



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

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This paper presents average values of levelized costs and levelized avoided costs for electric generating technologies entering service in 2021, 2023,<sup>1</sup> 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.<sup>2</sup> 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<sup>3</sup> 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.<sup>4</sup> LCOE is often cited as a convenient summary measure of the overall competitiveness 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.<sup>5</sup> 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.

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<sup>1</sup> Given the long lead-time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2023.

<sup>2</sup> AEO2019 are available online (<http://www.eia.gov/outlooks/aeo/>).

<sup>3</sup> Appendix A shows LCOE and LACE for the subset of technologies available to be built in 2021.

<sup>4</sup> 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.

<sup>5</sup> 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](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).

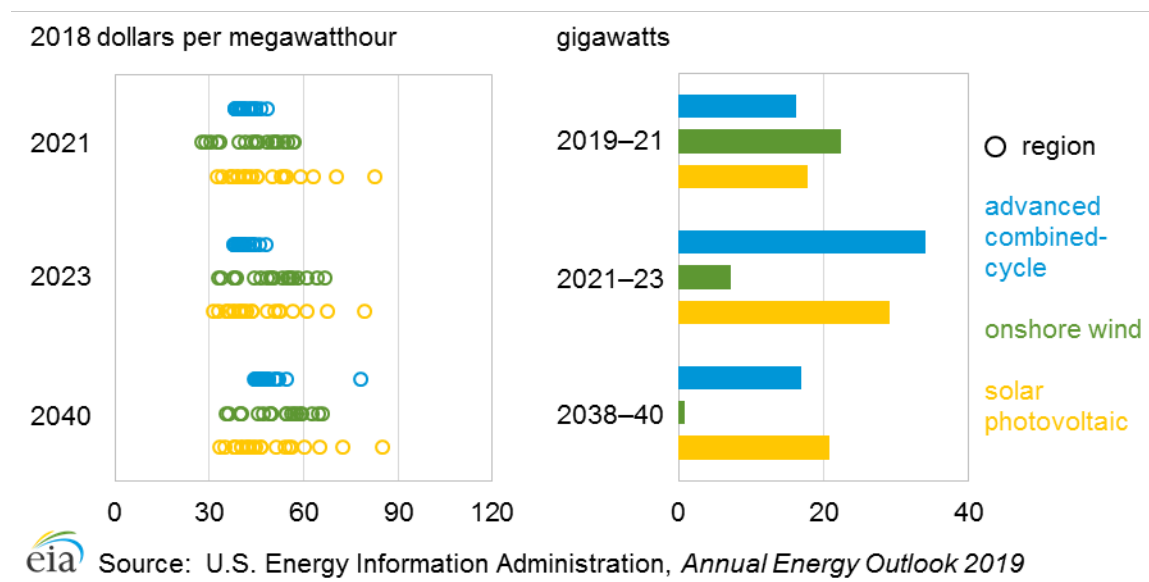
**Investment Tax Credit (ITC):** In June 2018, the IRS issued Notice 2018-59 (<https://www.irs.gov/pub/irs-drop/n-18-59.pdf>), a beginning of construction guidance for the ITC. EIA assumes all solar projects starting construction before January 1, 2020, have four years to bring the power plant online (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**



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).<sup>6</sup> 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

