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ASSESSING THE COSTS OF ELECTRICITY

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■ **Abstract** We review the economics of electricity generated, or conserved, from a diverse range of fossil-fuel, nuclear, and renewable energy sources and energy efficiency options. At the same time, we survey the methods used to compute the costs of generated and delivered electricity and power, including bus bar costs; wholesale and retail marketplace costs; life-cycle accounting systems; premiums associated with political, social, and environmental risks; costs that reflect explicit and implicit subsidies; costs inclusive of externalities calculated by a variety of means; and net costs, including a range of proposed and potential environmental tax regimes. These diverse and at times conflicting analytic methods reflect a wide range of assumptions and biases in how the inputs for energy generation as well as how the subsidies and social and environmental costs are computed or, is often the case, neglected. This review and tutorial provides side-by-side comparisons of these methods, international cost comparisons, as well as analysis of the magnitude and effects of a range of technological, market-based, and subsidy-driven costs on the final price of electricity. Comparability of costs between supply and conservation technologies and methods in the energy sector has consistently been a problem, and the diversity of energy cost accounting schemes provides significant opportunity for very different arguments to be made for specific technologies, regulatory and market regimes, and a wide range of social and environmental taxes. We provide a review of the tools and a commentary on how these methods are used to determine the cost of energy services. The conclusion contains an analysis of how these methods of energy valuation are similar, how they differ, as well as an analysis of the explicit and implicit assumptions that underlie each approach.

CONTENTS

INTRODUCTION: ANALYTIC METHODS FOR ENERGY COST COMPARISONS

Energy is the most significant international commodity in terms of material flows, financial transfers, and arguably in both sociopolitical and environmental impact. Eight of the largest ten global companies are involved in energy discovery or acquisition, refining, or the provision of energy services. At the same time, the methods used to assess costs of energy resources and services not only differ greatly in terms of the theoretical and philosophical perspectives employed and emphasized, but also because they are frequently used to highlight radically different assumptions about the economic, social, security, and environmental value of renewable and nonrenewable resources.

Independent of which agent sets or imposes the market price of electricity (e.g., market equilibrium methods, auctions, regulatory authorities), energy accounting is fundamental to assessments of the feasibility of proposed power generation or conservation projects. Traditional electricity costing combines capital and operating costs, resource and conversion equipment characteristics, and regulatory and financial constraints. Over the past decades, the importance of hidden costs and environmental externalities in the development of energy projects has evolved, and although the methods used to monetize these values are still debated, their influence on our thinking about cost-benefit analysis for decision making is indisputable.

This review represents a departure in form from many past *Annual Review of Energy and the Environment* chapters. As part of the new series format, we will undertake a series of periodic updates on the basics of energy and resource issues. The goal of *Annual Review of Environment and Resources* is to regularly publish updated reviews and tutorials covering the costs, values, and impacts of the uses of energy services. As a result, this review provides an assessment of the methods employed in the form of a tutorial in energy economics and finance as well as quantiative material on the actual costs of different energy technologies, resources, and delivered energy.

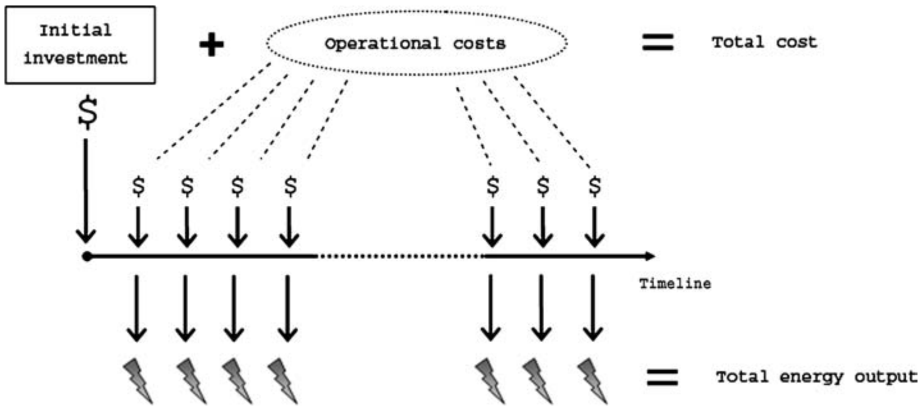

Figure 1 Simplified cash flow of a power plant.

METHOD I: BUS BAR COSTS

The break-even cost at which all expenses necessary to generate electricity are met is known as the levelized bus bar cost. Such cost is computed using cash flows throughout the facility's life cycle and includes initial expenses (design, licensing, installation), operating expenses, maintenance expenses, taxes, and decommissioning expenses. A simplified cash flow of a natural gas–fueled power plant, for example, consists of an initial investment to install the infrastructure plus a series of future operational costs, which include expenses with fuel purchases over the life cycle of the facility (Figure 1).

Ideally, each year the power plant produces the same amount of energy and consumes the same amount of fuel at a fixed cost, and the total life-cycle cost of a power plant combined with its total life-cycle energy output yields the electricity cost, which is usually expressed in terms of mills/kWh (one mill is a tenth of a cent). This value is the ratio between the annualized cost of the power plant and the energy output during one year. The calculation of the annualized cost involves the adoption of an annual discount rate (1). An annual discount rate is used to simplify the example in Figure 1, but discount rates based on shorter periods (months) may be also used. In order to convert from a fixed monthly discount rate (r_m) to a annual discount rate, (r_y): $r_y = (1 + r_m)^{12} - 1$.

Initially it is necessary to determine the present value of a stream of periodic costs to operate the power plant. The present value cost (*PVC*) aggregates future costs weighted by discounting factors, d_i, (Equation 1), where

$$PVC = C_0 + d_1C_1 + d_2C_2 + \dots d_nC_n. \qquad 1.$$

The nth year is the final year of the period of analysis that does not necessarily coincide with the end of life of the facility because power plants can have their lifetime extended through retrofits. Retrofits can, of course, be incorporated in the stream of costs on a one-time or regular basis so that the lifetime of the power plant is extended, and the period of analysis is longer.

Equation 1 is used to calculate the present value of fuel, including changes in future prices, such as natural gas price escalation, used in the operation of thermal power plants. Fuel price escalation affects the value of C, and whenever a constant price escalation rate is expected, it may be added to the discount rate present in Equation 2. The discounting weight for a year in the future is a function of the annual discount rate (r) and the time elapsed in years (t) (Equation 2), where

$$d_t = \frac{1}{(1+r)^t}. \qquad 2.$$

Discounting adjusts costs in the future to render them comparable to values placed on current costs. A positive discount rate reflects that a given amount of future consumption is worth less than the same amount of consumption today. Real market discount rates represent the opportunity cost of capital or the rate of return of the best available investment option (1). Although discounting is a simple matter, analytically, important philosophical as well as economic arguments exist behind many of the numeric choices used in the literature.

Because the cost calculation is computed using an annual interval, it is necessary to know the annual energy output (AEO) and the annualized cost (AC) of the power plant. The AC is the amount one would have to pay at the end of each year, which equals the same cost in present value terms as the stream of costs being annualized (PVC), including discounting adjustments, where

$$AC = PVC\frac{r}{1-(1+r)^{-t}}. \qquad 3.$$

The annual energy output is typically assumed to be constant and reflects the installed power of the power plant in watts times the number of hours the power plant operates. Alternatively, the number of operating hours can be calculated using the capacity factor (CF) for the power plant. The CF is just a ratio expressed as a percentage between the number of hours a power plant operates and the total number of hours in the period considered, where

$$CF = \frac{\text{hours power plant is running}}{\text{total amount of hours in the period}} \times 100. \qquad 4.$$

In a fossil-fueled power plant the CF is driven by the periods of actual energy demand, whereas in the case of renewable energy it is associated with resource availability. Finally, the electricity cost, which may be reported in units of mills per kWh, is

$$\frac{AC}{AEO}(=)\frac{mills}{kWh}. \qquad 5.$$

Although a power plant is simply an energy converter, each technology demands the knowledge of different parameters to carry on an economic assessment. For example, the cost of a geothermal power plant involves estimates about the cost of studies to quantify the resource, drilling wells, power conversion equipment, and so forth (2). The cost of electricity produced by natural gas–fueled power plants involves hedging against fuel price volatility (3). Access to transmission lines to transport electricity should also be part of installation costs of a new facility. Transmission lines pose a physical limit to the amount of electricity carried (congestion), and part of the energy is lost during transmission (4). With the cost of transmission between two locations set as the difference between the cost of the energy at the two extremes of the transmission line, a comparative assessment between electricity supply options would logically account for the avoided transmission cost as a credit for decentralized systems.

Economists classify costs as fixed or variable. Fixed costs are independent of the output of the power plant, whereas variable costs are scalable depending on the output of the power plant. However, energy cost data are commonly reported in a peculiar way that includes the overnight costs, which represent the cost of the installed capacity in $/kW, the fixed and the variable operation and maintenance (O&M) costs in $/kWh, and the heat rate in MJ/kWh or Btu/kWh in the United States (5), which is a proxy for the electric efficiency of the power plant and indicates how much fuel is consumed to generate a given energy output.

