The Private and Public Economics of Renewable Electricity Generation[†]

Severin Borenstein

The primary public policy argument for promoting electricity generation from solar, wind, and other renewable sources is the unpriced pollution externalities from burning fossil fuels. Some parties also advocate renewable electricity generation to improve energy security, price stability, or job creation, but these arguments are more difficult to support in a careful analysis, as I discuss later. Even comparing the higher costs of renewables with the environmental benefits, however, is not straightforward. Issues arise because the market value of electricity generation is very dependent on its timing, location, and other characteristics and because quantification of the nonmarket value from reduced emissions is difficult and controversial.

Since Pigou's (1920) seminal work, economists have understood that pricing externalities is likely to be the best way to move behavior towards efficiency. In the context of electricity, this insight means taxes on emissions or a tradable permit system, but such market-based policies have garnered limited political support in the United States and elsewhere. Instead, many governments have created policies to promote renewable electricity generation directly, through either subsidies or mandates. How well do these alternative policies substitute for pricing the negative externalities of generation from fossil fuel generation?

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In this paper, I discuss the market and nonmarket valuation of electricity generation from renewable energy, as well as the costs and the subsidies that are available. On a direct cost basis, renewables are expensive, but the simple calculations don't account for many additional benefits and costs of renewables. I begin by briefly discussing studies of the costs of renewables and conventional generation, highlighting the primary cost drivers. I then discuss the many adjustments that are necessary to account for the time, location, and other characteristics that vary across and within generation technologies. Many such adjustments are idiosyncratic, differing substantially by individual project, but broader technology characteristics also play an important part in their determinations.

The next steps in the analysis, evaluating the benefits of reducing externalities with renewables, are more difficult than they may at first seem. The timing and location of renewable generation will affect what generation is displaced, as will the pre-existing mix of fossil fuel generation in the system (for a short-run analysis) or counterfactual mix (for a longer-run analysis). I then turn to other potential market failures that may affect the value that renewable energy offers and describe how these impact justifications for government policy such as job creation, industry building, energy security, and moderating swings in energy prices. I argue that these justifications are generally not supported empirically and in some cases are based on faulty economic reasoning.

In normative analyses of renewable electricity generation, there is often confusion about which economic actors are included in the welfare being evaluated. For instance, should a small town that is considering installing solar panels on city hall count federal subsidies as a benefit or just a transfer? Though economic analyses often draw a bright line between private and public benefits, renewable energy demonstrates that in practice there is a continuum of perspectives. Each may be appropriate for answering a different question. Evaluating the incentives of participants in a market generally requires doing the analysis from many perspectives.

Thus, I do not attempt here to rank order the benefit/cost ratios for the major technologies for generating electricity, which in any event will vary with the decision maker's preferences, the perceived costs of environmental externalities, and the state of technology. Technological progress, as well as ongoing research on externalities, make any such table obsolete shortly after it is printed. However, the microeconomic tools to carry out and critique such analyses are longer-lived. In this paper, I use the current issues in renewable energy cost analysis to illustrate the use, and occasional misuse, of those tools.

Generation Costs of Conventional and Renewable Energy

Though renewable sources of electricity generation other than hydroelectricity have grown very quickly in the last decade, they were starting from a miniscule base, and they remain a very small share of total generation today due primarily to their high direct cost. Table 1 presents the share of electricity generated from

Table 1

Electricity Generation by Source

(*units are billion kWh; data are for 2007*)

Region/Country	Total	Natural gas	Coal	Nuclear	Hydro-electric	Oil and other liquids*	Wind	Geo-thermal	Solar	Other renewables**
OECD										
OECD North America	**5,003**	**20%**	**44%**	**18%**	**13%**	**3%**	**0.8%**	**0.4%**	**0.0%**	**1.3%**
United States	4,139	22%	49%	19%	6%	2%	0.8%	0.4%	0.0%	1.3%
Mexico	244	37%	18%	4%	11%	26%	0.0%	2.9%	0.0%	1.2%
OECD Europe	**3,399**	**22%**	**29%**	**26%**	**15%**	**2%**	**2.9%**	**0.3%**	**0.1%**	**3.1%**
OECD Asia	**1,747**	**23%**	**40%**	**22%**	**7%**	**6%**	**0.3%**	**0.3%**	**0.0%**	**1.4%**
Japan	1,063	28%	31%	24%	7%	8%	0.2%	0.3%	0.0%	2.1%
Total OECD	*10,149*	*21%*	*38%*	*21%*	*12%*	*3%*	*1.4%*	*0.4%*	*0.1%*	*1.9%*
Non-OECD										
Non-OECD Europe and Eurasia	**1,592**	**36%**	**25%**	**17%**	**18%**	**4%**	**0.0%**	**0.0%**	**0.0%**	**0.1%**
Russia	959	40%	23%	15%	18%	3%	0.0%	0.0%	0.0%	0.2%
Non-OECD Asia	**4,779**	**10%**	**69%**	**2%**	**14%**	**4%**	**0.4%**	**0.3%**	**0.0%**	**0.3%**
China	3,041	2%	80%	2%	14%	2%	0.2%	0.0%	0.0%	0.1%
India	762	6%	71%	2%	16%	3%	1.4%	0.0%	0.0%	0.3%
Middle East	**674**	**57%**	**5%**	**0%**	**3%**	**35%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Africa	**581**	**25%**	**45%**	**2%**	**17%**	**11%**	**0.2%**	**0.2%**	**0.0%**	**0.2%**
Central and South America	**1,009**	**15%**	**6%**	**2%**	**65%**	**9%**	**0.1%**	**0.3%**	**0.0%**	**2.6%**
Total Non-OECD	*8,634*	*20%*	*47%*	*5%*	*20%*	*7%*	*0.2%*	*0.2%*	*0.0%*	*0.5%*
Total world	**18,783**	**21%**	**42%**	**14%**	**16%**	**5%**	**0.9%**	**0.3%**	**0.0%**	**1.3%**

Source: EIA *International Energy Outlook 2010*, tables H11–H20.
* Includes petroleum-derived fuels and non-petroleum-derived liquid fuels, such as ethanol and biodiesel, coal-to-liquids, and gas-to-liquids. Petroleum coke, which is a solid, is included. Also included are natural gas liquids, crude oil consumed as a fuel, and liquid hydrogen.
** Includes biomass and other waste energy sources.

conventional and renewable sources for regions of the world and selected countries during 2007, the most recent year for which comparable worldwide data are available. Coal is the dominant generation source worldwide, with natural gas, hydroelectricity, and nuclear power also playing major roles.

Coal and natural gas remain the lowest-cost technology for new electricity generation in most parts of the world. These cost comparisons, however, show remarkable variance, with renewable generation far from competitive in some studies and quite cost-effective in others. Nearly all of these studies calculate a "levelized" cost of electricity, but as I discuss below, the exact economic assumptions made can drive enormous variation.

A User's Guide to Levelized Cost of Electricity Estimates

The levelized cost of electricity for a given generation plant is the constant (in real terms) price for power that would equate the net present value of revenue from the plant's output with the net present value of the cost of production.[1] Levelized cost estimates depend on numerous engineering factors that vary with the technology being reviewed, but these are not usually the main drivers of variation in estimates for a given plant. Current technological specifications for a plant are comparatively easy to establish with reasonable precision. For the most part, researchers agree on what inputs are going in and what outputs result.

Usually economic variables are behind the large discrepancies among levelized cost estimates. These include assumptions about inflation rates, real interest rates, how much the generator is going to be used, and future input costs, including fuel costs. Engineering factors also interact with these economic considerations; for example, the optimal usage of a plant will depend on the marginal cost of production, the speed with which its output can be adjusted, and the market price (plus other compensation, such as marginal subsidies) that the generator receives. The best levelized cost studies state these assumptions clearly, but many such studies do not.