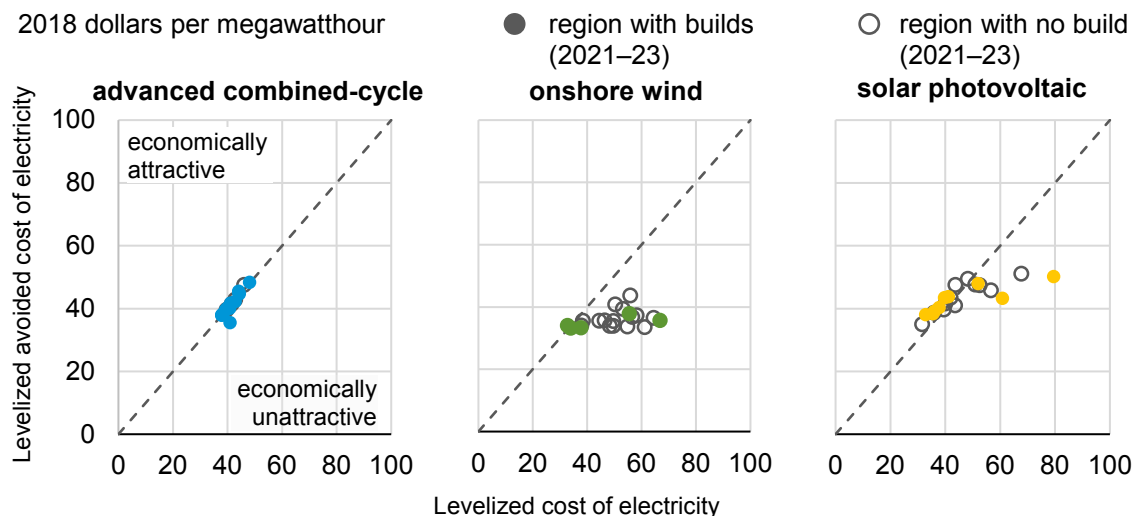
<sup>6</sup> Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found online: <http://www.eia.gov/renewable/workshop/gencosts/>.

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%.<sup>7</sup> 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<sup>8</sup> associated with major investments in long

<sup>7</sup>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>).

<sup>8</sup> 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 (CO<sub>2</sub>) emissions. AEO2019 takes into account two coal-fired technologies that are compliant with the New Source Performance Standard (NSPS) for CO<sub>2</sub> emissions under Section 111(b) of the Clean Air Act. One technology is designed to capture 30% of CO<sub>2</sub> emissions and would still be considered a high emitter relative to other new sources; therefore, it may continue to face potential financial risk if CO<sub>2</sub> emission controls are further strengthened. Another technology is designed to capture 90% of CO<sub>2</sub> 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.)

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*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<sup>1</sup>) 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 <sup>2</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>3</sup>	NB	NB	NB	NB	NB	NB	NB	NB
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>4</sup>	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 <sup>5</sup>	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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 <sup>1</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>2</sup>	85	61.3	9.7	32.2	1.1	104.3	NA	104.3
Coal with 90% CCS <sup>2</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>3</sup>	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 <sup>4</sup>	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

<sup>1</sup>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.

<sup>2</sup>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<sub>2</sub> 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.

<sup>3</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>4</sup>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)**

Plant type	Without tax credits				With tax credits <sup>1</sup>			
	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>3</sup>	93.7	104.3	NB	124.7	93.7	104.3	NB	124.7
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>4</sup>	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 <sup>5</sup>	39.1	39.1	39.1	39.1	39.1	39.1	39.1	39.1

<sup>1</sup>Levelized cost with tax credits reflects tax credits available for plants entering service in 2023. See note 1 in Tables 1a and 1b.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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 <sup>1</sup>	Maximum
<b>Dispatchable technologies</b>				
Coal with 30% CCS <sup>2</sup>	35.6	40.8	NB	48.6
Coal with 90% CCS <sup>2</sup>	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
<b>Non-dispatchable technologies</b>				
Wind, onshore	33.3	36.1	33.7	43.7
Wind, offshore	36.4	40.5	39.9	52.2
Solar PV <sup>3</sup>	35.1	43.4	40.3	51.1
Solar thermal	39.8	44.0	NB	51.2
Hydroelectric <sup>4</sup>	41.6	41.6	41.6	41.6

<sup>1</sup>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.

<sup>2</sup>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<sub>2</sub> 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.

<sup>3</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>4</sup>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 <sup>1</sup> LCOE with tax credits	Average capacity-weighted <sup>1</sup> LACE	Average value-cost ratio <sup>2</sup>
<b>Dispatchable technologies</b>			
Coal with 30% CCS <sup>3</sup>	NB	NB	NB
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>			
Wind, onshore	36.6	33.7	0.94
Wind, offshore	106.5	39.9	0.37
Solar PV <sup>4</sup>	37.6	40.3	1.07
Solar thermal	NB	NB	NB
Hydroelectric <sup>5</sup>	39.1	41.6	1.06

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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.<sup>9</sup>