At the present time, it is common to find power plants that not only produce electricity but also other services. This complicates the calculation of the electricity costs because it is often difficult to quantify the benefits arising from the provisioning of other services, and there is no consensual way to allocate the costs among different services. For example, a dam that is constructed for irrigation, water supply, and leisure may be also used to produce power (6). In the case of other forms of energy, which are by products of an electric generator, such as heat and power, the cost may be calculated for the total output using a common energy unit as a weighting factor for cost allocation.

In addition to electricity, combined heat and power (CHP) systems produce heat that is used for other purposes. The use of CHP can be compared with other energy sources that provide both power generation and another service. The electricity cost calculation for CHP involves the definition of the revenues from the steam supply, which may be included as a credit in the life-cycle cost calculations. Thus, the overall efficiency accounts for the electric output expressed in joules (0.293 J/Wh) added to the thermal output divided by the energy input. Accordingly, the net heat for electricity production is the fuel input minus the fraction of fuel attributable to produce steam that is being sold separately. Table 1 presents cost and efficiency calculations of various CHP systems. These alternatives may reduce cost and emissions through a more efficient primary energy use. (Fewer emissions do not always reduce environment and health problems because of the location of the emission source.) CHP systems have been recognized to be an opportunity for tremendous energy and economic savings. In some cases, efficient heat recovery and use can increase the overall efficiency of a power plant—now an electricity-heat facility—from from the 30% to 35% range to over 80%.

TABLE 1 Data for cost calculation of various combined heat and power (CHP) systems (7)

Size	Type	Cost ($/kWh)	O&M ($/kWh)[a]	Electric efficiency (%)[b]	Heat rate (Btu/kWh)	Thermal output (MMBtu/h)	Overall efficiency (%)[c]	Net heat rate (Btu/kWh)[d]
45–75 kW	Recip.	770	0.01	31	11,000	0.27	80	6,500
	MT	800	0.01	27.1	12,600	0.36	85	6,500
75–150 kW	Recip.	730	0.009	31.7	10,800	0.54	82	6,100
	MT	800	0.01	27.1	12,600	0.73	85	6,200
150–350 kW	Recip.	690	0.009	32.5	10,500	1.1	84	5,300
	MT	700	0.009	27.1	12,600	1.5	85	5,500
	Fuel cell	3,300	0.015	39.6	8,620	0.75	83.1	5,100
350–750 kW	Recip.	640	0.008	35	9,750	2.5	87	4,800
	MT	700	0.009	27.1	12,600	3.7	85	5,300
	Fuel cell	3,300	0.015	39.6	8,620	1.9	83.1	4,900
0.75–5 MW	Recip.	600	0.008	38	8,980	11	85	4,700
	Turbine	600	0.004	25.5	13,400	20	85	5,600
5–10 MW	Recip.	550	0.007	42	8,120	28	87.5	4,500
	Turbine	480	0.004	31	11,000	47	87.5	4,900
10–20 MW	Turbine	480	0.004	33	10,300	88	90	4,900
20–50 MW	Turbine	400	0.004	36.5	9,350	180	90	4,600
	CC	860	0.005	47	7,260	110	90	4,400
50–100 MW	Turbine	340	0.004	36.5	9,350	380	90	4,600
	CC	770	0.005	49.5	6,890	210	90	4,300
100+ MW	Turbine	270	0.004	36.5	9,350	500	90	4,400

[a]Abbreviations used include O&M, operation and maintenance; Recip., reciprocating engine; MT, microturbine—less than 750 kW; and CC, combined cycle.

[b]Electrical efficiency, overall efficiency, thermal output, and heat rates are based on lower heating value and for CHP operation at full load.

[c]Overall efficiency is based on electrical output (expressed as Btu equivalent) plus useful thermal output, divided by total energy input.

[d]Net heat rate is based on the fuel input minus the fuel required to produce the thermal output using a boiler (assuming a boiler efficiency of 85%), then divided by the full load electricity generated by the unit.

A similar approach can be applied to end use energy conservation investments. The final use of the energy, which is the energy service, may also be factored in cost calculations. Energy consumption is necessary because a service is demanded; therefore, if there is a technology that offers the same level of service but requires less energy, the annualized investment needed to install and maintain such technology (Equation 3) divided by the energy savings produces the cost of the conserved energy (CCE). Whenever the CCE is less than the marginal cost of electricity, which measures the cost to supply one unit of extra energy and deliver it to the consumer, it is better to invest in energy conservation than in supply. Figure 2 shows the CCE for different end uses in the residential and commercial sectors.

The calculation of CCE associated with different technologies and comparable energy services yields energy conservation supply curves (ECSCs) for use in the evaluation of the economic feasibility of energy conservation projects. The ECSC is assembled through the estimation of the potential energy savings and the CCE of several energy conservation measures (usually normalized to one year), and these are ranked based on their CCE. The curve is plotted in a graph where the vertical axis shows the CCE, and the horizontal axis measures the cumulative annual energy savings possible due to the incremental adoption of each technology (Figure 3). The cost of the (grid) energy supplied to the industry, which is also plotted on the conserved energy cost axis, determines the economic feasibility of projects (9, 10). Conservation supply curves were initially slow to win acceptance as a result of debates between neoclassical economists and energy conservation proponents over the value of conserved energy relative to purchased power. Thankfully, the debate over the value of "negawatts" as coined by Amory Lovins (10a), although not entirely resolved, has evolved to the point that energy savings are routinely evaluated and included in project assessments. Forecasts of energy savings and conservation have become central to evaluations of future needs and opportunities. The often dramatic savings possible for the U.S. economy are reflected in the cost of conserved energy curves produced as part of the widely cited Five Labs study (11) (Figure 4). A great many additional opportunities exist, such as the use of construction and building operation contracts in which the revenue is tied to energy efficiency performance.

There are at least two different methods to determine the total energy saved by the implementation of efficient technologies. One way is uses the baseline energy intensity, whereas the other one uses incremental savings.

Energy intensity measures the ratio between the output of a given commodity and the energy input needed to produce such output. For example, the introduction of technological changes reduced the energy intensity in the American cement industry from 7.9 GJ/Mg to 5.6 GJ/Mg ($\sim$30%) between 1970 and 1997. Currently, there is a potential for a 40% savings in the industry, which corresponds to 180 PJ (12); however, at present the actual real savings are likely to be limited to roughly one quarter of that total. Technological change has affected the American steel industry as well. In this industry the energy intensity dropped 27% between 1958 and 1994, corresponding to an energy intenstity of 9.7 GJ/Mg (13).

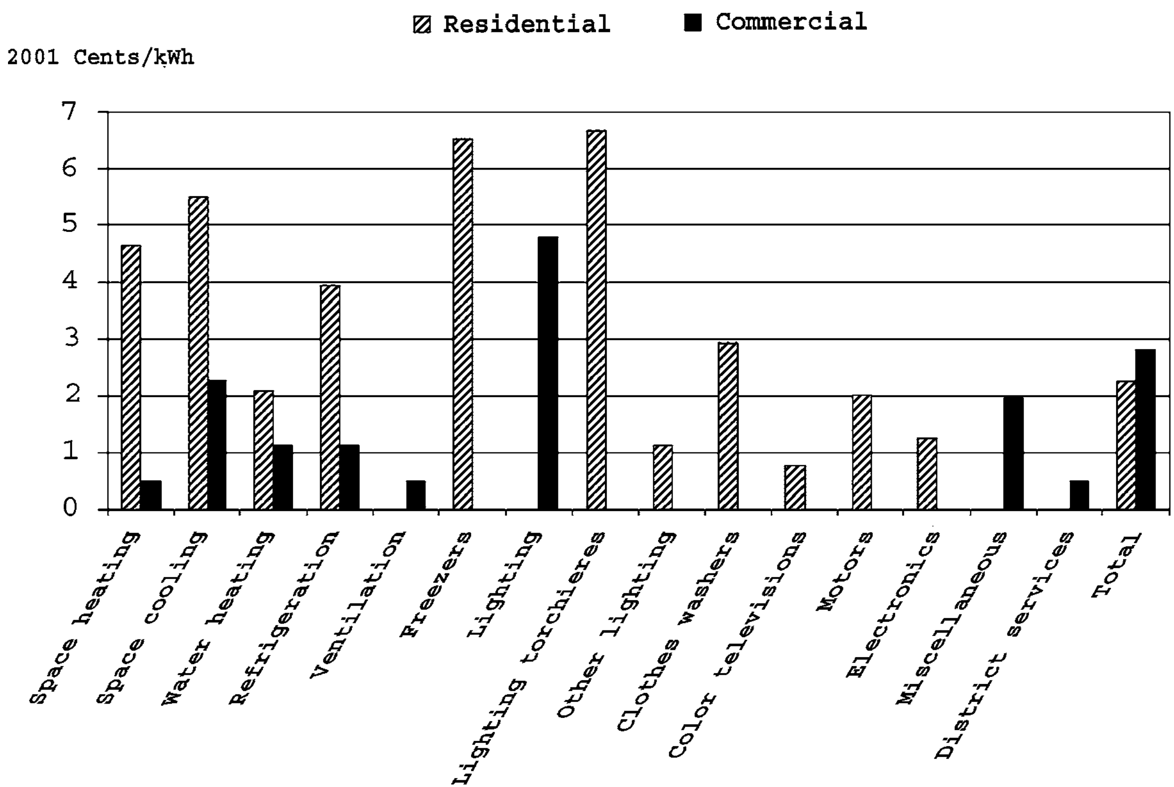

Figure 2 Cost of conserved energy for different end uses in the residential and commercial sectors (8).