Because generation plants are heterogeneous in location, architecture, and other factors, even plants with similar technology will not have the same levelized cost of electricity. The variation tends to be relatively small for coal and gas plants because the fuel is fairly standardized and the plant operation is less affected by location. Even the costs of these plants, however, are affected by idiosyncratic site characteristics (including property values), local labor costs, environmental constraints, access to fuel transportation, and access to electricity transmission lines, as well as variation in technical efficiency of operation. Production from solar and wind generation is largely driven by local climate conditions, and this greatly increases the variance in levelized cost across these types of projects.

The variation in levelized cost across plants with the same technology raises an important caveat: levelized cost studies are usually based on the average outcome at existing or recent plants, but they are generally intended to guide future investment decisions. Technological progress, learning-by-doing, and economies of scale in building multiple plants will tend to make the cost of the marginal plant *lower* than the average of existing or recent facilities, while scarcity of high-quality locations will tend to make the cost of a new plant *higher* than the pre-existing average. Some studies are explicitly prospective, evaluating the levelized cost of a technology that the

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[1] If a plant lasts N periods and produces q_n in period n, then discounting future cash flows at the real cost of capital r, the levelized cost of electricity is defined by

$$\sum_{n=1}^{N} q_n \frac{LCOE}{(1+r)^n} = \sum_{n=0}^{N} \frac{C_n(q_1,\ldots,q_N)}{(1+r)^n} \Leftrightarrow LCOE = \frac{\sum_{n=0}^{N} \dfrac{C_n(q_1,\ldots,q_N)}{(1+r)^n}}{\sum_{n=1}^{N} \dfrac{q_n}{(1+r)^n}}$$

where $C_n(q_1,\ldots,q_N)$ is the real (in period 0 dollars) expenditures in period n to produce the stream of output $(q_1,\ldots,q_N)$. As the formula suggests, this approach includes capital costs borne before any production can take place.

Figure 1
Levelized Cost Estimates
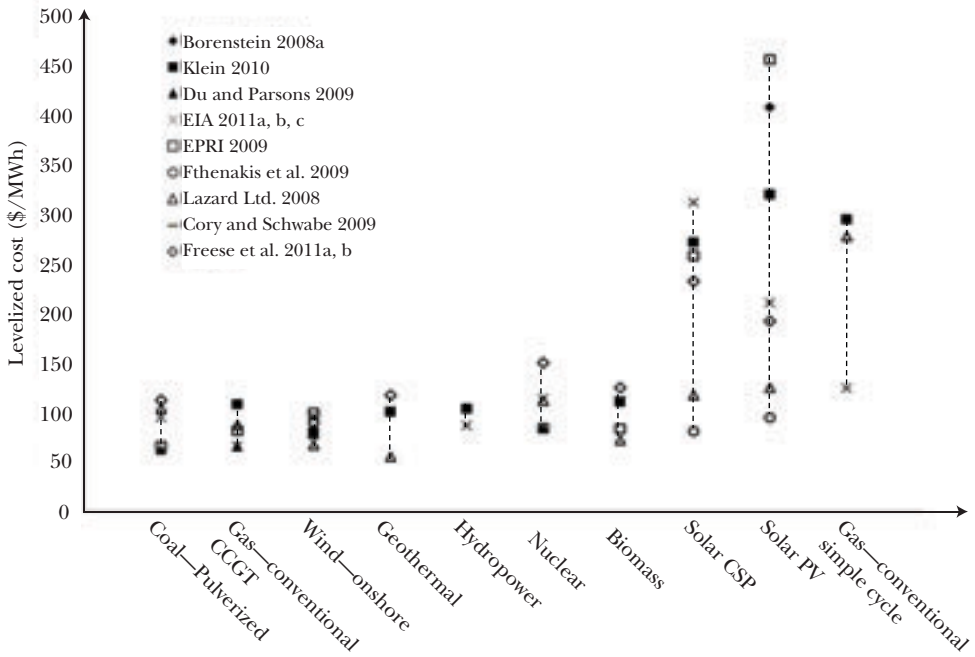
Notes: CCGT is "combined cycle gas turbine." CSP is "concentrated solar power." PV is "photovoltaic." MWh is "megawatt hour."

authors assume will be installed in some future year. These are necessarily the most speculative, forecasting future technological progress, which gives the authors great latitude to make varying assumptions that yield widely varying levelized cost estimates.

The lack of comparability in levelized cost analyses is particularly troubling because these cost figures are frequently the central focus of policy discussions about alternative technologies. These figures can potentially be useful benchmarks, but they must be thoughtfully adjusted for the attributes of the power produced and other impacts of the generation process.

I consider here only studies for U.S. generation. Costs vary around the world, both due to varying technologies and expertise, and because fuel costs and regulations differ.

Estimates of Levelized Costs of Electricity

With those cautions, Figure 1 presents levelized cost estimates for major electricity generation technologies. The notes in the Appendix at the end of this article present details of the calculations.[2] Clearly, the range of estimates can be significant

[2] Also see Intergovernmental Panel on Climate Change Working Group III (2011) for discussion of renewable energy technologies and Annex III for levelized cost estimates.

and the details in the Appendix table demonstrate why. Many of the studies include subsidies and tax benefits to the generator itself. With a sufficient subsidy, of course, any technology can appear to have a low cost. Nonetheless, these calculations can still be relevant for private decision making. A separate issue, which I discuss below, is accounting for upstream subsidies to fuel supply or transportation.

Coal and natural gas—the two leading sources of electricity generation—are fuel-intensive generation technologies (in terms of cost share) relative to the others, with natural gas being the most fuel-intensive major generation technology. (Oil-fired generation is even more fuel-intensive, but has a very small share of grid-connected generation in the United States due to its high cost.) Thus, forecasts of future fuel prices play a large role in levelized cost estimates. These forecasts have high variance due to uncertainty about the exhaustability of the resource, technological progress in exploration and extraction, and government regulation (Holland 2003).

Variation in technology and usage within generation technologies using the same fuel source can also greatly affect levelized cost. Combined-cycle gas turbine plants are highly efficient (in terms of "heat rate," the amount of fuel energy needed to generate a unit of electricity), but relatively costly to build, while single-cycle generation combustion turbine gas plants are less efficient but much cheaper to build. As a result, combined-cycle plants tend to run most of the time, while combustion turbines are used primarily at peak times, running far fewer hours per year. The levelized costs of these two technologies are quite different, but the comparison isn't informative, because they are intended for different uses. Because electricity demand is quite variable and electricity is not storable in a cost-effective way, there is demand for some "baseload" generation that runs in most hours and some "peaker" generation that is called on for relatively few hours per year. Neither technology could efficiently substitute for the other.

Hydroelectric and geothermal generation are generally viewed as renewable. They can be inexpensive, but locations that are usable and high productivity are quite limited. Large-scale hydroelectricity generation also creates such major alterations to the landscape that it is generally not considered environmentally friendly. In addition, hydroelectric generation usually faces a limit on total energy that can be produced in a year or other time frame due to precipitation and water storage limits.

The three broad categories of renewable energy that are considered closest to being scalable and cost competitive are wind, solar, and biomass. Wind and solar are also location-limited, though not to the same extent as hydro and geothermal. Studies have identified sufficient sites that if these locations were developed with wind and solar generation they could make these technologies the dominant electricity sources in the United States—see NREL (2010) on wind power and Fthenakis, Mason, and Zweibel (2009) on solar. The more significant barriers are cost of generation, cost of transmitting the power to where demand is, and the value of the power generated. The lowest-cost wind power is usually generated in fairly remote locations, so the cost of infrastructure to transmit the power to demand

sites can be significant. Transmission costs for connection to the grid are generally not included in levelized cost estimates, in part because they are so idiosyncratic by project. Local resident resistance to transmission lines and incomplete property rights in some cases can also create significant regulatory uncertainty.

