Independent Statistics & Analysis
U.S. Energy Information Administration

April 2014

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014

This paper presents average values of levelized costs for generating technologies that are brought online in 2019[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2014* (AEO2014) Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. 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.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while LCOE is a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.

A related factor is the ***capacity value***, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less

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[1] 2019 is shown because the long lead time needed for some technologies means that the plant could not be brought online prior to 2019 unless it was already under construction.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/oiaf/aeo/index.html.

flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of LCOE across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments. The avoided cost is divided by average annual output of the project to develop the "levelized" avoided cost of electricity (LACE) for the project.[4] The LACE value may then be compared with the LCOE value for the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology and represents the potential revenue available to the project owner from the sale of energy and generating capacity. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on ***portfolio diversification***. While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations.

The LCOE values shown for each utility-scale generation technology in Table 1 and Table 2 in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.5%. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2014 reference case, 3 percentage points are added to the cost of capital when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-

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

fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning.[5] The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Although the capital and operating components do not incorporate the production or investment tax credits available to some technologies, a subsidy column is included in Table 1 to reflect the estimated value of these tax credits, where available, in 2019. In the reference case, tax credits are assumed to expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. As noted above, the LCOE (and also subsequent LACE) calculations presented in the tables apply only to the utility-scale use of those technologies.

In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. They should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the LCOE values shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, LCOE for incremental wind capacity coming online in 2019 ranges from $71.3/MWh in the region with the best available resources in 2019 to $90.3/MWh in regions where LCOE values are highest due to lower quality wind resources and/or higher capital costs for the best sites that can accommodate additional wind capacity. Costs shown for wind may include additional costs associated with transmission upgrades needed to access

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[5] Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), www.morganstanley.com/about/press/articles/6017.html.

remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

As previously indicated, LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for intermittent resources, such as wind or solar, that 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. The LACE estimates in this table have been calculated assuming the same maximum capacity factor as in the LCOE. A subset of the full list of technologies in Table 1 is shown because the LACE value for similar technologies with the same capacity factor would have the same value (for example, conventional and advanced combined cycle plants will have the same avoided cost of electricity). Values are not shown for combustion turbines, because turbines are more often built for their capacity value to meet a reserve margin rather than to meet generation requirements and avoid energy costs.

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. While the build decisions in the real world, and as modeled in the AEO, are somewhat more complex than a simple LACE to LCOE comparison, including such factors as policy and non-economic drivers, the net economic value (LACE minus LCOE, including subsidy, for a given technology, region and year) shown in Table 4 provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either the LCOE or LACE tables individually. In Table 4, a negative difference indicates that the cost of the marginal new unit of capacity exceeds its value to the system, as measured by LACE; a positive difference indicates that the marginal new unit brings in value in excess of its cost by displacing more expensive generation and capacity options. The range of differences columns represent the variation in the calculation of the difference for each region. For example, in the region where the advanced combined cycle appears most economic in 2019, the LCOE is $61.5/MWh and the LACE is $62.3/MWh, resulting in a net difference of $0.8/MWh. This range of differences is not based on the difference between the minimum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

The average net differences shown in Table 4 are for plants coming online in 2019, consistent with Tables 1-3, as well as for plants that could come online in 2040, to show how the relative competitiveness changes over the projection period. Additional tables showing the LCOE cost components and regional variation in LCOE and LACE for 2040 can be found in the Appendix. In 2019, the average net differences are negative for all technologies except geothermal, reflecting the fact that on average, new capacity is not needed in 2019. However, the upper value for both combined cycle technologies is at or above zero, indicating competiveness in a particular region. Geothermal cost data is site-specific, and the relatively large positive value for that technology results because there may be individual sites that are very cost competitive, leading to new builds, but there is a limited amount of capacity available at that cost. By 2040, the LCOE values for most technologies are lower, typically reflecting declining capital costs over time. All technologies receive cost reductions from learning over time, with newer, advanced technologies receiving larger cost reductions, while conventional technologies will see smaller learning effects. Capital costs are also adjusted over time based on commodity prices, through a factor based on the metals and metal products index, which declines in real terms over the projection. However, the LCOE for natural gas-fired technologies rises over time, because rising fuel costs more than offset any decline in capital costs. The LACE values for all technologies increase by 2040 relative to 2019, reflecting higher energy costs and a greater value for new capacity. As a result, the difference between LACE and LCOE for almost all technologies gets closer to a net positive value in 2040, and there are several technologies (advanced combined cycle, wind, solar PV, hydro and geothermal) that have multiple regions with positive net differences.