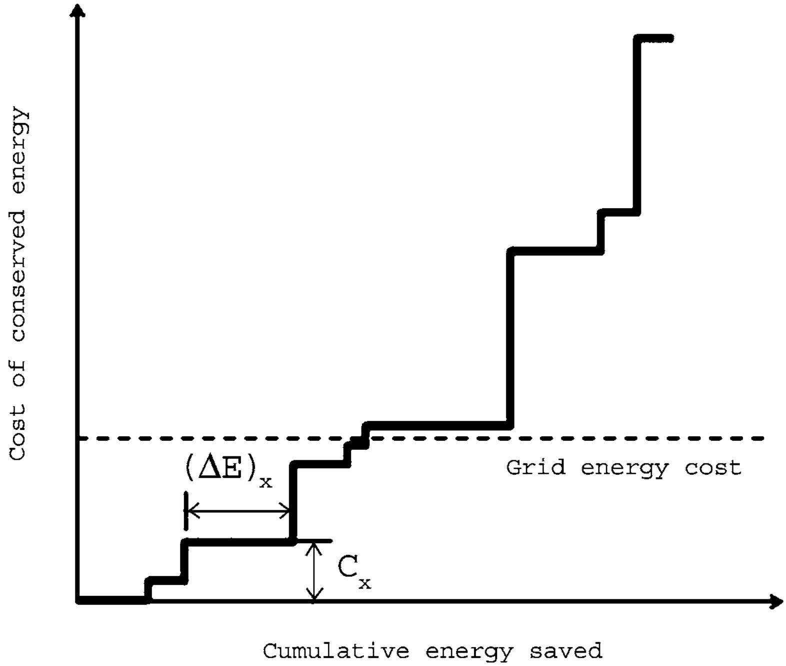

Figure 3 Energy conservation supply curve (ECSC) (10).

The ECSC based on incremental savings compares the marginal CCE versus the total amount of energy conserved. In this case, the benchmark to determine how much energy is conserved by a given technology is dynamic; that is, it is computed using the energy intensity of the previously implemented technology (14). In this case, the marginal CCE measures the investment needed to save one extra unit of energy.

Electricity costs for various current electricity generation technologies can be calculated using the equations presented herein, combined with values from Table 2, an appropriate discount rate, and fuel cost information. The differences between fossil-fuel systems, with relatively low capital costs yet sustained, sometimes volatile, fuel costs, and renewables with higher up-front costs and then both lower and more predicatable operation and maintenance costs can be striking, not only in terms of life-cycle impacts, but also in terms of revenue and expense cash flow.

METHOD II: MARKET-BASED COSTS, RISK PREMIUMS, AND COST VARIABILITY

By definition, power plants burning fuels for which there is a market are naturally subject to price fluctuations, which in turn impact the generation cost. Spot prices for both fuels (e.g., natural gas) and electricity have proved to be quite volatile,

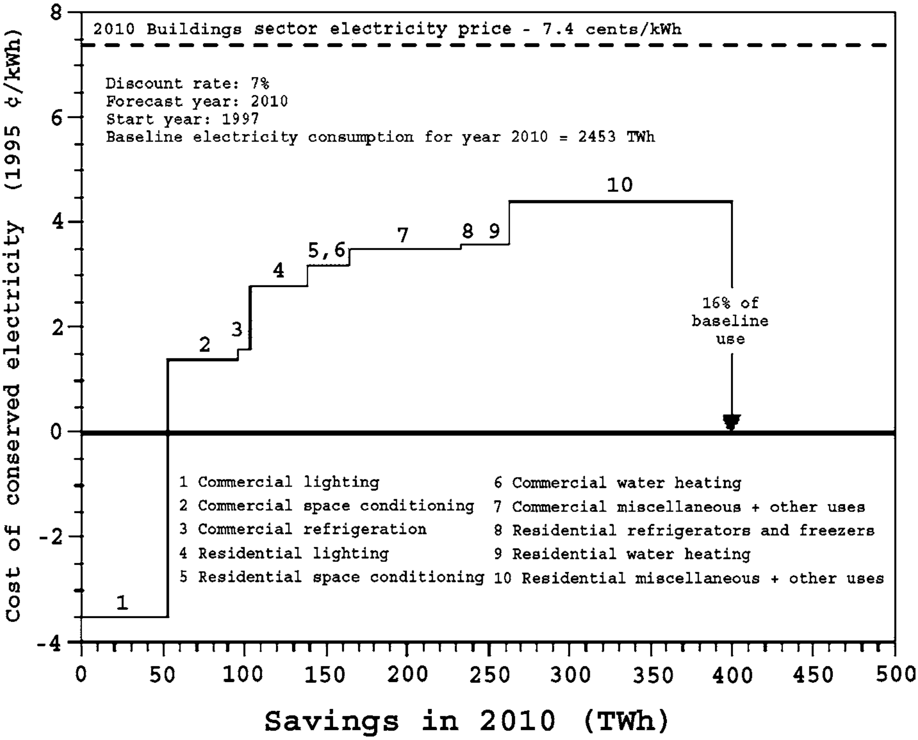

Figure 4 Conservation supply curve: forecast to 2010 (11).

largely as a result of market participants taking advantage of these vulnerabilities. A long-term economic assessment will tend to smooth out these price fluctuations. Whenever a comparison between the price of a commodity in the past and its current price is needed, values may be expressed either in nominal values, which reflect the absolute price of the commodity, or in real prices, which are also known as constant dollar prices. Real prices adjust nominal prices on the basis of inflation and measure the price of the commodity relative to the overall price level, which is measured through a basket of unchanged goods. The real price of a commodity is obtained through adjustments using the consumer price index (CPI). Monthly CPI values for the United States are available from the Bureau of Labor Statistics (15). The following example illustrates the conversion of $200 in 1995 to the corresponding 2001 value. First, the conversion factor is obtained by using Equation 6, in which

$$\frac{\text{annual average CPI for 2001}}{\text{annual average CPI for 1995}} = \frac{177.10}{152.4} = 1.16. \tag{6}$$

The conversion factor is multiplied by the 1995 value to obtain the 2001 value. For example, $200 in 1995 corresponds to $232 in 2001 (1.16 $\times$ $200.00 = $232.00).

TABLE 2 Cost components for various current electricity technologies[a]

Technology	Overnight costs in 2003 ($2002/kW)[b]	Fixed O&M ($2002/kW)[c]	Variable O&M ($2002 mills/kWh)[c]	Heat rate in 2003 (MJ/kWh)[d]
Scrubbed coal new technology	1,168	24.81	3.1	9.5
Integrated coal-gasification combined cycle (IGCC)	1,383	34.11	2.07	8.4
IGCC with carbon sequestration	2,088	40.47	2.53	10.1
Conventional gas/oil combined cycle	542	12.4	2.07	7.9
Advanced gas/oil combined cycle (ADVCC)	615	10.34	2.07	7.3
ADVCC with carbon sequestration	1,088	14.93	2.58	9.1
Conventional combustion turbine	413	10.34	4.14	11.5
Advanced combustion turbine	466	8.27	3.1	9.8
Fuel cells	2,162	7.23	20.67	7.9
Advanced nuclear	1,928	59.17	0.43	11.0
Distributed generation, base	813	13.95	6.2	9.9
Distributed generation, peak	977	13.95	6.2	11.0
Biomass	1,731	46.47	2.96	9.4
Municipal solid waste landfill gas	1,477	99.57	0.01	14.4
Geothermal[e,f]	2,203	79.28	0	39.3
Wind	1,015	26.41	0	10.9
Solar thermal[f]	2,916	49.48	0	10.9
Solar photovoltaic[f]	4,401	10.08	0	10.9

[a]Values in this table are from Reference 5, table 38, p.71. They are not based on any specific technology, but rather are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed on p. 86.

[b]Costs reflect market status and penetration as of 2002.

[c]O&M represents operation and maintenance.

[d]Conversion factor applied: 1 Btu = 1,055.87 J (5).

[e]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[f]Capital costs for geothermal and solar technologies are net of (reduced by) the 10% investment tax credit.

