Appendix E – Methods and Assumptions Used in Chapter 5

This appendix provides further detail on the methods employed and assumptions made in the analysis of Chapter 5.

THE LEVELIZED COST OF ELECTRICITY

The levelized cost of electricity (LCOE) is defined as the charge per kilowatt-hour (kWh) that equates the discounted present value of revenues to the discounted present value of costs, including the initial capital investment and annual operating costs as well as any future replacement capital costs incurred over the life of a facility. These costs include taxes paid. For example, for a solar project running for 25 years with installation over the year prior, let $t=0,1,2...25$. Write the annual capital investment as $K_t$, the annual operating and maintenance expenditures as $O_t$, the annual taxes paid as $V_t$, all denominated in $/year, and the annual output schedule as $Q_t$, denominated in megawatts per year (MW/year). Then the LCOE is defined implicitly by this formula:

$$\sum_{t=0}^{25} \frac{LCOE_t Q_t}{(1 + R)^{t}} = \sum_{t=0}^{25} \frac{K_t + O_t + V_t}{(1 + R)^{t}}$$

where $R$ is the cost of capital, which is discussed in more detail below.

Rearranging the formula gives an explicit definition:

$$LCOE = \frac{\sum_{t=0}^{25} \frac{K_t + O_t + V_t}{(1 + R)^{t}}}{\sum_{t=0}^{25} \frac{Q_t}{(1 + R)^{t}}}$$

The LCOE may be reported as either a real LCOE or a nominal LCOE. In calculating a real LCOE, the values of all of the cash flow inputs — $K_t$, $O_t$, and $V_t$ — must be real, i.e., with any inflation factor removed. Since tax calculations, such as depreciation charges, are inherently nominal, care must be taken to be sure that the tax cash flows have been correctly adjusted to remove the inflation factor properly. The cost of capital must also be a real cost of capital. The U.S. Energy Information Administration (EIA) reports real LCOEs in its Annual Energy Outlook. In calculating a nominal LCOE, the values of all cash flow inputs must be nominal — i.e., with inflation included. The cost of capital must also be a nominal cost of capital. The U.S. Department of Energy’s National Renewable Energy Lab (NREL) reports both real and nominal LCOEs as an output of its System Advisor Model (SAM). In general, with positive inflation, a nominal LCOE will be higher than a real LCOE.

\^See, for example, NREL\^1 and Short, Packey, and Holt.\^2
The traditional LCOE, whether real or nominal, is fixed throughout the life of the project — as indicated by the term “levelized.” However, in calculating a nominal LCOE, all other costs are understood to be increasing with inflation. An alternative definition of the nominal LCOE recognizes that the charge may be escalated at the inflation rate, $I$, and reports the first year’s charge. This is comparable to reporting the first-year price of a power purchase agreement that includes a clause increasing the annual price for the rate of inflation, as NREL’s SAM does. This LCOE is defined implicitly by the formula:

$$\sum_{t=0}^{25} \frac{LCOE_t (1 + I)^t Q_t}{(1 + R)^t} = \sum_{t=0}^{25} \frac{K_t + O_t + V_t}{(1 + R)^t}$$

Rearranging the formula gives an explicit definition:

$$LCOE_i = \frac{\sum_{t=0}^{25} \frac{K_t + O_t + V_t}{(1 + R)^t}}{\sum_{t=0}^{25} \frac{(1 + I)^t Q_t}{(1 + R)^t}}.$$ 

Although this calculation is executed in nominal dollars, it is comparable to a real LCOE because the charge escalates with inflation from the base value. This is the LCOE we report in Chapter 5.

**COST OF CAPITAL**

A key input in calculating the levelized cost of electricity is the discount rate applied to cash flows in different years. For our central case we employ a weighted average cost of capital (WACC) that is calculated using a 7.5% cost of debt, a 10% cost of equity, and a 60% debt ratio. We assume a marginal federal corporate income tax rate of 35% and, for California, a marginal state corporate tax rate of 8.84%. This yields a combined state and federal corporate tax rate of 40.75%, which gives us a WACC of 6.67%:

$$WACC = \frac{D}{V} R_D (1 - \tau_c) + \frac{E}{V} R_E = 60\% \times 7.50\% \times 59.25\% + 40\% \times 10\% = 6.67\%.$$ 

For Massachusetts, we assume a corporate income tax rate of 8% so that the WACC is 6.69%. These are all nominal discount rates, to be applied to cash flows that reflect anticipated inflation. We assume the corresponding inflation rate is 2.5%, which is the rate we apply to the various cash flows in our calculation.

