STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF 20 MWAC 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**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED TESTIMONY OF

JOHN E. HASELDEN – PUBLIC'S EXHIBIT NO. 2

AUGUST 12, 2019

Respectfully submitted,

T. Jason Haas
Attorney No. 34983-29
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS JOHN E. HASELDEN
CAUSE NO. 45245
INDIANA MICHIGAN POWER COMPANY
[redacted] **HIGHLIGHT IDENTIFIES CONFIDENTIAL MATERIAL**

I. INTRODUCTION

Q: Please state your name, business address, and employment capacity.

A: My name is John E. Haselden. My business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204. I am a Senior Utility Analyst in the Electric Division of the Indiana Office of Utility Consumer Counselor ("OUCC"). I describe my educational background, professional work experience, and preparation for this filing in Appendix A to my testimony.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes. I have testified in many proceedings on a number of issues before the Commission, including rate cases, demand side management, renewable energy, environmental trackers, and applications for Certificates of Public Convenience and Necessity ("CPCN").

Q: What is the purpose of your testimony?

A: I discuss how the request by Indiana Michigan Power Company ("I&M" or "Petitioner") is unreasonably expensive and not in the interest of ratepayers as proposed. Although the OUCC supports the development of renewable resources, I recommend the Commission deny recovery of the South Bend Solar Project's ("SBSP or "Project") costs in the manner I&M requests. Should the Commission decide to approve the Project, I offer recommended conditions and an alternative method of cost recovery that is reasonably comparable with the current market and more reasonable to ratepayers.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I reviewed the Verified Petition, Direct Testimony and Exhibits I&M submitted in this Cause. I reviewed I&M's recently submitted IRP.[1] I performed an analysis on the financial aspects of the Project. I composed data requests ("DRs") and reviewed I&M's responses. I also reviewed documents providing additional market information on solar energy.

Q: Are you sponsoring any attachments in this proceeding?

A: Yes. I sponsor:

- Attachment JEH-1 to this testimony, which is Slide 32 from I&M's IRP Stakeholder Workshop dated May 23, 2019.
- Attachment JEH-2 to this testimony, which contains Petitioner's Responses to selected CAC and OUCC DRs;
- Attachment JEH-3 to this testimony is a copy of the Stipulation and Settlement Agreement from Cause No. 45086;
- Attachment JEH-4 to this testimony is a copy of the Fifth Joint Modification to the Consent Decree approved by the US District Court for the Southern District of Ohio Eastern Division; and
- Attachment JEH-5 to this testimony contains copies of:

[1] Indiana Michigan Power Integrated Resource Plan submitted July 1, 2019.

- Northern Indiana Public Service Company's ("NIPSCO") Integrated Resource Plan 2018 Update, Public Advisory Meeting Three, July 24, 2018, Slide 19;
- "Levelized Cost and Levelized Avoided Cost of New generation Resources in the *Annual Energy Outlook 2019, February, 2019*," US. Energy Information Administration; and
- "Lazard's Levelized Cost of Energy Analysis Version 12.0," 2018, Lazard.

II. NEED FOR THE PROJECT

Q: What reasons does I&M provide concerning the need for the SBSP?

A: I&M sets out five reasons:

1. A comparable sized solar project was included in I&M's 2015 and 2019 IRPs.[2]
2. The Project creates a diverse portfolio of generating resources.[3]
3. The Project offers customers the opportunity to learn about renewable energy.[4]
4. Renewable energy projects, like the SBSP, support economic development of the communities in which I&M serves.[5]
5. Customers benefit from I&M ownership of the SBSP.[6]

Q: Do you agree with I&M's reasons for constructing the SBSP?

[2] Direct Testimony of Toby L. Thomas, page 9, line 14 – page 10, line 11.
[3] Thomas Direct, page 6.
[4] Thomas Direct, pages 7 and 13.
[5] Thomas Direct, page 12.
[6] Thomas Direct, pages 10-11.

A: No. While the SBSP superficially satisfies the objectives asserted by I&M Witness Toby Thomas, there are issues with each reason I&M provides that render them either incorrect or without merit.

Q: Please explain your concerns about the role the SBSP plays in fulfilling I&M's 2015 and 2019 IRPs.

A: Renewable resources were included in both IRPs; however, the SBSP does not provide any economic benefits warranting its inclusion. Currently I&M has excess capacity[7] and its IRP assumes this situation will not change due to the Rockport Unit 2 lease termination in 2022. Additionally, it is now known the Fifth Joint Modification to Consent Decree recently approved by the United States District Court for the Southern District of Ohio will effectively remove the environmental requirements on Rockport Unit 2 that were causing the lease to not be renewed.[8] Furthermore, I&M modeled solar resources in its most recent IRP at an estimated levelized cost of energy ("LCOE") of $50-54/MWh.[9] I&M Witness Joseph DeRuntz calculates the LCOE of the SBSP at $82.39/MWh; however, I calculate the LCOE as $90/MWh, as discussed below.[10] Regardless, the SBSP is far more expensive than the costs I&M used in its IRP's economic modeling, making the Project's selection unlikely if I&M had modeled it in its IRP. This is especially true given recent Rockport 2 developments, which imply less need for capacity and

[7] Indiana Michigan Integrated Resource Plan, July 1, 2019, Public Summary, page 5, Figure 2.
[8] Notice, June 7, 2019.
[9] Attachment JEH-1.
[10] Direct Testimony of Joseph G DeRuntz, page 13, line 9.

energy in the near future. The OUCC issued a data request asking whether I&M would be willing to rerun its modeling based on its updated numbers. I&M responded, declining to model the revised cost of this resource in its IRP.[11]As recommended below, I&M customers should not be required to pay for the project at a cost higher than I&M modelled in its recent IRP and should arguably be lower.

Q: Please elaborate on I&M's response regarding why updated costs should not be used to rerun the IRP model to determine if the SBSP would to be selected.

A: In response to a data request, I&M indicated the costs assumed four years ago in its 2015 IRP are close to the current cost estimate for the SBSP.[12] Furthermore, in the 2019 IRP I&M assumed the construction of the SBSP is included as a "going-in" position.[13] In other words, the construction of the SBSP is a fixed assumption already included in the 2019 IRP. I&M indicates that due to the long timeframe to develop such a project, it cannot change course despite the changed circumstances in the market showing solar prices at almost half of 2014/2015 prices, as explained below. The information used to develop a price forecast for solar power made four to five years ago is stale and does not justify ignoring current market conditions. It is not too late for I&M to change course and revisit the prudency of this project. Other than making an imprudent purchase of land for the SBSP, all other agreements are unexecuted. The SBSP will not start construction until 2020 and is expected to be completed within eight months. Despite an assumption to its IRP that this is a "going-in" position, it does not remove the obligation that costs for the

[11] Attachment JEH-2, Response to OUCC DR 3-31(c).
[12] Attachment JEH-2, Response to OUCC DR 3-31(a).
[13] *Id*.

SBSP should be at least comparable to the market price of solar power assumed in the same IRP. Nor does it relieve I&M of an obligation to construct a facility with a reasonable cost.[14] If I&M takes years to react to this changing renewable energy market, as it has in this instance, it should not be pursuing the development of such projects. As stated by the Commission in its recent order in Cause 45052,[15] where it quotes from the 2018 Statewide Analysis: "[a] key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake."[16] Also, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes *off ramps*, to react quickly to changing circumstances and make appropriate changes in resources."[17] I&M is demonstrating an inability to function in the manner described above. Utility-developed renewable energy resources should result in a lower cost, comparable to current market conditions, and at lower risk than through the means afforded by traditional ratemaking.[18]

Q: Please explain your concerns about the role the SBSP plays in diversifying I&M's generating portfolio.

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[14] IC §§ 8-1-2-0.5 and 8-1-2-4.

[15] Cause No. 45052, *Verified Petition of Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc. for Issuance of a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Gas Turbine Generation Facility*, Order, at 24 (April 24, 2019).

[16] 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity, page 5.

[17] 2018 Statewide Analysis, page 56 (emphasis in original).

[18] See e.g.: Cause No. 45086, Verified Petition of Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc., for Authority to Construct, Own and Operate a Solar Energy Project, Order at 28 (March 20, 2019).

A: Coal and nuclear units dominate I&M's generating portfolio. This is unlikely to change in the near term.[19] In comparison to I&M's thermal generators, renewable resources have relatively low capacity factors, and only a fraction of their nameplate capacity is credited towards I&M's resource adequacy.[20] Therefore, it is more relevant to consider the diversity of the energy produced. Table JEH-1 shows I&M's forecasted Test Year generation resource mix, as provided in response to an OUCC data request.[21] In addition, I calculated percentages of generation, by resources, both with and without the SBSP's estimated production.

TABLE JEH-1						
I&M System Generation by Type and Energy (GWH)						
	Nuclear	Solar	Hydro	Wind	Coal	Total
Without SBSP	17,818	24	111	1,701	11,706	31,360
Percent of Total	56.818%	0.077%	0.354%	5.424%	37.328%	
Percent Renewables (Wind+Solar+Hydro)						5.855%
With SBSP	17,818	61	111	1,701	11,706	31,397
Percent of Total	0.56751	0.194%	0.354%	5.418%	37.284%	
Percent Renewables (Wind+Solar+Hydro)						5.965%

The percentage of solar production will increase from 0.08% to 0.19%. Overall, the percentage of renewable generation (wind, solar and hydro) would increase from

[19] See Thomas Direct, Figure TLT-1, at page 4.
[20] Indiana Michigan Integrated Resource Plan, July 1, 2019, Public Summary, page 5.
[21] Attachment JEH-2, response to OUCC DR 1-2.

5.86% to 5.97%. This modest change of 0.1% does not represent meaningful diversification.

Q: Please explain your concerns about the role the SBSP may play in providing an opportunity to learn about renewable energy?

A: I&M has grossly overstated this benefit. There is not much new for customers to learn from a typical large solar facility such as the SBSP. Visiting such a facility may be novel for a few minutes but it soon becomes apparent such facilities are systems containing a few components such as panels, supporting racks, inverters, and transformers repeated many times. The SBSP will be a conventional commercial operation that has well-defined expectations of performance. It is not an experimental or research project.

Q: Please explain your concerns about the role the SBSP may play in offering customers the opportunity to participate in visible, local solar projects and encourage economic development.

A: I&M currently offers customers two green power-purchasing options and is proposing in their pending rate case to transition the existing programs into a new program. The new program is at a lower cost to participating customers than the existing programs because it is based upon a market price for Renewable Energy Credits ("RECs') (wind and solar) instead of the higher cost of solar RECs approved in Cause 44511. The current programs did not achieve significant participation due to cost. The proposed IM Green Rider is based upon New Jersey Class I RECs that are not site-specific.[22] I&M currently maintains a portfolio of approximately [redacted] of these RECs, almost all of which are generated by the

[22] Cause No 45235, Direct Testimony of I&M Witness Kurt Cooper, page 17.

wind farms under contract to I&M.[23] To say customers have the opportunity to participate in the SBSP is misleading. A customer would need to make a complicated and concerted effort to execute a contract with I&M for the RECs' specific source to realize that goal. Regardless, purchasing RECs will not satisfy the requirements of many corporate customers that subscribe to the Corporate Renewable Energy Buyer's Principles, as implied by I&M's response to OUCC DR 3-22.[24] Participants in the Corporate Renewable Energy Buyer's Principles require incremental (new) resources and not the purchase of RECs from an existing source.[25] As far as economic development, I&M provided no concrete evidence that the presence of the SBSP will spur companies to move to this region. I&M discussed how various municipal and commercial entities have renewable goals, but I&M has not specifically shown how the SBSP will lead to greater economic development.[26] As already stated, those corporate customers that subscribe to the Corporate Renewable Energy Buyer's Principles will not use the SBSP to further their renewable energy goals. It is an expensive, and incorrect, assumption that the SBSP will serve as a "Field of Dreams" proposition (i.e. "If you build it, [they] will come.") as further discussed by OUCC Witness Lauren Aguilar.

Q: What concerns do you have regarding I&M owning the SBSP?

A: My primary concerns about I&M's direct ownership of the SBSP are related to initial costs, treatment of federal tax incentives in I&M's proposed ratemaking

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[23] Attachment JEH-2, confidential response to OUCC DR 3-30.
[24] Attachment JEH-2, response to OUCC DR 3-22.
[25] https://buyersprinciples.org/principles/
[26] Attachment JEH-2, responses to OUCC DR 5-02, 5-03 and 5-04.

treatment, ongoing operation and maintenance ("O&M") costs and O&M risks. Compared to alternatives such as a power purchase agreement ("PPA"), there are significantly more costs and risks borne by ratepayers. I discuss those concerns in depth in the next section.

III. CUSTOMER RISKS

Q: Please explain customer risks related to the SBSP.

A: As stated above, there are four significant risks I&M is imposing on ratepayers that would not be present if the project were structured under a PPA:

1. Project costs and overruns;
2. O&M costs and risks;
3. Ratemaking treatment of federal tax incentives; and
4. The uncertainty surrounding I&M's history concerning the ability to monetize tax credits and the tax effects of accelerated depreciation.

Q: Please discuss the risks associated with project costs and cost overruns.

A: Under a traditional PPA, I&M would pay for power produced and received on a $/MWh basis and would not be exposed to financial risk should the project and associated interconnection costs be more than expected. In this case, I&M produced an estimate based upon an unsigned Engineering Procurement Construction ("EPC") contract and interconnection costs based upon a Class V estimate with an accuracy of -50% and +100%.[27] Even through the actual cost could double, I&M provided no evidence to support Witness DeRuntz's Class V estimate, so the actual

[27] Petitioner's Exhibit 2, page 11, Attachment JEH-2, Response to OUCC DR 1-26.

costs could more than double.[28] In addition, I&M included a contingency of $1.2 million. Any overruns to the estimate will be borne by I&M ratepayers. Furthermore, it is not clear if or when I&M will realize the 26% federal investment tax credit ("ITC") or the tax benefits of accelerated depreciation, as discussed below.

Q: Please discuss the risks associated with O&M costs.

A: I&M ratepayers are subject to all O&M risks associated with the SBSP. If equipment fails or needs repair, I&M ratepayers pay for the costs to repair or replace equipment net of any warranties. Ratepayers also continue to pay all fixed costs, regardless of output from the facility. Under a PPA, ratepayers are not liable for any of these costs or lost production. An example of the ownership risk is I&M's Deer Creek solar facility (approved in Cause No. 44511), which has not produced power since July, 2018 due to transformer failures.[29] I&M spent $382,698 in 2018 and $236,659 so far in 2019 on Deer Creek for a total of $619,357 in capital dollars.[30] On a $/kW basis, this is equivalent to $153/kW in 2018 and $95/kW so far in 2019. Comparing these costs to the $15/kW/year estimate for the SBSP,[31] one can see the magnitude of the O&M risk if something goes wrong. In addition, Deer Creek has been offline for more than a year and, unlike a PPA contract where no production means no revenue to the owner, I&M continues to recover its fixed costs through base rates despite no production for over a year. For these reasons, if the

[28] DeRuntz, Attachment JGD-1.
[29] Attachment JEH-2, Responses to OUCC DR 5-13.
[30] Attachment JEH-2, Cause No. 45235, Response to OUCC DR 7-01.
[31] DeRuntz Direct, page 15, lines 2-3.

SBSP is approved, I recommend the Commission cap cumulative O&M costs at $15/kW/year, escalated at 2% annually. This will reduce I&M ratepayers' exposure to O&M risk, placing the risks to ratepayers on par with a PPA.

Q: Please discuss the risks associated with ratemaking treatment of federal tax incentives.

A: I&M has a history of stating customers will benefit from the ITC for its solar projects. In Cause No. 44511, I&M Witness Paul Chodak III stated at page 19 of his testimony:

> **Q: Will I&M and its customers benefit from the Investment Tax Credit (ITC)?**
>
> A Yes. A key development that makes utility ownership appropriate to consider from a customer economics perspective is the federal tax laws that allows utilities, among others, to claim a 30% Investment Tax Credit (ITC) for certain renewable technologies such as solar (the 30% ITC decreases to 10% after 2016). This was enacted through the Emergency Economic Stabilization Act of 2008, and ultimately provides for a reduction in a utility's overall tax liability for investments in solar technology that was not available to utilities prior to that time. As Company witness Halsey describes, any ITC value that I&M receives from its investment in solar properties will benefit customers by reducing the revenue requirement over the depreciable life of the solar property in accordance with federal tax laws.[32]

In the subsequent Cause No. 44511 Solar Power Rider ("SPR") 1 filing, Mr. Chodak stated at pages 9-10 of his testimony:

> **Q. WHAT IS THE STATUS OF THE CONSTRUCTION AT THE FOUR SITES AND THE TIMETABLE FOR THE CESPP?**
>
> A. On July 24, 2015, I&M broke ground on the first solar facility, Deer Creek, which is located adjacent to I&M's Marion Service Center. This facility will generate a peak of 2.5 MWs, and is expected to begin generating energy by the

[32] Cause No. 44511, *Verified Petition of Indiana Michigan Power Company for Approval of a Clean Energy Solar Pilot Project*, I&M Direct Testimony of Witness Paul Chodak III, page 19 (July 7, 2014).

> end of this year. A ground breaking for I&M's second solar facility, Twin Branch, located in St. Joseph County, IN was held on October 26, 2015. This facility will generate 2.6 MWs and is expected to begin generating energy by the end of July 2016. I&M continues to move forward with two additional solar sites; Olive, which will be a 5.0 MW facility near New Carlisle, IN and Watervliet, which will be a 4.6 MW facility near Watervliet, MI. As planned, all four of the CESPP sites will be located on I&M-owned land in close proximity 1 to existing I&M substations and within I&M load centers, minimizing the cost of interconnecting to the grid. I&M has entered into contracts for each of these four sites that require the installation be completed by December 31, 2016, to take advantage of the 30% Investment Tax Credit (ITC). The ITC tax credit is an important benefit to I&M and its customers because it reduces the revenue requirement of the CESPP over the depreciable life of the solar property. Accordingly, the contracts provide for liquidated damages if the projects are not completed on time. Importantly, I&M has an experienced generation project management team closely overseeing construction and I am confident that the projects will be completed by December 31, 2016.[33]

However, a few months later, I&M Witness Matthew Horeled stated in his rebuttal testimony in SPR 1 at page 2:

> Q. **IS OUCC WITNESS THACKER'S PROPOSAL (PP. 4-5) TO UPDATE THE INVESTMENT TAX CREDITS (ITC) IN THE CURRENT SPR-1 TRACKER FILING ACCEPTABLE TO I&M?**
>
> A. Yes. As the OUCC noted, I&M informed the OUCC that I&M's forecasted taxable income indicates it will not realize the cash benefit of the Solar ITC until 2018 when I&M has sufficient taxable income. Due to tax normalization rules, I&M cannot provide customers the benefit of the ITC amortization until I&M receives the ITC cash benefit. Ultimately, this is a timing issue. I&M will still realize the full ITC benefit, which will be amortized over the remaining depreciable life of the project to reduce customer rates. I&M

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[33] Cause No. 44511 SPR 1, *Verified Petition of Indiana Michigan Power Company for Approval of an Adjustment to its Rates through its Solar Power Rider*, I&M Direct Testimony of Witness Paul Chodak III, pages 9-10 (November 20, 2015).

> agrees to the OUCC proposal to reflect the ITC amortization as zero in this SPR-1 filing because this supports tax normalization rules.[34]

To date, I&M has been unable to take advantage of the federal ITC and tax accelerated depreciation tax benefits associated with its four solar projects approved in Cause No. 44511.[35] I&M has been deferring the ITC and may be able to begin amortizing deferred ITC's for these projects at some future date. However, I&M will not speculate whether AEP will have a tax appetite in the near future to take advantage of the ITC.[36] We see the same issue arise in the current case where I&M discusses cost reduction through the ITC and includes the ITC in its LCOE calculation despite the fact AEP may not be able to take advantage of the ITC. This is a serious cost risk for ratepayers as demonstrated below in Table JEH-2. Not being able to use (and credit ratepayers) for the ITC yields an increased LCOE of $98/MWh.

Table JEH-2
Levelized Cost of Energy Estimates

I&M Estimate[1]	$82.38/MWh
OUCC Estimate Corrected for Property Taxes[2]	$90.00/MWh
OUCC Estimate without ITC[2]	$98.00/MWh

[1] DeRuntz, page 13
[2] Workpaper JEH-1

Furthermore, if I&M can realize the tax incentives in a timely manner, I&M will realize a significant improvement in cash flow by receiving the 26% tax credit immediately and tax effects of the accelerated depreciation over five years. I&M,

[34] Cause No. 44511, SPR 1, I&M Rebuttal Testimony of Witness Matthew Horeled, page 2 (March 22, 2016).
[35] Attachment JEH-2, Responses to OUCC DR 1-34 and DR 3-17 through 19
[36] Attachment JEH-2, response to OUCC DR 3-19.

in turn, will credit ratepayer revenue requirements over the subsequent 30 years leaving ratepayers no benefit for the time value of money associated with these tax incentives. I calculate the third year cost of energy from the SBSP (assuming the ability to take the ITC and cost estimates prove to be accurate) to be $109/MWh,[37] declining over time as straight-line depreciation occurs over 30 years. Costs increase in the third year due to higher property taxes on the improvements.[38] I calculate the LCOE for the SBSP to be $90/MWh over 30 years, using I&M's numbers for construction costs, O&M, and cost of capital.[39] I did not use I&M's estimate for property taxes. Pursuant to 50 IAC § 4.2-4, the tax rate on personal property ("True Tax Value" or "TTV") varies by year starting at 40%, rises to 63% in year three and declines thereafter. There is a 30% minimum TTV which would be applied in year eight and thereafter. I&M applied a constant federal tax rate of 42% and multiplied the product by 30%, instead of using 40% for the first year, rising to 63% in the third year, and decreasing to 30% by year eight.[40] In addition, I&M did not reflect increased property taxes on land, which will go into effect approximately one year after the solar facility is built. Nor did it take into account the use changes from agriculture.[41] I verified the timing and methods of calculations with staff at the Indiana Department of Local Government Finance. I&M initially refused to verify the first year cost of energy number[42] and replied in a subsequent

[37] Confidential Workpaper JEH-1.
[38] 50 IAC 4.2-4.
[39] Confidential Workpaper JEH-1.
[40] Attachment JEH-2, response to OUCC DR 5-14.
[41] Attachment JEH-2, response to OUCC DR 3-27.
[42] Attachment JEH-2, Responses to OUCC DR 1-37.

data request that, by Mr. Auer's calculations, the cost of energy in the first year of the project would be $100.80/MWh.[43] Mr. Auer's calculation correlates well with my estimate in Table JEH-2 where I account for the property tax timing error. However, this conflicts with I&M's response to OUCC DR 1-29 that lists the first year cost of electricity as $67.16/MWh.[44] Regardless, my calculations indicate customers will pay more than the LCOE for the first 11 years and less thereafter. All of this analysis assumes the cost recovery for the project occurs in a SPR proceeding. If, as I&M requests, the Project is placed into base rates, ratepayers will receive none of these tax benefits.

IV. PROJECT COSTS

Q: Is the cost of the SBSP competitive with the market?

A: No. By any metric, the SBSP is expected to cost significantly more than most other alternatives. The cost is estimated to be $1,838.54/kW compared to the average cost of $1,151.01/kW for utility-scale build-transfer solar projects reported this past year by NIPSCO in response to its Request for Proposal ("RFP").[45] Similarly, the average flat-priced PPA for solar reported by NIPSCO was $35.67/MWh, compared to an LCOE of $90/MWh for the SBSP. Other reference points for the LCOE of utility-scale solar published by the U.S. Energy Information Administration[46] and Lazard show cost ranges of $37.6 – 45.7/MWh and $36 –

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[43] Attachment JEH-2, Responses to OUCC DR 3-28 and 3-29.
[44] Attachment JEH-2, response to OUCC DR 1-29
[45] Attachment JEH-5.
[46] Attachment JEH-5, "Levelized Cost and Levelized Avoided Cost of New generation Resources in the *Annual Energy Outlook 2019, February, 2019*," Tables 1a and 1b.

44/MWh, respectively.[47] I&M's estimate assumes it can take advantage of the federal tax incentives in a timely manner -- something it has yet to do for earlier solar projects. A significant portion of the high capital investment is due to the excessive land cost and the 4.5-mile line to I&M's substation. Similar projects of this type would be located in more rural areas and closer to the receiving substation. I&M set out the site selection criteria as "…highly visible from public roads."[48] This deciding factor for site selection was a reason for not considering other sites. Apparently, I&M felt a close proximity to the Notre Dame campus was a top priority as well. I&M's response to OUCC DR 3-11, Attachment 1 (provided in OUCC Witness Aguilar's testimony) is a map showing a targeted zone of one and two mile radiuses from the center of campus. Unfortunately, this targeting results in high-cost urban and suburban properties for which all I&M customers will pay. It is the OUCC recommendation the cost of the land purchased for this project not be included in the project cost recovery due to the image building nature of the cost. In addition, the project appears to be designed to have a lower capacity factor than similar projects. It is common, due to lower cost panel prices, to add more panels such that the direct current ("DC") capacity of the panels is up to 35% more than the inverter alternating current ("AC") nameplate rating. This increases the capacity factor of the project. The SBSP is estimated to have a capacity factor of 20.6% compared to similar projects at this latitude of 23-24%. The SBSP will have a DC output of 25 MW, which is only 20% more than the 20 MW nameplate capacity.[49]

[47] Attachment JEH- 5, "Lazard's Levelized Cost of Energy Analysis Version 12.0," page 2.
[48] DeRuntz Direct, page 7, line 12.
[49] Attachment JEH-2, Response to OUCC DR 1-31.