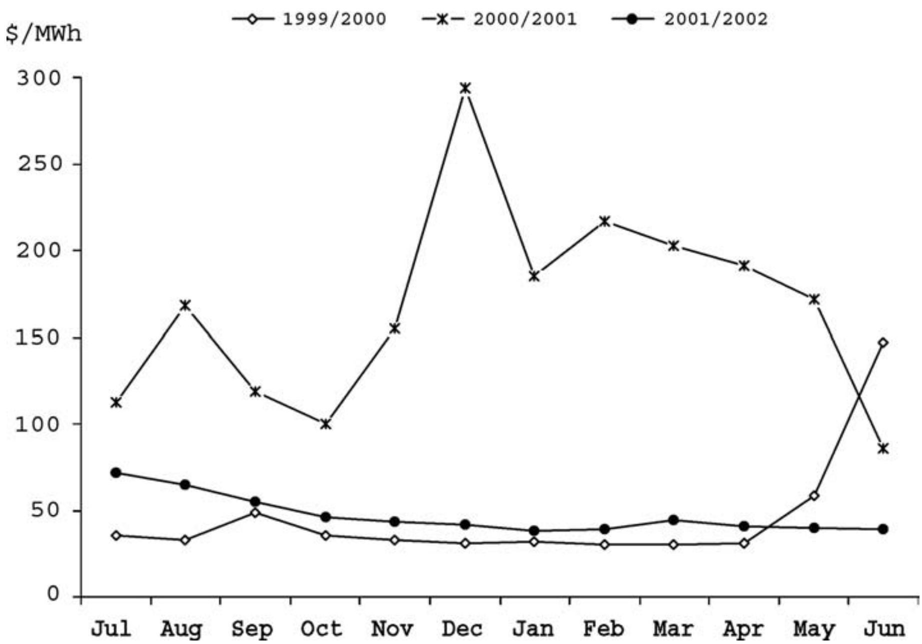

Figure 5 Average electricity cost in California of a megawatt hour (17).

The prediction of future price fluctuations is also important in calculating energy costs. For example, in January 2001, natural gas prices in California rose from values between \$2 to \$3 per GJ to \$97 per GJ (16). The recent price volatility in both electricity (Figure 5) and natural gas (Figure 6) prices during the California energy crisis, which has been extensively discussed in the literature, is now seen largely as the result of faulty market oversight and design as well as active market manipulation by power suppliers (19, 20).

Rapid and unpredictable price fluctuations are expected to increase in the future. According to the official energy statistics from the U.S. government, natural gas prices, which in 2002 averaged \$2.5/GJ (1.0825 GJ per 1000 ft^3), are projected to reach about \$3.4/GJ by 2020 and \$3.6/GJ by 2025 (equivalent to more than \$6.5/GJ in nominal dollars) (18). Thus in 2025, natural gas costs would lead to an electricity cost of \$0.05/kWh (1,025 Btu/1 ft^3 and 7000 Btu/kWh).

Different mechanisms are used by power producers to protect against fuel price changes. Hedging against natural gas prices includes both financial hedges, such as futures, swaps, and options, and investment in storage facilities, which allow withdrawal at high market prices and injection at low prices.

- *Futures* are traded in the New York Mercantile Exchange and guarantee a fixed price for a commodity for up to 6 years.
- *Swaps* allow two parties to exchange uncertain market prices for a fixed price over a shorter term than usually is considered by futures. The party selling

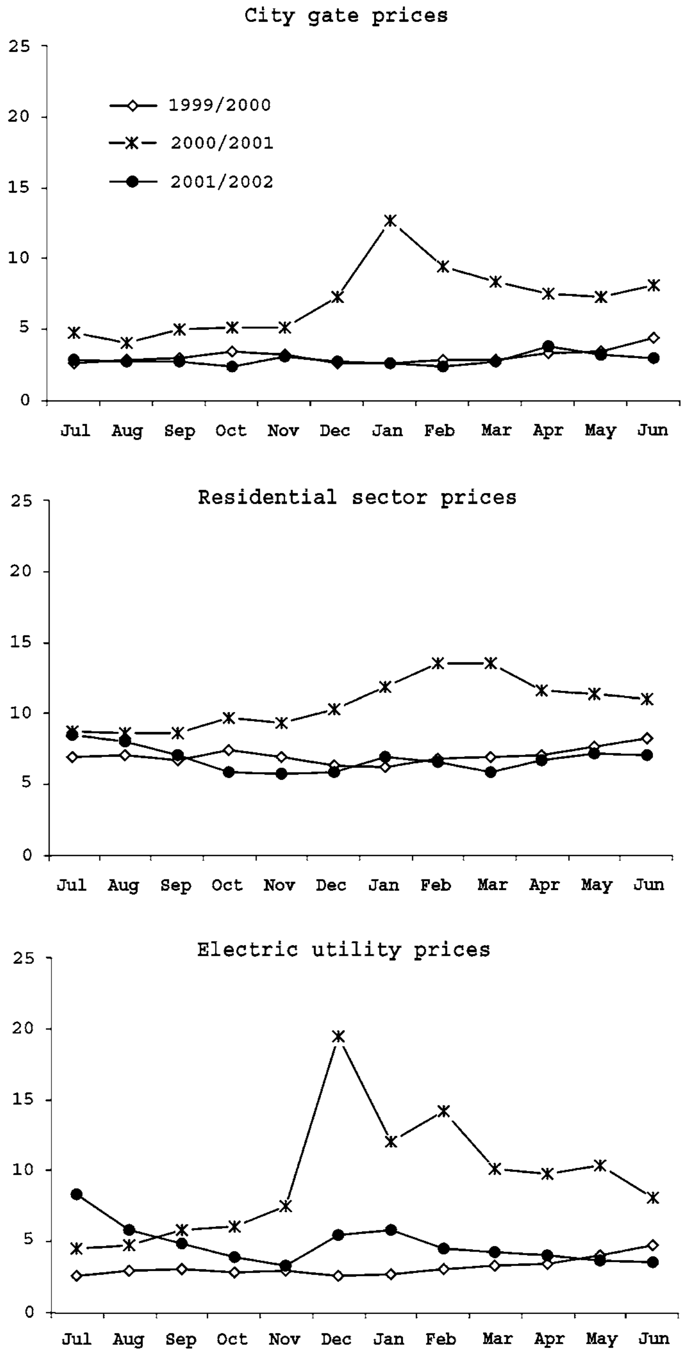

Figure 6 Nominal natural gas prices in California ($/million cubic feet) (18).

the swap is responsible for purchasing the commodity at actual prices and reselling at the agreed price level. The value of a swap can be calculated on the basis of the commodity's future series of prices and the appropriate discount rate using Equations 1, 2, and 3.

- *Options* refer to contracts that give the holder the right, but not the obligation, to buy or to sell the commodity at a specified price within a specified period in exchange for a premium payment (21).
- *Storage* corresponds to investments in physical infrastructure to control the supply of a commodity. The marginal benefit of storage, which is the amount in dollars that an investor gains in expanding her storage capacity by one unit, corresponds to the difference between the expected price of the commodity and its current price (22).

All options tend to agree in terms of actual costs, and a recent study concluded that electricity consumers have to pay $0.005/kWh ($0.50/GJ, or 0.35 ¢/kWh assuming an aggressive heat rate of 7.4 MJ/kWh) over market prices to secure natural gas prices for the next 10 years (3).

Alternatively, utilities that value stable electricity generation costs may invest in renewable generation options to hedge their vulnerability to future natural gas prices. Renewable energy technologies can contribute to a more reliable system through supply diversity, increased reliability, and predicatable and generally low O&M costs. For example, Hewlett-Packard estimates that a 20 minute blackout represents $30 million loss for a circuit fabrication plant. Overall, it is estimated that power outages cost the U.S. economy $80 billion per year (23).

In summary, when calculating electricity costs based on fossil-fueled power plants the analyst might usefully factor in the instability of future fuel prices and the risks and consequences of blackouts. A broadened definition of risk premiums also reflects the national economic cost of oil imports, and it includes costs associated with vulnerabilities to interruptions and price swings, increases in inflation, and deterioration of the balance of payments (24). This definition may be treated as a form of subsidies, which are discussed in the next section.

METHOD III: MARKET COSTS INCLUDING SUBSIDIES

A subsidy lowers producer costs or consumer prices below the preexisting market level. Sometimes they are difficult to identify, but usually, they tend to reduce production costs and intensify activity levels through financial benefits. There are different sorts of financial benefits that can be considered as subsidies. Examples include (*a*) a transfer of resources that both reduces prices paid for products or services and increases prices received for products or services and (*b*) market expansion.

The U.S. Department of Energy (DOE) quantifies federal energy subsidies by calculating the cost of the programs to the federal budget using, to the greatest

TABLE 3 Classification of subsidies

Direct	Indirect
Payment from government to producers or consumers	Insurance Loans or loan guarantees
Tax expenditures: Tax credits Measures that reduce taxable income Preferential tax rates Tax deferrals	Provision of services: Environmental and health safety Regulatory framework Energy services below market price Defense
Excise taxes	Research and development: Basic research Applied research—existing technologies Trust funds

extent possible, federal government outlays and/or near equivalents, including the outlay equivalent value of tax expenditures.[1] Subsidies are classified into two major categories: direct and indirect.

Direct Subsidies

Direct subsidies involve direct payments to producers and tax policies. Indirect subsidies do not involve direct payment but rather investments in research and development or the provision of various ancillary services to support energy production (Table 3).

Examples of direct payments at the federal level are investments in energy conservation projects, and the Renewable Energy Production Incentive (REPI). In the case of REPI, money transfers simulate a reduction in the generation costs of electricity from specified sources. The goal of the program, which in 1999 had a $4 million budget, is to promote the development of renewable energy, and on a larger scale, it is essentially the program currently used in Germany to promote the generation of electricity from solar photovoltaics, which receive a price premium.