Solar power encompasses two different fundamental technologies. Solar thermal generation focuses sunlight on a heat transfer fluid that is used to create steam, which is then used in a turbine to drive a generator. Photovoltaic systems use semiconductors to convert sunlight directly to electricity.[3] Either technology can be used for large-scale generation in open space, known as utility-scale generation, while photovoltaic panels can be installed on a small-scale near demand, such as on residential rooftops.

Rooftop solar reduces the need for investment in high-voltage transmission lines that carry power from large-scale generation to local distribution wires. Some argue that it also reduces the cost of the local distribution networks, but there do not seem to be reliable studies on the distribution cost impact, as I discuss below. Economies of scale at the local distribution level are significant, suggesting the marginal savings from reduced flow on distribution lines is well below the average cost of distribution per kilowatt hour. Small-scale rooftop solar, such as on a single-family home, also enjoys fewer economies of scale in construction or panel procurement, so the up-front cost per unit of capacity tends to be much greater.[4]

Biomass is a broad category that includes both burning the inputs directly and biomass gasification, in which the inputs are heated to produce a synthetic gas. The primary biomass fuels are wood scraps and pulping waste, but also agricultural residue, landfill gas, and municipal solid waste. The levelized cost of biomass tends to depend to a great extent on the idiosyncratic local cost of collecting and preparing the fuel. In 2007, biomass provided about half of the non-hydro renewable electricity generation in the United States and the world. Mostly, this is from mixing biomass with coal and burning in a conventional coal-fired power plant, which requires fairly small incremental equipment investments. Such approaches represent the lower end of the levelized cost estimates in Figure 1, but the opportunity for expansion is limited.

Limitations of Using Levelized Cost Estimates to Compare Electricity Technologies

Although levelized cost in some form has been the starting point for cost comparisons since the beginning of electricity generation—McDonald (1962) discusses levelized cost comparisons from the early twentieth century—it is by no

[3] The International Energy Agency provides brief useful overviews of alternative energy technologies at ⟨http://www.iea.org/techno/essentials.htm⟩.

[4] To some extent, the lower panel cost for photovoltaic "farms" is a pecuniary economy, not representing real resource savings, if it is just a rent transfer from sellers to buyers. But to the extent that the panel cost is higher for small installations due to higher shipping or transaction costs of small orders, or because of the need to customize panel selection to particular types of installations, those probably reflect real cost differences.

means the final word. Difficulties arise because electricity generation technologies have different temporal and spatial production profiles.

Because electricity is very costly to store, wholesale prices can vary by a factor of 10 or more within a day. As a result, time variation in production, and the operator's control over that variation, greatly affects the value of power produced. Generation resources over which an operator has greater temporal control are considered "dispatchable," while those that vary significantly due to exogenous factors are considered "intermittent." Joskow (2011a, 2011b) discusses in detail the impact of temporal output variation on the value of power produced by different generating sources.

Among conventional gas and coal plants, there are constraints on how quickly a plant's output level can be increased or decreased ("ramping rates"), how long the plant must remain off once it has been shut down, and how frequently it must be shut down for planned or unplanned maintenance, and there is the cost of starting the plant. Economic tradeoffs also arise here between short-run benefits of pushing the plant to or beyond the engineering specifications and the longer-run costs of increased wear on the plant components that cause greater need for planned outages and greater incidence of unplanned outages.

Gas-fired peaker plants, for instance, have low fuel efficiency, but are very flexible, with rapid ramping capability and low start-up costs. Hydroelectric generation is also highly valued for its ability to adjust output very quickly. If the optimal "dispatch" of a plant implies that it will run disproportionately at times when electricity is of particularly high value—as is the case with gas-fired peaker generation and most hydro generation—then any levelized cost comparison must be augmented with adjustment for this enhanced value of the power that is produced.

Generation resources that depend on the local weather—such as wind and solar—are intermittent and therefore the least dispatchable. Such generation is almost entirely out of the control of the plant operator (although these technologies can be shut down fairly easily and quickly, so the plant operator can usually put an upper limit on their output). Power from intermittent resources must be evaluated in terms of the time at which it is produced. Solar power is produced only during daylight hours and tends to peak in the middle of the day. In many areas, this is close to coincident with the highest electricity demand, which usually occurs on summer afternoons. Thus, the average economic value of generation from solar is greater than if it produced the same quantity of power on average at all hours of the day. Wind power often has the opposite generation pattern in the United States, in most locations producing more power at night and at times of lower demand and prices.

Adjustment for the time variation of production is straightforward: compare the levelized cost to the average wholesale value of the power it delivers. In Borenstein (2008a), I find that power from solar photovoltaics in California is likely to be about 20 percent more valuable than the average power sold in the state, because it is produced disproportionately at high-priced times. The premium would be as high as 50 percent if the wholesale market were allowed to clear at

very high prices, but that doesn't occur, because grid operators use "generation reserves," discussed below, to meet demand without allowing prices to rise too high at peak times. Fripp and Wiser (2008) find that wind power production in the West is likely to be 0–10 percent less valuable per unit than if the wind generator had the same average output in every hour of the day, though that study may understate the appropriate discount in wind value because it uses data from a period of very low power price volatility.

However, even this temporal adjustment for wholesale power prices doesn't completely capture the granularity over which the true value of power fluctuates. Because electricity is not storable at reasonable cost and the demand side of the market has had limited opportunity to respond to price fluctuations in very short time intervals, it is more cost-effective to build back-up generation in sufficient quantity to have most adjustment occur on the supply side of the market.[5] The presence of back-up generation in itself is not a barrier to efficient pricing that reflects the actual shadow value of power at each point in time, though the shadow value is likely to be low at most times. Grid operation, however, has never been based on such a precise market model. That approach made sense under the old utility model in which all generation was owned by one company, a company which solved a complex optimization problem and implemented the solution administratively. Even in the more than 20 years in which merchant (non-utility) generators have played a significant role in U.S. electricity markets, grid operators have generally just procured "reserve" generation services and charged it to the system as a whole. Thus, the cost to the system of an intermittent producer has been socialized across all generators and prices have not fully reflected the time-varying value of power. There is now an active debate about how much the failure to assign these costs of intermittency to specific generators skews incentives.

Adjusting levelized cost estimates for the intermittency depends on the degree to which intermittency requires additional reserve generation or increases the risk of a supply shortage that causes blackouts or brownouts. While a grid can easily handle very small shares of intermittent resources—in fact, to a grid operator they look almost the same as the stochastic component of demand that supply must follow—some grid engineers have argued that the cost will increase more than proportionally if intermittent resources constitute a significant share of generation, such as 20 percent or more, as is currently contemplated and has been achieved in some locations in Europe. This too is an area of active debate; a detailed discussion appears in New York Independent System Operator (2010). Ideal market pricing would reveal the value of a generator's production at every instant, but wholesale electricity markets are not set up to generate such fine-grained price signals.

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[5] The technology for near-instantaneous demand response now exists, but questions remain about the cost-effectiveness of incorporating such sophisticated demand activity. If customers found it acceptable to have their thermostat respond automatically to retail price changes, that is, if they considered the associated cost to be fairly low, then the cost of intermittency could be substantially reduced. See Callaway (2009).

There is also a multiyear temporal issue that complicates comparisons of level-ized costs. Levelized cost does not incorporate any variation in the real value of power across years. For instance, if the real cost of electricity is expected to rise substantially over time, then power produced in the near-term is less valuable than in the distant future. Comparing levelized costs implicitly assumes that the real marginal value of power will be constant. This assumption is particularly important if the output profiles of two generators differ substantially, such as comparing a nuclear plant that will take five to ten years to build to solar panels that will start producing within a year or less.