It does not appear I&M optimized the SBSP for energy output in view of the high fixed costs; therefore, the LCOE will be higher. The optimization involves balancing the cost of additional panels to increase kWh production against the value of the incremental production. A review of the RFP for the project does not list capacity factor or kWh production as one of the performance criteria.[50]

Q: How will I&M treat the RECs generated at the SBSP?

A: It is not clear from the testimony and discovery responses. I&M initially inferred that 40% of the RECs generated by the SBSP would be retired pursuant to an agreement with the University of Notre Dame.[51] However, I&M also stated the production of the SBSP is merely a metric used to calculate how many PJM Class 1 RECs will be retired.[52] Rather, Notre Dame will not receive RECs directly generated by the SBSP, but will instead receive RECs from I&M's general portfolio of RECs.[53] I&M has a large inventory of PJM Class 1 RECs generated by its wind and other solar projects.[54] Later in response to the Commission's Docket Entry Dated July 3, 2019, I&M produced an unsigned draft of a purchase and sale agreement for renewable energy credits between I&M and Notre Dame that stated

[50] Attachment JEH-2, Response to CAC DR 1-02.
[51] Thomas Direct, page 13, lines 10-12.
[52] Direct Testimony of Brent E. Auer, page 12, lines 1-7.
[53] *Id.*
[54] Attachment JEH-2, confidential response to OUCC DR 1-40.

the RECs would be transferred to Notre Dame from the SBSP unless there was a failure of the SBSP to generate.[55]

Q: How does I&M manage its RECs portfolio?

A: It appears I&M retires some RECs pursuant to customer participation in its IM Green program. However, the majority of RECs in the portfolio appear to be held until they expire. The current amount of solar and wind RECs in the I&M portfolio is approximately [redacted] and worth approximately [redacted]. Despite I&M Witness Thomas' inference that RECs may be monetized to reduce ratepayer costs,[56] I&M has not done so in recent years.[57] I&M stated in response to OUCC DR 3-7 "By not monetizing (selling) the unsubscribed RECs, I&M and its customers are able to claim that certain amounts of generation and energy consumption are carbon free." In view of the 6% of the power customers receive that is presumably composed of renewable energy, it is the OUCC's opinion customers could benefit more directly by the sale of excess RECs into the market and thus lower costs by millions of dollars per year. However, I&M will not commit to selling remaining RECs into the market to ease some of the financial burden to ratepayers.[58] Due to the substantial monetary benefit of selling excess RECs, as discussed below, the OUCC recommends the sale of excess RECs from the SBSP. The OUCC further recommends I&M credit ratepayers with any profits from the sale of excess RECs from the SBSP through a SPR or the Fuel Clause Adjustment

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[55] IURC DE 1-1 Attachment 1. Confidential response to OUCC DR 1-10.
[56] Thomas Direct, page 16, lines 2-4.
[57] Attachment JEH-2, confidential response to OUCC DR 3-30.
[58] Attachment JEH-2, Response to OUCC DR 3-8.

("FAC") rider. The OUCC will address the issue of monetizing RECs in I&M's pending rate case, Cause No. 45235.

Q: Are I&M ratepayers subsidizing Notre Dame's REC purchases?

A: It is not clear. According to I&M Witness Auer, the RECs Notre Dame is purchasing will come from I&M's portfolio and not necessarily from the SBSP.[59] However, the unsigned Purchase and Sale Agreement for Renewable Energy Credits Transaction Confirmation is very specific that the RECs are <u>solar</u> RECs ("SRECs") from the SBSP.[60] I&M's existing Green Power Rider uses SRECs priced at the Pennsylvania Solar REC index, currently $19.80/MWh. The Renewable Energy Option price is $35.30/MWh. I&M could sell the SRECs from its solar facilities and the SBSP at far more than the estimated $6/MWh price to Notre Dame. To the extent other customers are realizing $6/MWh instead of at least $19.80/MWh, other customers are being shorted $13.80/SREC, or approximately $200,000/year. Unfortunately, I&M plans to replicate this subsidization according to I&M Witness Thomas.[61]

Q: Mr. Thomas stated Notre Dame will receive naming rights to the SBSP.[62] How might this affect the RECs generated by the SBSP?

A: It appears that this action could invalidate the remaining 60% of RECs generated by the SBSP. Naming the facility as an extension of Notre Dame implies Notre Dame is the recipient of all environmental attributes, and perhaps power generated from the facility, unless there is a clear expression this is not the case. This

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59 Auer Direct, page 12, lines 3-5.
60 Attachment JEH-2, confidential response to OUCC DR 1-10, page 1.
61 Thomas Direct, page 7, lines 6-9.
62 Thomas Direct, page 13, lines 9-10.

arrangement could be considered a violation pursuant to the Federal Trade Commission's Green Guides.[63] The OUCC could not verify what "naming rights" means since this reference appears only in Mr. Thomas' testimony and press releases but not in the unsigned Purchase and Sale Agreement for Renewable Energy Credits Transaction Confirmation. Mr. Auer also notes Notre Dame will also pay a 20% administrative fee to cover "…customer specific aspects of the arrangement."[64]To the extent these administrative costs are greater than the fees collected from Notre Dame, I&M customers should not be required to pay the excess costs.

V. PUBLIC INTEREST

Q: Is the construction of the SBSP in the public's interest as currently proposed?

A: No, not as proposed. While the OUCC supports renewable generation, I&M should develop it in a cost-effective manner. The SBSP clearly falls short of satisfying reasonable criteria for being in the public interest for many reasons already discussed, but primarily due to its exorbitant cost. On its face, the SBSP appears to be an expensive public relations and image-building project for I&M and the University of Notre Dame. Ratepayers will not likely receive any significant environmental benefits but will foot the bill for the increased cost of the land investment and the project's construction and maintenance

[63]https://www ftc.gov/policy/federal-register-notices/guides-use-environmental-marketing-claims-green-guides

[64] Auer Direct, page 12, lines 6-7.

VI. RECOMMENDATIONS

Q: Please summarize the OUCC's recommendations.

A: The OUCC recommends the Commission deny the request for approval to construct the SBSP and for related ratemaking and accounting treatment. However, should the Commission approve I&M's proposal, the OUCC recommends the following modifications:

1. Disallow recovery of the cost of land purchased for this project. The premium cost of the land is for image-building reasons and I&M customers should not have to pay this expense;

2. Monetizing all unused RECs in the market and credit proceeds to the SPR or FAC;

3. Do not allow I&M expenditures for "customer specifics of the arrangement"[65] in excess of the 20% administrative fee paid by Notre Dame to be included in the SPR-like tracker.[66] These activities are for the primary benefit of Notre Dame and should not be borne by all other ratepayers.

4. Cap cumulative O&M expenses at the estimated amount of $15/kW/year, escalated at 2% annually. This will reduce the exposure of I&M ratepayers to O&M risk, as previously discussed, putting the risks on par with a PPA; and

5. Set a market competitive fixed price per kWh recovered through an SPR-like tracker such that ratepayers receive the time value of the federal tax incentives, regardless of AEP's tax appetite. This price should be no higher than a flat $50/MWh over the life of the project. This is the value I&M used in modeling solar in its most recent IRP and should be lower to comport with the declining price of solar in the market.

Q: Does this conclude your testimony?

A: Yes.

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[65] Auer Direct, page 12, lines 6-7.
[66] Auer Direct, page 3.

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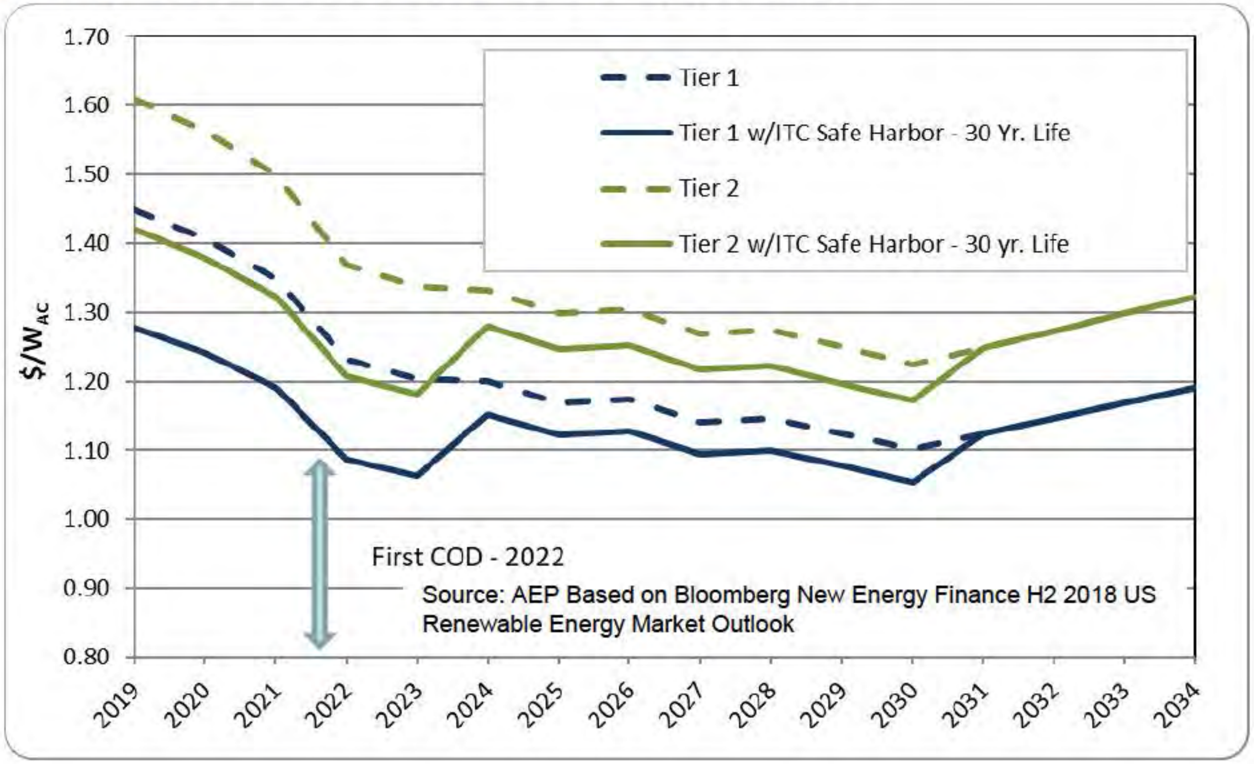
An AEP Company

Updated IRP Inputs and Assumptions

Updated Solar Resources for the IRP



- Two Tranches Available as a Modeling Constraint – Tier 1 and Tier 2 Pricing with Normalized ITC impact
- 300MW of Solar Available per year; 150MW at Tier 1 & 150MW at Tier 2, with a maximum build over the planning period of 1,700MW
- Expected Capacity Factor ~24.4%, from Single Axis Tracking system
- For a 2022 Commercial Operation Date ~LCOE $50 to $54/MWh, a slight decline since 3rd Stakeholder Meeting
- Solar capacity credit increased to 51.1% from 38% based on PJM proposal released in February

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-02

REQUEST

Mr. Toby Thomas; Referencing page 4, Figure TLT-1:
What are the energy generation amounts and percentages by the same fuel sources in the I&M test year?

RESPONSE

Please see the table below, for I&M's 2020 test year end energy generation amounts and percentages, by fuel source. Unless otherwise noted, the forecasted generation represents total plant.

I&M Test Year End Generation Resource Mix*

Nuclear	Solar	Hydro	Wind	Coal
56.8%	0.1%	0.4%	5.4%	37.3%
17,818 GWH	24 GWH	111 GWH	1,701 GWH	11,706 GWH
Cook Unit 1 Cook Unit 2	Four Solar Plants	Six Run-of-River Hydroelectric Dams	Wildcat Headwaters Fowler Ridge	Rockport 1 Rockport 2 OVEC**

* This table does not include the 20 MW_{AC} South Bend Solar Project.
**Includes I&M's share of the Clifty Creek and Kyger Creek generation.

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-04

REQUEST

Mr. Toby Thomas; Referencing page 11, lines 11-13:

Please provide the listing of I&M's renewable energy resources, capacity (AC), and whether they are owned or contracted under a PPA. If a PPA, please list the expiration date.

RESPONSE

Please see the table below, for I&M's 2020 test year end renewable energy resource capacity.

I&M 2020 Test Year Renewable Energy Resource Capacity

Solar	**Hydro**	**Wind**	
Owned	Owned	PPA	
14.7 MW*	22.4 MW	450 MW	Expiration Date
Watervliet – 4.6 Olive – 5.0 Deer Creek – 2.5 Twin Branch – 2.6	Berrien Springs – 7.2 Buchanan – 4.1 Constantine – 1.2 Elkhart – 3.4 Mottville – 1.7 Twin Branch – 4.8	Wildcat – 100 Headwaters – 200 Fowler Ridge I – 100 Fowler Ridge II – 50	01/15/33 12/22/34 01/31/29 12/17/29

*Excludes the 20 MW_{AC} South Bend Solar Project.

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-10

REQUEST

Mr. Toby Thomas; Referencing page 13, lines 7-10:

Please provide the agreement with Notre Dame.

RESPONSE

The agreement with Notre Dame, while agreed to in principle, remains under negotiations between the Parties and is not available at this time. Once the agreement is fully executed, I&M will supplement this response subject to confidentiality considerations.

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-26

REQUEST

Mr. Joseph DeRuntz; Referencing page 11, lines 12-15:

What is the accuracy of a Class V estimate?

RESPONSE

The range of accuracy for a Class V estimate is -50%/+100%, as established in the Association for the Advancement of Cost Engineering International (AACEI) standard.

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-29

REQUEST

Mr. Joseph DeRuntz; Referencing page 13, lines 2-10:

Please provide the supporting calculations for the LCOE.

RESPONSE

See "OUCC 1-29_Attachment_1.xlsx."

30 Year Levelized Cost of Electricity ($/MWh)	$82.38
Discount Rate	7.11%
Year 1 Electricity Price ($/MWh)	$67.16
Project Life (Yrs)	30
Escalation Rate	2.0%

	YEAR	Electricity Price ($/MWh)
1	2020	$67.16
2	2021	$68.51
3	2022	$69.88
4	2023	$71.28
5	2024	$72.70
6	2025	$74.16
7	2026	$75.64
8	2027	$77.15
9	2028	$78.69
10	2029	$80.27
11	2030	$81.87
12	2031	$83.51
13	2032	$85.18
14	2033	$86.89
15	2034	$88.62
16	2035	$90.40
17	2036	$92.20
18	2037	$94.05
19	2038	$95.93
20	2039	$97.85
21	2040	$99.80
22	2041	$101.80
23	2042	$103.84
24	2043	$105.91
25	2044	$108.03
26	2045	$110.19
27	2046	$112.40
28	2047	$114.64
29	2048	$116.94
30	2049	$119.27

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-31

REQUEST

Mr. Joseph DeRuntz; Referencing page 13, lines 2-10:

What is the design output of the solar panels (dC)?

RESPONSE

The design output of the SBSP solar panels is 25 MW_{DC}.

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

DATA REQUEST NO OUCC 1-34

REQUEST

Mr. Brent Auer;

Has I&M been able to take full advantage of the ITC associated with the previous four solar projects constructed pursuant to Cause No.44511? If not, please explain.

RESPONSE

AEP did not have sufficient taxable income in the year of, or the years subsequent to, Cause No. 44511 to utilize the federal ITC and also could not amortize Deferred ITC related to the solar projects constructed pursuant to Cause No. 44511. However, AEP presently expects to have sufficient taxable income in the forthcoming tax years to utilize the federal ITC and also begin amortizing prior year's Deferred ITC related to the solar projects.

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 1-36

REQUEST

Mr. Brent Auer;

Referencing page 9, lines 4-5, please provide the breakdown of the components of the estimated property taxes.

RESPONSE

Please see "OUCC 1-36,_Attachment_1.xlsx."

Question 1.36

South Bend Solar Estimated Property Tax Calculation:

12,968,764	Est TY2021 Federal Tax Basis of Personal Property
30%	Minimum Value of Property in Service
2.1025%	Local Tax Rate
1.00%	Est. Depreciation - Year 1
80,982	TY2021 Taxes Paid - Personal Property
319,000	Est. Real Estate Assessment TY2021
2.1025%	Local Tax Rate
6,707	TY2021 Taxes Paid - Real Property
87,689	TY2021 Total Taxes Paid

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-37

REQUEST

Mr. Brent Auer;

Referencing BEA-1, it appears the first year cost of energy is $3,708,000 (Line 13) divided by 36,787 MWh (DeRuntz, page 13, line 8) equal $100.80/MWh. Is this correct? If not, please provide I&M's calculation of the first year cost of energy.

RESPONSE

The question is ambiguous as to the intent of the calculation. For rate making purposes, rates will be set based upon actual plant in-service either in I&M's current base case or within the proposed Solar Power Rider closer to the time the assets are placed in service. Further, simply dividing the revenue requirement by the forecasted energy produced is not a good indicator of the cost of energy. A levelized cost of energy, as provided in the response to OUCC DR-1 Q 1.28, provides a better mechanism for calculating cost of energy. As noted in I&M's response to Q1.29, the levelized cost of energy over the life of the project is $82.38/MWh.

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DATA REQUEST SET NO. OUCC DR 1
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 1-40

REQUEST

Mr. Brent Auer; Referencing page 12, lines 4-5:

What is I&M's current inventory of New Jersey Class 1 Renewable Energy Certificates broken down by source and vintage?

RESPONSE

I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. In addition, I&M states please see "OUCC 1-40,_Confidential_Attachment_1.xlsx."

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-08

REQUEST

Will I&M commit to monetizing the unused RECs for the benefit of ratepayers?

RESPONSE

I&M disagrees with the premise assumed in the question that monetizing unused RECs would benefit customers. As explained in response to DR 3-7, not monetizing RECs also benefits customers. As previously indicated above and in Company witness Thomas' testimony (pp. 15-16), I&M may occasionally monetize unsubscribed RECs based upon then current or expected market conditions.

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DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-17

REQUEST

Mr. Brent Auer
Did AEP currently have sufficient tax appetite to take advantage of the federal ITC if the project had been completed in 2018?

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks an analysis, compilation, study or calculation that I&M has not performed and to which I&M objects to performing. I&M further objects to the request on the grounds and to the extent the request calls for speculation. Subject to and without waiver of the foregoing objections, I&M provides the following response. AEP's 2018 federal income tax return has yet to be filed and will not be filed until later in 2019. Under the assumption the project had been completed in 2018, the estimated results for 2018 related to prior year federal solar ITC indicate that AEP will not utilize the federal ITC. However, AEP will know if sufficient taxable income exists to utilize any federal ITC once the 2018 return is filed in 2019.

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DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-18

REQUEST

Did AEP currently have sufficient tax appetite to take advantage of the federal ITC if the project had been completed in 2019?

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks an analysis, compilation, study or calculation that I&M has not performed and to which I&M objects to performing. I&M further objects to the request on the grounds and to the extent the request calls for speculation. Subject to and without waiver of the foregoing objections, I&M provides the following response. AEP, parent of I&M, presently expects to have sufficient taxable income in 2019 to begin amortizing prior year's Deferred ITC related to solar projects. Provided that the project would have been completed in 2019, AEP would expect to utilize the federal ITC, provided sufficient taxable income existed in 2019.

INDIANA MICHIGAN POWER COMPANY
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DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-19

REQUEST

Will AEP currently have sufficient tax appetite to take advantage of the federal ITC if the project is completed in 2020?

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks an analysis, compilation, study or calculation that I&M has not performed and to which I&M objects to performing. I&M further objects to the request on the grounds and to the extent the request calls for speculation. Subject to and without waiver of the foregoing objections, I&M provides the following response. AEP, parent of I&M, presently expects to have sufficient taxable income in 2020 to begin amortizing prior year's Deferred ITC related to solar projects. Provided that the project would be completed in 2020, AEP would expect to utilize the federal ITC, provided sufficient taxable income exists in 2020.

INDIANA MICHIGAN POWER COMPANY
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DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-22

REQUEST

As a follow-up to I&M's answer to OUCC DR 1-21, I&M states: "the Project also has value in economic development, customer education, and can be a source of pride for the South Bend and the Michiana region..."

a. Please provide any and all documentation I&M relied upon to determine that these characteristics provide a value.
b. What is the monetary amount assigned to this claimed "value"?
c. Does I&M have any documentation to show I&M customers have requested this type of project in this area? If yes, please provide the documentation.

RESPONSE

I&M objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent the request seeks "any and all documentation". I&M further objects to the request on the grounds and to the extent the request seeks an analysis, compilation, calculation or study that I&M has not performed and to which I&M objects to performing. Subject to and without waiver of the foregoing objections, I&M provides the following response.

a. Over the past few years, I&M has been engaged in many different conversations with site selectors, companies, customers, economic development organizations and industry groups on the value of renewables and the growing trend of sustainability commitments from many different companies. According to the Corporate Renewable Energy Buyers' Principles, "As of 2017, 63% of the Fortune 100 had set targets to reduce greenhouse gas emissions and buy clean energy." (buyersprinciples.org.)

The US EPA supports I&M's perspective relative to the value of renewable energy. Under the benefits section of the US EPA's Green Power Partnership program (epa.gov/greenpower/benefits-using-green-power) it states the following benefits for organizational users (i.e. customers participating in green energy):

- Potential to serve as a brand differentiator
- Generate customer, investor, or stakeholder loyalty and employee pride
- Create positive publicity and enhance your organization's public image
- Demonstrate civic leadership

The SBSP provides the opportunity for the Michiana area to bring these benefits to existing businesses in the area as well as attract new businesses.

The economic development benefit of a renewable energy project has previously been recognized by the Commission. For example, in March 2019, the Commission stated as follows in its decision in *Southern Indiana Gas & Electric*, Cause No. 45086 (IURC 3/20/2019) (pp. 24-25, 26):

> In addition to the foregoing statutory provisions, we previously have recognized the importance of fuel diversity generally, with respect to generation portfolios, and

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DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

recognized the benefits of local renewable solar resources, in particular. For example, in approving a long-term purchase of power by Duke Energy Indiana from a wind provider, we stated:

> Not only does the environment benefit from such emissions free electric generation but also Indiana benefits through the development of another "home grown" energy resource. The price volatility of foreign energy and carbon fuels and the historically increasing costs and stringency of environmental emissions compliance make the potential Indiana savings from reasonably-priced Indiana renewable energy sources more economically beneficial than ever before. In addition, as the record substantiates here, this renewable energy project offers the traditional economic benefits of local Indiana business investment, revenue generation, and job creation.

Verified Petition of PSI Energy, Inc. d/b/a Duke Energy Indiana, Inc.for Approval of a Renewable Wind Energy Project Purchased Power Agreement, Cause No. 43097 (IURC; Dec. 6, 2006) at 16-17.

* * *

In addition to the benefits of fuel diversification, Petitioner presented substantial evidence that renewable resources are beneficial in efforts to retain and attract industrial and commercial customers seeking to meet renewable energy goals .. Petitioner presented evidence that within its service territory alone, approximately twenty corporations have publicly created sustainability goals and/or support efforts taken by Petitioner to construct the Solar Project. Petitioner has had discussions with Toyota regarding Toyota potentially purchasing energy produced by the Solar Project and has entered into a letter of intent with AstraZeneca to enter into a contract for AstraZeneca to purchase power generated by the Solar Project. Petitioner also has had site selectors inquire as part of their RPI process whether the utility has solar assets and is willing to allow a prospective customer to enter into an agreement to purchase renewable energy generated by those assets. Petitioner's residential customers also have indicated that they want Petitioner to add renewable resources to its portfolio.

b. No monetary value has been assigned. The ability to have a visible solar facility in the area will provide a significant benefit to economic development efforts in the region, however it is one of a number of different factors that ultimately determine the location of the new companies to the region.

c. Yes. As a part of normal business and customer service, I&M has had dialogue with a number of customers in the Michiana area that have inquired about renewables, sustainability, and future plans around solar. I&M provides the following as examples of the types of input I&M has received. At the South Bend field hearing conducted in this proceeding on July 11, 2019, several speakers voiced an interest in additional renewable energy, including local clean energy projects. As part of I&M's 2018-2019 IRP stakeholder process, I&M received many comments from South Bend residents requesting I&M invest in renewable energy. Please see "OUCC DR 3-22c Customer Requests.pdf" for a sampling of requests received from residents in South Bend, Indiana requesting renewable projects in the South Bend area. In addition, in I&M's last rate case (Cause No. 44967), South Bend Witness Therese Dorau encouraged I&M to invest in "Indiana-based renewable energy generation". See Dorau direct testimony, pages 9-10.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-27

REQUEST

As a follow-up to I&M's answer to OUCC DR 1-36, in what year does I&M expect the value of the land (shown in the response to be $319,000 TY2021) to be changed to the market value of approximately $5.2 million?

RESPONSE

I&M objects to the request on the grounds and to the extent the request calls for speculation. Subject to and without waiver of the foregoing objection, I&M provides the following response. It is very difficult to predict future real property assessed values. I&M's experience is that assessed property values are quite variable in terms of timing and assessed amounts. At this time, I&M has no information as to if/when the assessed value will change and by how much.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-28

REQUEST

As a follow-up to I&M's answer to OUCC DR 1-37, please answer the original data request: "please provide I&M's calculation of the first year cost of energy."