**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 <sup>1</sup>	Minimum <sup>2</sup>	Maximum <sup>2</sup>
<b>Dispatchable technologies</b>					
Coal with 30% CCS <sup>3</sup>	104.3	40.8	0.39	0.35	0.44
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>					
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 <sup>4</sup>	45.7	43.4	0.98	0.63	1.16
Solar thermal	121.2	44.0	0.37	0.30	0.43
Hydroelectric <sup>5</sup>	39.1	41.6	1.06	1.06	1.06

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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*

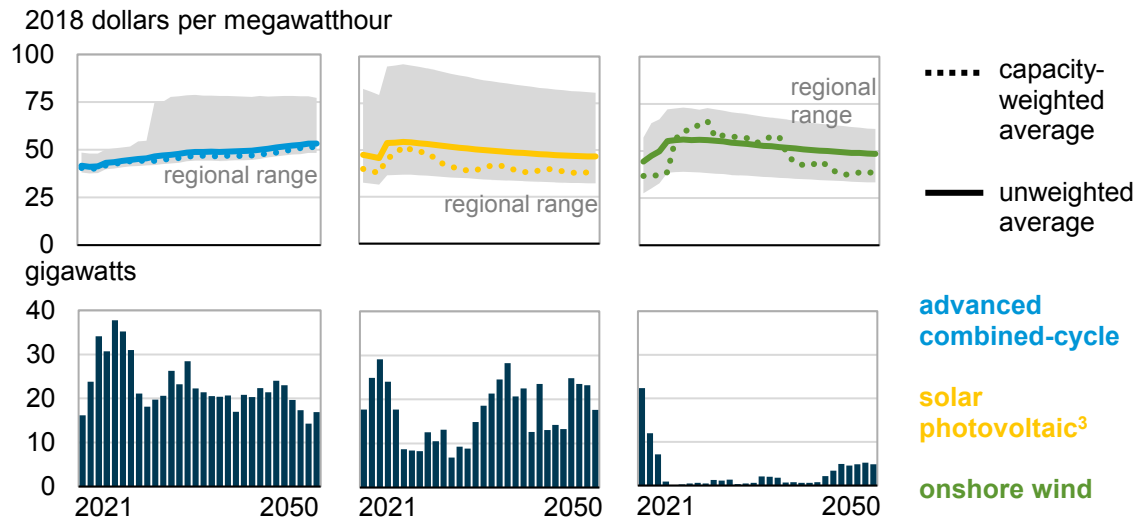
## LCOE and LACE projections

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

<sup>9</sup> 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](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<sup>1</sup> and unweighted levelized cost of electricity<sup>2</sup> projections and three-year moving capacity additions for selected generating technologies, 2021–50**



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

<sup>1</sup>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.

<sup>2</sup>Levelized-cost includes tax credits available for plants entering service during the projection period. See note 1 in Tables 1a and 1b.

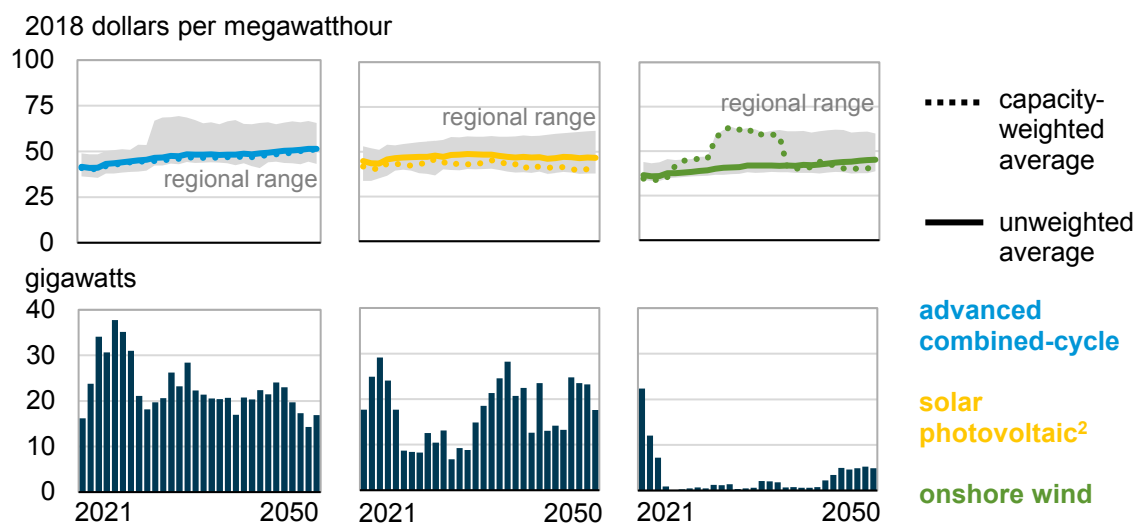
<sup>3</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

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<sup>1</sup> and unweighted levelized avoided cost of electricity projections and three-year moving capacity additions for selected generating technologies, 2021–50**



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

<sup>1</sup>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.