Just as the value of electricity varies temporally due to storage constraints, it also varies locationally due to transmission constraints. Complete locational pricing is difficult logistically due to the complex physics of power flows, but a number of areas of the United States do have what is known as "locational marginal pricing" that sends fairly efficient short-run price signals. The greater challenge in locational pricing is in the long run, because the full incremental cost of adding new transmis-sion capacity can differ significantly from the direct infrastructure cost once one accounts for the resulting change in transmission capacity on all lines in the grid. Highly granular pricing—in both time and location—had less value in the historical electricity supply paradigm, with its lower reliance on intermittent generation and with its single utility that could coordinate long-term generation and transmission investment and internalize the externalities created by each in terms of grid capacity and intermittency. Even in the markets that remain regulated today, many of these issues still arise as regulated utilities buy much more power from independent generators than they did 10 or 20 years ago.

Locating electricity generation at the customer site, known as "distributed generation," engenders the most controversy in locational valuation. Retail prices are a very poor guide to locational value, because they include significant fixed cost recovery (for instance, the fixed costs of local distribution networks) and they reflect little or none of the locational (or time) variation in wholesale power purchase or production cost. At one extreme, some advocates of distributed solar and wind generation argue that customers should not only be able to reduce their power bills to zero by generating as much power over a billing period as they consume, they should be paid the retail rate by the utility for any net power they contribute to the system. At the other extreme, some grid engineers argue that intermittent distributed generation not only doesn't reduce local distribution costs much at all—so should be compensated no more than the wholesale price of power—the intermittent nature of the power and the reverse flow from customers increases the stress on distribution transformers and increases the frequency of repairs. At the heart of this conflict is an internal inconsistency in the utility revenue model: local electricity distribution service is a regulated, largely fixed-cost, business, but costs are recovered primarily through charges that vary with the quantity of electricity consumed. In the United States, wholesale electricity costs average only about 50 to 75 percent of residential retail electricity bills; most of the rest represents costs that don't vary with marginal electricity consumption.

Residential solar photovoltaic generation has been at the center of this debate. Residential solar does offer greater value than suggested by its high levelized cost—because it produces disproportionately at times of high demand, reduces transmission investment, and avoids the small percentage of power that is dissipated as heat when it is sent through the transmission and distribution lines from a distant generator (Borenstein 2008a). Nonetheless, *retail* rates don't accurately reflect the social value of distributed solar generation. With distributed generation, a significant share of the savings customers see in their electricity bills would have gone to pay the utility's fixed costs. These costs change very little, even in the long run, when customers generate some of their own power.

Adjustments for Subsidies and Preferential Tax Treatment

Some of the levelized cost estimates shown in Figure 1 (and described in detail in the Appendix) reflect costs after direct subsidies and preferential tax treatments, and some don't state clearly how subsidies and taxes are handled. Excluding subsidies and tax advantages seems sensible for cost analyses that are intended to guide public policy, but even that approach can be questioned. For instance, should state regulators consider federal subsidies and tax breaks when evaluating a proposed renewable energy facility? Given the political and logistical barriers to accomplishing Pareto-improving trades in these markets, the appropriate treatment will depend on whose welfare the decision maker weighs most heavily.

Excluding direct subsidies and tax breaks from levelized cost analyses is relatively straightforward, though it can be challenging in practice. Indirect subsidies that occur upstream and affect the price of inputs are more difficult to sort out. Advocates for renewable electricity argue that fossil fuel extraction receives special tax treatment in the United States. While that is likely true, and subsidies for fossil fuels are larger than for renewable energy in aggregate, the subsidy per kilowatt hour for fossil fuel generation is quite small. Adeyeye, Barrett, Diamond, Goldman, Pendergrass, and Schramm (2009) estimate that total subsidies for fossil fuels from 2002–2008 were $72 billion in the United States, of which about $21 billion plausibly went to domestically produced coal and natural gas that went into electricity production (explained in the online Appendix available with this paper at ⟨http://e-jep.org⟩). Even if these subsidies were passed through 100 percent to consumers, which seems highly unlikely for these internationally traded goods, that would amount to $0.0011 per kilowatt hour of generation in the United States over this period. Other estimates of subsidies to coal and natural gas for electricity generation are substantially lower (EIA 2008) or many times higher (Koplow 2010), but over the range of subsidies claimed, the effect on electricity generation costs will not materially affect their comparison to renewable sources.

In 29 U.S. states and the District of Columbia, renewable energy benefits from a different sort of indirect subsidy, a minimum share of electricity that is mandated to come from renewables, often termed a "renewable portfolio standard." Nearly all such programs, however, translate this quantity standard to some extent into a subsidy/tax system through tradable credits for renewable energy, which can be

purchased by retail electricity providers in lieu of meeting the standard through their own generation. As a result, some calculations of the economics of renewables may include the value of these credits. Whether such value should be counted in a social cost calculation depends on whether the credit price reflects the true cost of externalities avoided by the generation, which is difficult to assess, as I discuss in the next section. Schmalensee (forthcoming) discusses the different policies for promoting renewable energy generation and their effectiveness.[6]

With many factors affecting calculations of the full cost and benefit of generation technologies, claims that a new technology has attained "grid parity" must be interpreted with great caution. Advocates of wind generation who argue that it is at grid parity in some locations generally do not adjust for the timing, location, and intermittency factors that can make wind substantially less valuable. Residential solar photovoltaic power is sometimes claimed to be at grid parity if it saves the customer money (usually, after subsidies), but such analyses do not consider that the retail electricity rate pays for much more than just the energy that the solar generation replaces. Of course, grid parity on market factors alone is not the socially optimal driver of technology choice if some technologies produce greater negative externalities than others.

Incorporating Environmental Externalities

Until the 1960s, air pollution from conventional electricity generation was largely unregulated and in that sense "free" to the polluter. But in the 1960s and 1970s, legislation restricted the rights of generators to emit local air pollutants, particularly sulfur dioxide, nitrous oxides, and mercury. These policies didn't put prices on pollutants, but were command and control regulation, such as requiring the installation of smokestack devices ("scrubbers") that remove sulfur dioxide and other pollutants. In the last two decades, carbon dioxide has been found to be a major contributor to climate change, leading to efforts to restrict its emissions as well. About 33 percent of anthropogenic greenhouse gas emissions in the United States come from the electric power sector, with 27 percent coming from transportation, 20 percent from industry, and the remaining 20 percent is agriculture, commercial, or residential (EPA 2011, table 2-12).

In a first-best economic world, pollution rights would be just another input to the production of electricity from a given technology and would automatically be included in the levelized cost calculation. In most of the United States and the world, however, markets for rights to emit greenhouse gases or local pollutants are spotty at best. Most levelized cost estimates do not include the costs of emissions directly, though they do generally include the cost of technology that must be installed in order to meet command and control regulations.

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[6] Also see ⟨http://www.dsireusa.org/⟩, a comprehensive database of such programs in the United States.

A large literature exists on the marginal social cost of the air pollutants that power plants emit. For local pollutants, the cost varies across plants and depends very much on the population density, climate, and geography around the plant, as well as the presence of other pollutants (Fowlie and Muller 2010). For greenhouse gases, the damage is not localized, so valuation is much more uniform across plants. All of these studies rely heavily on meteorological, climate, and public health models, as well as valuations of statistical lives. Muller and Mendelsohn (2007) explain the details and uncertainties of such studies and present estimates of the cost of local pollutants. The caveats applied to local pollution cost estimates are even stronger for estimates of the marginal social costs of greenhouse gas emissions because there is even more uncertainty in the underlying climate and public health models. Greenstone, Kopits, and Wolverton (2011) present a detailed discussion of the uncertainties in estimating the social cost of greenhouse gas emissions.

Absent government intervention, the external costs will not be borne by producers and will not affect choices among electricity generation technology. The obvious solution is to price the externalities—either through a tax or tradable permit program. The relative merits of these approaches have been debated at length (Keohane 2009; Metcalf 2009; and cites therein). Still, the reality is that both approaches remain relatively rare compared to alternative interventions such as technology mandates and subsidies for green power.