RESPONSE

The year 1 cost of energy for the project is $100.80/MWh. As noted in I&M's response to OUCC DR 1-37, the question was ambiguous as to the intent of the calculation. For rate making purposes, rates will be determined based upon actual plant in-service costs. Further, it is important to note that the revenue requirement, and subsequent cost of energy, will decline over time as a function of the declining book value of the project over time.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-29

REQUEST

As a follow-up to I&M's answer to OUCC DR 1-37, does I&M agree that if cost recovery were granted as I&M requests through a Rider SPR, the first full year of costs is what ratepayers will be charged? If not, please explain.

RESPONSE

Attachment BEA-1 in Company witness Auer's testimony provides an estimate of what the annual cost will be in the first full year of operation of the facility. Actual cost and timing of the project will ultimately determine the first full year of costs to be recovered through the Rider SPR.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-30

REQUEST

What are the monthly beginning and ending balances in the REC inventory, including any consumption, retirement, or sales, from January 1, 2016 through the present?

RESPONSE

I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. In addition, I&M states: please see "OUCC 3-30, Confidential Attachment 1.xslx." It is important to note that the inventory levels for 2019 are total company. The process for allocating RECs among the jurisdictions is done annually, so the allocation of RECs generated in 2019 will not occur until early 2020.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC 3-31

REQUEST

I&M stated it modeled the LCOE of solar resources in its IRP at a cost of $50 -54/MWh (Slide 32, IRP Stakeholder Workshop, May 23, 2019). The LCOE of the SBSP is not within this range.

a. Does this change Mr. Thomas' answer to the question on page 9, line 14 of his testimony in regard to price used to model solar in the IRP?
b. Did I&M run the IRP model with the LCOE of the SBSP?
c. Is I&M willing to rerun the IRP model with the LCOE of the SBSP to ascertain if the model selects this resource at the proposed cost?
d. Is the SBSP the only project able to meet the 20 MWs of solar identified in the IRP? If yes, please explain.

RESPONSE

I&M objects to the request on the grounds and to the extent it is vague and ambiguous, particularly with respect to the references to "the IRP". In support of this objection, I&M notes that the referenced portion of Mr. Thomas' testimony was addressed to both the 2015 IRP and the modeling conducted in support of the 2018-2019 IRP.

a. No, the 2015 IRP solar cost estimates are shown on page 106 of the 2015 IRP and in 2020 the cost is approximately $2,000/kW which compares to the estimated cost of the SBSP of $1,838/kW with a 2020 in-service date. Further, the 2015 IRP Preferred Plan identified 20MW of solar resources in 2020, which also aligns with the SBSP capacity size.

Mr. Thomas' testimony (p. 10) also explained "At the time of this filing, I&M's proposed Preferred Portfolio Resource plan for the 2019 IRP is reasonably expected to include additional solar resources beginning in 2020 that will exceed the amounts identified in the 2015 IRP." Since the filing of this testimony the 2018-19 IRP has been filed with the IURC. The 2018-19 IRP includes the solar already in service as well the additional solar in 2020 identified in the 2015 IRP.

In other words, within the 2018-19 IRP, the incremental solar resources modeled are assumed to be available in 2022, due to the time it takes to be identified, permitted, constructed and approved. The 2018-19 IRP included 64MW of solar resources in the "going-in" position, 20MW, 24MW and 20MW (nameplate) in 2021, 2022 and 2023, respectively. This implies an in-service date at the end of year of the previous year of the date shown. These resources were included because the Company is actively moving forward to develop these resources, subject to further project due diligence and regulatory approval. The Preferred Plan included in the 2018-19 IRP optimized 150MW (nameplate) solar in both 2022 and 2023.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 3
IURC CAUSE NO. 45245

b. No, for the 2018-19 IRP the Company did not utilize the LCOE from the SBSP in its IRP modeling as described in the response to part a. The IRP modeling process is not designed to model or provide guidance regarding specific projects. The purpose of the IRP modeling process is to develop a long term portfolio of resources to meet customer needs.

c. No, the Company has developed the SBSP project based on the 2015 IRP and customer requests to add solar resources. The 2018-19 IRP considered incremental or new solar resources and the cost identified in the 2018-19 IRP reflects the estimated cost of new solar to be available in 2022.

d. No, there are almost limitless combinations of resource sizes and locations to meet any specific resource need indicated in the IRP. However, as indicated in Company witness DeRuntz's testimony (p. 7, lines 11-14), specific criteria were used to select the site location. Further, this particular location provides I&M the ability to offer customers the opportunity to participate in solar projects that are visible in the local community, encourage economic development, and create partnerships with customers (i.e. Notre Dame) committed to sustainable energy as indicated in Company witness Thomas' testimony (p. 12, lines 20-22 and p. 13, lines 1-2).

INDIANA MICHIGAN POWER COMPANY
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DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC DR 05-02

REQUEST

Please refer to the direct testimony of Toby Thomas, page 6, lines 17-19. Please provide any documentation to support the statement that "[s]ome of our communities want to differentiate themselves and include electric supply alternatives in their sustainability and climate action plans."

RESPONSE

Please see Company's response to OUCC 3-22.

Additionally the Company offers the following examples.
The City of South Bend Mayor Pete Buttigieg has committed to the Global Covenant of Mayors for Climate & Energy, a global coalition of city leaders dedicated to reducing greenhouse gas emissions, enhancing community resilience to the unavoidable impacts of climate change, and increasing access to sustainable energy. In the article below, Mayor Buttigieg states, "We joined the Covenant because we are serious about ensuring South Bend is a healthy, prosperous place for the next several generations, and because we want South Bend to contribute to the global effort to protect the climate." Source: https://southbendin.gov/2018/04/25/city-joins-global-covenant-of-mayors-for-climate-energy/

Consistent with the South Bend's commitment to climate and energy, it has established a Municipal Energy Office that is focused on sustainability issues. From the City's website, it states "Communities that commit to sustainability have stronger economies, bounce back more easily after disasters, are inclusive of all types of people, and are enjoyable places to live and work. Working together towards sustainability will promote investment in our community, celebrate and preserve our local assets, and cultivate parks and open spaces." Source: https://southbendin.gov/department/public-works/sustainability/

I&M has met with representatives of the City of South Bend concerning the SBSP project and have agreed that the SBSP project is a great opportunity for I&M and the City of South Bend to work collaboratively to achieve a common goal of a sustainable energy future.

Additionally, in March 2019 a group of citizens presented 1,000 petitions asking Fort Wayne Mayor Tom Henry to sign a letter endorsing more investment in renewable energy. According to an article in the Fort Wayne Journal Gazette,

the petitions were aimed to urge I&M to include more energy from renewable sources such as solar and wind. Members of the group that presented the petition pointed out that South Bend Mayor Pete Buttigieg and Muncie Mayor Dennis Tyler had signed on to increase the renewable energy in I&M's generation portfolio.
Source: http://www.journalgazette.net/news/local/20190320/mayor-pushed-to-ask-im-for-renewable-energy

The SBSP project is consistent with I&M's plans to continue to transition its generation fleet to more diverse energy resources and to support I&M's local communities and customers that value a sustainable energy future.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC DR 05-03

REQUEST

Please refer to the direct testimony of Toby Thomas, page 12, lines 5-16.
a. Please provide any documentation to support the statement that "[m]ore and more companies that are considering locating in I&M's service area are asking about the availability of renewable resources to meet their energy needs."
b. Please provide any documentation supporting the statement that a "key component to achieving that recognition is the ability to site a project in close proximity to the interested customers."
c. Please provide any documentation supporting the statement that "[b]eing able to answer the question positively and meaningfully makes I&M more attractive to these prospective customers..."

RESPONSE

For all parts please see Company's response to OUCC 3-22.

The Company also offers the following additional information:
a. In 2019, I&M's Economic Development team has been in contact with no fewer than five confidential companies considering placing a new facility in the I&M service area that have requested I&M to include a renewable generation solution as part of its proposal to provide electric service.

b. and c. Seventy-eight percent of S&P 500 companies issue annual sustainability reports with environmental performance metrics and that rate for the world's largest companies is as high as ninety-three percent. Of those companies that issued sustainability reports, ninety-five percent offer environmental performance metrics and sixty-seven percent set quantified and time-bound environmental goals. Lukomnik, Jon. "State of Integrated and Sustainability Reporting 2018." *Harvard Law School Forum on Corporate Governance and Financial Regulation.* https://corpgov.law.harvard.edu/2018/12/03/state-of-integrated-and-sustainability-reporting-2018/ December 3, 2018

These statistics are consistent with AEP and I&M's recent experience that companies are increasingly considering access to renewable energy that will support their environmental goals as a significant consideration in the where they choose to locate their facilities. I&M, AEP, Notre Dame, and local economic development partners will be able to use the SBSP project as a visible sign of Michiana's commitment to renewable energy and sustainability which will help in recruiting companies that value sustainability to the Michiana region.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC DR 05-04

REQUEST

Please refer to the direct testimony of Toby Thomas, page 12, lines 17-19. Please provide any documentation to support the statement that "[o]ffering more renewable resources also is of interest to existing customers that have sustainability goals to achieve. Many customers these days are seeking to meet their energy needs with a greater percentage of renewable energy."

RESPONSE

Please see Company's response to OUCC 3-22.

I&M would offer the following additional examples of customers in our service territory that have sustainability goals to achieve, however it should be noted that it is not possible to identify all customers due to the significant number of companies that have similar goals.

Target plans to power 100% of its US operations with renewable generation by 2030, including stores, distribution centers and offices (7 stores in I&M service area). Source: https://corporate.target.com/article/2019/06/renewable-electricity

Walmart has a goal to be supplied by 100% renewable energy (21 stores in I&M service area) including various types of renewable energy sources - most notably solar and wind - as well as several types of arrangements with energy providers, such as utilities and proprietary installations. Scaling renewables drive the production of procurement of 7 billion kilowatt hours (kWh) of renewable energy globally by December 31, 2020. Source: https://corporate.walmart.com/media-library/document/walmarts-approach-to-renewable-energy

Grupo Bimbo, the largest baking company in the world, announced its commitment to use 100 percent renewable energy for its electricity throughout the world by 2025 (also known as Allen Foods, 3 facilities in I&M service area). Source: https://grupobimbo.com/en/press-room/release/grupo-bimbo-joins-re100-and-commits-being-100-percent-renewable-2025

Fifth Third Bank is the first publicly traded company worldwide - and first U.S. bank and Fortune 500 company, to adopt a goal to purchase 100 percent renewable energy , a fact confirmed by the independent RE100 Global Energy Initiative (10 locations in the I&M service area). Source: https://www.53.com/content/fifth-third/en/personal-banking/about/in-the-community/sustainability.html

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DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO. 45245

Ball State University is signatory to the Climate Leadership Commitment, the American College and University Presidents Climate Commitment, and the Talloires Declaration. They are also a charter school member of the Sustainability Tracking Assessment and Rating System. Ball State has integrated sustainability into their strategic plans for the University and is working directly with I&M on a number of areas to achieve their sustainability goals. Source: https://www.bsu.edu/academics/centersandinstitutes/cote/sustainability

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO. 45245

DATA REQUEST NO OUCC DR 05-13

REQUEST

Referencing the Deer Creek solar facility:
a. Confirm the Deer Creek solar facility has not produced power since July, 2018.
b. Is the Deer Creek solar facility producing power at this time? If not, what is I&M's estimate when production will recommence?
c. What was the cause of the extended outage?
d. What is I&M's solution to repairs to the Deer Creek solar facility?
e. When did I&M begin operating and maintaining the Deer Creek solar facility with its own employees?

RESPONSE

a. Confirmed. The Deer Creek solar facility has been in a forced outage, since July of 2018.
b. The Deer Creek solar facility is not currently producing power. Its forced outage is scheduled to end and make the facility available for operation in July, 2019.
c.-d. The cause of the outage was transformer failure. The type of transformer installed at Deer Creek was different than that used at the remaining three Pilot Program sites, which were all made by the same manufacturer and have provided reliable performance. As a result of the outage, the original transformers at Deer Creek have been replaced with the same type used at the remaining three Pilot Program sites, and are excluded from the qualified equipment list for the proposed SBSP.
e. March, 2018.

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INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 05
IURC CAUSE NO., 45245

DATA REQUEST NO OUCC DR 05-14

REQUEST

As a follow up to OUCC DR1.36, please provide the calculation that supports the $12,968,764 as the Federal Tax Basis for 2021.
a. Is this amount inclusive of the solar ITC?
b. Why is this number multiplied by 30%?

RESPONSE

The calculation that supports the $12,968,764 is as follows: $30,878,010 x 42% = $12,968,764. The $30,878,010 figure is from the estimate of the original plant-in-service cost. Indiana property tax is based on Federal Income Tax Basis. The Company used 42% to estimate the Federal Income Tax Basis, using historical information on the Company's other Indiana in-service solar plants.
a. This amount is not inclusive of the solar ITC.
b. The Company multiplied the number by 30% because that is Indiana's depreciation floor. The Company files the property tax return on all of its assets. For property tax purposes, Indiana depreciation is the greater of the Company's total tax depreciation or a floor of 30% of Federal Income Tax Basis. The total tax depreciation on all of the Company's assets is below 30%.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 7
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 7-01

REQUEST

Please refer to Figure TCK-3 in the Direct Testimony of Petitioner's witness Mr. Timothy C. Kerns, page 8. Please provide individual data and information for each solar facility identified in Fig. TCK-3 in your response. To the extent that data and information is in electronic spreadsheet format, please provide the data and information in electronic spreadsheet format with formulas intact.

a) What is the monthly Net Generation (MWh) – total electric power generated by each solar facility, net of any in-plant (or in-facility) use or other drain on power delivered for station service or auxiliaries, in 2017, 2018, and 2019 Year-to-Date?

b) Please identify the outage dates and outage cause(s) of each solar facility in 2017, 2018, and 2019 Year-to-Date, if any. Please explain each outage event.

c) Please identify and explain all curtailments each solar facility experienced, if any, in 2017, 2018, and 2019 Year-to-Date.

d) What is the monthly Capacity Factor (%) – net generation as a percent of operating capacity multiplied by the number of operating hours, of each solar facility in 2017, 2018, and 2019 Year-to-Date?

e) Please provide the annual Capacity Factor (%) of each solar facility in 2017, 2018, and 2019 Year-to-Date.

f) What is the monthly total Operating & Maintenance Expense per megawatt-hour generated ($/MWh) of each solar facility in 2017, 2018, and 2019 Year-to-Date?

g) Please provide the annual Total O&M Expense per MWh ($/MWh) generated by each solar facility in 2017, 2018, and 2019 Year-to-Date.

h) Did any of the solar facilities incur additional capital and/or O&M expense related to outages? If yes, please provide and explain the amount/s and dates of such expenses for each outage event.

RESPONSE

a-g. Please see "OUCC 7-01 Attachment_1.xlsx" and "OUCC 7-01 Attachment_2.pdf." for the requested information.

h. Transformers at Deer Creek Solar failed in February and July 2018. For transformer and inverter replacement, I&M has spent the following Capital dollars:

2018 $ 382,698
2019 $ 236,659

FILED
October 10, 2018
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC., FOR: (1) AUTHORITY TO CONSTRUCT, OWN AND OPERATE A SOLAR ENERGY PROJECT AND A FINDING THAT SUCH PROJECT CONSTITUTES A CLEAN ENERGY PROJECT PURSUANT TO IND. CODE CH. 8-1-8.8; (2) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF THE SOLAR ENERGY PROJECT PURSUANT TO IND. CODE CH. 8-1-8.5; AND (3) AUTHORITY TO TIMELY RECOVER COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE PROJECT IN ACCORDANCE WITH IND. CODE § 8-1-8.5-6.5 AND IND. CODE § 8-1-8.8-11.	)	**CAUSE NO. 45086**

STIPULATION AND SETTLEMENT AGREEMENT AMONG VECTREN SOUTH, THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR AND CITIZENS ACTION COALITION OF INDIANA, INC.

This Stipulation and Settlement Agreement (the "Settlement Agreement") is entered into by and among Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenor Citizens Action Coalition of Indiana, Inc. ("CAC"). Vectren South, the OUCC and CAC are collectively referred to herein as the "Settling Parties." The Settling Parties, solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth in this Settlement Agreement represent a fair, just and reasonable resolution of all matters raised in this proceeding, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order without modification or further condition that is unacceptable to any Settling Party ("Final Order"). The Settling Parties agree that this Settlement Agreement resolves all disputes, claims and issues arising from the Commission proceeding currently pending in Cause No. 45086 as between the Settling Parties.

I. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND RELATED REQUESTS FOR RELIEF

1. **Certificate of Public Convenience and Necessity**. The Settling Parties agree the Commission should grant Vectren South a certificate of public convenience and necessity ("CPCN") pursuant to Ind. Code § 8-1-8.5-1 *et seq.*, to construct a solar energy project totaling approximately 50 megawatts of alternating current ("MWac") and approximately 64 megawatts of direct current ("MWdc") located in Spencer County, Indiana and as described with specificity in Vectren South's case-in-chief (referred to herein as the "Solar Project"). Electricity collected at the substation on the Solar Project's site will be delivered to the adjacent Hoosier Energy Rural Electric Cooperative substation which is connected to the Vectren South system. The Solar Project is in the Midcontinent Independent System Operator ("MISO") Generator Interconnection queue.

2. **Cost Estimate**. The Settling Parties agree Vectren South's construction cost estimate for the Solar Project of $76.174 million, including a contingency, exclusive of AFUDC and post-in-service carrying costs, constitutes a reasonable estimate of the construction costs for the Solar Project and should be approved by the Commission in accordance with Ind. Code § 8-1-8.5-5. This estimate will be used in determining the revenue requirement and rate per unit of production for the Solar Project, and actual costs to construct the Solar Project that exceed or fall below the estimate will not change the agreed upon revenue requirement or rate.

3. **Clean Energy Project**. The Settling Parties agree the Solar Project is a "clean energy project" as defined in Indiana Code § 8-1-8.8-3.

4. **Commencement of Construction**. The Settling Parties acknowledge time is of the essence and will use their best efforts to obtain an Order in this proceeding on or

before February 28, 2019 so construction can commence on or before April 1, 2019 to ensure the Solar Project is eligible for the full 30% Investment Tax Credit ("ITC"). As further described below, the Settling Parties have agreed upon a non-traditional ratemaking approach designed, in part, to accelerate the flow of the benefit from the ITC to customers.

II. USE OF LEVELIZED RATE

5. **Unique Nature of Ratemaking Approach**. The Settling Parties acknowledge that due to the special nature of the Solar Project, including the availability of the ITC to offset project costs, the Solar Project represents a unique opportunity to evaluate alternative approaches to traditional ratemaking not applicable to other CPCN projects. Based on that understanding, the Settling Parties have structured the ratemaking terms set forth in this Settlement Agreement to use a fixed levelized rate per kilowatt hour ("kWh") of produced energy for the life of the investment in the Solar Project. The approach is further designed to allow customers to realize the impact of the ITC more quickly than otherwise could be accomplished through traditional ratemaking.

6. **Initial Levelized Rate**. The Settling Parties agree a levelized rate of $0.05452 per kWh will initially be used to determine the amount recovered annually with respect to Vectren South's investment in the Solar Project (the "Levelized Rate"), subject to adjustment only as set forth in Paragraph 7 of this Settlement Agreement. The Levelized Rate will be incorporated in the Clean Energy Cost Adjustment ("CECA") mechanism, which the Commission approved on August 16, 2017 in Cause No. 44909 for renewable energy projects, in the manner described in Section III of this Settlement Agreement.

7. **Adjustments to Levelized Rate**. The Levelized Rate is subject to adjustment only as set forth below:

a. The Levelized Rate will be adjusted upon issuance of any final order in a future base rate proceeding to capture the impact of changes to the Company's approved return on equity ("ROE"). The Company will make an adjustment to the Levelized Rate in the first CECA proceeding filed after the issuance of the final base rate case order. In establishing the Levelized Rate, the Settling Parties agreed to an annual baseline production level described below as well as other adjustments to the cost recovery approach, reflected in workpapers that will be made available to the OUCC to review in each CECA proceeding.

b. The Levelized Rate will be adjusted if any adjustments are made to the law governing Indiana State and/or Federal Income Tax Rates that result in a change to other approved tariff rates. The Company will make a thirty (30) day filing seeking an adjustment to the Levelized Rate within sixty (60) days of the effective date of any such adjustments to the Indiana State and/or Federal Income Tax Rates. The Company will provide support for the adjustment to the Levelized Rate to the OUCC upon request, including the workpapers described above.

c. The Levelized Rate will be adjusted if any Liquidated Damages are received in accordance with the provisions of Paragraph 15.

8. **Adjustments to the CECA Recoverable Costs.** The Levelized Rate is based upon an assumed level of production (kWh) from the Solar Project on an annual basis ("Production Baseline"). The Production Baseline, set forth in the table below, shall not change over the life of the Solar Project but for conditions noted in Paragraph 15.

Year	Annual Baseline Production (kWh)
1	109,193,400
2	108,647,433
3	108,104,196
4	107,563,675
5	107,025,856
6	106,490,727
7	105,958,274
8	105,428,482
9	104,901,340
10	104,376,833

11	103,854,949
12	103,335,674
13	102,818,996
14	102,304,901
15	101,793,376
16	101,284,409
17	100,777,987
18	100,274,097
19	99,772,727
20	99,273,863
21	98,777,494
22	98,283,607
23	97,792,189
24	97,303,228
25	96,816,711
26	96,332,628
27	95,850,965
28	95,371,710
29	94,894,851
30	94,420,377
31	93,948,275
32	93,478,534
33	93,011,141
34	92,546,085
35	92,083,355

a. In the event that actual annual production from the Solar Project for a rolling three-year period is less than 90% of the Production Baseline set forth in the table above for the same rolling three-year period and such deviation is not the result of a force majeure event (e.g.and without limitation, tornado, lightning damage, fire, earth quake, acts of state or governmental action impeding performance), Vectren South shall credit the CECA in the next annual filing in the amount of the Levelized Rate multiplied by the difference between the rolling three-year period actual annual production and Production Baseline, demonstrated in the following calculation:

	Actual Production	Baseline Production
2021	100,000,000	109,193,400
2022	97,000,000	108,647,433
2023	95,000,000	108,104,196
Rolling 3-Year Average	97,333,333	108,648,343
Baseline Production Threshold (90%)		97,783,509
Actual Production Below Baseline Threshold	450,175	
Levelized Rate per kWh	$ 0.05452	
CECA Production Credit	$ 24,544	

b. In the event that actual annual production from the Solar Project for a rolling three-year period is greater than 110% of the Production Baseline set forth in the table above for the same rolling three-year period, Vectren South shall include as a recoverable cost in the CECA in the next annual filing the amount of the Levelized Rate multiplied by the difference between the rolling three-year period actual annual production and Production Baseline, demonstrated in the following calculation:

	Actual Production	Baseline Production
2021	121,000,000	109,193,400
2022	120,000,000	108,647,433
2023	119,000,000	108,104,196
Rolling 3-Year Average	120,000,000	108,648,343
Baseline Production Threshold (110%)		119,513,177
Actual Production Above Baseline Threshold		486,823
Levelized Rate per kWh		$ 0.05452
CECA Production Charge		$ 26,542

III. <u>LEVELIZED RATE RECOVERED THROUGH CECA</u>

9. **<u>CECA Components</u>**. The CECA will recover: (a) the revenue requirement associated with the three solar energy projects totaling approximately 4.3 megawatts of alternating current ("MWac") and two energy storage systems approved in Cause No. 44909 (the "Cause No. 44909 Projects"); and (b) the approved revenue requirement for the Solar

Project.

10. **<u>Derivation of Solar Project Component of CECA</u>**. The Solar Project component of the CECA will be derived by multiplying the then effective Levelized Rate per kWh, as determined in the manner set forth in Paragraphs 6 and 7, by the projected kWh produced by the Solar Project during the upcoming twelve (12) month period, grossed up for Indiana Utility Receipts Tax ("IURT") prior to allocation to the customer classes in the manner set forth in Paragraph 12. Any Production Credit or Charge as defined in Paragraph 8 will be added to this amount to determine the total CECA recoverable costs.

11. **<u>Filing of CECA and Ratemaking Treatment</u>**. The CECA will be filed annually as a subdocket in Cause No. 44909, as follows:

a. In anticipation of completion of two of the Cause No. 44909 Projects by late-2018, the initial filing of the CECA will occur on February 1, 2019 for investments made and completed through December 31, 2018, with initial CECA rates to be effective June 1, 2019;

b. On February 1, 2020, Vectren South will make the second CECA filing and propose two sets of rates for approval:

i. The first set of rates, effective June 1, 2020, will recover the revenue requirement associated with the Cause No. 44909 Projects only.

ii. The second set of rates, effective on the date of in-service of the Solar Project, will recover the revenue requirement associated with both the Cause No. 44909 Projects as well as the Solar Project.

c. Thereafter, CECA filings will occur annually on February 1st of each subsequent year.

d. All costs and recoveries associated with the Solar Project will be excluded from the actual Net Operating Income utilized for the quarterly Fuel

Adjustment Clause statutory earnings test. All costs and recoveries associated with the Solar Project will be excluded from the calculation of Vectren South's electric revenue requirement in each rate case over the life of the Solar Project. The Solar Project will be excluded from Rate Base in such future base rate cases. In addition, the Solar Project CECA revenue and expenses will be excluded from the calculation of the Revenue Requirement in such future base rate cases.

