6	81.1	80.6	90.2	74.6	81.1	80.6	90.2
Non-dispatchable technologies								
Wind, onshore	39.6	56.5	48.8	69.3	27.5	44.4	36.7	57.2
Solar PV[3]	41.7	62.5	52.2	111.6	32.6	47.4	39.9	82.8

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2021. See note 1 in Tables A1a and A1b.
[2]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2019–2021.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Note: EIA calculated the levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region that can vary significantly by region. The capacity factor ranges for these technologies are 36%–45% for onshore wind and 22%–34% for solar PV. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Conventional CC	36.2	41.6	41.7	49.0
Advanced CC	36.2	41.6	40.8	49.0
Non-dispatchable technologies				
Wind, onshore	33.9	36.6	34.7	44.0
Solar PV[4]	33.7	44.8	41.7	52.9

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2019–2021.
[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Levelized Cost of Energy—Key Assumptions

		Solar PV				
	Units	Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline [(2)]	Utility Scale—Thin Film [(2)]
Net Facility Output	MW	0.005	1	5	50	50
Total Capital Cost [(1)]	\$/kW	\$2,950 – \$3,250	\$1,900 – \$3,250	\$1,850 – \$3,000	\$1,250 – \$950	\$1,250 – \$950
Fixed O&M	\$/kW-yr	\$14.50 – \$25.00	\$15.00 – \$20.00	\$12.00 – \$16.00	\$12.00 – \$9.00	\$12.00 – \$9.00
Variable O&M	\$/MWh	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—
Capacity Factor	%	19% – 13%	25% – 20%	25% – 20%	32% – 21%	34% – 23%
Fuel Price	\$/MMBtu	—	—	—	—	—
Construction Time	Months	3	3	4 – 6	9	9
Facility Life	Years	25	25	30	30	30
Levelized Cost of Energy	\$/MWh	\$160 – \$267	\$81 – \$170	\$73 – \$145	\$40 – \$46	\$36 – \$44

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 50 MW system in high insolation jurisdiction (e.g., Southwest U.S.).

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LIST OF TABLES

Table 2-9
Design and cost estimate classification

Item	Design Estimate Effort	Project Contingency Range (%) (see note)	Design Information Required	Cost Estimate Basis		
				Major Equipment	Other Materials	Labor
Class I (Similar to Amer. Assoc. of Cost Engineers (AACE) Class 5/4)	Simplified	30–50	General site conditions, geographic location and plant layout Process flow/operation diagram Product output capacities	By overall project or section-by-section based on capacity/cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II (Similar to AACE Class 3)	Preliminary	15–30	As for Type Class I plus engineering specifics, such as Major equipment specifications Preliminary piping and instrumentation flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment costs on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates
Class III (Similar to AACE Class 3/2)	Detailed	10–20	A complete process design Engineering design usually 20% to 40% complete Project construction schedule Contractual conditions and local labor conditions	Firm quotations adjusted for possible price escalation with some critical items committed	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off	Estimated labor hour units (including assessment) using expected labor rate for each job classification
				Pertinent taxes and freight included		
Class IV (Similar to AACE Class 1)	Finalized	5–10	As for Class III, with engineering essentially complete	As for Class III, with most items committed	As for Class III, with material on approximately 100% firm basis	As for Class III, some actual field labor productivity may be available

Note: Expressed as a percentage of the total of process capital, engineering and home office fees, and process contingency.