Although this calculation is executed in nominal dollars, it is comparable to a real LCOE because the charge escalates with inflation from the base value. This is the LCOE we report in Chapter 5.

Applying the WACC to cash flows that already
reflect interest tax shields double counts the tax benefits of debt. All tax shields other than interest tax shields — such as depreciation tax shields — are included in the cash flows to which the WACC is applied.

This cost of capital is appropriate for a power generator operating in a competitive wholesale market without any assured rate of return — i.e., a “merchant model.” Many solar projects are financed using a power purchase agreement (PPA) sold to a utility, whether regulated or operating in competitive wholesale markets. The PPA shifts price risk from the power generator to the power purchaser. This would then mean that the project’s revenue is less risky and should be discounted by a lower rate. Of course, the price negotiated as part of a PPA will reflect the cost of shifting this risk, so that the net value of the stream of revenue should remain roughly the same. In any case, the PPA does not affect the cost of producing the power — hence we do not reflect the lower risk of PPAs in our calculation of LCOE.

We also use this cost of capital for the residential PV system, which would be appropriate for the third-party ownership model in which the tax and financial position of the corporate owner is like that of the corporate owner of a utility-scale PV system.

\[
R_A = \frac{D}{V} R_D + \frac{E}{V} R_E = 60\% \times 7.50 + 40\% \times 10\% = 8.50\% .
\]

\(^{ii}\) An alternative would be to employ the cash flows after tax, including the interest tax shields along with all others. In this case, it is appropriate to use a weighted average with the before-tax cost of debt, which gives us a cost of capital of 8.50%:
REFERENCES


The hyperlinks in this document were active as of April 2015.
The simulations discussed in Chapter 8 of this report, concerning the integration of solar electricity generation with wholesale electricity markets, focused on a particular year (2030) and used a single set of assumptions for projected electricity demand, fuel costs, and installed generation mix (for a medium-term time frame). This appendix briefly summarizes the data used.

ASSUMPTIONS FOR THE ERCOT-LIKE SYSTEM

• For hourly load in 2030, we assumed the reference annual profile based on hourly demand in 2011 and 2012. The profile was downloaded from the Electric Reliability Council of Texas (ERCOT) website.1 To scale the profile to the year 2030, we assumed a constant rate of growth in demand of 1% per year.

• Wind and solar profiles likewise use 2012 data from the ERCOT website1 (Planning and Operations Information). The profiles were scaled in proportion to the installed solar capacity being simulated. Installed wind capacity in 2030 was assumed to total 15 GW.

• Assumptions concerning the already installed generation mix for both the medium- and long-term scenarios are shown in the figure below, which uses data published by the U.S. Energy Information Administration (EIA).2

We assume that cogeneration capacity remains unchanged at 17 GW.

Key assumptions for thermal generators (e.g., investment cost, fuel cost, heat rate, etc.) are summarized in Table F.1.

Sources: SunShot Vision Study (February 2012)3
“Cost and performance data for power generation technologies” by Black and Veatch4
ERCOT’s Long-Term Transmission Analysis 2010–2030 (for start-up costs)1
ASSUMPTIONS FOR THE CALIFORNIA-LIKE SYSTEM

• For hourly load in 2030, we assumed the reference annual profile based on hourly demand in 2011. The profile was taken from the California Independent System Operator (ISO) Open Access Same-time Information System (OASIS).\(^5\) To scale the profile to the year 2030, we assumed a constant rate of growth in demand of 1% per year.

• Wind and solar production profiles were obtained from the daily California ISO Renewables Watch.\(^6\)

• For hydro units, we used historical production data profiles to estimate relevant input parameters such as maximum output, run-of-the-river capacity, and maximum energy available in each period.\(^5\)

• For thermal generators, we assumed the same characteristics as in our simulations for the ERCOT-like system (see Table F1).

• In the long-term scenario, the already installed generation mix is assumed to include 10 GW of wind, 8.5 GW of cogeneration, and 7.95 GW of thermal capacity (Figure F2).

Table F.1 Assumptions for Thermal Generators in the ERCOT-Like System\(^4\)

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Figure F.2 Installed Capacity for the California-Like System (Long-Term Analysis)\(^2\)
REFERENCES

1 Electric Reliability Council of Texas (ERCOT). www.ercot.com


5 Open Access Same-time Information System (OASIS). California ISO. http://oasis.caiso.com/mrioasis


The hyperlinks in this document were active as of April 2015.