Technology mandates for pollution controls on conventional electricity generation have been and remain the most common response to these market failures. Technologies to remove some pollutants from the smokestack emissions of power plants have been used since the 1960s. It is well-known that such mandates can be inefficient, because they apply uniform standards to emitters with very different production profiles, costs of meeting the regulations, and costs of alternative technologies or production changes that would allow similar pollution reductions. Also known, but less highlighted, is that these command and control regulations don't account for whether the emissions occur at times when they are likely to be more or less damaging to public health. This is particularly important for nitrous oxides, which under some, but not all, meteorological conditions combine with volatile organic compounds and sunlight to make ozone. Even pricing the externality solves this problem only if prices reflect such variation, which is often not the case, generally for reasons of simplicity (Fowlie and Muller 2010).

Subsidies for green power (or mandated utility offer prices for power generated in this way, known as "feed-in tariffs") have been portrayed as nearly equivalent to pricing externalities, but more politically acceptable. This approach, however, is very problematic for three closely related reasons.

First, subsidizing green power for reducing pollution (relative to some counterfactual) is not equivalent to taxing "brown" power to reflect the marginal social damage. If end-use electricity demand were completely inelastic and green and brown power were each completely homogeneous, they would have the same effect; the only effect of the subsidy would be to shift the production *share* towards green and away from brown power. But the underlying market failure is the underpricing

of brown power, not the overpricing of green power, so subsidizing green power from government revenues artificially depresses the price of power and discourages efficient energy consumption.[7] As a result, government subsidies of green power lead to overconsumption of electricity and disincentives for energy efficiency. In addition, for any given level of reduction, it will be achieved more efficiently by equalizing the marginal price of the pollutant across sectors as well as within sectors. This is not achievable through *ad hoc* subsidies to activities that displace certain sources of emissions. Fowlie, Knittel, and Wolfram (forthcoming) estimate that failure to achieve uniform marginal prices in the emissions of nitrogen oxides in the United States has raised the cost of regulation by at least 6 percent.

Second, subsidizing green power generally fails to recognize the heterogeneity within the green power sector and among the brown power sources that are being displaced. Solar power that reduces coal-fired generation lowers greenhouse gas emissions by about twice as much on average as if it reduces natural-gas-fired generation. Assuming that the marginal generation displaced is equal to the average generation mix in the system can be a poor approximation. A number of studies have attempted to go further and infer the generation that is displaced by an incremental unit of power from wind or solar within a system, accounting for the timing and location of the green power (for example, Callaway and Fowlie 2009; Cullen 2011; Gowrisankaran, Reynolds, and Samano 2011). These studies have made it clear how difficult it is to identify the alternative generation emissions even after the fact. But to give efficient long-run incentives for investment, policymakers must commit to subsidies well before they could have the data to calculate the alternative emissions. The problem arises because subsidizing green power is an indirect approach to the pollution problem, and the relationship between green power and emissions avoided is not uniform. It would not arise with a direct tax (or pricing through tradable permits) on pollution.[8]

Third, because subsidizing green power addresses the policy goal only indirectly, it introduces an opportunity for what might be called "benefit leakage" in which the effect on the policy goal takes place out of the immediate area. If producing more green power in one state lowers the production of brown power in a distant area that exports electricity to the state, then the benefits of the pollution reduction are less likely to flow to those underwriting the subsidies. Obviously, with greenhouse gases this would be an accounting issue, not a real change in the benefits, but with local pollutants the local environmental gains from subsidizing green power could be much less than would be suggested by a calculation that assumes no change in trade.

[7] Green power subsidies that are paid for through a general surcharge on electricity are likely to be a step in the right direction, but only in very special cases do they result in electricity prices that reflect the social cost of pollution.
[8] Both subsidizing green and taxing brown power require committing to the level of a policy instrument—such as prices or quantities—with only imperfect knowledge of its optimal level. Subsidizing green has the *additional* problem of setting the level of the policy instrument while knowing only imperfectly the relationship between the policy instrument and the variables of real interest.

All energy sources have environmental implications for which property rights have not been clearly assigned or would be costly to enforce. Wind turbines harm birds, as well as create low-frequency thumping that some people find difficult to live with. Large-scale solar projects in the desert can endanger habitat for native animals. Solar photovoltaic panels contain some heavy metals that require careful handling in disposal. Geothermal generation may cause ground water pollution and small-scale seismic activity. Tidal and wave power—both in nascent development stages—will likely run into concern that the generators interfere with marine life. Coal mining creates significant quantities of solid waste. Oil and gas production can result in leaks that spoil nearby ecosystems. Recently there have been concerns about the environmental impact of fluids used in hydraulic fracturing. Nearly all generation sources are at some point accused of visual pollution.

Many of these externalities involve substantial costs which mean substantial wealth transfers and potentially large efficiency implications. Externalities from fossil fuels have triggered litigation for years. With each new energy source, new property rights conflicts emerge and must be adjudicated. Even if Coasian efficiency results after property rights are assigned, the assignment process is costly. In one vivid example in Sunnyvale, California, a conflict arose between one neighbor with solar panels and another with redwood trees that had grown tall enough to shade the panels. After a lengthy lawsuit, the solar panels won and the redwood trees had to be removed (Rogers 2008).

Non-Environmental Externalities

While environmental externalities are the leading argument for public policy that encourages alternative energy sources, they are certainly not the only argument made. Although these non-environmental justifications have become more prominent in public policy discussions in the last year or so, they are generally much less persuasive.

Energy Security

"Energy security" is rarely defined precisely, but the phrase generally is used to suggest that the United States should produce a higher share of the energy it uses. One justification is macroeconomic: If the price of a fuel for which the United States is highly import-dependent rises suddenly, the common wealth shock to most consumers could potentially disrupt the macroeconomy. Empirically, this argument may apply to oil—the United States now consumes nearly twice as much oil as it produces—but it does not apply to coal or natural gas, for which the United States is about self-sufficient. Moreover, the United States uses almost no oil in producing electricity. Energy security arguments could perhaps support a move towards electric cars (or other alternatives to oil for transportation fuels). In that case, however, producing the electricity from coal or natural gas enhances security as much as producing it from renewables. In addition, electricity from coal and natural gas

is less expensive, so using those sources would make electric transportation more affordable. The distinct advantage of renewable electricity generation is its lower environmental impact, not its ability to enhance energy security.

A second "energy security" argument is that high energy prices enrich some energy-exporting countries that are hostile to U.S. global interests. By reducing use of these fuels, the argument goes, the United States could lower the price of energy, which would both help United States consumers and reduce the wealth flows to hostile regimes and possibly reduce military expenditures directed towards ensuring unimpeded energy trade. This argument again does not have traction in analysis of coal or natural gas in the United States. Even in oil-importing countries where oil is a significant source of electricity generation, the quantities of oil used for generation are so small relative to the world oil market that replacing them with renewables is unlikely to have any noticeable impact on world oil prices, as indicated in Table 1. This argument has been raised with more credibility in the context of European natural gas purchases from Russia.

Non-Appropriable Intellectual Property

Even with the strong intellectual property laws that have been adopted in the most advanced countries, in most cases a successful innovator captures relatively little of the value from the innovation. That outcome surely creates some dynamic inefficiency, which governments have addressed in many sectors by subsidizing basic research. Whether this incentive problem is greater in energy than other sectors is not clear, but it is clear that U.S. government expenditures on energy R&D have been much smaller as a share of GDP contribution than in health care, defense, or technology (NSF 2010 Chapter 4).

Government support for generating fundamental scientific knowledge in energy has increased with the creation of the Advanced Research Projects Agency—Energy (ARPA-E) within the Department of Energy in 2009, but the ARPA-E budget for 2012 is likely to be under $200 million. Studies from across the political spectrum have suggested it should be 50 percent to many times higher (Augustine et al. 2011; Loris 2011).

