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Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement

Levelized Cost of Electricity

Levelized cost of electricity, as reported by EIA in conjunction with its Annual Energy Outlook publications, represents the average revenue per unit of energy production that would be required by a project owner to recover all investment and operating costs. It includes a specified return on investment over a specified project financial life, as well as an assumed project utilization rate. The computation for LCOE takes the following general form:

$$LCOE = \frac{fixed\ charge\ factor * capital\ costs + fixed\ O\&M}{annual\ expected\ generation\ hours} + variable\ O\&M + fuel$$

Where:

- **LCOE** is the levelized cost of electricity, expressed in units of $/Megawatthour ($/MWh).
- **Capital cost** is the initial investment per unit of capacity in the project, expressed in $/Megawatt ($/MW). For any given technology, this cost may vary over time based on a number of factors, including declining technology costs due to learning and cost adjustments from broader economic factors, such as the cost of construction commodities and availability of resources for geographically constrained energy sources like wind, geothermal, or hydro.
- **Fixed charge factor** annualizes the capital cost, accounting for the weighted average cost of capital (return on debt and return on equity), Federal tax burden for the project, and the expected financial life of the project. This factor is estimated using a cash-flow model within the National Energy Modeling System (NEMS), and may vary over time, based on changes to the cost of debt and cost of equity, and across technologies, based on differing tax depreciation treatments for different technologies and for the market risks associated with certain carbon-intensive generation options.
- **Fixed O&M** is the annual expenditure per unit of project capacity for operations and maintenance, expressed in $/MW/year. This includes costs that remain relatively constant, regardless of plant utilization levels, such as worker salaries and maintenance or refurbishment costs that are scheduled on a calendar basis rather than an operating-hours basis.
- **Annual expected generation hours** are the number of hours in a year that the plant is assumed to operate. For dispatchable generation such as coal, nuclear, or gas-fired plants, EIA calculates this based on an annual capacity factor that corresponds to the maximum annual availability for that unit. Alternatively, in the case of units primarily serving peak load, this calculation is based

on 30 percent annual capacity factor. For intermittent renewable resources, the calculation is based on location-specific resource availability.

- **Variable O&M** is the expenditure per unit of generation for operations and maintenance, expressed in $/MWh. This expenditure includes costs that are closely tied to the actual operating hours of the equipment, such as consumable maintenance items and refurbishment costs that are scheduled based on operating hours (rather than on a calendar basis).
- **Fuel** is the expenditure for fuel, expressed in terms of $/MWh It is the product of the heat rate of the equipment (a measure of unit conversion efficiency) and the fuel price in native units (e.g. $/thousand cubic feet or $/ton). These costs represent the hourly average of the long-term fuel costs over the assumed financial life of the equipment (not the fuel costs for the single year for which the estimate is provided).

LCOE Example:

Consider a wind turbine with a capital cost of $2,000/kW ($2 million/MW), and a fixed O&M cost of $40/kW/yr ($40,000/MW/year). There is no fuel cost and no variable O&M. The fixed charge factor for wind, accounting for the standard 5-year MACRS[1] depreciation, is 9% per year. The capacity factor is 30% per year.

- Annualized capital cost = $2 million/MW * 0.09 =$180,000/MW/year
- Total annual expenditure = $180,000/MW/year + $40,000/MW/year = $220,000/MW/year
- Expected annual hours of generation = 0.3 * 8760 hours/year = 2628 hours/year
- Levelized Cost = $220,000/MW/year / 2628 hours/year= $84/MWh

Levelized Avoided Cost of Electricity

The levelized avoided cost of electricity, as developed for this discussion, represents the potential revenue available to the project owner from the sale of energy and generating capacity. This cost is a weighted average of the marginal cost of electricity dispatch during the periods in which the project is assumed to operate, weighted by the number of hours of assumed operation in each time period. The marginal cost of meeting system planning reserves is weighted by the estimated capacity credit for each technology.

$$LACE = \frac{\sum_{t=1}^{Y}(marginal\ generation\ price_t * dispatched\ hours_t) + (cap\ payment * cap\ credit)}{annual\ expected\ generation\ hours}$$