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2019

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019							
Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[1]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore Text	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

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

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2019

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	87.0	95.6	114.4			
IGCC	106.4	115.9	131.5			
IGCC with CCS	137.3	147.4	163.3			
Natural Gas-fired						
Conventional Combined Cycle	61.1	66.3	75.8			
Advanced Combined Cycle	59.6	64.4	73.6			
Advanced CC with CCS	85.5	91.3	105.0			
Conventional Combustion Turbine	106.0	128.4	149.4			
Advanced Combustion Turbine	96.9	103.8	119.8			
Advanced Nuclear	92.6	96.1	102.0	82.6	86.1	92.0
Geothermal	46.2	47.9	50.3	43.1	44.5	46.4
Biomass	92.3	102.6	122.9			
Non-Dispatchable Technologies						
Wind	71.3	80.3	90.3			
Wind – Offshore	168.7	204.1	271.0			
Solar PV[2]	101.4	130.0	200.9	92.6	118.6	182.6
Solar Thermal	176.8	243.1	388.0	162.6	223.6	356.7
Hydroelectric[3]	61.6	84.5	137.7			

[1]Levelized cost with subsidies reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005.

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

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated 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 as follows: Wind – 31% to 45%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 30% to 65%. 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 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 3: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2019

	Range for LACE (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal-fired plant types without CCS	54.6	62.2	70.6
IGCC with CCS[1]	54.6	62.0	70.6
Natural Gas-fired Combined Cycle	54.5	62.9	74.2
Advanced Nuclear	54.6	61.7	70.5
Geothermal	58.3	60.9	62.4
Biomass	54.5	63.3	74.5
Non-Dispatchable Technologies			
Wind	51.7	55.7	66.4
Wind – Offshore	55.1	62.3	73.7
Solar PV	50.8	73.4	89.6
Solar Thermal	48.2	73.3	82.3
Hydroelectric	54.1	59.9	69.5

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

Table 4: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE), 2019 and 2040

Plant Type	Average LCOE	Average LACE	Average Difference	Range of DIfferences	
	Comparison of LACE - LCOE (2012 $/MWh)				
2019					
Dispatchable Technologies					
Conventional Coal	95.6	62.2	-33.5	-48.9	-25.1
IGCC	115.9	62.2	-53.7	-66.1	-43.9
IGCC with CCS	147.4	62.0	-85.4	-104.7	-74.8
Natural Gas-fired					
Conventional Combined Cycle	66.3	62.9	-3.4	-13.7	0.0
Advanced Combined Cycle	64.4	62.9	-1.5	-11.2	0.8
Advanced CC with CCS	91.3	62.9	-28.4	-34.6	-23.7
Advanced Nuclear	86.1	61.7	-24.4	-33.0	-13.0
Geothermal	44.5	60.9	16.4	15.2	18.1
Biomass	102.6	63.3	-39.3	-57.2	-28.5
Non-Dispatchable Technologies					
Wind	80.3	55.7	-24.5	-37.6	-6.3
Wind – Offshore	204.1	62.3	-141.8	-210.1	-107.1
Solar PV	118.6	73.4	-45.2	-96.5	-21.2
Solar Thermal	223.6	73.3	-150.3	-279.3	-83.4
Hydro	84.5	59.9	-24.6	-54.7	-1.0
2040					
Dispatchable Technologies					
Conventional Coal	87.0	76.4	-10.7	-26.3	-5.3
IGCC	99.7	76.4	-23.3	-34.3	-18.2
IGCC with CCS	121.2	77.0	-44.3	-51.8	-38.8
Natural Gas-fired					
Conventional Combined Cycle	81.2	77.7	-3.5	-7.7	-0.4
Advanced Combined Cycle	77.8	77.7	-0.1	-3.9	2.0
Advanced CC with CCS	103.0	77.7	-25.3	-30.0	-15.5
Advanced Nuclear	83.0	76.1	-6.8	-10.1	-0.2
Geothermal	63.5	78.7	47.0	0.5	75.2
Biomass	97.0	78.0	-19.0	-38.4	-9.4
Non-Dispatchable Technologies					
Wind	73.1	70.8	-2.3	-11.8	13.0
Wind – Offshore	170.3	77.4	-92.9	-150.7	-59.3
Solar PV	101.3	89.4	-11.9	-58.4	10.6
Solar Thermal	188.7	96.5	-92.2	-205.1	-36.0
Hydro	84.6	75.3	-9.3	-27.8	11.0