For those renewable electricity technologies currently available, a common argument for subsidies is that greater installation will lead to learning-by-doing that will drive down the cost and price of the technology. This possibility justifies government intervention, however, only if the knowledge from that learning-by-doing is not appropriable by the company that creates it—that is, if the knowledge spills over to other firms. Though the argument has some merit, proponents frequently overstate the strength of the evidence on this point.

First, most studies of learning-by-doing are not able to separate learning-by-doing from other changes. In solar photovoltaic power, costs have come down dramatically since the 1960s as the total number of installed panels has increased, with estimates that every doubling of the installed base has on average been associated with about a 20 percent decline in the cost of solar panels (for instance, Duke and Kammen 1999; Swanson 2006). Many factors have affected costs over this time

(Nemet 2006). Significant exogenous technological advances in crystalline silicon solar technologies have resulted from investments made outside the commercial solar power sector, especially public investments made as part of the U.S. space program and private investments in the semiconductor industry. In addition, firms in the industry have gotten larger, which has lead to savings from economies of scale—producing more units of output in each period—rather than learning-by-doing, which is the knowledge gained from a larger aggregate history of production over time. Barbose, Dargouth, Wiser, and Seel (2011) present comprehensive data on changing costs of solar photovoltaics over time.

The distinction between learning-by-doing and economies of scale may seem minor, but the implications for public policy are immense. If one firm can drive down its costs by producing at large scale in its factory or its installation operation, those benefits are highly appropriable by that large firm. Smaller firms are not likely to experience a cost decline because a competitor is enjoying economies of scale. Thus, significant economies of scale in any industry, short of creating a natural monopoly, are not generally seen as a basis for government intervention.

Learning-by-doing creates more spillovers, because knowledge is likely to be portable across firms. Still, the evidence of strong learning-by-doing is thin and credible results on spillovers are even more rare. Nemet's (2006) analysis suggests that learning-by-doing has actually played a relatively small role in the decline of solar photovoltaic costs over the last 30 years. He finds that the scope for learning-by-doing using the current crystalline silicon technology is quite limited given the current state of the industry. While the evidence of minimal learning-by-doing effects in solar photovoltaics is not dispositive, it is more convincing than any existing research claiming significant effects.

Green Jobs

The "job creation" justification for government policies to promote renewable energy took on greater prominence after the downturn that began in 2007 and the failure of climate change legislation in Congress since then. In the green jobs debate of 2008–2010, there was much confusion between the short-run stimulus goal and the longer-run policy of subsidizing green job creation. As a stimulus program, the advisability of subsidizing renewable energy depends on how rapidly the investment can take place and the elasticity of investment with respect to those subsidies. In general, the renewable energy sector tends to require large up-front construction costs, which is likely to be attractive in the context of short-term job creation, but the capacity to expand such projects rapidly is likely to be fairly limited.

When the economy recovers and the stimulus justification fades, is there a longer-term job creation justification for subsidizing renewable energy? This question has a static and a dynamic component. The static view is that renewable energy and energy efficiency are more labor-intensive technologies for producing (or conserving) energy than conventional energy production. The empirical support for these claims is uneven, but even if true, it is far from making the case that green job creation is welfare improving. To the extent that renewable energy costs more,

even after accounting for environmental externalities, renewable energy absorbs more resources to produce the same value of output—a unit of electricity—and lowers GDP compared to conventional sources. Another possibility is that renewable energy creates "better" jobs than conventional sources, perhaps by targeting workers whose incremental economic welfare is of particular importance because they are otherwise difficult to employ or because they would otherwise have very low-wage jobs.

The dynamic view is that investment in renewable energy is justifiable as an attempt to change the equilibrium path of investment and the economy. One reason suggested is that renewable energy is a growth industry and, implicitly, that private investors are too slow to recognize the opportunity, leading to suboptimal investment. However, it seems hard to argue the general case that government policymakers are better at identifying emerging business opportunities than the private sector. A more nuanced and potentially compelling version of this argument is that up-front investment will create network externalities and learning that spill over much more strongly intra-nationally than internationally, creating a sustainable economic advantage for the country that makes the investment (Moretti 2012). Such effects could be important, but as countries make competing investments to become the dominant center of renewable energy, it seems likely that at least some of those rents would be dissipated or transferred to firms that can choose their locations.

The network effects argument is often heard in political debates, but evidence supporting it is scarce. Both Germany and Spain have subsidized enormous investments in installation of renewable energy, particularly solar. In 2008, Spain was the largest market for new solar generation in the world, but its manufacturing and installation of new capacity virtually disappeared in 2009 when the country cut back subsidies. Germany has continued to grow installations of solar photovoltaics, more than quadrupling new capacity from 2008 to 2010, but panel manufacturing in Germany has declined from 77 percent of new installed capacity in 2008 to 27 percent in 2010 as China and Taiwan have made massive investments in panel manufacturing, according to data from Earth Policy Institute (2011).

This area is ripe for further research. I am not aware of any credible studies that have assessed the short-run stimulus effect of green energy investment relative to other stimulus policies, the quality of the jobs created in the long run by green energy investment, or the ability of governments to make strategic investments that trigger a sustainable new sector.

Lowering the Cost of Fossil Fuel Energy

Increasing adoption of renewable energy lowers the demand for fossil fuels and drives down their prices. As a public policy argument, this is essentially advocating the exercise of monopsony power in the fossil fuel market (a buyer or set of buyers can drive down price by reducing purchases). That outcome has clear inefficiencies— some fossil fuels are replaced by more-expensive renewable power—but it still might be surplus-enhancing on net for the set of economic actors that the policymaker represents. In the United States, the effect of increasing renewable power is

Table 2

Levelized Cost of Residential Solar Photovoltaic Power under Alternative Discount Rates

(per kilowatt hour)

Real interest rate	*1%*	*3%*	*5%*	*7%*	*9%*
Levelized cost	$0.249	$0.315	$0.389	$0.468	$0.551

Notes: Table 2 presents the implied levelized cost of power for a 5 kilowatt system located in Sacramento, California. Assumptions: A five kilowatt system costs $36,500 installed. Panels last for 30 years with no shading or soiling and no maintenance costs, producing on average 0.77 kilowatts over all hours in first year. Output of panels declines by 0.5 percent per year due to aging. The inverter is replaced after 10 years (at $2,552) and 20 years (at $2,171), based on current cost of $3000 declining by 2 percent annually in real terms. For further details and sources, see online Appendix.

to reduce demand for natural gas and coal. U.S. production of these fossil fuels is nearly equal to consumption, so the effect is to transfer wealth from U.S. producers to U.S. consumers. On the state level within the United States, the effect is much more uneven since many states are large importers of fossil fuels and a smaller number are large exporters.

The size of this effect on prices is also questionable. While some advocates have focused on short-run price variation, the impact of a long-term shift towards renewables will depend on the long-run elasticity of supply for natural gas and coal. With the advent of hydraulic fracturing, it seems likely that the long-run elasticity of natural gas supply has become quite high. The long-run elasticity of coal supply is generally seen as quite high as well (Miller, Wolak, and Zhang 2011). Thus, a shift to renewables is not likely have a large effect on fossil fuel prices.

An Application to Residential Solar Photovoltaic Power

Here, I apply the analytic approach described above to update the calculations of levelized cost of residential solar power from Borenstein (2008a), taking into account recent changes in the cost of solar photovoltaic systems.

According to Barbose, Dargouth, Wiser, and Seel (2011), the cost of installing residential-scale solar systems (less than 10 kilowatt capacity) in 2010 varied in average price from $6.3/watt in capacity in New Hampshire to $8.4/watt of capacity in Utah, with California—by far the largest state for residential solar—at $7.30. Taking California's number as the benchmark, Table 2 presents the implied levelized cost of power for a 5 kilowatt system located in Sacramento, California, under alternative real discount rates. The underlying assumptions noted in the table are intended to be median estimates: if anything, they are tilted somewhat towards lowering the cost.