12. **Allocation of CECA to Rate Schedules**. The CECA will be allocated to the Rate Schedules in each CECA tracker filing using the Modified 4CP Allocators Factors as set forth in the approved CECA Tariff in Cause No. 44909, noted as follows:

Rate Schedule	Modified 4CP Allocation Percentage
RS	40.4145%
B	0.1225%
SGS	1.7089%
DGS/MLA	26.1523%
OSS	2.0202%
LP	28.7431%
HLF	0.8385%

The foregoing allocation factors will be updated based on the results of a 4CP Demand study to be presented in a subdocket to Cause No. 43354-MCRA21. Upon Commission approval of the updated 4CP Allocation Factors, the revised factors will be applied to the CECA in the next annual CECA filing.

13. **Energy Charge**. The CECA will be recovered through the energy charge component of all Rate Schedules.

14. **Reconciliation**. The CECA will be reconciled annually as a part of each annual CECA filing, with any over- or under-recovery collection variances returned to or recovered from customers in the Company's subsequent CECA filings. In this manner, the

Levelized Rate for the Solar Project will not change during the agreed upon recovery period, but the variances due to actual customer usage will be reconciled in the CECA.

15. **Liquidated Damages under EPC Agreement**. To the extent First Solar Electric, LLC ("First Solar") pays Vectren South Liquidated Damages as a result of the Solar Project failing to achieve the Minimum Guaranteed Capacity or Guaranteed Capacity established in the Engineering, Procurement and Construction Agreement ("EPC Agreement"), such Liquidated Damages received by Vectren South will be used as an offset to revenue requirements and the Levelized Rate will be recalculated to reflect the reduced revenue requirement. A corresponding adjustment will be made to the annual Production Baseline for the impacted year(s) to match the recalculated Levelized Rate due to decreased Solar Project production.

IV. RECs AND CUSTOMER SPECIFIC CONTRACTS

16. **Renewable Energy Credits.** Any RECs obtained by Vectren South for energy produced by the Solar Project will be utilized by Vectren South in the best interest of its customers. The Settling Parties agree this could include retaining the REC or, after consultation with the OUCC and CAC, selling some amount of RECs to specific customers or to the REC market. The net proceeds resulting from the sale of RECs, will be used as an offset to revenue requirements and returned to customers through the CECA.

17. **Customer Specific Contracts**. In the event a specific customer elects to pay directly for energy produced by the Solar Project, Vectren South agrees to sell this energy and the corresponding RECs at a rate equal to the Levelized Rate, pursuant to a specific contract or rate approved by the Commission; provided, however, that each of the Settling Parties reserves the right to recommend a different rate for Commission approval. All proceeds from contracts for the sale of energy produced by the Solar Project will be used

as an offset to the Company's revenue requirements and returned to customers through the CECA.

IV. <u>FUTURE IMPROVEMENTS TO THE SOLAR PROJECT</u>

18. In the event an investment is made at a later date to either expand the Solar Project to increase production or add technological improvements (*e.g.*, battery storage or other investments to extend the life of the Solar Project beyond that which is contemplated in this Settlement Agreement), such investments will be excluded from this Agreement and included within standard Vectren South rate base to be proposed for recovery in a future proceeding before the Commission.

V. <u>REPORTING</u>

19. **<u>Construction Reporting</u>**. Vectren South will provide quarterly reports documenting the status of the construction of the Solar Project, including actual costs incurred to date, projected costs through the end of construction of the Solar Project, and anticipated completion (in-service) date of the Solar Project. In addition, Vectren South will notify the Commission and the Settling Parties within sixty (60) days of the in-service date of the Solar Project.

20. **<u>On-going Reporting</u>**. In accordance with the Order in Cause No. 44909, Vectren South will include with its annual CECA filings, the following information relating to the Solar Project:

a. generation output of the Solar Project (with monthly detail);

b. the actual revenue requirement during the 12 months covered by the report (the "Reporting Period") based upon the Levelized Rate per kWh and the estimated Production for the 12 month period;

c. the actual production of the Solar Project compared to the Baseline Production as defined in Paragraph 8, both over a three-year rolling period;

d. the total RECs proceeds (in U.S. dollars), if any, associated with solar generation at the Solar Project; and

e. the average annual billing impact on all customer classes

VI. SETTLEMENT AGREEMENT -- SCOPE AND APPROVAL

21. Neither the making of this Settlement Agreement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. Neither the making of this Settlement Agreement, nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

22. This Settlement Agreement shall not constitute nor be cited as precedent by any person or deemed an admission by any Settling Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. This Settlement Agreement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceedings.

23. The Settling Parties' entry into this Settlement Agreement shall not be construed as a limitation on any position they may take or relief they may seek in other pending or future Commission proceedings not specifically addressed in this Settlement Agreement.

24. The undersigned have represented and agreed that they are fully authorized to execute this Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby, subject to the agreement of the Settling Parties on the provisions contained herein.

25. The communications and discussions during the negotiations and conferences have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are privileged. All prior drafts of this Settlement Agreement and any settlement proposals and counterproposals also are or relate to offers of settlement and are privileged.

26. This Settlement Agreement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party.

27. Vectren South and the OUCC shall, and the CAC may, offer supplemental testimony supporting the Commission's approval of this Settlement Agreement and will request that the Commission issue a Final Order incorporating the agreed proposed language of the Settling Parties and accepting and approving the same in accordance with its terms without any modification. Such supportive testimony will be agreed-upon by the Settling Parties and offered into evidence without objection by any Settling Party. The Settling Parties hereby waive cross-examination of each other's witnesses.

28. The Settling Parties will support this Settlement Agreement before the Commission and request that the Commission accept and approve the Settlement Agreement. This Settlement Agreement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party. If the Commission does not approve the Settlement Agreement in its entirety, the Settlement Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Settlement Agreement is withdrawn, the

Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

29. The Settling Parties will work together to prepare an agreed upon proposed order to be submitted in this Cause. The Settling Parties will request Commission acceptance and approval of this Settlement Agreement in its entirety, without any change or condition that is unacceptable to any party to this Settlement Agreement.

30. The Settling Parties also will work cooperatively on news releases or other announcements to the public about this Settlement Agreement.

31. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement Agreement in its entirety without changes or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically and exclusively implementing the provisions hereof) and shall not oppose this Settlement Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

Accepted and Agreed on this 10th day of October, 2018

[signature pages follow]

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.

Robert E. Heidorn

Robert Heidorn
P. Jason Stephenson
An Attorney for Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.

CITIZENS ACTION COALITION OF INDIANA, INC.

Jennifer Washburn

Jennifer Washburn
An Attorney for Citizens Action Coalition of Indiana, Inc.

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

Randall C. Helmen
Karol Krohn
An Attorney for the Indiana Office of Utility Consumer Counselor

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson

ORDER

This matter came before the Court on the Parties' Joint Motion to Enter the Fifth Joint Modification of Consent Decree (ECF No.). Having reviewed the submissions of all Parties and being fully advised of the positions therein, the Court hereby **GRANTS** the Joint Motion and **ORDERS** that the following Paragraphs of the Consent Decree entered in this case are modified as set forth herein.

IT IS SO ORDERED.

7-17-2019
DATE

EDMUND A. SARGUS, JR.
CHIEF UNITED STATES DISTRICT JUDGE

FIFTH JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS, On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS, Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS, pursuant to Paragraph 87 of the Consent Decree (Case No. 99-1250, Docket # 363), as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Case No. 99-1250, Docket # 371), as modified by a Second Joint Modification to Consent Decree with Order Modifying Consent Decree filed on December 28, 2010 (Case No. 99-1250, Docket # 372), as modified by a Third Joint Modification With Order Modifying Consent Decree filed on May 14, 2013 (Case No. 99-1182, Docket # 548), and as modified by an Agreed Entry Approving Fourth Joint Modification to Consent Decree filed on January 23, 2017 (Case No. 99-1182, Docket # 553), no later than December 31, 2025, the American Electric Power (AEP) Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization (FGD) system on, or Retire, Refuel, or Re-Power one Unit at the Rockport Plant, and no later than December 31, 2028, the AEP Defendants are required to install and continuously operate a FGD system on, or Retire, Refuel, or Re-Power the second Unit at the Rockport Plant.

WHEREAS, the AEP Defendants filed a Motion for Fifth Modification of Consent Decree in Case No. 99-1182 on July 21, 2017 (Case No. 99-1182, Docket # 555) and in the related cases seeking to further modify the provisions of Paragraph 87 and make other changes.

WHEREAS, the United States, the States, and Citizen Plaintiffs filed memoranda in opposition to the motion by the AEP Defendants (Case No. 99-1182, Docket # 571 and 572, and Case No. 99-1250, Docket # 405) on September 1, 2017.

WHEREAS, the Parties made additional supplemental filings and engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Fifth Joint Modification finds, that this Fifth Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq.*; and that entry of this Fifth Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Fifth Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Fifth Joint Modification in the *Federal Register*, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Fifth Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Fifth Joint Modification by this Court or challenge any provision of this Fifth Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Fifth Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Motion or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

Modify the provisions of the Consent Decree, as amended by the first four modifications, as follows:

Add a new Paragraph 5A that states:

5A. A "30-Day Rolling Average Emission Rate" for Rockport means, and shall be expressed as, lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the combined Rockport stack during a Day which is an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; second, sum the total heat input to both Rockport Units in mmBTU during the Day which was an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Days which were Operating Days for either or both Rockport Units by the total heat input during the thirty such Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Day which is an Operating Day for either or both Rockport Units. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs from both Rockport Units that occur during a period of Malfunction at either Rockport Unit shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NOx and BTU inputs from both Rockport Units that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a single Rockport Unit during any 30-Day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR at the Unit in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NOx emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) at a single unit shall be the lesser of (i) those NOx emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NOx emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time a single Rockport Unit is synchronized with a utility electric distribution system through the time that both Rockport Units cease to combust fossil fuel and the fire is out in both boilers.

Paragraph 14 is replaced in its entirety and now reads as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, Enhanced DSI, ESP or other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

Add a new Paragraph 20A that states:

20A. "Enhanced Dry Sorbent Injection" or "Enhanced DSI" means a pollution control system in which a dry sorbent is injected into the flue gas prior to the NOx and particulate matter controls in order to provide additional mixing and improved SO_2 removal as compared to Dry Sorbent Injection.

Paragraph 67 is replaced in its entirety and now reads as follows:

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit NO_X in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	Eastern System-Wide Annual Tonnage Limitations for NO_X
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016-2017	72,000 tons per year
2018-2020	62,000 tons per year
2021-2028	52,000 tons per year
2029 and each year thereafter	44,000 tons per year

Paragraph 68 is replaced in its entirety and now reads as follows:

68. No later than the dates set forth in the table below, Defendants shall install and

Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-Power such Unit:

Unit	NOx Pollution Control	Date
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-Power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-Power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-Power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River units 1-3, Tanners Creek Units 1-3 and/or Kammer Units 1-3	Retire, Retrofit, or Re-Power	December 31, 2018

Add a new Paragraph 68A that reads as follows:

68A. 30-Day Rolling Average NO_x Emission Rate at Rockport. Beginning on the thirtieth Day which is an Operating Day for either one or both Rockport Units in calendar year 2021, average

NOx emissions from the Rockport Units shall be limited to 0.090 lb/mmBTU on a 30-day Rolling Average Basis at the combined stack for the Rockport Units. Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B.

Add a new Paragraph 68B that reads as follows:

68B. Informational NOx Monitoring. During the ozone seasons (May 1 – September 30) in each of calendar years 2019 and 2020, prior to the effective date of the 30-Day Rolling Average NOx Rate at the Rockport Units in Paragraph 68A, the AEP Defendants shall provide an estimate of the 30-day rolling average NOx emissions from Rockport Unit 1, based on NOx concentrations and percent CO_2 measured at an uncertified NOx monitor in the duct from Unit 1 before the flue gases from Rockport Units 1 and 2 combine at the common stack. Hourly NOx rates shall be calculated for each hour for which valid data is available, using the following equation:

$$\text{NOx lb/mmBtu} = [(1.194 \times 10^{-7}) \times \text{NOx ppm} \times 1840 \text{ scf } CO_2 \text{ per mmBtu} \times 100]/\%\ CO_2$$

The monitor shall be calibrated daily and maintained in accordance with good engineering and maintenance practices. If valid NOx or CO_2 data is not available for any hour, that hour shall not be used in the calculation of the informational data provided to Plaintiffs, including periods of monitor downtime, calibrations, and maintenance. For informational purposes only, NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for May – June shall be reported to Plaintiffs by July 30, and NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for July – September shall be reported to Plaintiffs by October 30. Nothing in this Paragraph shall be construed to establish a Unit-specific NOx Emission Rate for Rockport Unit 1, and these interim reporting obligations are not required to be incorporated into the Title V permit for the Rockport Plant.

Paragraph 86 is replaced in its entirety and now reads as follows:

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	145,000 tons
2017	145,000 tons
2018	145,000 tons
2019-2020	113,000 tons per year
2021-2028	94,000 tons per year
2029, and each year thereafter	89,000 tons per year

Paragraph 87 is replaced in its entirety and now reads as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD, Dry Sorbent Injection, or Enhanced Dry Sorbent Injection system on each Unit identified therein, or, if indicated in the table, Cease Burning Coal, Retire,

Retrofit, Re-power, or Refuel such Unit:

Unit	SO_2 Pollution Control	Date
Amos Unit 1	FGD	February 15, 2011
Amos Unit 2	FGD	April 2, 2010
Amos Unit 3	FGD	December 31, 2009
Big Sandy Unit 2	Retrofit, Retire, Re-Power or Refuel	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the Unit

Unit	SO_2 Pollution Control	Date
		will be taken out of service no later than December 31, 2015, and will not restart until the Refueling project is completed. The refueling project must be completed by June 30, 2017.
Rockport Unit 1	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack And Retrofit, Refuel, or Re-Power, but must satisfy the provisions of Paragraphs 133 and 140	April 16, 2015 December 31, 2020 December 31, 2028
Rockport Unit 2	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack	April 16, 2015 June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3,	Retire, Retrofit, or Re-power	December 31, 2018

Unit	SO_2 Pollution Control	Date
Tanners Creek Units 1-3, and/or Kammer Units 1-3		

Paragraph 89A is replaced in its entirety and now reads as follows:

89A. Plant-Wide Annual Tonnage Limitation and 30-Day Rolling Average Emission Rate for SO_2 at Rockport. For each of the calendar years set forth in the table below, AEP Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to the Plant-Wide Annual Tonnage Limitation for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitation for SO2
2016-2017	28,000 tons per year
2018-2019	26,000 tons per year
2020	22,000 tons per year
2021-2028	10,000 tons per year
2029, and each year thereafter	5,000 tons per year

In addition to the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, beginning on the thirtieth Day which is an Operating Day for either or both Rockport Units in calendar year 2021, SO_2 emissions from the Rockport Units shall be limited to 0.15 lb/mmBTU on a 30-Day Rolling Average Basis at the Rockport combined stack (30-Day Rolling Average Emission Rate for SO_2 at Rockport). Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B. Nothing in this Consent Decree shall be construed to prohibit the AEP Defendants from further optimizing the Enhanced DSI system, utilizing alternative sorbents, or upgrading the SO_2 removal technology at the Rockport Units so long as the Units maintain compliance with the 30-day Rolling Average Emission Rate for SO_2 at Rockport and the 30-day Rolling Average Emission Rate for NO_x at Rockport.

Paragraph 127 is replaced in its entirety and now reads as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

Pursuant to the Fifth Joint Modification Indiana Michigan Power Company ("I&M") will provide as restitution or as funds to come into compliance with the law $4 million in additional funding for the States to support projects identified in Section VIII, Subsection B during the period from 2019 through 2021. I&M shall provide the funding within seventy-five (75) days of receipt of a written request for payment and in accordance with instructions from counsel for the States.

Paragraph 128B is replaced in its entirety and now reads as follows:

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide \$2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed \$2.5 million.

In addition to the \$2.5 million provided in 2014, pursuant to the Fifth Joint Modification I&M will provide as restitution or as funds to come into compliance with the law \$3.5 million in funding for Citizen Plaintiffs to support projects that will promote energy efficiency, distributed generation, and pollution reduction measures for nonprofits, governmental entities, low income residents and/or other entities selected by Citizen Plaintiffs. I&M shall provide the \$3.5 million in funding within seventy-five (75) days of the Date of Entry of the Fifth Joint Modification of the Consent Decree by the Court in accordance with instructions from counsel for Citizen Plaintiffs.

Paragraph 133 is replaced in its entirety and now reads as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that

arise based on a modification commenced before December 31, 2018, or, solely for Rockport Unit 1, before December 31, 2028, or, solely for Rockport Unit 2, before June 1, 2020, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of the original Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

With respect to Rockport Unit 1, the United States agrees that the AEP Defendants' obligation to Retrofit, Re-Power, or Refuel Rockport Unit 1 would be satisfied if, by no later than December 31, 2028, the AEP Defendants Retrofit Rockport Unit 1 by installing and commencing continuous operation of FGD technology consistent with the definition in Paragraph 56 of the Third Joint Modification of the Consent Decree, Re-Power the Unit consistent with the definition in Paragraph 54 of the Consent Decree, or Refuel the Unit consistent with the provisions of Paragraph 53A of the Third Joint Modification of the Consent Decree. If the AEP Defendants elect to Retire Rockport Unit 1 by December 31, 2028, that would also satisfy the requirements of this Paragraph and fulfill the AEP Defendants' obligations with regard to Rockport Unit 1 under this Consent Decree. The term "modification" as used in this paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

Paragraph 140 is replaced in its entirety and now reads as follows:

140. With respect to the States and Citizen Plaintiffs, except as specifically set forth in this Paragraph, the States and Citizen Plaintiffs expressly do not join in giving the Defendants the

covenant provided by the United States in Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of the original Consent Decree, and reserve their rights, if any, to bring any actions against Defendants pursuant to 42 U.S.C. §7604 for any claims arising after the Date of the Lodging of the original Consent Decree. AEP, the States, and Citizen Plaintiffs also recognize that I&M informed state regulators in its most recent base rate proceedings that the most realistic date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028, and the Indiana Utility Regulatory Commission and the Michigan Public Service Commission have approved depreciation rates for I&M's share of Rockport Unit 1 to be consistent with the retirement of Unit 1 in December 2028. Notwithstanding the existence of any other compliance options in Paragraphs 87 and 133, AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028. AEP Defendants and the States and Citizen Plaintiffs agree that Paragraph 140 prevails in any conflict between it and Paragraphs 87 and/or 133.

a. On or before March 31, 2025, AEP Defendants shall submit to PJM Interconnection, LLC, or any other regional transmission organization with jurisdiction over the Rockport Units, notification of the planned retirement of Rockport Unit 1 by no later than December 31, 2028, and a request for such regional transmission organization to evaluate and identify any reliability concerns associated with such retirement.

Paragraph 180 is replaced in its entirety and now reads as follows:

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state

implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport.

Paragraph 182 is replaced in its entirety and now reads as follows:

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

Paragraph 188 is modified as follows to update the information required in order to provide required notices under the Consent Decree:

188.

As to the United States:

Case Management Unit
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893
eescdcopy.enrd@usdoj.gov

Phillip Brooks
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460
Brooks.phillip@epa.gov

Sara Breneman
Air Enforcement & Compliance Assurance Branch
U.S. EPA Region 5
77 W. Jackson Blvd.
Mail Code AE-18J
Chicago, IL 60604
Breneman.sara@epa.gov

and

Carol Amend, Branch Chief
Air, RCRA & Toxics Branch (3ED20)
Enforcement & Compliance Assurance Division
U.S. EPA, Region 3
1650 Arch Street
Philadelphia, PA 19103-2029
Amend.carol@epa.gov

For all notices to EPA, Defendants shall register for the CDX electronic system and upload such notices at https://cdx.gov/epa-home.asp.

As to the State of Connecticut:

Lori D. DiBella
Office of the Attorney General
Environment Department
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120
Lori.dibella@ct.gov

As to the State of Maryland:

Frank Courtright
Program Manager
Air Quality Compliance Program

Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, Maryland 21230
fcourtright@mde.state.md.us

and

Matthew Zimmerman
Assistant Attorney General
Office of the Attorney General
1800 Washington Boulevard
Baltimore, MD 21230
mzimmerman@mde.state.md.us

As to the Commonwealth of Massachusetts:

Christophe Courchesne, Assistant Attorney General
Office of the Attorney General
1 Ashburton Place, 18th floor
Boston, Massachusetts 02108
Christophe.courchesne@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
Concord, New Hampshire 03302-0095

and

K. Allen Brooks
Senior Assistant Attorney General
Office of the Attorney General
33 Capitol Street
Concord, New Hampshire 03301
Allen.brooks@doj.nh.gov

As to the State of New Jersey:

Section Chief
Environmental Enforcement
Dept. of Law & Public Safety
Division of Law
R.J. Hughes Justice Complex
25 Market Street

P.O. Box 093
Trenton, New Jersey 08625-0093
Lisa.morelli@dol.lps.state.nj.us

As to the State of New York:

Michael J. Myers
Senior Counsel
Environmental Protection Bureau
New York State Attorney General
The Capitol
Albany, New York 12224
Michael.Myers@ag.ny.gov

As to the State of Rhode Island:

Gregory S. Schultz
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903
gschultz@riag.ri.gov

As to the State of Vermont:

Nicholas F. Persampieri
Assistant Attorney General
Office of the Attorney General
109 State Street
Montpelier, Vermont 05609-1001
Nick.persampieri@vemont.gov

As to the Citizen Plaintiffs:

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, New York 10011
nmarks@nrdc.org

Kristin Henry
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
kristin.henry@sierraclub.org

Margrethe Kearney
Environmental Law and Policy Center
35 East Wacker Dr. Suite 1600
Chicago, Illinois 60601-2110
MKearney@elpc.org

and

Shannon Fisk
Earthjustice
1617 John F. Kennedy Blvd., Suite 1130
Philadelphia, PA 19103
sfisk@earthjustice.org

As to AEP:

John McManus
Vice President, Environmental Services
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
jmmcmanus@aep.com

David Feinberg
General Counsel
American Electric Power
1 Riverside Plaza
Columbus, OH 43215
dmfeinberg@aep.com

and

Janet Henry
Deputy General Counsel
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
jjhenry@aep.com

As to Gavin Buyer:

Nicholas Tipple
Plant Manager
Gavin Power, LLC
7397 N. St Rt #7
Cheshire, OH 45620
Nicholas.tipple@lightstone.com

Karl A. Karg
Latham & Watkins LLP
330 North Wabash Avenue, Suite 2800
Chicago, IL 60611
karl.karg@lw.com

and

Alexandra Farmer
Kirkland & Ellis LLP
1301 Pennsylvania Avenue, N.W.
Washington, DC 20004
alexandra.farmer@kirkland.com

Add a new Paragraph 205A that reads as follows:

205A. 26 U.S.C. Section 162(f)(2)(A)(ii) Identification. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), with respect to obligations incurred under this Fifth Joint Modification, performance of Section II (Applicability), Paragraph 3; Section IV (NO_x Emission Reductions and Controls), Paragraphs 67, 68, 68A, and 68B; Section V (SO_2 Emission Reductions and Controls), Paragraphs 86, 87, and 89A; Section VII (Prohibition on Netting Credits or Offsets from Required Controls), Paragraph 117; Section XI (Periodic Reporting), Paragraphs 143 – 147; Section XII (Review and Approval of Submittals), Paragraphs 148 and 149 (except with respect to dispute resolution); Section XVI (Permits), Paragraphs 175, 177, 179, and 180 – 183; Section XVII (Information Collection and Retention), Paragraphs 184 and 185; Section XXIII (General Provisions), Paragraph 207; and Appendix B; is restitution or required to come into compliance with law.

Modify Appendix B (Reporting Requirements) as follows:

Section I Paragraph O is replaced in its entirety and now reads as follows:

O. Plant-Wide Annual Tonnage Limitation and Emission Rate for SO_2 at Rockport.

Beginning March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 - 2020, Defendants shall report the daily sorbent deliveries to the Rockport Plant by weight. Beginning in calendar year 2021, the annual reports shall report the 30-day rolling average SO_2 Emissions Rate at the Rockport stack as required under Section I, Paragraph J of Appendix B, and reporting of daily sorbent deliveries will no longer be required.

Section I Paragraph S. is replaced in its entirety and now reads as follows:

S. Notification of Retirement of Rockport Unit 1.

AEP Defendants shall provide to the Plaintiffs a copy of the notification submitted to PJM Interconnection, LLC, or any other regional transmission organization pursuant to Paragraph 140.a, and a copy of any response received from PJM Interconnection, LLC, or any other the regional transmission organization.

Delete Paragraphs T and U from Section I of Appendix B.

Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 17th DAY OF July, 2019.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE UNITED STATES

Myles E. Flint, II

Myles E. Flint, II
Senior Counsel
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20530
(202) 307-1859

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FOR THE UNITED STATES

Rosemarie A. Kelley
Director
Office of Civil Enforcement
United States Environmental Protection Agency

Phillip A. Brooks
Director, Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency

Sabrina Argentieri
Attorney-Advisor
Office of Civil Enforcement
Civil Enforcement Division
United States Environmental Protection Agency

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FOR THE STATE OF CONNECTICUT

WILLIAM TONG
ATTORNEY GENERAL

By: Lori D. DiBella

Lori D. DiBella
Assistant Attorney General
Office of the Attorney General
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120

FOR THE STATE OF MARYLAND:

BRIAN E. FROSH
Attorney General

By: ____________________
MATTHEW ZIMMERMAN
Assistant Attorney General
Office of the Attorney General
1800 Washington Blvd.
Baltimore, Maryland 21230

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FOR THE COMMONWEALTH OF MASSACHUSETTS

MAURA HEALEY
ATTORNEY GENERAL

Christophe Courchesne
Assistant Attorney General
Office of the Attorney General
1 Ashburton Place, 18th Floor
Boston, MA 02108

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FOR THE STATE OF NEW HAMPSHIRE

GORDON J. MACDONALD
ATTORNEY GENERAL

K. Allen Brooks
Senior Assistant Attorney General
Office of the Attorney General
33 Capitol Street
Concord, New Hampshire 03301

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FOR THE STATE OF NEW JERSEY

GURBIR S. GREWAL
ATTORNEY GENERAL

Lisa J. Morelli
Deputy Attorney General
Dept. of Law & Public Safety
Division of Law
R.J. Hughes Justice Complex
25 Market Street
P.O. Box 093
Trenton, NJ 08625-0093

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FOR THE STATE OF NEW YORK

LETITIA JAMES
ATTORNEY GENERAL

Michael J. Myers
Senior Counsel
Environmental Protection Bureau
New York State Attorney General
The Capitol
Albany, NY 12224

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FOR THE STATE OF RHODE ISLAND

PETER F. NERONHA
ATTORNEY GENERAL

Gregory S. Schultz
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903

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FOR THE STATE OF VERMONT

THOMAS J. DONOVAN, JR.
ATTORNEY GENERAL

Thea Schwartz
Assistant Attorney General
Office of the Attorney General
109 State Street
Montpelier, VT 05609-1001

SIGNATURE PAGE FOR THE
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in

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Civil Action No. 99-CV-1182 and consolidated cases

FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.

Nancy S Marks

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, NY 10011

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in

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FOR SIERRA CLUB

Kristin A. Henry

Kristin Henry
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612

**SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

Margrethe K. Kearney

Margrethe Kearney
Environmental Law and Policy Center
35 East Wacker Drive, Suite 1600
Chicago, IL 60601-2110

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Civil Action No. 99-CV-1182 and consolidated cases

FOR THE AEP COMPANIES

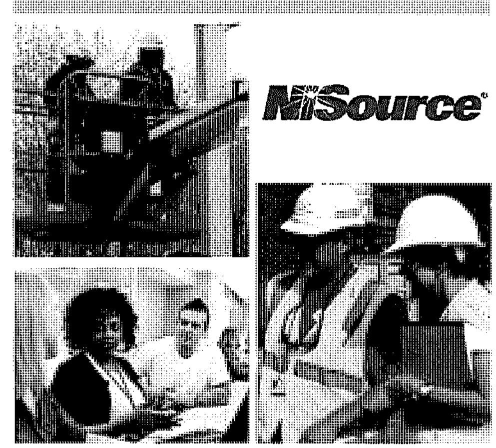
David M. Feinberg
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Three

July 24, 2018

NIPSCO



NiSource

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

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2019

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the *Annual Energy Outlook 2019*

This paper presents average values of levelized costs and levelized avoided costs for electric generating technologies entering service in 2021, 2023,[1] and 2040 as represented in the National Energy Modeling System (NEMS) for the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2019* (AEO2019) Reference case.[2] Both values estimate the factors contributing to the capacity expansion decisions modeled, which also consider policy, technology, and geographic characteristics that are not easily captured in a single metric.

The costs for electric generating facilities entering service in 2023 are presented in the body of the report, with those for 2021[3] and 2040 included in Appendices A and B, respectively. Both a capacity-weighted average based on projected capacity additions and a simple average (unweighted) of the regional values across the 22 U.S. supply regions of the NEMS electricity market module (EMM) are provided, together with the range of regional values.

Levelized Cost of Electricity

Levelized cost of electricity (LCOE) represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle.[4] LCOE is often cited as a convenient summary measure of the overall competiveness of different generating technologies.

Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[5] The importance of each of these factors varies across the technologies. For technologies with no fuel costs and relatively small variable O&M costs, such as solar and wind electric generating technologies, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies with significant fuel cost, both fuel cost and capital cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (see text box on page 2), can also affect the calculation of LCOE. As with any projection, these factors are uncertain because their values can vary regionally and temporally as technologies evolve and as fuel prices change.

---

[1] Given the long lead-time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2023.
[2] AEO2019 are available online (http://www.eia.gov/outlooks/aeo/).
[3] Appendix A shows LCOE and LACE for the subset of technologies available to be built in 2021.
[4] Duty cycle refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions.
[5] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available online (http://www.eia.gov/outlooks/aeo/assumptions/).

Actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve many other factors not reflected in LCOE values. One such factor is the projected utilization rate, which depends on the varying amount of electricity required over time and the existing resource mix in an area where additional capacity is needed. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different economic value than one that would displace existing coal-fired generation. A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region. Because load must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) such as those using intermittent resources to operate. The LCOE values for dispatchable and non-dispatchable technologies are listed separately in the tables because comparing them must be done carefully.

AEO2019 representation of tax incentives for renewable generation

Federal tax credits for certain renewable generation facilities can substantially reduce the realized cost of these facilities. Where applicable, the LCOE tables show the cost both with and without tax credits that EIA assumed would be available in the year in which the plant enters service, as follows.

Production Tax Credit (PTC): New wind, geothermal, and closed-loop biomass plants receive 24 dollars per megawatthour ($/MWh) of generation; other PTC-eligible technologies receive $12/MWh. The PTC values are adjusted for inflation and applied during the plant's first 10 years of service. Plants that were under construction before the end of 2016 received the full PTC. After 2016, wind continues to be eligible for the PTC but at a dollar-per-megawatthour rate that declines by 20% in 2017, 40% in 2018, 60% in 2019, and expires completely in 2020. Based on documentation released by the Internal Revenue Service (IRS, https://www.irs.gov/irb/2016-23_IRB/ar07.html), EIA assumes that wind plants have four years after beginning construction to come online and claim the PTC. As a result, wind plants entering service in 2021 will receive $19.20/MWh while those entering service in 2023 will receive $9.60/MWh (inflation-adjusted).

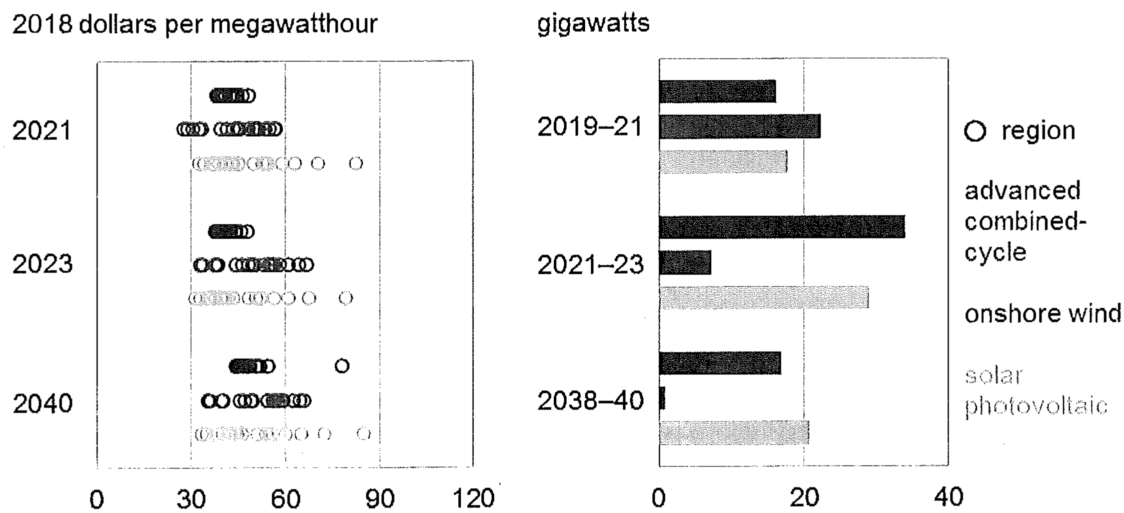
Investment Tax Credit (ITC): In June 2018, the IRS issued Notice 2018-59 (https://www.irs.gov/pub/irs-drop/n-18-59.pdf), a beginning of construction guidance for the ITC. EIA assumes all solar projects starting construction before January 1, 2020, have four years to bring the power plant online (before January 1, 2024) to receive the full 30% ITC. Solar projects include both utility-scale solar plants—those with capacity rating of 1 megawatt (MW) or greater—and small-scale systems—those with capacity rating of less than 1 MW. Projects starting construction in 2020 have three years to enter service and receive 26% ITC, and those with a 2021 construction start year have two years to enter service and claim a 22% ITC. All commercial and utility-scale plants with a construction start date on or after January 1, 2022, or those placed in service after December 31, 2023, receive a 10% ITC. ITC, however, expires completely for residential-owned systems starting in 2022. Results in this levelized cost report only include utility-scale solar facilities and do not include small-scale solar facilities.

Both onshore and offshore wind projects are eligible to claim the ITC in lieu of the PTC. Although EIA expects that onshore wind projects will choose the PTC, EIA assumes offshore wind projects will claim the ITC in lieu of the PTC because of the relatively higher capital costs for those projects.

Levelized Avoided Cost of Electricity

LCOE does not capture all of the factors that contribute to actual investment decisions, making the direct comparison of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. As illustrated by Figure 1 below, on average, wind LCOE is shown to be the same or lower than solar photovoltaic (PV) LCOE in 2021, with more wind generating capacity expected to be installed than solar PV. Wind LCOE continues to be about the same or lower than solar PV LCOE on average in 2040, but EIA projects much more solar PV capacity to be installed than wind during that time.

Figure 1. Levelized cost of electricity (with applicable tax subsidies) by region and total incremental capacity additions for selected generating technologies entering into service in 2021, 2023, and 2040



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

Comparing two different technologies using LCOE alone evaluates only the cost to build and operate a plant and not the value of the plant's output to the grid. EIA believes an assessment of economic competitiveness between generation technologies can be gained by considering the avoided cost: a measure of what it would cost to generate the electricity that would be displaced by a new generation project. Avoided cost provides a proxy measure for potential revenues from sales of electricity generated from a candidate project. It may be summed over a project's financial life and converted to a level annualized value that is divided by average annual output of the project to develop its *levelized* avoided cost of electricity (LACE).[6] Using LACE and LCOE together gives a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load. If several technologies are available to meet load, a LACE-to-LCOE ratio (or value-cost ratio) may be calculated for each technology to determine which project provides the most value relative to its cost. Projects with a value-cost ratio greater than one (i.e., LACE is greater than

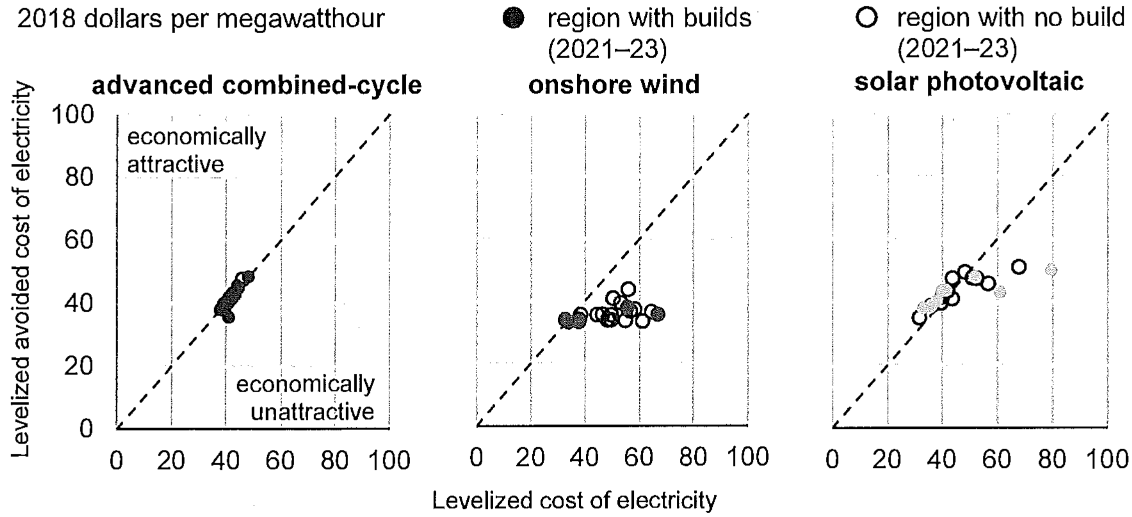
[6] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found online: http://www.eia.gov/renewable/workshop/gencosts/.

LCOE) are more economically attractive as new builds than those with a value-cost ratio less than one (i.e., LACE is less than LCOE).

Estimating LACE is more complex than estimating LCOE because it requires information about how the system would operate without the new option being considered. LACE is calculated based on the marginal value of energy and capacity that would result from adding a unit of a given technology to the system as it exists or is projected to exist at a specific future date. LACE represents the potential value available to the project owner from the project's contribution to satisfy both energy and capacity requirements. LACE accounts for both the variation in daily and seasonal electricity demand in the region where a new project is under consideration and the characteristics of the existing generation fleet to which new capacity will be added, therefore comparing the prospective new generation resource against the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different value than one that would displace existing coal-fired generation.

Although the economic decisions for capacity additions in EIA's long-term projections do not use either LACE or LCOE concepts, the LACE and value-cost ratio presented in this report are generally more representative of the factors contributing to the build decisions found in EIA's long-term projections than looking at LCOE alone. Figure 2 below shows selected generating technologies that are feasible to come online in 2023. The x-axis is LCOE, and the y-axis is LACE. The diagonal lines are breakeven lines, so that anything above them is considered to be economically attractive to build because the value (or LACE) is higher than the cost (or LCOE). Each dot represents an electricity market region of the United States as modeled in NEMS. Colored dots show regions where the technology is built in the AEO projection; circles show where the technology is not built from 2021 to 2023. Advanced combined-cycle (CC) and solar PV have colored dots mostly above or at the diagonal lines. Onshore wind has mostly circles at or below the diagonal line and a few colored dots below the line. This pattern is partly because the builds are calculated from capacity added in the preceding three years, and onshore wind was subject to greater tax incentives in those three years than in 2023 alone. In addition, some regions are adding uneconomic capacity builds to fulfill state-level renewable portfolio standards (RPS) that require that a certain percentage of generation come from renewables. Even so, looking at both LCOE and LACE together as shown in Figure 2 is more predictive of the full analysis from the AEO model shown in Figure 1 than LCOE alone.

Figure 2. Levelized cost of electricity and levelized avoided cost of electricity by region for selected generating technologies, 2023 online year



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

Nonetheless, both the LACE and LCOE estimates are simplifications of modeled decisions, and they may not fully capture all factors considered in NEMS or match modeled results. EIA calculates levelized costs using an assumed set of capital and operating costs, but investment decisions may be affected by factors other than the project's value relative to its costs. For example, the inherent uncertainty about future fuel prices, future policies, or local considerations for system reliability may lead plant owners or investors who finance plants to place a value on portfolio diversification or other risk-related concerns. EIA considers many of the factors discussed above in its analysis of technology choice in the electricity sector in NEMS, but not all of these concepts are included in LCOE or LACE calculations. Future policy-related factors, such as new environmental regulations or tax credits for specific generation sources, can affect investment decisions. The LCOE and LACE values presented here are derived from the AEO2019 Reference case, which includes state-level renewable electricity requirements as of October 2018 and a phase-out of federal tax credits for renewable generation.

LCOE and LACE calculations

EIA calculates LCOE values based on a 30-year cost recovery period, using a real after-tax weighted average cost of capital (WACC) of 4.2%.[7] In reality, a plant's cost recovery period and cost of capital can vary by technology and project type. In the AEO2019 Reference case, EIA includes a three-percentage-point increase to the cost of capital when evaluating investments for new coal-fired power plants and new coal-to-liquids (CTL) plants without carbon capture and sequestration (CCS) and pollution control retrofits. This increase reflects observed financial risks[8] associated with major investments in long

[7]The real WACC of 4.2% corresponds to a nominal after-tax rate of 7.0% for plants entering service in 2023. For plants entering service in 2021 and 2040, the nominal WACC used to calculate LCOE was 6.8% and 7.0%, respectively. An overview of the WACC assumptions and methodology can be found in the *Electricity Market Module of the National Energy Modeling System: Model Documentation 2018* (https://www.eia.gov/analysis/pdfpages/m068index.php).

[8] See, for example, "Companies End Effort to Buy Navajo Generating Station", *Power*, September 21, 2018 for an example of both financing and off-take risks facing coal-fired capacity or "One of U.K.'s largest banks won't fund new plants or mines,"

operating-life power plants with a relatively higher rate of carbon dioxide (CO2) emissions. AEO2019 takes into account two coal-fired technologies that are compliant with the New Source Performance Standard (NSPS) for CO2 emissions under Section 111(b) of the Clean Air Act. One technology is designed to capture 30% of CO2 emissions and would still be considered a high emitter relative to other new sources; therefore, it may continue to face potential financial risk if CO2 emission controls are further strengthened. Another technology is designed to capture 90% of CO2 emissions and would not face the same financial risk; therefore, EIA does not assume the three-percentage-point increase in the cost of capital. As a result, the LCOE values for a coal-fired plant with 30% CCS are higher than they would be if the same cost of capital were used for all technologies.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with tax laws without a sunset date, which vary by technology. For AEO2019, EIA assumes a corporate tax rate of 21% as specified in the Tax Cuts and Jobs Act of 2017. For technologies eligible for the ITC or PTC, EIA reports LCOE both with and without tax credits, which are assumed to phase out and expire based on current laws and regulations. Some technologies, notably solar PV, are used in both utility-scale generation and in distributed residential and commercial applications. The LCOE and LACE calculations presented here apply only to the utility-scale use of those technologies. Costs are expressed in terms of net alternating current (AC) power available to the grid for the installed capacity.

The LCOE values shown in Tables 1a and 1b are region-specific LCOE values using weights reflecting the projected regional capacity builds in AEO2019 (Table 1a) and unweighted (simple average, Table 1b) for new plants coming online in 2023. The weights were developed based on the cumulative capacity additions during three years, reflecting the two years preceding the online year and the online year (e.g., the capacity weight for a 2023 online year represents the cumulative capacity additions from 2021 through 2023.)

ClimateWire (subscription required), August 3, 2018 for an example of increasingly limited options in international finance markets for such plants.

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 CO_2 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 have a similar average annual capacity factor; therefore, they are shown separately as non-dispatchable technologies. Similarly, hydroelectric resources, including facilities where storage reservoirs allow for more flexible day-to-day operation, generally have high seasonal variation in output. EIA shows them as non-dispatchable to discourage comparison with technologies that have more consistent seasonal availability. The capacity factors for solar, wind, and hydroelectric resources are the average of the capacity factors (weighted or unweighted) for the marginal site in each region, which can vary significantly by region, and will not necessarily correspond to the cumulative projected capacity factors for these both new and existing units for resources in AEO2019 or in other EIA analyses.

Table 2 shows the significant regional variation in LCOE values from local labor markets and the cost and availability of fuel or energy resources (such as windy sites). For example, without consideration of the PTC, the LCOE for incremental onshore wind capacity ranges from $38.9/MWh in the region with the best available wind resources to $72.9/MWh in the region with the lowest-quality wind resources and/or higher capital costs for the best sites. Because onshore wind plants will most likely be built in regions that offer low costs and high value, the weighted average cost across regions is closer to the low end of the range at $42.8/MWh. Costs for wind generators may include additional expenses associated with transmission upgrades needed to access remote resources, as well as other factors that markets may not internalize into the market price for wind power.

Table 2. Regional variation in levelized cost of electricity for new generation resources entering service in 2023 (2018 $/MWh)

	Without tax credits				With tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Coal with 30% CCS[3]	93.7	104.3	NB	124.7	93.7	104.3	NB	124.7
Coal with 90% CCS[3]	89.0	98.6	NB	109.8	89.0	98.6	NB	109.8
Conventional CC	42.4	46.3	42.8	55.0	42.4	46.3	42.8	55.0
Advanced CC	37.8	41.2	40.2	48.1	37.8	41.2	40.2	48.1
Advanced CC with CCS	55.6	67.5	NB	75.7	55.6	67.5	NB	75.7
Conventional CT	84.1	89.3	NB	100.1	84.1	89.3	NB	100.1
Advanced CT	71.1	77.7	77.5	86.7	71.1	77.7	77.5	86.7
Advanced nuclear	75.1	77.5	NB	81.2	75.1	77.5	NB	81.2
Geothermal	38.2	41.0	39.4	46.5	35.9	38.3	36.9	43.1
Biomass	83.1	92.2	92.1	114.1	83.1	92.2	92.1	114.1
Non-dispatchable technologies								
Wind, onshore	38.9	55.9	42.8	72.9	32.8	49.8	36.6	66.8
Wind, offshore	115.5	130.4	117.9	158.8	104.0	117.5	106.5	142.6
Solar PV[4]	40.3	60.0	48.8	106.9	31.5	45.7	37.6	79.5
Solar thermal	138.2	157.1	NB	178.7	107.3	121.2	NB	138.2
Hydroelectric[5]	39.1	39.1	39.1	39.1	39.1	39.1	39.1	39.1

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2023. See note 1 in Tables 1a and 1b.
[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 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.
[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.
Note: EIA calculated the levelized costs for non-dispatchable technologies based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are 37%–46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 76% for hydroelectric. 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*

LACE accounts for the differences in the grid services each technology is providing, recognizing that intermittent resources, such as wind or solar, have substantially different duty cycles than the baseload, intermediate, and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. EIA calculated the LACE in this table assuming the same maximum capacity factor as used for the LCOE. Values are not shown for combustion turbines because combustion turbines are generally built for their capacity value to meet a reserve margin rather than for generation requirements and to collect avoided energy costs.

Table 3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Coal with 30% CCS[2]	35.6	40.8	NB	48.6
Coal with 90% CCS[2]	35.6	40.8	NB	48.6
Conventional CC	35.5	41.1	38.3	48.4
Advanced CC	35.5	41.1	40.4	48.4
Advanced CC with CCS	35.5	41.1	NB	48.4
Advanced nuclear	35.7	40.3	NB	47.7
Geothermal	41.4	44.6	45.8	48.1
Biomass	35.5	41.3	41.7	48.7
Non-dispatchable technologies				
Wind, onshore	33.3	36.1	33.7	43.7
Wind, offshore	36.4	40.5	39.9	52.2
Solar PV[3]	35.1	43.4	40.3	51.1
Solar thermal	39.8	44.0	NB	51.2
Hydroelectric[4]	41.6	41.6	41.6	41.6

[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]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). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build. The build decisions in the real world and as modeled in AEO2019, however, are more complex than a simple LACE-to-LCOE comparison because they include such factors as policy and non-economic drivers. Nevertheless, the value-cost ratio (the ratio of LACE-to-LCOE) provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either LCOE or LACE tables individually. In Tables 4a and 4b, a value index of less than one indicates that the cost of the marginal new unit of capacity exceeds its value to the system, and a value-cost ratio greater than one indicates that the marginal new unit brings in value higher than its cost by displacing more expensive generation and capacity options. The *average value-cost ratio* represents the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions. This range of ratios is not based on the ratio between the minimum and maximum values shown in Tables 2 and 3, but rather it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.

Table 4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Average capacity-weighted[1] LCOE with tax credits	Average capacity-weighted[1] LACE	Average value-cost ratio[2]
Dispatchable technologies			
Coal with 30% CCS[3]	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB
Conventional CC	42.8	38.3	0.90
Advanced CC	40.2	40.4	1.00
Advanced CC with CCS	NB	NB	NB
Advanced nuclear	NB	NB	NB
Geothermal	36.9	45.8	0.74
Biomass	92.1	41.7	0.45
Non-dispatchable technologies			
Wind, onshore	36.6	33.7	0.94
Wind, offshore	106.5	39.9	0.37
Solar PV[4]	37.6	40.3	1.07
Solar thermal	NB	NB	NB
Hydroelectric[5]	39.1	41.6	1.06

[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 *average value-cost ratio* represents the economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.

[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). PV=photovoltaic.