Subsidies classified as tax expenditures are provisions that reduce the tax liability for individuals and firms that generate electricity in a way that is perceived as beneficial for the public interest. Table 3 lists a series of tax expenditures. Such tax expenditures are considered direct subsidies whenever they discriminate between energy activities controlled by specific individuals or firms.

Subsidies in the form of excise taxes and trust funds aim to internalize social costs of energy production and consumption or to offset the financial or environmental risks associated with a specific technology. The burden of pollution resulting from fuel combustion is widely cited as a social cost of our energy

[1]An outlay equivalent is the amount of the outlay that would be required to provide the taxpayer with the same after-tax income as would be received through the tax preference.

economy, yet the extent of this social subsidy is also widely disputed, so that it is rarely, if ever, addressed quantitatively by producers and consumers involved in transactions in energy markets (25). Limits on private sector liability for accidents or remediating the adverse environmental or health impacts of pollution are also important subsidies for energy producers.

Indirect Subsidies

Indirect subsidies include financial and institutional aids, which do not imply direct or explicit monetary transfers to the producers, and public sector production of infrastructure needed to make an energy source economic. A classic example is construction of the U.S. railroad system that was, of course, built for multiple reasons, but it provided an invaluable subsidy to the coal industry. A list of indirect subsidies is presented on Table 3.

Insurance constitutes one example of indirect subsidy that is important, for example, for the nuclear power sector and is discussed in detail in the next section. Special loans can be offered to energy producers at below market interest rates, such as the ones provided to rural utilities.

The provision of market and safety oversight services may be also characterized as an indirect subsidy. Among these services are those offered by health and environmental agencies, regulatory agencies, and energy services that are provided at below market costs. Finally, expenses for defense of energy infrastructure—such as pipelines, refineries, and transmission and distribution assets—are important subsidies.

Another class of subsidies employs price discrimination between different sectors or consumers. Electricity prices vary across consumer sectors. For example, if in the same region industrial consumers pay less than residential consumers per kilowatt hour, they are being subsidized by the residential sector (26). A cross subsidy requires that some customers pay more for a good or service than it would otherwise cost so that others can pay less. Distinct delivery costs, which account for power losses and economics of scale, explain only part of price differences between residential and industrial costumers (26). Electricity price discrimination between residential and industrial consumers is a common practice around the world (8), and it has become an increasingly contentious issue as classes of "preferred" and "low value" customers emerge in deregulated energy markets (Figure 7).

Assessing Subsidies

The definition and valuation of subsidies, particulary indirect ones, is difficult, frequently subjective, and rarely done. Evaluating subsidies consists of either measuring the value of an outlay or measuring the variance between market prices with and without the subsidy. In the case of oil, for example, the impact of security expenses play a significant role. Both the costs of defending oil shipments through the Persian Gulf and the cost of building and maintaining a desirable oil reserve

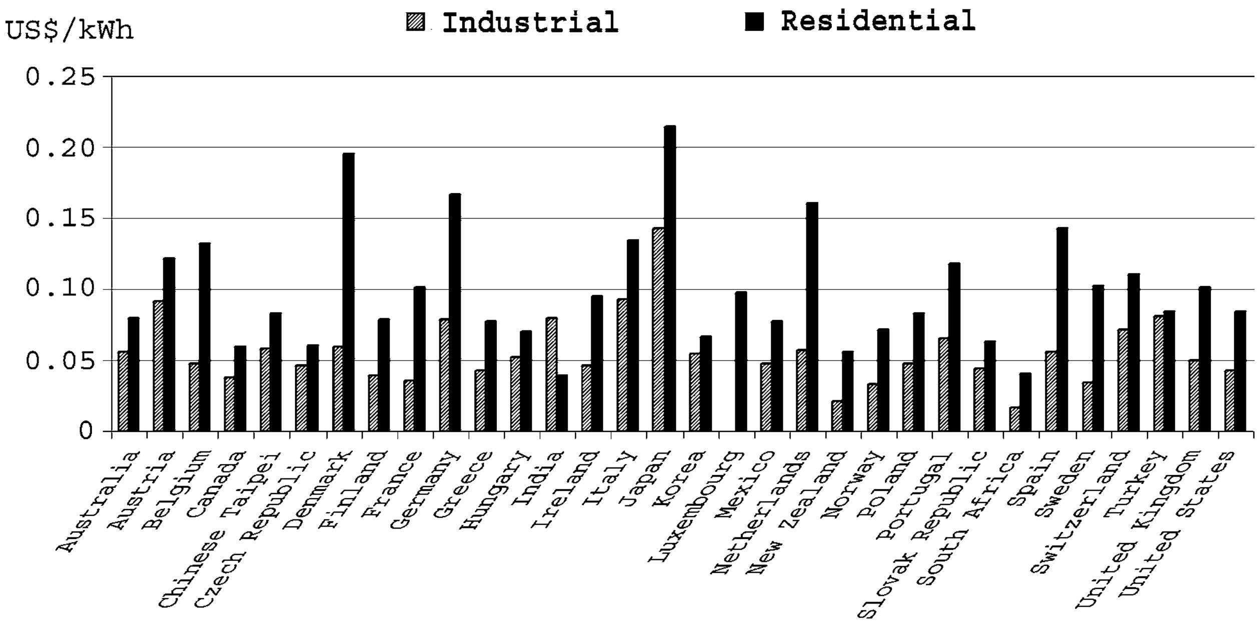

Figure 7 Electricity price discrimination between residential and industrial sectors (8).

might reasonably be included in a summation of the indirect subsidies (27). The inclusion or exclusion of energy security premiums and environmental externalities, for example, result in published estimates spanning almost four orders of magnitude for the subsidies afforded to fossil fuels (Figure 8).

A recent review found that fossil-based energy receives the majority of federal subsidies followed by nuclear power (27). The characterization of subsidies is fundamental for energy policy and has implications for our economic security, the environment, welfare, and trade. Analysis by the U.S. Energy Information Administration found that from 1% to over 7% of total U.S. carbon emissions could be attributed to the structure of the subsidies provided to the energy industry.

A politically charged and controversial example of the oil-security linkage is that of the cost of the Gulf Wars. The cost of the first Persian Gulf war was $76.1 billion (2002 dollars) and the 2003 Iraq war is expected to cost up to $478 billion (2002 dollars) (28). The Iraqi invasion of Kuwait on August 2, 1990, resulted in the immediate reduction of 4.3 million barrels per day of crude oil normally supplied to the world oil market from the two countries, or nearly 18% of the Organization of Petroleum Exportating Countries' exports and nearly 10% of the total world supply. The spot price of crude oil in United States and world markets rose from $21 per barrel the day before the invasion to $28 per barrel within a week afterward (an increase of 33%) (29). Currently budgeted by the White House at $20 billion, the cost for reconstruction of Iraq after the 2003 war has also been counted by some analysts as an oil subsidy (30).

It is difficult to allocate investments in research and development (R&D) as part of the cost of a final product or service. For instance, two thirds of the $2.8 billion invested by DOE in 1999 was allocated to basic energy production research, which cannot be directly tied to production or consumption at the time of the investment because of the lag of the effect of R&D on production. Nonetheless, R&D investments are also energy subsidies and may be significant for many technologies, with photovoltaics and nuclear power often cited as examples for which this has strongly been the case.

Since 1948, the U.S. Department of Energy has spent over US$110 billion on R&D, and over 80% of this has subsidized the nuclear and fossil-fuel sectors. In the 50-year period up to 1998, the nuclear industry received $66 billion in subsidies and fossil-fuel industries received US$26 billion. During the same period, the government spent US$8 billion on energy efficiency measures and US$12 billion on R&D programs for renewable sources of energy (31).

In developing a comparative analysis of electricity generation technologies, a breakdown of subsidies based on technology type and their respective generation share is particularly useful. After coal subsidies ($6.7 billion), the second largest apportionment of subsidies for an electricity source goes to nuclear power ($4.6 billion) (32) (Figure 9). Quantifying the subsidies provided to a particular technology remains a subjective step, but if accomplished, or at least attempted, it does provide a basis to internalize such expenses as part of the electricity generation costs and produce a more realistic comparison between technologies (Figure 10).