Where:

- **LACE** is the levelized avoided cost of electricity, expressed in units of $/MWh.
- **t** is the time period and **Y** is the number of time periods in the year. NEMS represents nine time periods for electricity capacity planning purposes; each of the three seasons of the year (winter,

[1] The Modified Accelerated Cost Recovery System (MACRS) is the current depreciation method for most assets for the purpose of Federal taxes. Under MACRS, renewable energy equipment tends to have more rapid depreciation schedules relative to some other asset types.

summer, and fall/spring) includes a representation of peak hours, intermediate hours, and off-peak hours. The summation is performed for all of the periods in the year.

- **Marginal generation price** is the cost of serving load to meet the demand in the specified time period. This price is typically determined by the variable cost (fuel cost plus variable O&M) of the most expensive generating unit that needs to be dispatched to meet energy demand. This price may also be impacted by the cost of meeting any environmental or portfolio policy requirements by the marginal generators (that is, the cost of purchasing renewable energy credits for a non-qualifying generator).
- **Dispatched hours** is the estimated number of hours in the time period the unit is dispatched. This number is consistent with the utilization parameters assumed for the LCOE calculation.
- **Capacity payment** is the value to the system of meeting the reliability reserve margin. It is determined as the payment that would be required to incentivize the last unit of capacity needed to satisfy a regional reliability reserve requirement.
- **Capacity credit** is the ability of the unit to provide system reliability reserves. For dispatchable units, the entire nameplate capacity is allowed to participate in the reliability capacity market (capacity credit of 1 or 100%). For intermittent renewables, the capacity credit is derated as a function of the availability of the resource during peak load periods and the estimated probability of correlated resource-derived outages within a given region. For example, the capacity credit is the probability that if the wind is not blowing in on part of the region, it is or isn't blowing in a different part of the region.
- **Annual expected generation hours** are the number of hours in a year that the plant is assumed to operate; the derivation is identical to that described in the LCOE section above.

LACE Example:

The wholesale price of electricity (marginal generation price) is known for 9 time periods during the year, representing the daytime peak, nighttime off-peak, and shoulder hours during the winter, summer, and spring/fall seasons. The number of dispatched hours is calculated for each period by multiplying the number of hours in that period by the corresponding assumed capacity factor. The revenue available for each period is calculated by multiplying dispatched hours by the wholesale electricity price. In the region used in this example, wind has a capacity credit of 15 percent, and the cost of a new combustion turbine to meet reliability requirements is $670/kW, or, using the fixed charge factor derived for the LCOE calculation, $60/kW/year ($60,000/MW/year).

Table 1: Energy Value

Season	Time-of-Day	Wholesale Electricity Price ($/MWh)	Wind Capacity Factor	Hours in Period	Dispatched Hours	Revenue Available
Summer	Daytime	$110	0.2	640	128	$14,080
	Nighttime	$80	0.4	1100	440	$35,200
	Shoulder	$90	0.5	460	230	$20,700
Winter	Daytime	$90	0.3	460	138	$12,420
	Nighttime	$70	0.5	1100	550	$38,500
	Shoulder	$80	0.3	640	192	$15,360
Spring/Fall	Daytime	$80	0.4	1090	436	$34,880
	Nighttime	$60	0.6	2180	1308	$78,480
	Shoulder	$70	0.5	1090	545	$38,150
Annual Total					3,967	$287,770

The wind plant earns energy revenue of $287,770/MW/year, and has a capacity payment of 0.15*$60,000=$9,000/MW/year. The total annual revenue stream is $296,770/MW/yr. With annual generation of 3,967 MWh/MW (3,967 equivalent operating hours), the average revenue per MWh for this plant is $75/MWh.

Computing Net Value

The net value is simply the difference between the LACE and the LCOE, and can be thought of as the potential profit (or loss) per unit of energy production for the plant.

$$Net\ Value = LACE - LCOE$$

Net Value Example

From the examples above, the wind plant has a LCOE of $84/MWh and a LACE of $75/MWh, resulting in a net value of -$9/MWh.