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

As shown in Table 4a, the capacity-weighted average value-cost ratio is greater than one for solar PV, advanced CC, and hydroelectric in 2023, suggesting that these technologies are being built in regions where they are economically viable. Furthermore, the capacity-weighted average value-cost ratio for advanced CC is close to one, suggesting that the technology has been an attractive marginal capacity addition, and the market has developed the technology to an equilibrium point where the net economic value is close to breakeven after having met load growth and/or displaced higher cost generation.[9]

Table 4b. Value-cost ratio (unweighted) for new generation resources entering service in 2023

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[2]
Dispatchable technologies					
Coal with 30% CCS[3]	104.3	40.8	0.39	0.35	0.44
Coal with 90% CCS[3]	98.6	40.8	0.41	0.37	0.51
Conventional CC	46.3	41.1	0.89	0.79	0.93
Advanced CC	41.2	41.1	1.00	0.87	1.03
Advanced CC with CCS	67.5	41.1	0.61	0.53	0.78
Advanced nuclear	77.5	40.3	0.52	0.46	0.60
Geothermal	38.3	44.6	1.17	1.03	1.34
Biomass	92.2	41.3	0.45	0.41	0.49
Non-dispatchable technologies					
Wind, onshore	49.8	36.1	0.75	0.54	1.04
Wind, offshore	117.5	40.5	0.35	0.30	0.48
Solar PV[4]	45.7	43.4	0.98	0.63	1.16
Solar thermal	121.2	44.0	0.37	0.30	0.43
Hydroelectric[5]	39.1	41.6	1.06	1.06	1.06

[1]The *average value-cost ratio* represents the economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables 2 and 3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[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). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

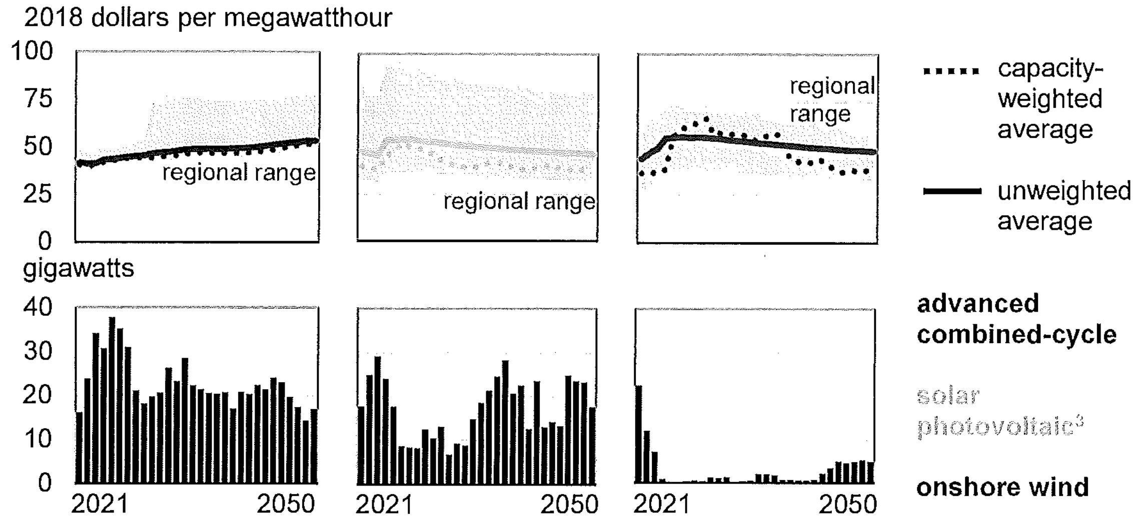
LCOE and LACE projections

Figure 3 shows capacity-weighted and unweighted LCOE for advanced CC, solar PV, and onshore wind plants entering service during the AEO2019 Reference case projection period (2021–50). Changes in costs over time reflect a number of different model factors, sometimes working in different directions. For both solar PV and onshore wind, LCOE increases in the near term with the phase-out and expiration of ITC and PTC, respectively. However, LCOE eventually declines over time because of technology improvement that tends to reduce LCOE through lower capital costs or improved performance (as

[9] For a more detailed discussion of the LACE versus LCOE measures, see *Assessing the Economic Value of New Utility-Scale Electricity Generation Projects* (http://www.eia.gov/renewable/workshop/gencosts/pdf/lace-lcoe_070213.pdf).

measured by heat rate for advanced CC plants or capacity factor for onshore wind or solar PV plants), partly offsetting the loss of the tax credits. The availability of high-quality resources may also be a factor. As the best, least-cost resources are used, future development will occur in less favorable areas, potentially resulting in lower-performing resources, higher project development costs, and higher costs to access transmission lines. For advanced CC, changing fuel prices also factor into the change in LCOE, as well as any environmental regulations affecting capital or operating costs.

Figure 3. Capacity-weighted[1] and unweighted levelized cost of electricity[2] projections and three-year moving capacity additions for selected generating technologies, 2021–50



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

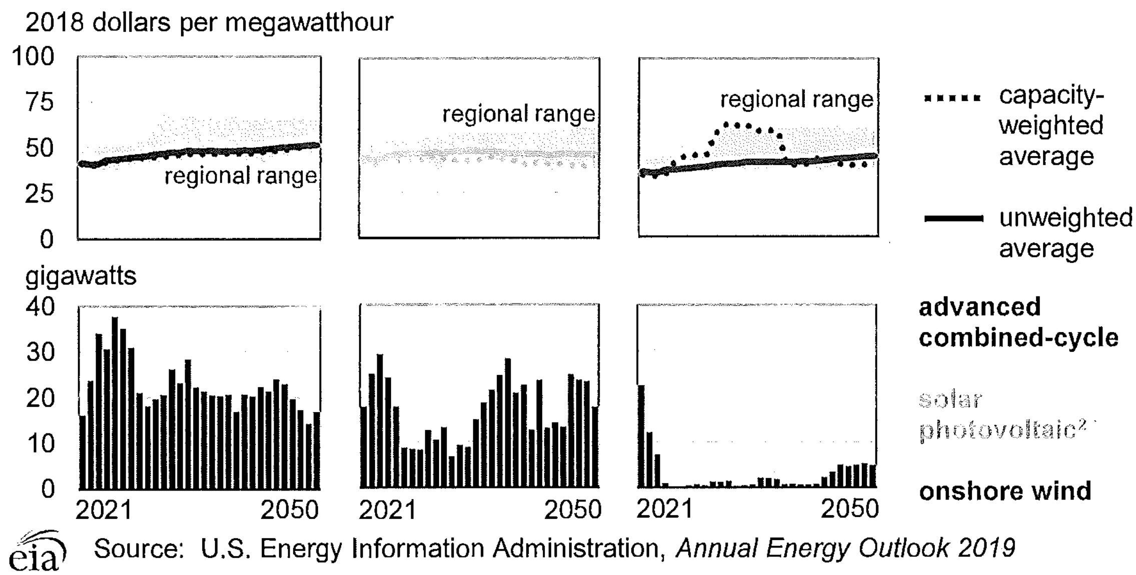
[1]Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2023 are based on additions from 2021–2023.
[2]Levelized-cost includes tax credits available for plants entering service during the projection period. See note 1 in Tables 1a and 1b.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

For advanced CC, the capacity-weighted average LCOE and unweighted average LCOE are not far apart from each other because new builds are expected across several regions throughout the projection period. The capacity-weighted average LCOE and unweighted average LCOE for solar PV are more differentiated because new capacity builds are concentrated primarily in regions with favorable resources and/or higher electricity costs. Solar PV plants continue to be installed throughout the projection period so the capacity-weighted average LCOE stays lower than the unweighted average LCOE, reflecting the build-out in low-cost regions. In the near and mid term, wind builds are significantly influenced by both state and federal policy, leading to higher-cost sites being built. Later in the projection period, well after the influence of federal tax credits has subsided, market economics are more influential in spurring wind capacity additions, and the capacity-weighted average LCOE returns to its expected position below the unweighted line.

The projected regional range for advanced CC is generally narrow in the early years, but this range widens in later years because of the increase in variable O&M costs for plants in California as a result of California's phase-out of fossil generation starting in 2030.

Figure 4 shows capacity-weighted and unweighted averages LACE over time. Changes in the value of generation, represented by LACE, are primarily a function of load growth. Wind and solar may show strong daily or seasonal generation patterns within any given region; as a result, the value of such renewable generation may see significant reductions as these time periods become more saturated with generation from resources with similar hourly operation patterns. As this saturation occurs, generation from new facilities must compete with lower-cost options in the dispatch merit order. LACE for onshore wind is generally lower than other technologies because in many regions, wind plants generate mostly at night or during fall and spring seasons when the demand for and the value of electricity are typically low. Solar PV plants produce most of their energy during the middle of the day, when higher demand increases the value of electricity, resulting in higher LACE.

Figure 4. Capacity-weighted[1] and unweighted levelized avoided cost of electricity projections and three-year moving capacity additions for selected generating technologies, 2021–50

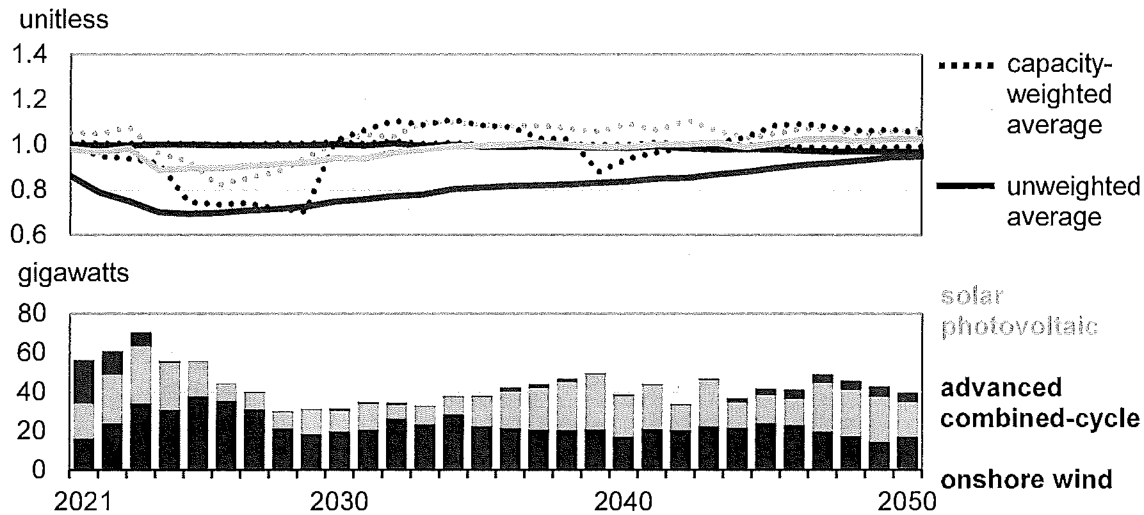


[1]Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2023 are based on additions from 2021–2023.
[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

Similar behaviors and patterns are observed with LACE as with LCOE. For onshore wind, the capacity-weighted average LACE traces the maximum bound of the regional range because California, which also has the highest LACE starting in 2030, is among the few regions with new capacity expected. The capacity-weighted LACE returns to near the level of unweighted average LACE in later years as new capacity is expected across a wider number of regions.

As illustrated in Figure 5, when considering both the value and cost of building and operating a power plant, advanced CC, solar PV, and onshore wind all reach market equilibrium or a break-even point. The break-even point represents a stable solution point where LACE equals LCOE. Once a technology achieves a value-cost ratio greater than one (*grid parity*), its value-cost ratio tends to remain close to unity as seen with advanced CC. If the value-cost ratio becomes significantly greater than one, the market will quickly build-out the technology until it meets the demand growth and/or displaces the higher cost incumbent generation. Similarly, if the value-cost ratio becomes negative, continued load growth, technology cost declines, or perhaps escalation in the fuel cost of a competing resource will tend to reduce the technology costs and/or increase the technology value to the grid over time.

Figure 5. Value-cost ratio and three-year moving capacity additions for selected generating technologies, 2021–50



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

Market shocks may cause a divergence between LACE and LCOE, therefore disturbing the market equilibrium. These market shocks include technology change, policy developments, or fuel price volatility that can increase or decrease the value-cost ratio of any given technology. However, EIA expects the market to correct the divergence by either building the high-value resource (if the value-cost ratio increased) or waiting for slow-acting factors such as load growth to increase the value in the case of a value-cost ratio decrease, as seen for the capacity-weighted average value-cost ratios of both wind and solar PV.

Appendix A: LCOE tables for new generation resources entering service in 2021

Table A1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2021 (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								
Conventional CC	87	8.9	1.5	35.2	1.0	46.7	NA	46.7
Advanced CC	87	7.1	1.4	30.9	1.0	40.5	NA	40.5
Conventional CT	30	25.6	6.9	49.3	2.7	84.6	NA	84.6
Advanced CT	30	19.7	2.7	54.8	3.3	80.6	NA	80.6
Non-dispatchable technologies								
Wind, onshore	43	33.4	13.1	0.0	2.3	48.8	-12.1	36.7
Solar PV[3]	31	41.0	8.3	0.0	2.9	52.2	-12.3	39.9

[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]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 2021 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]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.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A1b. Estimated levelized avoided cost of electricity (unweighted average) for new generation resources entering service in 2021 (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								
Conventional CC	87	9.1	1.5	35.0	1.1	46.8	NA	46.8
Advanced CC	87	7.4	1.4	31.8	1.1	41.6	NA	41.6
Conventional CT	30	28.3	6.9	51.5	3.2	89.9	NA	89.9
Advanced CT	30	18.1	2.7	57.1	3.2	81.1	NA	81.1
Non-dispatchable technologies								
Wind, onshore	41	40.2	13.7	0.0	2.5	56.5	-12.1	44.4
Solar PV[2]	29	50.2	8.9	0.0	3.3	62.5	-15.1	47.4

[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 2020 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]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.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

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*

Table A4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Average capacity-weighted[1] LCOE with tax credits	Average capacity-weighted[1] LACE	Average value-cost ratio[2]
Dispatchable technologies			
Conventional CC	46.7	41.7	0.89
Advanced CC	40.5	40.8	1.01
Non-dispatchable technologies			
Wind, onshore	36.7	34.7	1.00
Solar PV[3]	39.9	41.7	1.05

[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]The *average value-cost ratio* represents the net economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[3]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*

Table A4b. Value-cost ratio (unweighted) for new generation resources entering service in 2021

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[2]
Dispatchable technologies					
Conventional CC	46.8	41.6	0.89	0.79	0.93
Advanced CC	41.6	41.6	1.00	0.88	1.04
Non-dispatchable technologies					
Wind, onshore	44.4	36.6	0.86	0.60	1.23
Solar PV[3]	47.4	44.8	0.98	0.61	1.20

[1]The *average value-cost ratio* represents the net economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables A2 and A3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[3]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*

Appendix B: LCOE and LACE tables for new generation resources entering service in 2040

Table B1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2040 (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	7.8	1.5	40.3	1.1	50.7	NA	50.7
Advanced CC	87	6.5	1.4	37.9	1.2	46.9	NA	46.9
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	15.0	2.7	63.2	3.8	84.6	NA	84.6
Advanced nuclear	NB	NB	NB	NB	NB	NB	NB	NB
Geothermal	93	18.8	15.9	0.0	1.5	36.2	-1.9	34.3
Biomass	NB	NB	NB	NB	NB	NB	NB	NB
Non-dispatchable technologies								
Wind, onshore	42	27.6	13.2	0.0	2.7	43.5	NA	43.5
Wind, offshore	NB	NB	NB	NB	NB	NB	NB	NB
Solar PV[4]	30	30.9	8.6	0.0	3.1	42.6	-3.1	39.5
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	73	39.4	13.7	1.4	1.9	56.3	NA	56.3

[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 2038–2040. 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 2040 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 B1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2040 (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	58.9	9.7	36.7	1.2	106.5	NA	106.5
Coal with 90% CCS[2]	85	47.9	11.2	36.5	1.2	96.8	NA	96.8
Conventional CC	87	9.2	1.5	43.0	1.2	55.0	NA	55.0
Advanced CC	87	6.9	1.4	39.7	1.2	49.2	NA	49.2
Advanced CC with CCS	87	17.5	4.5	50.6	1.2	73.8	NA	73.8
Conventional CT	30	27.8	6.9	62.2	3.6	100.5	NA	100.5
Advanced CT	30	15.6	2.7	63.7	3.6	85.5	NA	85.5
Advanced nuclear	90	49.3	13.1	10.0	1.1	73.5	NA	73.5
Geothermal	93	22.6	16.4	0.0	1.5	40.5	-2.3	38.3
Biomass	83	31.0	15.7	37.1	1.3	85.1	NA	85.1
Non-dispatchable technologies								
Wind, onshore	40	34.6	13.8	0.0	2.9	51.3	NA	51.3
Wind, offshore	45	87.5	20.3	0.0	2.6	110.4	NA	110.4
Solar PV[3]	29	40.0	8.9	0.0	3.7	52.7	-4.0	48.7
Solar thermal	25	99.5	33.3	0.0	4.7	137.5	-10.0	127.5
Hydroelectric[4]	63	35.9	9.7	1.9	2.2	49.6	NA	49.6

[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 2040 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*

Table B2. Regional variation in levelized cost of electricity for new generation resources entering service in 2040 (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								
Coal with 30% CCS[3]	90.8	106.5	NB	160.0	90.8	106.5	NB	160.0
Coal with 90% CCS[3]	84.2	96.8	NB	111.8	84.2	96.8	NB	111.8
Conventional CC	50.6	55.0	50.7	81.1	50.6	55.0	50.7	81.1
Advanced CC	44.4	49.2	46.9	78.1	44.4	49.2	46.9	78.1
Advanced CC with CCS	60.8	73.8	NB	82.3	60.8	73.8	NB	82.3
Conventional CT	92.2	100.5	NB	137.1	92.2	100.5	NB	137.1
Advanced CT	77.1	85.5	84.6	119.8	77.1	85.5	84.6	119.8
Advanced nuclear	71.4	73.5	NB	77.0	71.4	73.5	NB	77.0
Geothermal	35.8	40.5	36.2	43.3	33.9	38.3	34.3	40.9
Biomass	77.4	85.1	NB	109.4	77.4	85.1	NB	109.4
Non-dispatchable technologies								
Wind, onshore	35.3	51.3	43.5	66.0	35.3	51.3	43.5	66.0
Wind, offshore	97.8	110.4	NB	133.7	97.8	110.4	NB	133.7
Solar PV[4]	36.0	52.7	42.6	92.6	33.5	48.7	39.5	84.9
Solar thermal	121.3	137.5	NB	156.5	112.7	127.5	NB	145.3
Hydroelectric[5]	38.9	49.6	56.3	64.6	38.9	49.6	56.3	64.6

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2040. See note 1 in Tables B1a and B1b.
[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 2038–2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.
[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.
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 37%–46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 30%–79% for hydroelectric. 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 B3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2040 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Coal with 30% CCS[2]	42.5	48.0	NB	67.3
Coal with 90% CCS[2]	42.5	48.0	NB	67.3
Conventional CC	42.4	48.3	44.5	67.1
Advanced CC	42.4	48.3	46.8	67.1
Advanced CC with CCS	42.4	48.3	NB	67.1
Advanced nuclear	41.5	46.8	NB	56.7
Geothermal	48.8	55.6	65.8	66.7
Biomass	42.6	48.5	NB	67.4
Non-dispatchable technologies				
Wind, onshore	37.8	41.9	40.2	61.3
Wind, offshore	41.9	47.4	NB	73.2
Solar PV[3]	38.4	46.8	42.9	58.5
Solar thermal	41.1	48.4	NB	55.3
Hydroelectric[4]	41.7	51.1	57.6	65.8

[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 2038–2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.

[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). PV=photovoltaic.

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

Table B4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2040

Plant type	Average capacity-weighted[1] LCOE with tax credits (2018 $/MWh)	Average capacity-weighted[1] LACE (2018 $/MWh)	Average value-cost ratio[2]
Dispatchable technologies			
Coal with 30% CCS[3]	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB
Conventional CC	50.7	44.5	0.88
Advanced CC	46.9	46.8	1.00
Advanced CC with CCS	NB	NB	NB
Advanced nuclear	NB	NB	NB
Geothermal	34.3	65.8	1.93
Biomass	NB	NB	NB
Non-dispatchable technologies			
Wind, onshore	43.5	40.2	0.94
Wind, offshore	NB	NB	NB
Solar PV[4]	39.5	42.9	1.09
Solar thermal	NB	NB	NB
Hydroelectric[5]	56.3	57.6	1.02

[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 2038–2040. 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 *average value-cost ratio* represents the economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[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). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table B4b. Value-cost ratio (unweighted) for new generation resources entering service in 2040

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[3]
Dispatchable technologies					
Coal with 30% CCS[3]	106.5	48.0	0.45	0.42	0.52
Coal with 90% CCS[3]	96.8	48.0	0.50	0.44	0.60
Conventional CC	55.0	48.3	0.88	0.81	0.94
Advanced CC	49.2	48.3	0.99	0.86	1.03
Advanced CC with CCS	73.8	48.3	0.66	0.55	0.83
Advanced nuclear	73.5	46.8	0.64	0.58	0.74
Geothermal	38.3	55.6	1.48	1.19	1.96
Biomass	85.1	48.5	0.57	0.52	0.70
Non-dispatchable technologies					
Wind, onshore	51.3	41.9	0.84	0.63	1.08
Wind, offshore	110.4	47.4	0.43	0.36	0.72
Solar PV[4]	48.7	46.8	0.99	0.69	1.19
Solar thermal	127.5	48.4	0.38	0.29	0.45
Hydroelectric[5]	49.6	51.1	1.04	0.89	1.21

[1]The *average value-cost ratio* represents the economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables B2 and B3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[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). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

NOVEMBER 2018

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 12.0

LAZARD

Introduction

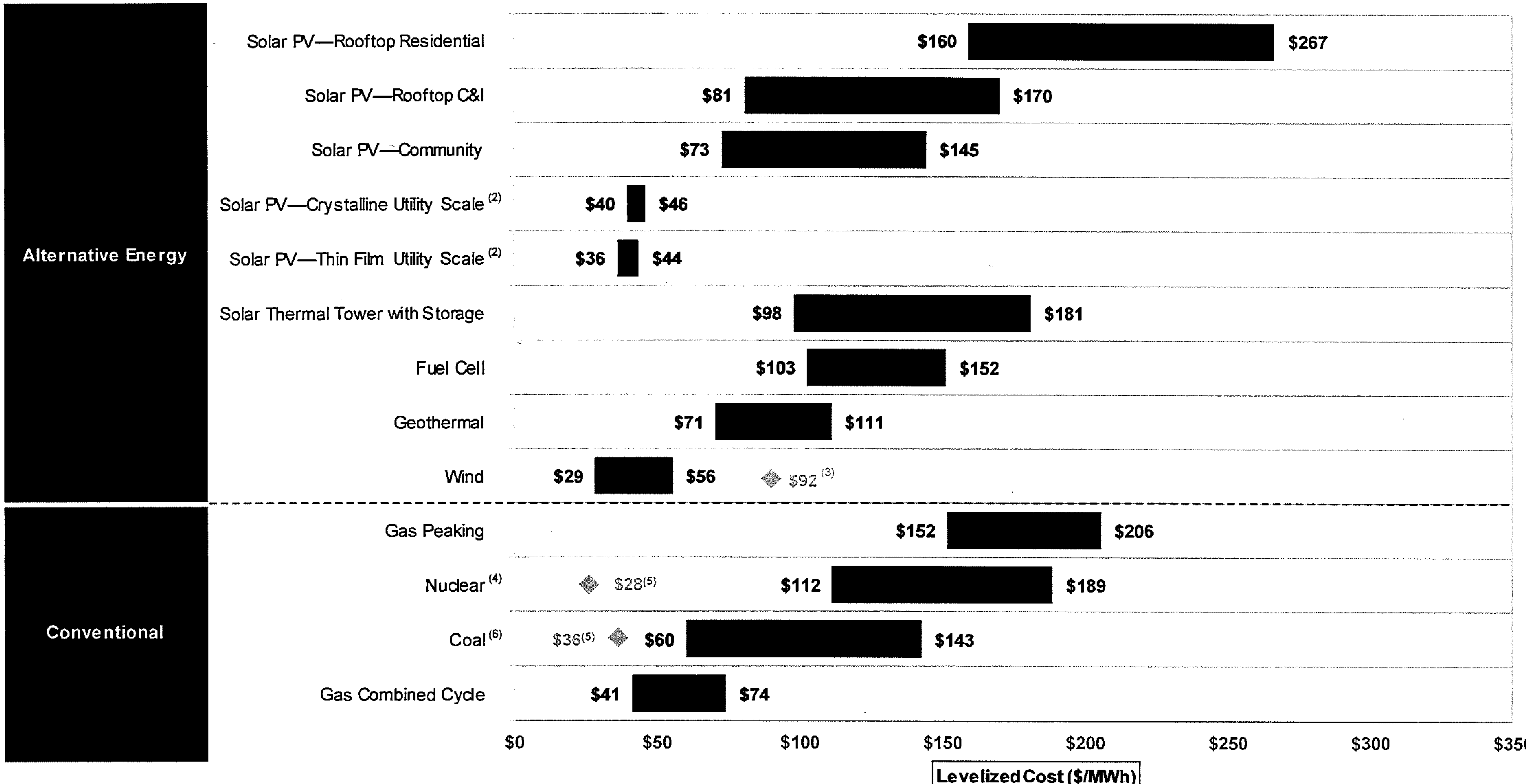
Lazard's Levelized Cost of Energy ("LCOE") analysis addresses the following topics:

- Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel prices and costs of capital
- Illustration of how the LCOE of wind and utility-scale solar compare to the marginal cost of selected conventional generation technologies
- Historical LCOE comparison of various utility-scale generation technologies
- Illustration of the historical LCOE declines for wind and utility-scale solar technologies
- Illustration of how the LCOE of utility-scale solar compares to the LCOE of gas peaking and how the LCOE of wind compares to the LCOE of gas combined cycle generation
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the LCOE for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense and fuel cost, as relevant
- A methodological overview of Lazard's approach to our LCOE analysis
- Considerations regarding the usage characteristics and applicability of various generation technologies
- An illustrative comparison of the cost of carbon abatement of various Alternative Energy technologies relative to conventional generation
- Summary assumptions for Lazard's LCOE analysis
- Summary of Lazard's approach to comparing the LCOE for various conventional and Alternative Energy generation technologies

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.)

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances[1]



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Such observation does not take into account other factors that would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.).

(2) Unless otherwise indicated herein, the low end represents a single-axis tracking system and the high end represents a fixed-tilt design.

(3) Represents the estimated implied midpoint of the LCOE of offshore wind, assuming a capital cost range of approximately $2.25 – $3.80 per watt.

(4) Unless otherwise indicated, the analysis herein does not reflect decommissioning costs or the potential economic impacts of federal loan guarantees or other subsidies.

(5) Represents the midpoint of the marginal cost of operating fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research. Please see page titled "Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation" for additional details.