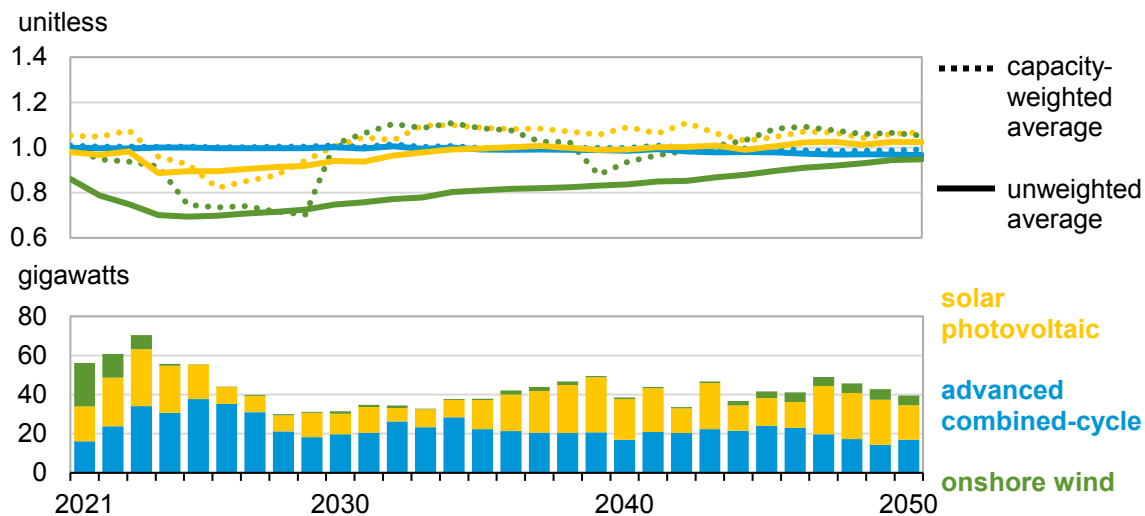
<sup>2</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

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<sup>1</sup>) 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 <sup>2</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
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
<b>Non-dispatchable technologies</b>								
Wind, onshore	43	33.4	13.1	0.0	2.3	48.8	-12.1	36.7
Solar PV <sup>3</sup>	31	41.0	8.3	0.0	2.9	52.2	-12.3	39.9

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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 <sup>1</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
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
<b>Non-dispatchable technologies</b>								
Wind, onshore	41	40.2	13.7	0.0	2.5	56.5	-12.1	44.4
Solar PV <sup>2</sup>	29	50.2	8.9	0.0	3.3	62.5	-15.1	47.4

<sup>1</sup>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.

<sup>2</sup>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)**

Plant type	Range for total system levelized costs				Range for total system levelized costs with tax credits <sup>1</sup>			
	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum
<b>Dispatchable technologies</b>								
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
<b>Non-dispatchable technologies</b>								
Wind, onshore	39.6	56.5	48.8	69.3	27.5	44.4	36.7	57.2
Solar PV <sup>3</sup>	41.7	62.5	52.2	111.6	32.6	47.4	39.9	82.8

<sup>1</sup>Levelized cost with tax credits reflects tax credits available for plants entering service in 2021. See note 1 in Tables A1a and A1b.

<sup>2</sup>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.

<sup>3</sup>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 <sup>1</sup>	Maximum
<b>Dispatchable technologies</b>				
Conventional CC	36.2	41.6	41.7	49.0
Advanced CC	36.2	41.6	40.8	49.0
<b>Non-dispatchable technologies</b>				
Wind, onshore	33.9	36.6	34.7	44.0
Solar PV <sup>4</sup>	33.7	44.8	41.7	52.9

<sup>1</sup>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.