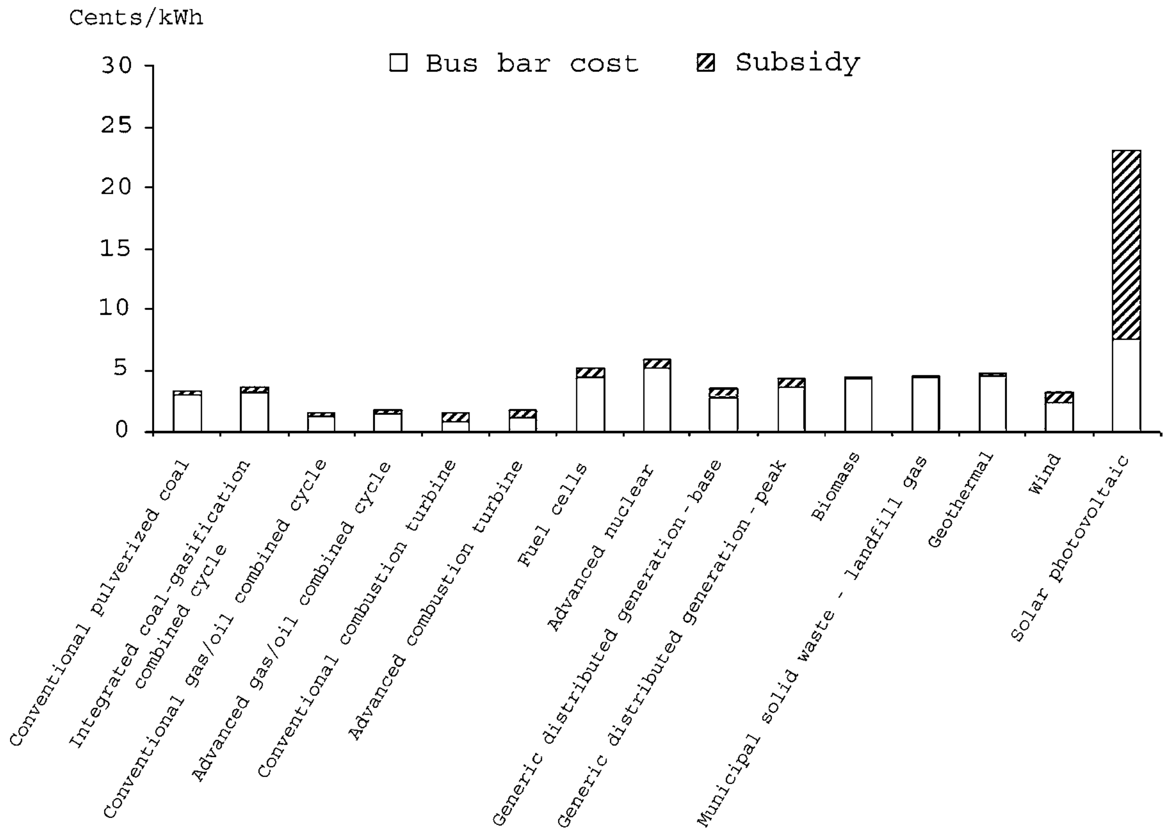

Figure 10 Electricity costs (38).

Subsidies to Nuclear Power

A high profile and often debated subsidy in the nuclear power industry is related to insurance issues, specifically the Price-Anderson Act. The act was promulgated in 1957, as an amendment to the Atomic Energy Act of 1954, to support the development of the incipient nuclear industry. Although it was originally a temporary act, it was reenacted several times (1967, 1977, 1988, 2002) following the interest of a powerful industry.

The Price-Anderson Act poses a cap on the private liability for nuclear power plants, which works as a subsidy, and reduces insurance costs for nuclear facilities. Besides offering an incentive to private investments in nuclear power plants, the act also ensures that adequate funds are available to the public to satisfy liability claims in the case of nuclear accidents. When required, resources are ultimately provided by taxpayers. The scope of the act includes fuel transportation, storage, power generation, and radioactive discharges and effluents (33).

Nuclear power facilities in the United States have two layers of insurance. A private insurer is responsible for the primary liability up to $200 million. In addition, there is an insurance pool formed by the accumulation of past deferred premiums on each nuclear facility, which currently corresponds to $94 million for each of the 110 commercial facilities. This pool of resources today amounts to $10.3 billion and serves as a self-insurance pool so that nuclear plant operators are covered in the event of a nuclear accident (34–36).

The U.S. Department of Energy is responsible for secondary indemnity under settlements of claims and judgments in lawsuits brought under the Price-Anderson Act cap. Regardless of who is legally liable for a U.S. nuclear incident, DOE facilitates a fund, to be collected through the Price-Anderson Act, which would be used to pay the indemnity.

The American Nuclear Insurers (ANI) estimates that the costs of private insurance would be prohibitive without the Price-Anderson Act because the damage of a serious nuclear incident would greatly exceed $200 million. If ANI had to provide insurance up to $200 million for each facility without the Price-Anderson Act, they would charge an annual premium from $500,000 to $2,000,000, depending on various factors, such as type and vintage of facility insured, nature of the activities performed, type and quantities of nuclear material handled, location of the facility, qualifications of site management, quality of safety-related programs, and operating history (34).

On the basis of a damage assessment, which does not take into account health effects, done by the Nuclear Regulatory Commission (NRC), it was concluded in 1990 that after the 1988 amendments the total amount of subsidy for the nuclear industry would reach $21,411,000 (1985 dollars) per facility (37). The output of 104 nuclear power plants in the year 2000 was 752 TWh (38). Dividing the total subsidy to the sector by the total energy output renders 0.5 cents/kWh of subsidy only from the Price-Anderson Act.

Besides support from the Price-Anderson Act, the nuclear power industry received in 1999 federal support for R&D as follows: $30 million for new nuclear plants, $467 million for waste management and fuel safety, and $143 million for generic investments (32). In addition, there are two more funds that support the nuclear industry. The nuclear waste fund collects user fees (1 mill/kWh in 1998) proportional to the energy output of the industry. For the fiscal year of 1999, the receipts amounted to $642 million. Second, the Uranium Enrichment Decontamination and Decommissioning Fund, which is responsible for the management of the three U.S. gaseous diffusion plants, received $171 million in 1999 from the government and commercial utilities. In the same year, the interest income for these funds corresponded to $507 million and $474 million, respectively, and the funds totaled $8.2 billion and $1.74 billion (32).

Part of the R&D funds for nuclear energy, which are categorized as "energy research and development" by the federal administration, are invested in environmental restoration and waste management of nuclear research facilities, and more than half of the R&D money to improve existing technologies is directed to nuclear activities. The investment in R&D for environment, safety, and health amounted to $47.4 million and targets the management of nuclear research facilities. In addition, $222.6 million were invested in R&D for fusion (32). An additional $53 million are spent by the NRC in nuclear R&D (32).

The suite of subsidies listed above can be totaled, adjusted to 2000 dollars, and then compared to total power output. This analysis—frequently sparred over by nuclear proponents and opponents—in many ways hinges on the the Price-Anderson Act. Proponents of nuclear power note that the insurance provided by the Act is consistent with that afforded a number of other industries, such as steel and aircraft. Opponents note that it is questionable if any nuclear plants would have been constructed in the United States without this support, and thus the value of the Price-Anderson subsidy is incalculable. This important debate aside, as of 2003 the annual subsidy totals at least $6.6 billion. Dividing the total subsidy for the sector by the total energy output (752 TWh) results in a conservative estimate of 9 mills/kWh of subsidy for nuclear power.

The 2003 Energy Bill calls for the indefinite extension of the Price-Anderson Act (39). The bill confers new authority on the U.S. secretary of energy to provide financial assistance to new nuclear projects if the secretary determines that such projects are necessary to achieve energy security, fuel or technology diversity, or attainment of clean air goals. The financial assistance can include any combination of loans, loan guarantees, lines of credit, and agreements to purchase the power from new nuclear projects. The assistance is limited to 50% of "eligible project costs," which include possible cost increases owing to regulatory or licensing delays. The legislation gives the secretary of energy 12 months to promulgate regulations implementing the new authority (40). In what has so far been a little-discussed aspect of this new bill, one section creates a nuclear parallel to the Strategic Petroleum Reserve, ensuring stability in the nuclear fuel market by specifying the amounts of uranium from the

U.S. government's stockpile that can be released into the market and the timing for such releases.

Renewable Energy Subsidies

Renewable energy technologies benefit from a range of subsidies through different programs. The introduction of the federal "million solar roofs" initiative, federal R&D programs, and the environmental regulations that encourage power generation from municipal waste combustion are all examples of subsidies that affect the economic feasibility of renewable energy. Not only are there subsidies consisting of financial assistance for the use of renewable energy, but other incentives, such as regulatory mandates, which are supported by legislation or institutional agencies, exist as well. Examples of institutional subsidies include

- Requiring utilities to purchase power from nonutilities;
- Efforts to introduce full-cost pricing that incorporates social/environmental costs of fossil fuels; and
- Requiring a minimum percentage of generation from renewables.

A milestone for the development of renewables was the National Energy Act of 1978 (NEA). In response to energy security concerns of the mid-1970s, President Carter promulgated the NEA, a compendium of five bills that sought to decrease the U.S. dependence on foreign oil and to increase domestic energy conservation and efficiency. A major regulatory mandate that has encouraged renewable energy, the Public Utility Regulatory Policies Act of 1978 (PURPA), was established as a result of the NEA.

PURPA requires utilities to buy electricity from qualifying facilities (QFs) controlled by independent power producers. The maximum installed capacity of a QF was set at 80 MW. In addition to renewable sources, cogeneration is also accepted as an energy source; however, to qualify the facility, at least 5% of the output from a cogeneration facility must be dedicated to thermal applications.

In California, QFs have relied on on 15 to 30 year contract terms that guarantee fixed payments based on future short-run avoided costs. Avoided costs represent utility power generation costs, including fuel escalation costs. Depending on future fossil-fuel cost forecasts, the rates are attractive; however, the rate is only guaranteed for the first 10 years. After that period, the price is adjusted to the new utility's short-term avoided cost, which sometimes compromises the survival of the project (41). The attractiveness of the scheme depends on the expected cost of fossil fuels at the moment the contract is signed.