The real interest rate of 3 percent implies a levelized cost of $0.315 per kilowatt hour. I follow Borenstein (2008a) in adjusting for the timing of production

(including line losses), increasing the value of residential solar by 20 percent, and for the location of production, increasing value by 1 percent. I incorporate these effects by adjusting the levelized cost down to $0.260 per kilowatt hour ($= 0.315/(1.2 \times 1.01)$). An additional downward adjustment of $0.02 per kilowatt hour accounts for long-run savings in transmission investment, as discussed in Borenstein (2008b, p. 10), which brings the net cost to $0.240. Details of these adjustments are in the online Appendix available with this paper at ⟨http://e-jep .org⟩. This result compares to levelized costs for combined-cycle gas-fired generation that are now generally below $0.08 per kilowatt hour, given the reduced price forecasts for natural gas that are now common due to the expected supply increases.

Adjusting next for environmental externalities, if one assumes that new residential solar generation substitutes for new combined-cycle gas turbines, then the local pollutant reduction is valued at about $0.0015 per kilowatt hour according to Muller, Mendelsohn, and Nordhaus (2011). That leaves a cost gap between residential solar and combined-cycle gas turbine generation of at least $0.158. The gas plant emits slightly less than 0.0005 tons of carbon dioxide per kilowatt hour of electricity, so residential solar would be cost competitive on a social cost basis only if the cost of carbon dioxide emissions were greater than $316 per ton. Nearly all social cost and price forecasts for carbon dioxide are well below $100 per ton (Greenstone, Kopits, and Wolverton 2011), which leaves residential solar still at least $0.108 per kilowatt hour more expensive.

This analysis of the costs of residential solar power does not account for potential cost savings in reducing the size of the necessary distribution network for electricity, nor for spillovers from learning-by-doing, for which analyses offer much less guidance. On the other side, it also doesn't incorporate reduced output due to shading or soiling of the panels, or installation at a less-than-ideal angle due to the building orientation (Borenstein 2008b). But this analysis provides a good notion of the gap that those factors would have to fill in order for residential solar photovoltaics to substitute cost-effectively for gas-fired generation.

Medium-scale and large-scale solar photovoltaics installations and large-scale solar thermal generation are somewhat more cost competitive. Contracts for these larger systems are not public, but reports in the industry press suggest the unsubsidized levelized cost from these installations is probably between $0.15 and $0.20 per kilowatt hour in 2011, before any of the market or externality adjustments and likely using more than a 3 percent real cost of capital. These systems enjoy the same production timing benefit as residential solar, but less (or none) of the reduction in line losses and transmission savings. These systems would require a much lower cost of carbon dioxide to be competitive with gas-fired generation, though still probably $100 per ton or greater.

Conclusion

The most important market failure in energy markets is almost certainly environmental externalities, and the single most efficient policy would be to price those

externalities appropriately. Yet policymakers often find pricing externalities to be nearly impossible politically. Thus, the second-best discussion is over which, if any, alternative policy interventions are likely to do the most good, or at least to do more good than harm.

Instead of pricing externalities, the far more prevalent government response has been targeted programs to promote specific alternatives to conventional electricity generation technologies. Justifications for such programs have generally begun with environmental concerns, but have often expanded to energy security, job creation, and driving down fossil fuel prices, generally without support of sound economic analysis. Such targeted programs also seem especially vulnerable to political manipulation.

If governments are to implement reasoned renewable generation policy, it will be critical to understand the costs and benefits of these technologies in the context of modern electricity systems. This requires developing sophisticated levelized cost estimates, and adjusting for both the market value of the power generated and the associated externalities, so they can be usefully compared across projects and technologies. Such adjustments are complex and frequently controversial. More research at the interface of the economics and engineering of electricity markets would be very valuable, particularly on the cost of intermittency, the benefits of end-use distributed generation, and the economic spillovers from learning-by-doing and network externalities. Progress on these questions would enhance renewable energy public policy and private decision making, particularly in a world where first-best, market-based options are greatly restricted.

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Appendix

Table A1

Details for Levelized Cost of Energy Estimates

Borenstein 2008a	**Inflation:** All calculations use 2007\$; **Interest**: 3% real annual interest rate; **Lifetime**: 25 years; **Capacity factor**: 16%; **Subsidies:** None; **Online:** 2007; **Notes:** Capacity factor is for AC production, based on production simulation for Sacramento, CA. Levelized cost of energy (LCOE) in real 2007\$.
Klein 2010	**Inflation:** About 1.6% per year, plus 0.5% escalation for O&M costs; **Interest:** 4.67% weighted average cost of capital (WACC) for publicly-owned utilities; **Carbon cost:** None; **Local pollutant cost:** None; **Online:** 2018; **Notes:** LCOE given is in nominal terms. Used "average" case. Used publicly-owned utility estimates. *Gas CCGT:* **Lifetime**: 20 years; **Fuel**: \$6.56/MMBtu in 2009 to \$16.80/MMBtu in 2029, at nominal prices; **Capacity factor:** 75%. *Wind – onshore:* **Lifetime:** 30 years; **Capacity factor:** 37%; **Subsidies:** Federal production incentive of \$4.10/MWh. *Geothermal:* **Lifetime:** 30 years; **Capacity factor:** 94%; **Subsidies:** Federal production incentive of \$4.10/MWh. *Hydropower:* **Lifetime:** 30 years; **Capacity factor:** 30%; **Subsidies**: None; **Online:** 2018; **Notes:** For "small-scale and existing sites." *Biomass:* **Lifetime:** 20 years; **Fuel:** \$2.00/MMBtu in 2009 to \$2.91/MMBtu in 2029, at nominal prices; **Capacity factor:** 85%; **Subsidies:** Federal production incentive of \$4.10/MWh; **Online:** 2018; **Note:** Data are for stoker boiler. *Solar CSP & Solar PV:* **Lifetime:** 20 years; **Capacity factor:** 27%; **Subsidies:** Receives federal production incentive of \$4.10/MWh, and exempt from state ad valorem tax; **Notes:** 250 MW gross capacity parabolic trough for solar CSP (concentrated solar power); 250 MW gross capacity single axis system for PV (photovoltaic). *Gas – conventional simple cycle:* **Lifetime:** 20 years; **Fuel:** \$6.56/MMBtu in 2009 to \$16.80/MMBtu in 2029, at nominal prices; **Capacity factor:** 75%.
Du and Parsons 2009	**Inflation:** 3% annual inflation, plus 1% real escalation in O&M and 0.5% real escalation in fuel; **Lifetime:** 40 years; **Capacity factor:** 85%; **Subsidies:** None; **Online:** 2009; **Notes**: Real LCOE in 2007\$. *Pulverized:* **Interest:** 7.8% real WACC; **Fuel:** \$2.60/MMBtu in 2007\$ with escalation as described above; **Notes:** Based on recently proposed supercritical and ultrasupercritical pulverized coal plants. *Gas – Conventional CCGT*: **Interest:** 7.8% real WACC; **Fuel:** \$7/MMBtu in 2007\$ with escalation as described above. *Nuclear*: **Interest:** 10% real WACC; **Fuel:** \$0.67/MMBtu in 2007\$ with escalation as described above.