Appendix: Tables for 2040

Table A5. Estimated levelized cost of electricity (LCOE) for new generation resources, 2040

Plant Type	Capacity Factor (%)	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2040: Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[1]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	52.0	4.2	29.7	1.1	87.0		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	62.8	6.9	28.9	1.1	99.7		
IGCC with CCS	85	77.2	9.8	33.1	1.2	121.2		
Natural Gas-fired								
Conventional Combined Cycle	87	12.5	1.7	65.8	1.2	81.2		
Advanced Combined Cycle	87	13.0	2.0	61.7	1.2	77.8		
Advanced CC with CCS	87	23.4	4.2	74.3	1.2	103.0		
Conventional Combustion Turbine	30	35.2	2.8	107.1	3.4	148.5		
Advanced Combustion Turbine	30	21.8	2.7	87.9	3.4	115.8		
Advanced Nuclear	90	56.7	11.8	13.3	1.1	83.0		
Geothermal	94	43.6	22.9	0.0	1.4	67.8	-4.4	63.5
Biomass	83	39.8	14.5	41.4	1.2	97.0		
Non-Dispatchable Technologies								
Wind	34	56.6	13.3	0.0	3.2	73.1		
Wind – Offshore	37	141.7	22.8	0.0	5.7	170.3		
Solar PV[2]	25	95.3	11.4	0.0	4.0	110.8	-9.5	101.3
Solar Thermal	20	156.2	42.1	0.0	5.9	204.3	-15.6	188.7
Hydroelectric[3]	51	71.2	4.5	7.0	2.1	84.6		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

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

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A6. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2040

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	78.9	87.0	106.7			
IGCC	90.8	99.7	114.7			
IGCC with CCS	113.0	121.2	135.7			
Natural Gas-fired						
Conventional Combined Cycle	75.8	81.2	94.0			
Advanced Combined Cycle	73.4	77.8	89.4			
Advanced CC with CCS	97.8	103.0	114.8			
Conventional Combustion Turbine	118.8	148.5	172.3			
Advanced Combustion Turbine	108.9	115.8	132.3			
Advanced Nuclear	80.2	83.0	87.6			
Geothermal	54.4	67.8	81.3	50.7	63.5	76.3
Biomass	85.3	97.0	118.8			
Non-Dispatchable Technologies						
Wind	63.4	73.1	82.9			
Wind – Offshore	140.9	170.3	225.3			
Solar PV[2]	86.5	110.8	170.2	79.2	101.3	155.0
Solar Thermal	148.6	204.3	325.6	137.2	188.7	300.5
Hydroelectric[3]	63.6	84.6	122.4			

[1]Levelized cost with subsidies reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992.
[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated 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 as follows: Wind – 32% to 41%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 35% to 65%. 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 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A7: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2040

	Range for LACE (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal-fired plant types without CCS	72.3	76.4	80.7
IGCC with CCS[1]	72.3	77.0	88.6
Natural Gas-fired Combined Cycle	72.2	77.7	88.4
Advanced Nuclear	72.2	76.1	80.6
Geothermal	75.0	78.7	88.0
Biomass	72.3	78.0	88.7
Non-Dispatchable Technologies			
Wind	65.8	70.8	84.1
Wind – Offshore	71.9	77.4	88.1
Solar PV	83.2	89.4	96.5
Solar Thermal	87.7	96.5	104.4
Hydroelectric	71.0	75.3	88.0

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.