A significant source of financial support for renewable energy technologies comes from tax credits. In 1992, the Energy Policy Act (EPACT) introduced a production tax credit, which offered 1.5 cents per kWh of incentive. EPACT also established the Renewable Energy Production Incentive (REPI). REPI is a federal program that offers direct payments to renewable energy producers. In 1999, the total amount available was $4 million (32). Finally, the Energy Policy Act of 1992 offered a 10% business credit for solar and geothermal projects and \$0.015/kWh for wind and biomass projects (32). Liquid fuels derived from agricultural crops receive sizeable federal support, with apportionments totaling \$740 million in 1999 (32). In addition, many corn-producing states also support alcohol production. In Minnesota, for example, the Omnibus Environment, Natural Resources and Agriculture Appropriations bill (SF 3353) mandates the production of 240 million gallons of instate ethanol, and the state allocates up to \$36.4 million per year for payments to producers.

Other initiatives at the regional level also support the development of renewable energy. For instance, following AB 1890, all electricity sold in California by investor owned utilities is charged a 0.7% fee that is used to support the development of renewable energy through rebates up to 1.5 cents per kWh. The Public Interest Energy Research Program supports research development and demonstration of energy projects in the public interest and makes \$62.5 million available per year. In addition, solar and wind installations under 10 kW in capacity are eligible for net metering (the same rule is effective in Colorado) (41).

Initiatives in other states support renewable energy as well. In Illinois, a \$0.50 monthly flat rate for commercial and residential consumers and a \$37.5 flat rate for larger consumers fund the Renewable Energy Resources Trust, and wind and solar systems up to 40 MW of installed capacity are allowed to participate in net metering schemes (41). In Iowa, grants for energy efficiency and renewable energy, guaranteed buy back rates, property and sale tax incentives, net metering, research and outreach programs, and an alternative energy loan program are among the renewable energy support measures (41). In Minnesota, a 1.5 cent per kWh subsidy is offered for 10 years to wind projects up to 2 MW, and a property tax exemption excludes from taxation all or part of the value added by wind systems. Sales tax exemption for wind energy systems and net metering for renewable energy facilities up to 40 MW are also available in Minnesota (41).

Analysis of subsidies available to fossil-fuel and renewable energy technologies inevitably leads to comparisons and discussions of the playing field, i.e., the balance of incentives and disincentives in energy markets that favor certain technologies over others. In the United States, the ratio between subsidies to fossil fuels and renewable sources is at least 10:1 (42). If the analysis is confined to federal subsidies, 5% goes to renewable energy and energy conservation (43). In Australia, subsidies for renewable energy amounted to 2% of the total federal energy subsidies in 1996 (44). A UN Environment Program report finds that the allocation of subsidies between fossil fuels and renewable sources is more uneven in developing countries (43). Although interesting as a means to gauge public sector support for different energy technologies, cross-technology comparisons are arguably most directly reflections of the maturity of different energy supply systems.

In the United States, the most widely used public policy tool to promote the use of renewable energy is the "renewable energy portfolio standard" (RPS). The precise implementation of the RPS varies from state to state, but it is generally a requirement that power producers in a given service region, or state, meet a minimum content standard for energy from a set of approved technologies (often solar, wind, geothermal, wave/tidal, or biomass derived energy). California, for example, recently enacted a 20% RPS by 2017, whereas Nevada has enacted a 15% RPS (with 5% to be set aside for generally more expensive photovoltaic electricity) by 2013. The goals of RPS standards can vary dramatically, from a 30% standard for Maine that actually includes some fossil-fuel usage, to a 1.1% RPS in Arizona, although 60% of the 2007 year target is to be from solar energy. As of early 2004, 13 states have enacted RPS targets (see Figure 11).

Critical to making a RPS an economically effective tool is to couple the renewable energy generation requirement to a market for emissions permits, so that producers exceeding the local requirement can sell power, whereas those below the required level can buy permits.

Fossil-Fuel Subsidies

Fossil fuels, such as coal, receive subsidies targeting different phases of the energy production process: fuel production, operation of the plants, including technological improvements, and mitigation of health effects. For example, the royalty income of individual owners of coal leases is taxed at a 28% rate rather than at the normal tax rate of 39.6%, although this exemption is not available to corporations. This tax break amounted to $85 million in subsidies in 1999 (32). Examples exist

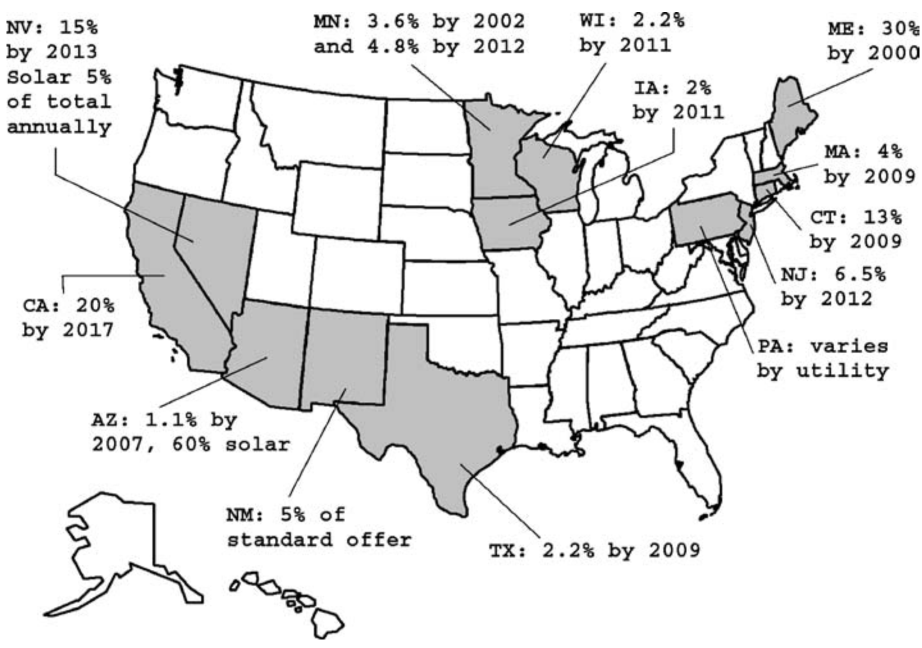

Figure 11 Map showing the 13 U.S. states with renewable energy portfolio standards as of 2003 (Staff Attorney M. Friedman, The Utility Reform Network, personal communication).

of energy taxes to address social damages as well. The Black Lung Disability Fund is a trust financed by excise taxes on coal to compensate for the health and social costs of coal production and consumption. As of 1999, this fund was in deficit, with assets of \$638 million and outlays of \$1021 million due to interest payments on past borrowings needed to cover outstanding claims (32).

The natural gas industry benefits from a range of subsidies. In 1999, subsidies for R&D in advanced natural gas turbine systems totaled \$33 million (32), and federal subsidies for natural gas production from coalbed methane amounted to \$1.2 billion. Coalbed methane accounted for 6% of all natural gas production in 1999, corresponding to natural gas sales valued at \$39 billion (1999 dollars) at the wholesale level in 1998 (32).

METHOD IV: EXTERNALITIES AND ENERGY COSTS

An externality arises when the utility of an economic agent is affected by the action of another agent, and there is no control over such actions because the variables involved have no market value. External effects are not appropriately priced and allocated by the market. Efforts to quantify externalities, resulting from energy use, are not only widely debated, but when performed, they often significantly exceed fiscal subsidy levels (27).

Energy systems impact ecosystem services, including climate regulation, nutrient cycling, water distribution, soil dynamics, natural population dynamics, and others. The pressures we place on these natural systems may lead to their complete destruction, and because these life-support systems are fundamental for the operation of the economy, it is fair to claim that they have an infinite monetary value. A partial monetary valuation of the world's ecosystem services estimated the value of the aggregated world's ecosystem services to be in the range of \$18 to \$59 trillion with an average of \$36 trillion per year (values published in 1997 were converted to 2001 dollars using CPI index) (45). Although this precise monetary valuation has been widely critiqued, the calculation has proven illustrative of the subsidy we receive from nature and of the need to put human activities into a wider ecological context. Our current energy economy is arguably the largest driver of the toll we place on the biosphere.

Hydroelectric Plant Environmental Externalities

The construction of large hydroelectric plants is usually associated with a series of social, cultural, environmental, and health externalities. Traditionally, benefits of water projects have been overestimated and costs underestimated. Hydroelectric projects have been highly controversial, with projected and real costs differing dramatically (46). For example, costs for land acquisition and resettlement for the Kayraktepe hydroelectric plant in Turkey increased from an estimate of \$30 million in 1986 to more than \$180 million in late 1993 (47). Assuming that the plant operates for 40 years and each year it generates 768 GWh, resettlement costs would amount to 6 mills/kWh or about 36% of the project cost (48). The World Bank estimates that between 1986 and 1993, when the construction of 300 large dams started, more than 4 million people were displaced (49). The annual incremental global energy output from hydropower in the same period was 45.5 TWh (50), and the average cost of resettling people affected by reservoirs is estimated at $3000 per capita (46). This crude estimate results in an average resettlement cost of 7 mills/kWh.