EIA 2011a, b, c	**Inflation:** Average 2.9% annually; **Interest:** 10.4% real WACC for fossil generators without CCS, 7.4% real WACC for all others; **Lifetime:** 30 years; **Subsidies:** None; **Carbon cost:** Cost of capital for fossil plants without CCS is 3 percentage points higher than for other generators; **Online:** 2016; **Notes:** LCOE is in 2009$. *Pulverized:* **Fuel:** Delivered price is about $2.50/MMBtu in 2009$ through 2035; **Local pollutant cost:** Plants choose least-cost combination of scrubbers and emissions allowances to comply with Clean Air Interstate Rule; **Capacity factor:** 85%. *Gas – Conventional CCGT:* **Fuel:** Lower 48 wellhead price rises from about $4/kCF in 1990 to about $6.50/kCF in 2035; **Capacity factor:** 87%. *Wind – onshore:* **Capacity factor:** 34%. *Geothermal:* **Capacity factor:** 92%. *Hydropower:* **Capacity factor:** 52%. *Nuclear:* **Fuel:** Proprietary model starting from Energy Resources International uranium price forecasts; **Capacity factor:** 90%. *Biomass:* **Fuel:** Not given; **Capacity factor:** 83%. *Solar CSP:* **Capacity factor:** 25%. *Solar PV:* **Capacity factor:** 25%; **Notes:** For 150 MW fixed-tilt flat plat PV. *Gas – conventional simple cycle:* **Fuel:** Lower 48 wellhead price rises from about $4/kCF in 1990 to about $6.50/kCF in 2035; **Capacity factor:** 30%.
EPRI 2009	**Inflation:** All calculations use real 2008$; no escalation is modeled for any cost component; **Interest:** Real, after-tax WACC of 5.5%; **Lifetime:** 30 years; **Subsidies:** None; **Carbon cost:** none; **Online:** 2015; **Notes:** LCOE in 2008$. *Pulverized:* **Fuel:** $15/MWh in 2008$; **Capacity factor:** 80%; **Local pollutant cost:** Mercury removal; **Notes:** For 650–750 MW supercritical plant. *Gas – Conventional CCGT:* **Fuel:** $8–$10/MMBtu in 2008$; **Capacity factor:** 80%. *Wind – onshore:* **Capacity factor:** 35%; **Notes:** 100 MW wind farm; location not specified. *Nuclear:* **Fuel:** $0.80/MMBtu in 2008$; **Capacity factor:** 90%; **Notes:** 1400 MW plant. *Biomass:* **Fuel:** $1.22–$2.22/MMBtu in 2008$; **Capacity factor:** 85%; **Notes:** 75 MW circulating fluidized bed plant, with 28% efficiency. *Solar CSP:* **Capacity factor:** 32%; **Notes:** 125 MW facility in New Mexcio with wet cooling and 10% combustion. *Solar PV:* **Capacity factor:** 26%; **Notes:** 20 MW fixed flat plate PV with 10% conversion efficiency.
Fthenakis, Mason, and Zweibel 2009	**Inflation:** 1.9% annual; **Interest:** 6.7% after-tax WACC; 5% real discount rate; **Lifetime:** 30 years; **Subsidies:** not specified; **Online:** 2020; **Notes:** Assumes new HVDC transmission construction costs of $0.007/kWh. *Solar CSP:* **Capacity factor:** 90% (16 hours of thermal storage); **Notes:** "Gigawatt scale" CSP plant in southwest US with 16 hours of thermal storage capacity. *Solar PV:* **Capacity factor:** 90% (300 hours of compressed air storage); **Notes:** "Multi-hundred MW scale" PV; assumes major technological advances lower cost.

Lazard Ltd. 2008	**Inflation:** 2.5% annual escalation for fuel, O&M, and tax credits (no overall inflation specified); **Interest:** 7.3% after-tax WACC; **Lifetime:** 20 years; **Notes:** Online years imputed based on stated construction times; LCOE in 2008$; **Carbon cost:** None; **Local pollutant cost:** None. *Pulverized coal:* **Fuel:** $2.50/MMBtu in 2008$, with escalation as described above; **Capacity factor:** 85%; **Online:** 2013; **Notes:** Range of estimates $74–$135/MWh (high end includes 90% carbon capture and compression). *Gas – Conventional CCGT:* **Fuel:** $8.00 / MMBtu in 2008$; **Capacity factor:** 40%–85%; **Online:** 2011; **Notes:** Range $73–$100/MWh. *Wind – onshore:* **Capacity factor:** 28%–36%; **Subsidies:** Production tax credit of $20/MWh; **Online:** 2009; **Notes:** 100 MW facility; Range $44–$91/MWh. *Geothermal:* **Capacity factor:** 70%–80%; **Subsidies:** Production tax credit of $20/MWh; **Online:** 2011; **Notes:** Range $42–$69/MWh. *Nuclear:* **Fuel:** $0.50/MMBtu in 2008$; **Capacity factor:** 90%; **Online:** 2014; **Range:** $98–$126. *Biomass:* **Fuel:** $0–2/MMBtu in 2008$; **Capacity factor:** 80%; **Subsidies:** Production tax credit of $10/MWh; **Online:** 2012; **Notes:** Range $50–$94/MWh. *Solar CSP:* **Capacity factor:** 26%–38%; **Subsidies:** 30% investment tax credit; **Online**: 2010; **Notes:** Range $90–$145/MWh (low end tower, high end trough). *Solar PV:* **Capacity factor:** 20%–26%; **Subsidies:** 30% investment tax credit; **Online:** 2009; **Notes:** Range $96–$154/MWh; low end is for 10 MW net capacity thin film installation; high end is for 10 MW crystalline fixed axis installation. *Gas – Conventional simple cycle:* **Fuel:** $8.00/MMBtu in 2008$ with escalation as described above; **Capacity factor:** 10%; **Online:** 2010; **Notes:** Range $221–$334; Low end is for GE 7FA turbine; High end is for GE LM6000PC turbine.
Cory and Schwabe 2009	**Inflation:** 4% annually; **Interest:** All equity financing with 10% target internal rate of return; Interest rate 5.8%; **Lifetime:** 20 years; **Capacity factor:** 34%; **Subsidies:** Production tax credit of $15–$21/MWh; **Online:** 2008; **Notes:** 120 MW facility; Used "corporate" financing structure and "base case" scenario.
Freese, Clemmer, Martinez, and Nogee, 2011a, b	**Inflation:** All calculations use real 2010$. **Interest:** Not specified. Capital costs based on EIA technology-specific fixed charge rates; **Lifetime:** 20 years; **Subsidies:** None; **Carbon cost:** None; **Online:** 2015; **Notes:** LCOE is given in 2010$. *Pulverized coal:* **Fuel:** $1.60–$2.70/MMBtu in 2010$; **Capacity factor:** 85%; **Notes:** Range of estimates $103–$130/MWh; for 600 MW supercritical plant. *Gas – conventional combined cycle:* **Fuel:** $4.00–$6.75/MMBtu in 2010$; **Capacity factor:** 50%–87%; **Notes:** Range $52–$98/MWh; 400 MW plant. *Wind – onshore:* **Capacity factor:** 25%–45%; **Notes:** Range $57–$125/MWh. *Geothermal:* **Capacity factor:** 85%; **Notes:** Range $65–$169/MWh. *Nuclear:* **Fuel:** $0.8/MMBtu in 2010$; **Capacity factor:** 80%–90%; **Notes:** Range $141–$184/MWh; for 1100–1350 MW plant. *Biomass:* **Fuel:** $1.88–$4.06/MMBtu in 2010$; **Capacity factor:** 80%; **Notes:** Range $147–$328/MWh; 50 MW circulating fluidized bed plant. *Solar CSP:* **Capacity factor:** 27%–43%; **Notes:** Range $147–$328/MWh; 50–100 MW facility. *Solar PV:* **Capacity factor:** 20%–28%; **Notes:** Range $126–$260/MWh.

Notes: LCOE is "levelized cost of energy." WACC is "weighted average cost of capital." O&M is "operation and maintenance." CCS is "carbon capture and storage." CSP is "concentrated solar power." PV is "photovoltaic." CCGT is "combined cycle gas turbine." HVDC is "high-voltage, direct current."