(6) Unless otherwise indicated, the analysis herein reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

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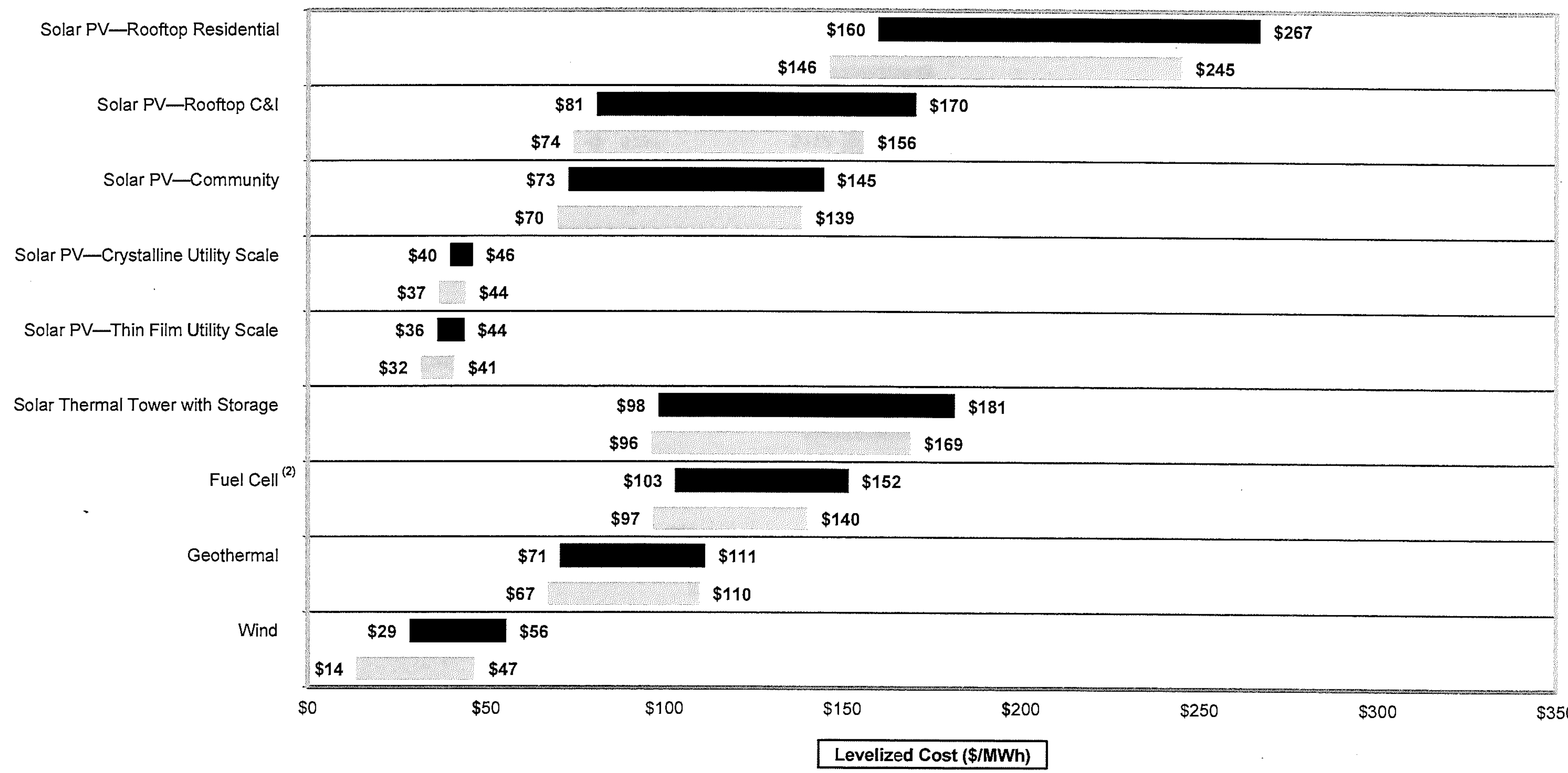
Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies(1)

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies

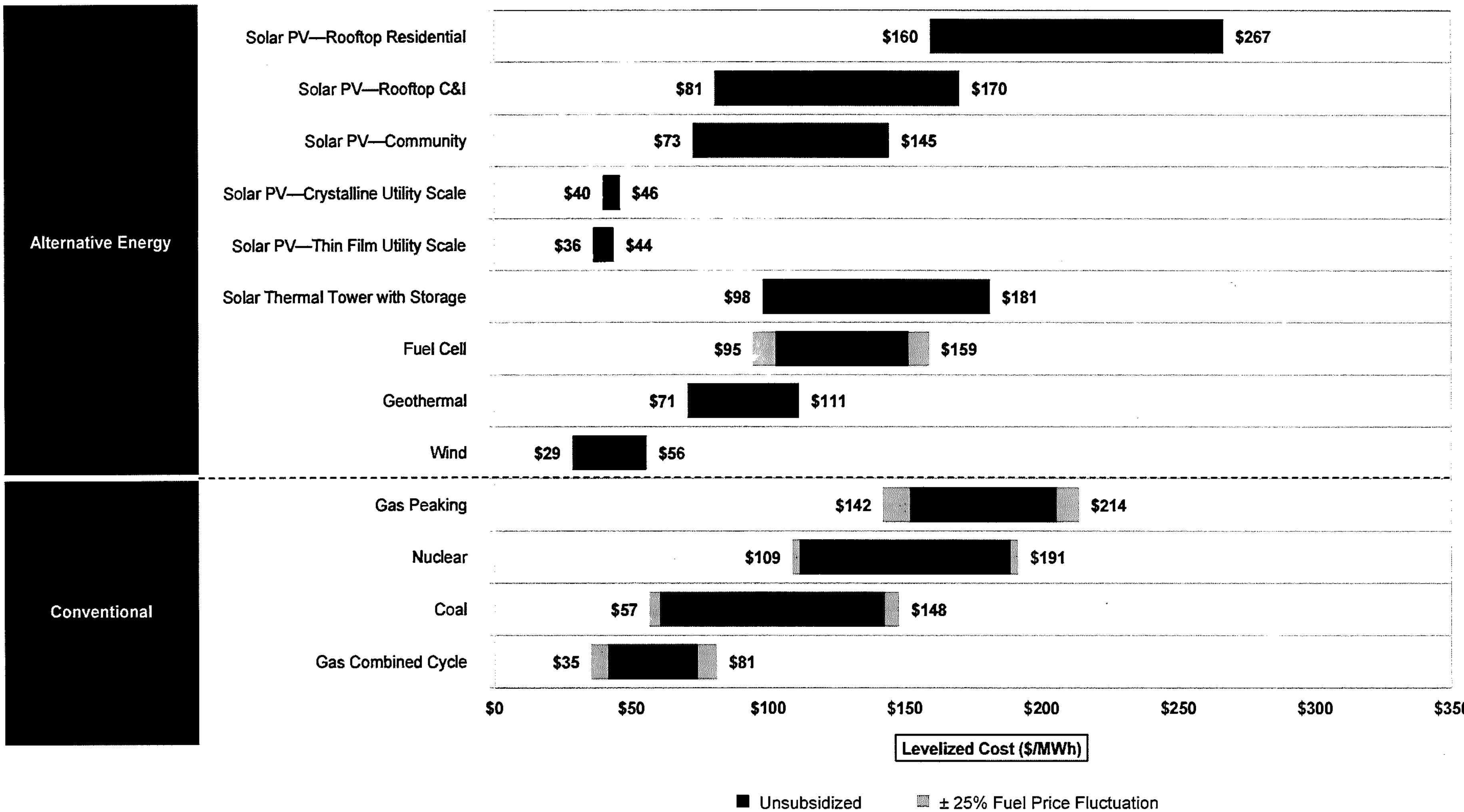


Source: *Lazard estimates.*
Note: The sensitivity analysis presented on this page also includes sensitivities related to the U.S. Tax Cuts and Jobs Act ("TCJA") of 2017. The TCJA contains several provisions that impact the LCOE of various generation technologies (e.g., a reduced federal corporate income tax rate, an ability to elect immediate bonus depreciation, limitations on the deductibility of interest expense and restrictions on the utilization of past net operating losses). On balance, the TCJA reduced the LCOE of conventional generation technologies and marginally increased the LCOE for Alternative Energy technologies.

(1) The sensitivity analysis presented on this page assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, tax equity and debt.
(2) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the LCOE of conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

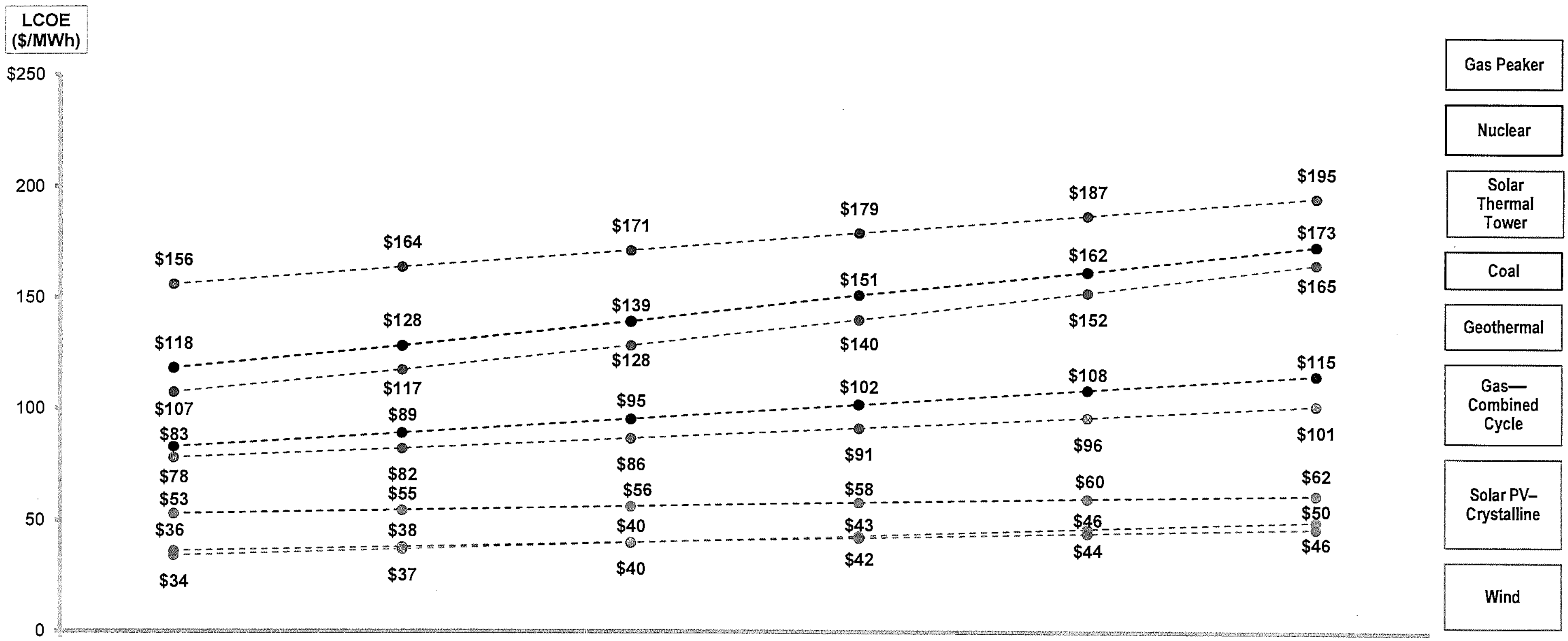


Source: *Lazard estimates.*

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration for utility-scale generation technologies is the impact of the availability and cost of capital[1] on LCOE values; availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them

Midpoint of Unsubsidized LCOE[2]

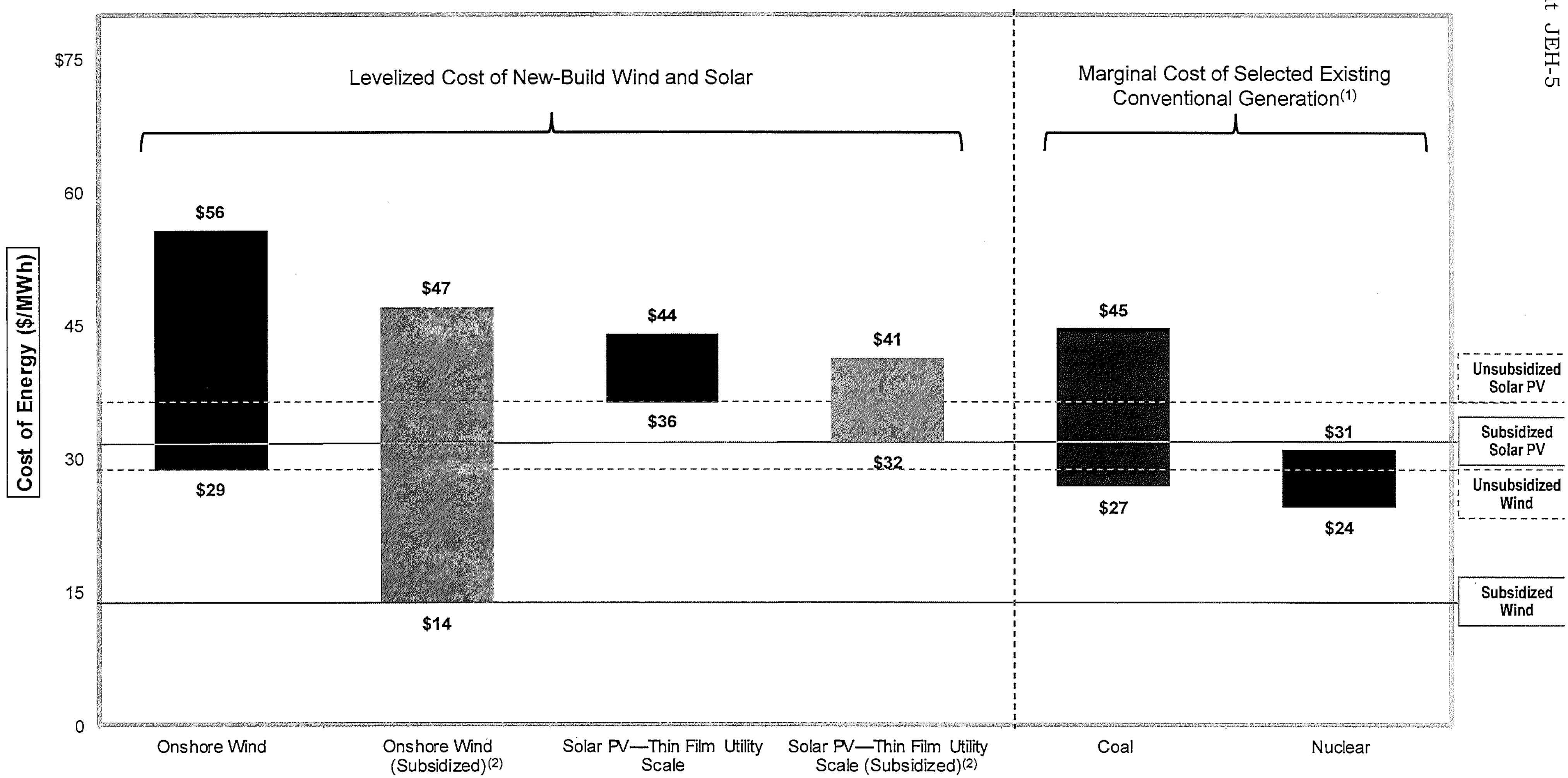


After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Source: *Lazard estimates.*
Note: Analysis assumes 60% debt and 40% equity.
(1) Cost of capital as used herein indicates the cost of capital for the asset/plant and not the cost of capital of a particular investor/owner.
(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation

Certain Alternative Energy generation technologies, which became cost-competitive with conventional generation technologies several years ago, are, in some scenarios, approaching an LCOE that is at or below the marginal cost of existing conventional generation technologies



Source: *Lazard estimates.*

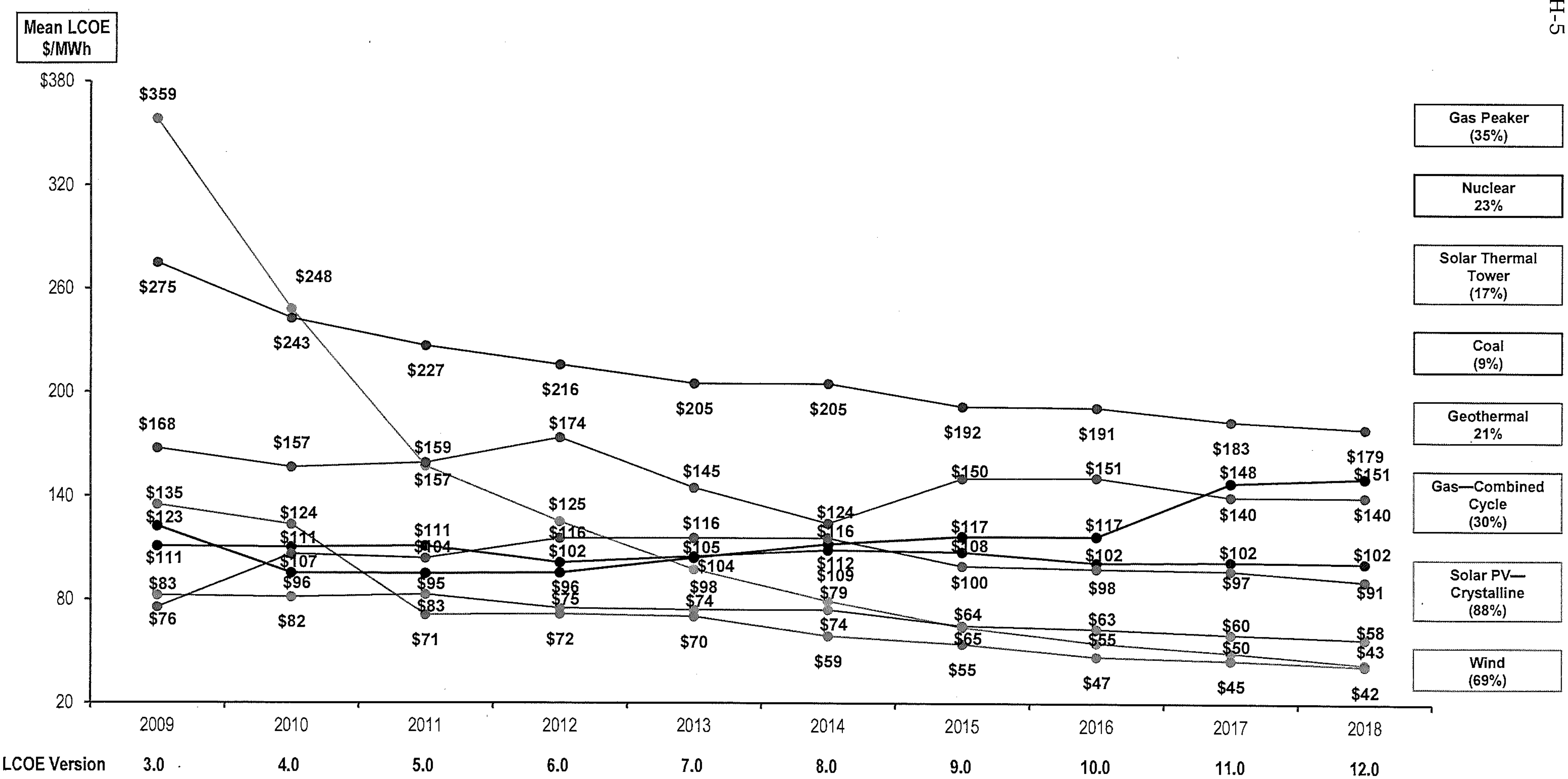
(1) Represents the marginal cost of operating, fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research.

(2) The subsidized analysis includes sensitivities related to the TCJA and U.S. federal tax subsidies. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

Levelized Cost of Energy Comparison—Historical Utility-Scale Generation Comparison

Lazard's unsubsidized LCOE analysis indicates significant historical cost declines for utility-scale Alternative Energy generation technologies driven by, among other factors, decreasing supply chain costs, improving technologies and increased competition

Selected Historical Mean Unsubsidized LCOE Values(1)

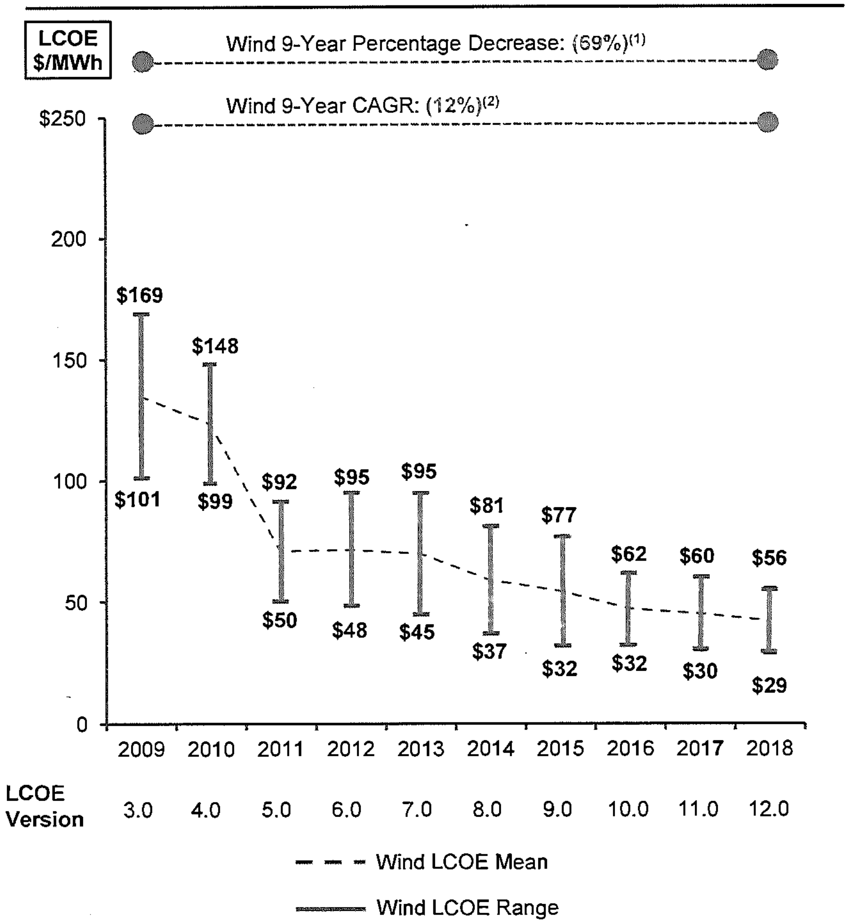


Source: *Lazard estimates.*
(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE—Version 3.0.