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

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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 <sup>1</sup>	Minimum <sup>2</sup>	Maximum <sup>2</sup>
<b>Dispatchable technologies</b>					
Conventional CC	46.8	41.6	0.89	0.79	0.93
Advanced CC	41.6	41.6	1.00	0.88	1.04
<b>Non-dispatchable technologies</b>					
Wind, onshore	44.4	36.6	0.86	0.60	1.23
Solar PV <sup>3</sup>	47.4	44.8	0.98	0.61	1.20

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sup>1</sup>) 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 <sup>2</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>3</sup>	NB	NB	NB	NB	NB	NB	NB	NB
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>4</sup>	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 <sup>5</sup>	73	39.4	13.7	1.4	1.9	56.3	NA	56.3

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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 <sup>1</sup>	Total LCOE including tax credit
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>2</sup>	85	58.9	9.7	36.7	1.2	106.5	NA	106.5
Coal with 90% CCS <sup>2</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>3</sup>	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 <sup>4</sup>	63	35.9	9.7	1.9	2.2	49.6	NA	49.6

<sup>1</sup>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.

<sup>2</sup>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<sub>2</sub> 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.

<sup>3</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>4</sup>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)**

Plant type	Range for total system levelized costs				Range for total system levelized costs with tax credits <sup>1</sup>			
	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum	Minimum	Simple average	Capacity-weighted average <sup>2</sup>	Maximum
<b>Dispatchable technologies</b>								
Coal with 30% CCS <sup>3</sup>	90.8	106.5	NB	160.0	90.8	106.5	NB	160.0
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>								
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 <sup>4</sup>	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 <sup>5</sup>	38.9	49.6	56.3	64.6	38.9	49.6	56.3	64.6

<sup>1</sup>Levelized cost with tax credits reflects tax credits available for plants entering service in 2040. See note 1 in Tables B1a and B1b.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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)**

<b>Plant type</b>	<b>Minimum</b>	<b>Simple average</b>	<b>Capacity-weighted average<sup>1</sup></b>	<b>Maximum</b>
<b>Dispatchable technologies</b>				
Coal with 30% CCS <sup>2</sup>	42.5	48.0	NB	67.3
Coal with 90% CCS <sup>2</sup>	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
<b>Non-dispatchable technologies</b>				
Wind, onshore	37.8	41.9	40.2	61.3
Wind, offshore	41.9	47.4	NB	73.2
Solar PV <sup>3</sup>	38.4	46.8	42.9	58.5
Solar thermal	41.1	48.4	NB	55.3
Hydroelectric <sup>4</sup>	41.7	51.1	57.6	65.8

<sup>1</sup>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.

<sup>2</sup>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<sub>2</sub> 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.

<sup>3</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>4</sup>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**

<b>Plant type</b>	<b>Average capacity-weighted<sup>1</sup> LCOE with tax credits (2018 \$/MWh)</b>	<b>Average capacity-weighted<sup>1</sup> LACE (2018 \$/MWh)</b>	<b>Average value-cost ratio<sup>2</sup></b>
<b>Dispatchable technologies</b>			
Coal with 30% CCS <sup>3</sup>	NB	NB	NB
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>			
Wind, onshore	43.5	40.2	0.94
Wind, offshore	NB	NB	NB
Solar PV <sup>4</sup>	39.5	42.9	1.09
Solar thermal	NB	NB	NB
Hydroelectric <sup>5</sup>	56.3	57.6	1.02

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup>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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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 <sup>1</sup>	Minimum <sup>2</sup>	Maximum <sup>3</sup>
<b>Dispatchable technologies</b>					
Coal with 30% CCS <sup>3</sup>	106.5	48.0	0.45	0.42	0.52
Coal with 90% CCS <sup>3</sup>	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
<b>Non-dispatchable technologies</b>					
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 <sup>4</sup>	48.7	46.8	0.99	0.69	1.19
Solar thermal	127.5	48.4	0.38	0.29	0.45
Hydroelectric <sup>5</sup>	49.6	51.1	1.04	0.89	1.21

<sup>1</sup>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.

<sup>2</sup>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.

<sup>3</sup> 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<sub>2</sub> 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.

<sup>4</sup>Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>5</sup>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*