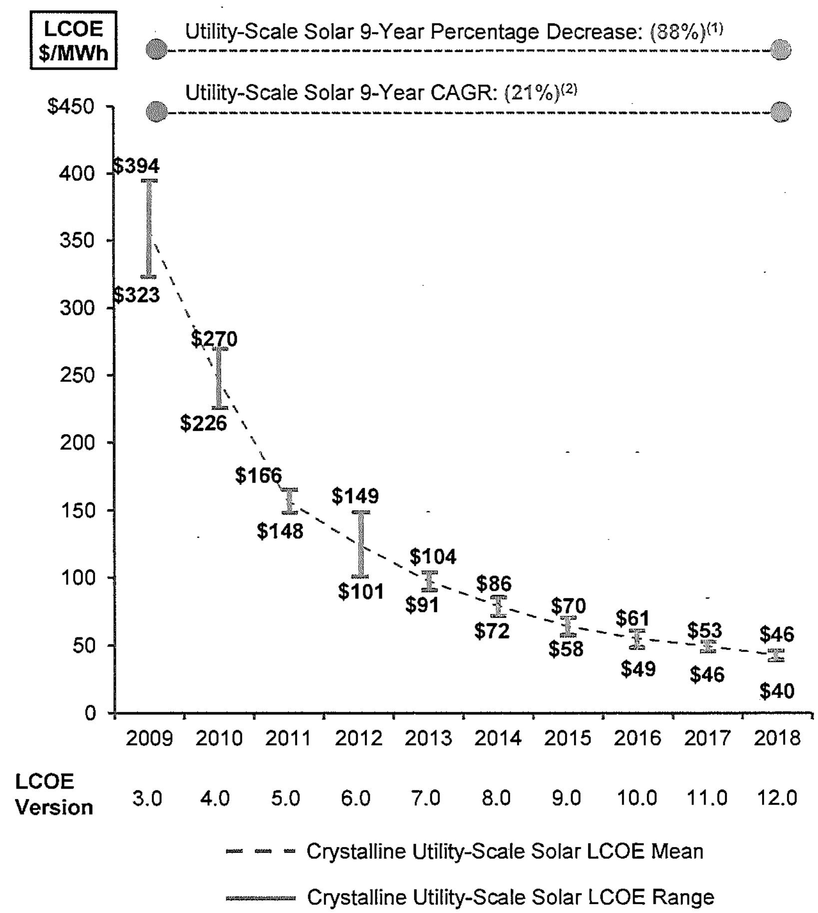
Levelized Cost of Energy Comparison—Historical Alternative Energy LCOE Declines

In light of material declines in the pricing of system components (e.g., panels, inverters, turbines, etc.) and improvements in efficiency, among other factors, wind and utility-scale solar PV have seen dramatic historical LCOE declines; however, over the past several years the rate of such LCOE declines have started to flatten

Unsubsidized Wind LCOE



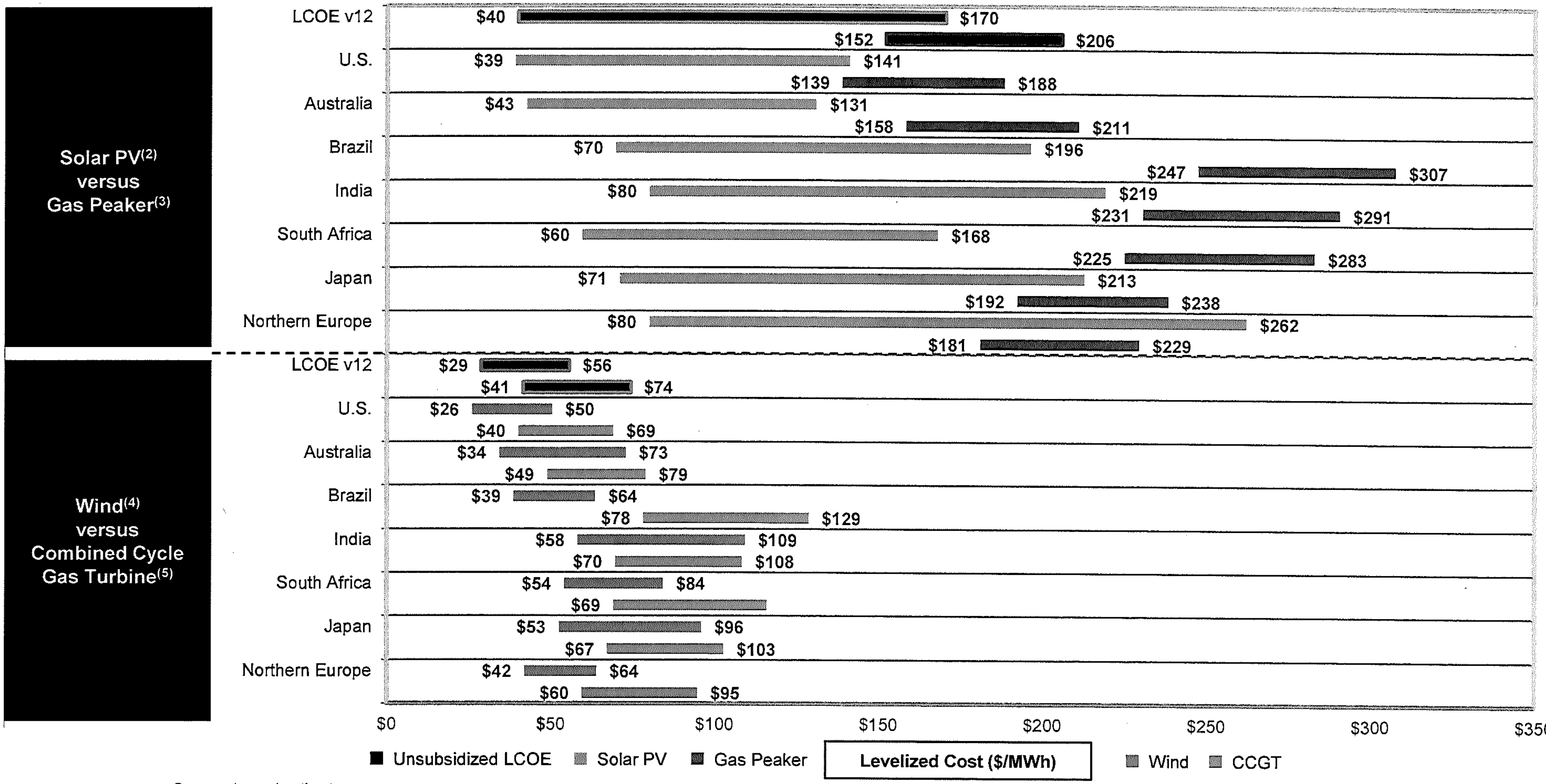
Unsubsidized Solar PV LCOE



Source: Lazard estimates.
(1) Represents the average percentage decrease of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Solar PV versus Peaking and Wind versus CCGT—Global Markets(1)

Solar PV and wind have become an increasingly attractive resource relative to conventional generation technologies with similar generation profiles; without storage, however, these resources lack the dispatch characteristics of such conventional generation technologies



Source: Lazard estimates.

(1) Equity IRRs are assumed to be 10% for the U.S., 12% for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa. Cost of debt is assumed to be 6% for the U.S., 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(2) Low end assumes crystalline utility-scale solar with a single-axis tracker. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 21% – 28% for the U.S., 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe.

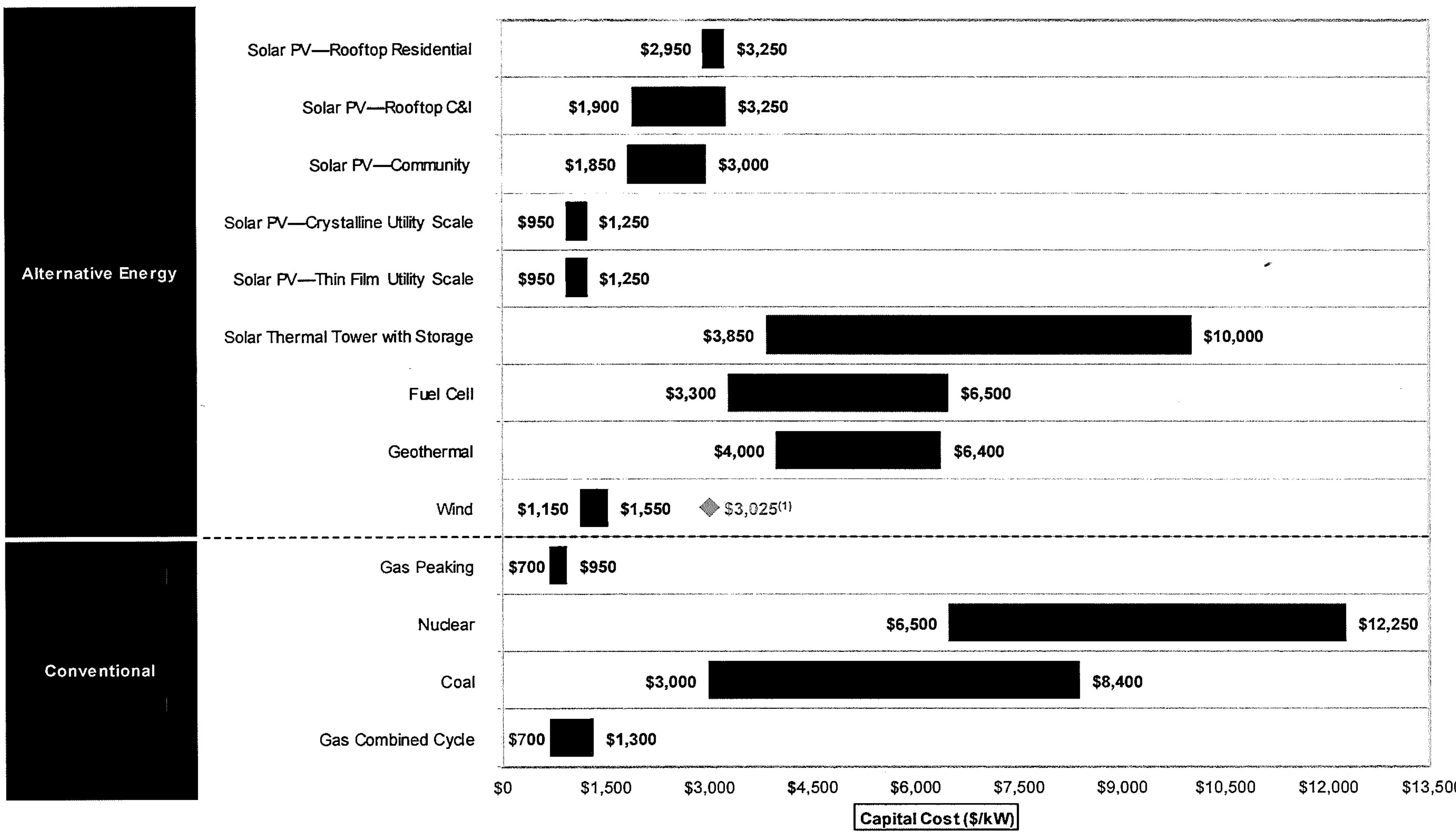
(3) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes a capacity factor of 10% for all geographies.

(4) Wind projects assume illustrative capacity factors of 38% – 55% for the U.S., 29% – 46% for Australia, 45% – 55% for Brazil, 25% – 35% for India, 31% – 36% for South Africa, 22% – 30% for Japan and 33% – 38% for Northern Europe.

(5) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes capacity factors of 43% – 80% on the high and low ends, respectively, for all geographies.

Capital Cost Comparison

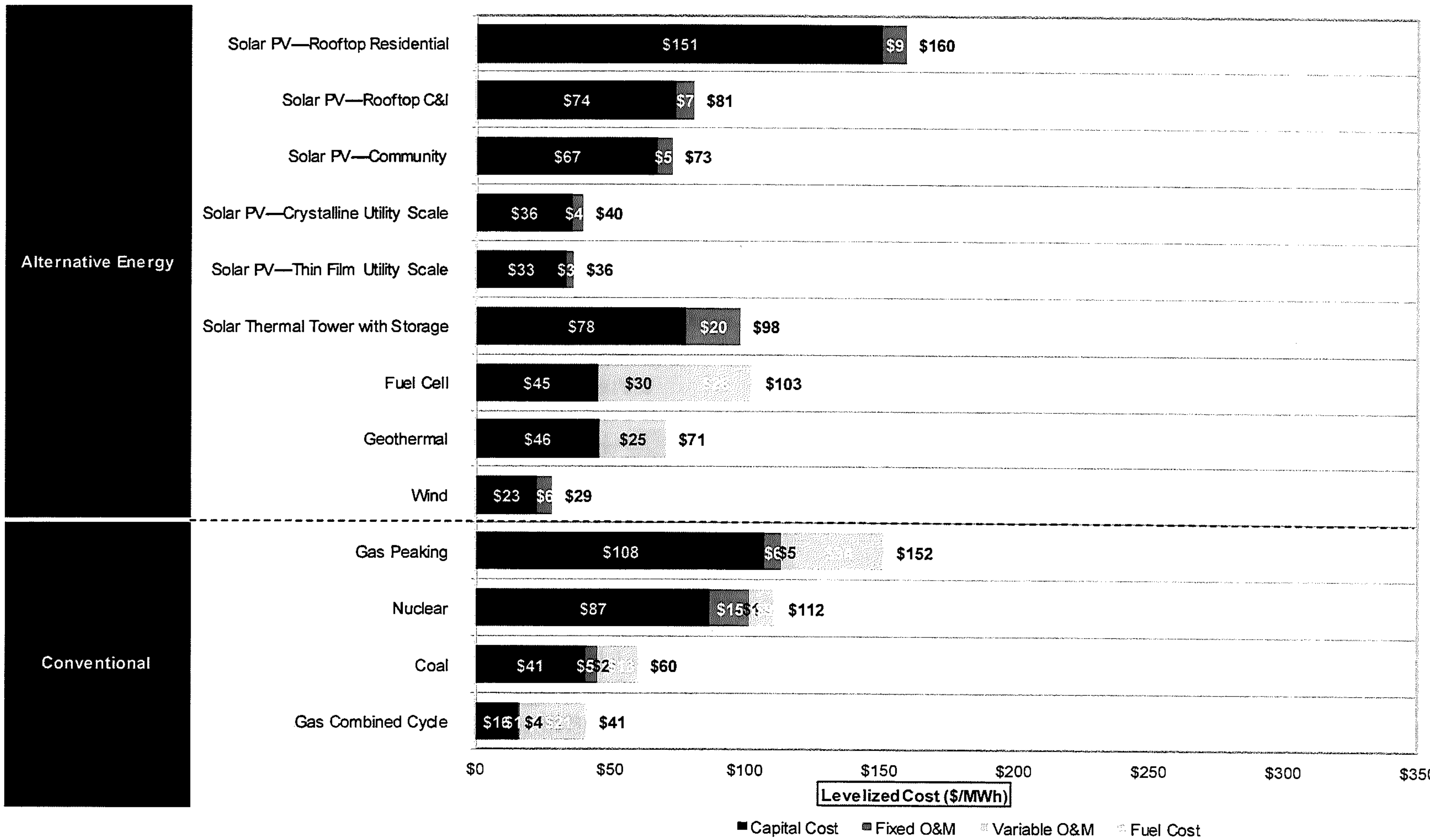
While capital costs for a number of Alternative Energy generation technologies are currently in excess of some conventional generation technologies, declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in LCOE values



Source: *Lazard estimates.*
(1) Represents the estimated midpoint of the total capital cost for offshore wind.

Levelized Cost of Energy Components—Low End

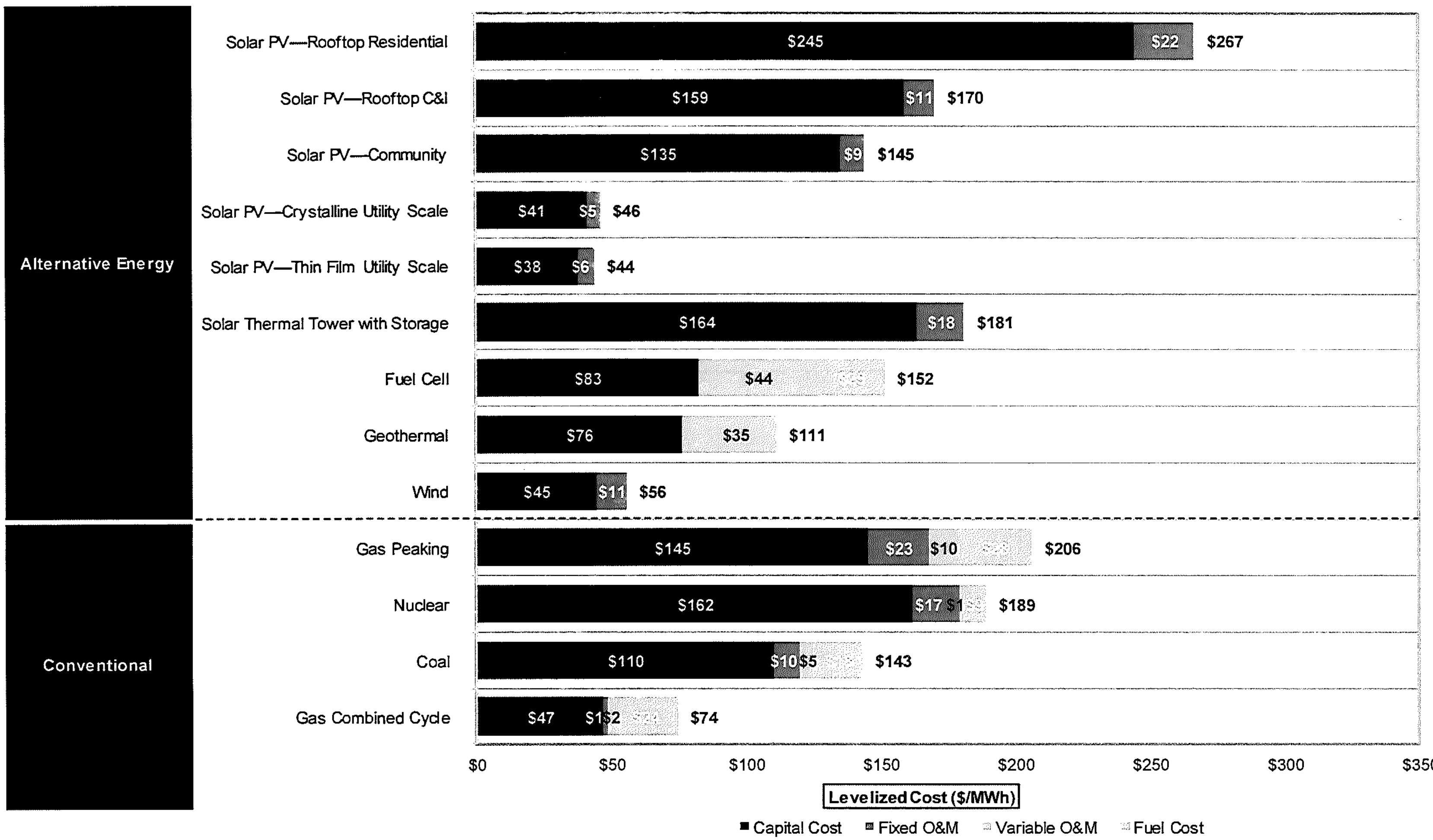
Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies



Source: *Lazard estimates.*

Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies



Source: Lazard estimates.

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOE analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see appendix for detailed assumptions by technology)

Unsubsidized Wind — High Case Sample Illustrative Calculations

Year (1)		*0*	*1*	*2*	*3*	*4*	*5*	*20*
Capacity (MW)	(A)		150	150	150	150	150	150
Capacity Factor	(B)		38%	38%	38%	38%	38%	38%
Total Generation ('000 MWh)	(A) x (B) = (C)*		499	499	499	499	499	499
Levelized Energy Cost ($/MWh)	***(D)***		*$55.6*	*$55.6*	*$55.6*	*$55.6*	*$55.6*	*$55.6*
Total Revenues	**(C) x (D) = (E)***		$27.8	$27.8	$27.8	$27.8	$27.8	$27.8
Total Fuel Cost	(F)		–	–	–	–	–	–
Total O&M	(G)*		5.5	5.6	5.7	5.9	6.0	8.4
Total Operating Costs	**(F) + (G) = (H)**		**$5.5**	**$5.6**	**$5.7**	**$5.9**	**$6.0**	$8.4
EBITDA	**(E) - (H) = (I)**		**$22.3**	**$22.2**	**$22.0**	**$21.9**	**$21.8**	**$19.4**
Debt Outstanding - Beginning of Period	(J)		$139.5	$136.7	$133.7	$130.5	$127.0	$24.8
Debt - Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)	(2.0)
Debt - Principal Payment	(L)		(2.8)	(3.0)	(3.2)	(3.5)	(3.8)	(11.9)
Levelized Debt Service	(K) + (L) = (M)		($13.9)	($13.9)	($13.9)	($13.9)	($13.9)	($13.9)
EBITDA	(I)		$22.3	$22.2	$22.0	$21.9	$21.8	$19.4
Depreciation (MACRS)	(N)		(46.5)	(74.4)	(44.6)	(26.8)	(26.8)	–
Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)	(2.0)
Taxable Income	**(I) + (N) + (K) = (O)**		**($35.4)**	**($63.2)**	**($33.3)**	**($15.3)**	**($15.2)**	**$17.4**
Tax Benefit (Liability) (2)	**(O) x (tax rate) = (P)**		**$14.2**	**$25.3**	**$13.3**	**$6.1**	**$6.1**	**($7.0)**
After-Tax Net Equity Cash Flow	**(I) + (M) + (P) = (Q)**	($93.0)(3)	**$22.5**	**$33.5**	**$21.4**	**$14.1**	**$13.9**	**($1.5)**
IRR For Equity Investors		12.0%						

Key Assumptions (4)	
Capacity (MW)	150
Capacity Factor	38%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$36.5
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years) (5)	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,550
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,550
Total Capex ($mm)	$233

Technology-dependent

Levelized

Source: *Lazard estimates.*
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Assumes full monetization of tax benefits or losses immediately.
(3) Reflects initial cash outflow from equity investors.
(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Energy Resources—Matrix of Applications

While the LCOE for Alternative Energy generation technologies is, in some cases, competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV[1]	✓	✓	✓	Universal[2]	✓	✓		
	Solar Thermal	✓		✓	Varies	✓	✓	✓	
	Fuel Cell	✗	✓		Universal				✓
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Varies	✓			
Conventional	Gas Peaking	✗	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	✗[3]		✓	Co-located or rural				✓
	Gas Combined Cycle	✗		✓	Universal			✓	✓

Source: *Lazard estimates.*
(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.
(3) For the purposes of this analysis, carbon neutrality also considers the emissions produced during plant construction and fuel extraction.

Cost of Carbon Abatement Comparison

As policymakers consider ways to limit carbon emissions, Lazard's LCOE analysis provides insight into the implicit "costs of carbon avoidance", as measured by the abatement value offered by Alternative Energy generation technologies. This analysis suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost-effective means of limiting carbon emissions; providing an implied value of carbon abatement of $26 – $34/Ton vs. Coal and $10 – $25/Ton vs. Gas Combined Cycle

- **These observations do not take into account potential social and environmental externalities or reliability or grid-related considerations**

		Conventional Generation			Alternative Energy Generation			
	Units	**Coal**	**Gas Combined Cycle**	**Nuclear**	**Wind**	**Solar PV Rooftop**	**Solar PV Utility Scale**	**Solar Thermal with Storage**
Capital Investment/KW of Capacity [1]	$/kW	$3,000	$700	$6,500	$1,150	$2,950	$950	$3,850
Total Capital Investment	$mm	**1,800**	**490**	**4,030**	**1,162**	**8,673**	**1,558**	**5,044**
Facility Output	MW	600	700	620	1,010	2,940	1,640	1,310
Capacity Factor	%	93%	80%	90%	55%	19%	34%	43%
Effective Facility Output	**MW**	**558**	**558**	**558**	**558**	**558**	**558**	**558**
MWh/Year Produced [2]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$60	$41	$112	$29	$160	$36	$98
Total Cost of Energy Produced	**$mm/yr**	**$296** 2	**$203**	**$546**	**$140**	**$781**	**$178** 1	**$480**
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	4.51 3	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($93)	$250	($155)	$485	($118) 4	$185
vs. Gas		—	—	$343	($63)	$578	($25)	$278
Implied Abatement Value/(Cost)	$/Ton							
vs. Coal		—	$46	($55)	$34	($108)	$26 5	($41)
vs. Gas		—	—	($137)	$25	($231)	$10	($111)

: Favorable vs. Coal/Gas : Unfavorable vs. Coal/Gas

Implied Carbon Abatement Value Calculation (Solar vs. Coal)—Methodology

4 Difference in Total Energy Cost (Solar vs. Coal) = 1 – 2
= $178 mm/yr (Solar) – $296 mm/yr (Coal) = ($118) mm/yr

5 Implied Carbon Abatement Value (Solar vs. Coal) = 4 ÷ 3
= $118 mm/yr ÷ 4.51 mm Tons/yr = $26/Ton

Source: Lazard estimates.
(1) Inputs for each of the various technologies are those associated with the low end LCOE.
(2) All facilities illustratively sized to produce 4,888 GWh/yr.

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.).

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Solar Thermal Tower with Storage	Fuel Cell	Geothermal	Wind—Onshore	Wind—Offshore
Net Facility Output	MW	135 – 110	2.4	20 – 50	150	210 – 385
Total Capital Cost [1]	$/kW	$3,850 – $10,000	$3,300 – $6,500	$4,000 – $6,400	$1,150 – $1,550	$2,250 – $3,800
Fixed O&M	$/kW-yr	$75.00 – $80.00	—	—	$28.00 – $36.50	$80.00 – $110.00
Variable O&M	$/MWh	—	$30.00 – $44.00	$25.00 – $35.00	—	—
Heat Rate	Btu/kWh	—	8,027 – 7,260	—	—	—
Capacity Factor	%	43% – 52%	95%	90% – 85%	55% – 38%	55% – 45%
Fuel Price	$/MMBtu	—	3.45	—	—	—
Construction Time	Months	36	3	36	12	12
Facility Life	Years	35	20	25	20	20
Levelized Cost of Energy	$/MWh	$98 – $181	$103 – $152	$71 – $111	$29 – $56	$62 – $121

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Gas Peaking	Nuclear	Coal	Gas Combined Cycle
Net Facility Output	MW	241 – 50	2,200	600	550
Total Capital Cost [(1)]	$/kW	$700 – $950	$6,500 – $12,250	$3,000 – $8,400	$700 – $1,300
Fixed O&M	$/kW-yr	$5.00 – $20.00	$115.00 – $135.00	$40.00 – $80.00	$6.00 – $5.50
Variable O&M	$/MWh	$4.70 – $10.00	$0.75 – $0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	9,804 – 8,000	10,450 – 10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	10%	90%	93%	80%
Fuel Price	$/MMBtu	$3.45 – $3.45	$0.85 – $0.85	$1.45 – $1.45	$3.45 – $3.45
Construction Time	Months	12 – 18	69 – 69	60 – 66	24 – 24
Facility Life	Years	20	40	40	20
Levelized Cost of Energy	$/MWh	$152 – $206	$112 – $189	$60 – $143	$41 – $74

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Summary Considerations

Lazard has conducted this analysis comparing the LCOE for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including environmental and social consequences of various conventional generation technologies, RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase and government subsidies in certain regions.

In this analysis, Lazard's approach was to determine the LCOE, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the LCOE. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This analysis (as well as previous versions) has benefited from additional input from a wide variety of Industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.).

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

John E. Haselden
Senior Utility Analyst

Indiana Office of Utility Consumer Counselor

Cause No. 45245

8-12-19
Date

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***Indiana Office of Utility Consumer Counselor's Redacted Testimony of John E. Haselden*** has been served upon the following parties of record in the captioned proceeding by electronic service on August 12, 2019.

Indiana Michigan
Teresa Morton Nyhart
Jeffrey M. Peabody
BARNES & THORNBURG LLP
tnyhart@btlaw.com
jpeabody@btlaw.com

Matthew S. McKenzie
AMERICAN ELECTRIC POWER SERVICE CORP.
msmckenzie@aep.com

Citizens Action Coalition of Indiana
Jennifer A. Washburn
Margo Tucker
CAC
jwashburn@citact.org
mtucker@citact.org

T. Jason Haas
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PNC Center
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Telephone
317/232-5923 – Facsimile