The social and environmental impacts of large dams are varied, and include population displacement, siltation in reservoirs, salinization, loss of biodiversity, and greenhouse gas emissions from flooded reservoirs. Dams are also linked to increases in diseases assocated with waterborne pests, including malaria, schistosomiasis, and dysenteries, caused by large reservoirs. The loss of cultural assets associated with sacred places and archeological sites is also of great concern and cannot be captured in economic assessments, as is true for loss of species and ecosystems.

Fossil-Fuel Environmental Externalities

The shortcomings in our abilities to measure the externalities associated with the use of energy has been a driver of efforts to develop a new set of analytic tools. The application of both epidemiological tools and methods from risk assessment have been applied to the analysis of the costs of energy services.

To quantify the impact of pollutants associated with fossil-fuel combustion, it is necessary to model the dispersion of pollutants, their transformation in the atmosphere, and the production of different compounds that affect human health and the environment. Finally, population exposure to air pollution causes morbidity and mortality, which are converted to economic values. The regional context is fundamental in this part of the analysis, which draws on air pollution modeling, atmospheric chemistry, demographics, epidemiology, and statistics in a complex analytical chain.

A recent assessment of health impacts caused by coal-fired power plants found that nine power plants in the Illinois region are linked to 300 deaths and 22,000 asthma attacks every year, two power plants in Massachusetts are linked to 100 deaths and 7,500 asthma attacks per year, and five plants in Washington are linked to 250 deaths and 20,000 asthma attacks per year.

The analysis can focus on individual plants, such as that completed for the Waukegan, Illinois, plant, which has been linked to an average of 40 deaths annually, or the Oak Creek, Wisconsin, plant, whose operation is tied to 50 annual deaths (51). Electricity generation at these two facilities in the year 2000 was 283,762 MWh and 608,118 MWh, respectively (52). If a "value of a statistical life," which represents the value of reducing a collection of individual risks, corresponding to $5 million, (53) is allocated to each death, the annual cost due to the operation of those power plants would amount to $450 million, or $0.50/kWh.

Efforts to place the human and ecological impacts of electricity generation in economic terms are clearly still evolving, but an important emerging finding is that the externalities are frequently significantly larger than the prices we associate with electricity supply options today (54–60). Figure 12 presents one such compilation, where the market prices of electricity from a range of supply options capture as little as one fifth of what an ecological or epidemiological evaluation of the costs of energy supply would dictate.

The commingling of pollutants has been a challenge to providing improved calcualtions of the full costs of electricity generation. In urban areas, in particular, it is difficult to differentiate between pollution coming from power plants and pollution coming from nonpoint sources, such as vehicles. Annual health costs associated with auto air emissions have been estimated in the range of \$29.3 to \$542 billion (61). Another study estimates that the same costs would be \$34.2 to \$79.8 billion (62); the authors find that the cost of total suspended particles is \$67.9 to \$114.0 billion, and the cost of impaired visibility is \$10.3 to \$39.9 billion. These values are based on hedonic evaluation methods, determined using willingness to pay surveys (each converted to 2001 dollars).

Full-Cost Accounting of Environmental Externalities of Power Plants: Life-Cycle Assessment and Life-Cycle Costing

Social costs of air pollution (Table 4) can be combined with emission factors (Table 5) to compute a cost per energy output associated with the operation of fossil power plants and their impacts due to emissions of criteria air pollutants (fossil-fuel power plants also emit other toxic air pollutants, such as dioxins, benzene, and mercury, which pose serious health and environmental risks). An environmental cost accounting approach that adds environmental cost information into existing energy cost accounting methods was described above. However, the comparison of externalities associated with different power sources demands the assessment of emissions over the whole life cycle of the facilities. Full-cost accounting would then involve the addition of direct and indirect environmental costs into energy costing (65).

Life-cycle assessment (LCA) has become increasingly popular as a standardized platform to compare the costs of a given technology over its lifetime. In fact, LCA of energy technologies grew out of earlier ideas of net energy analysis, a term coined after the first oil crisis to designate the assessment of the energy input-output ratio of energy supply and conservation technologies (66).

A modern LCA captures energy input and emissions during the entire production and supply chain associated with power systems, including resource extraction and materials manufacturing for construction (concrete and steel) and operation (coal, natural gas, and enriched uranium fuels), manufacturing, transportation, and installation of power plant equipment, retrofits and upgrades of power systems, waste management, and decommissioning (Figure 13). An LCA captures emissions beyond those generated during electricity production, such as those associated with the construction of the power plant.

Both process-based LCA (67) and economic input-output analysis-based LCA (68, 69) may be used to estimate emissions from supply chains. Actually, the two

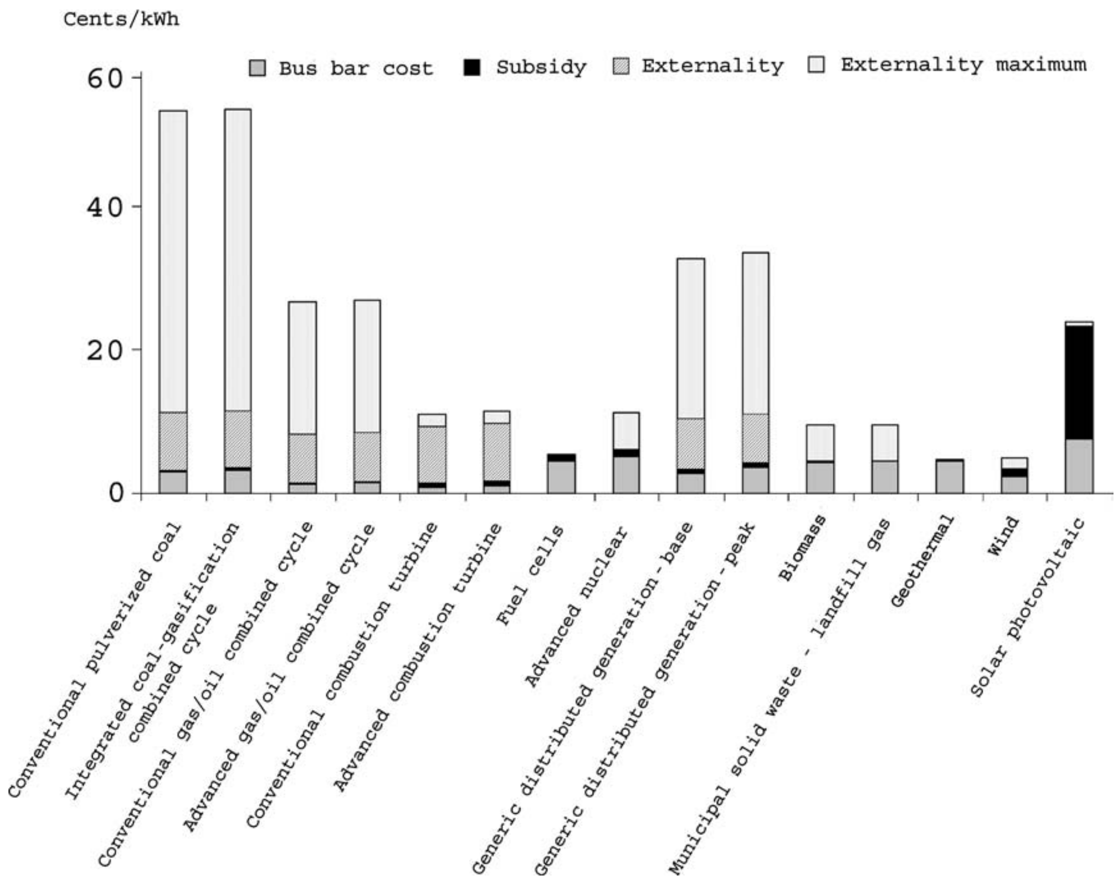

Figure 12 Electricity costs.

TABLE 4 External costs for emission of criteria pollutants in 2003 \$/ton[a]

Reference and location of study	Particles	SO_2	NO_x
Ottinger et al., United States (85)	\$2,958[b]	\$5,258	\$2,191
Alfsen et al., Norway (85)	\$2,300–\$30,345[b]	\$548–\$8,326	\$1,753–\$34,398
Pearce, United Kingdom (85)	\$23,370[b]	\$402	\$136
Pearce, United Nations Economic Commission for Europe (UNECE) region (85)	\$23,370[b]	\$698	\$537
Scheraga & Leary, United States (85)	\$438–\$11,941[b]	\$329–\$1,972	\$11–\$110
Hashem and Haites, United States (85)	\$69,599[b]	\$8,964	\$17,484
European Commission, Europe (58)	\$24,296[c]	NA[c]	NA
Levy et al., United States (58)	\$13,252[d]	\$872	\$850
Levy et al., Sterling site—United States (58)	\$3,092[d]	\$8	\$1,104
EPA (63), United States	\$2,249[d]	NA	NA
Matthews (56)[e]	\$5,637[e]	\$2,622	\$3,671

[a]All values are converted using CPI values assuming the date of publication unless specified by the author.

[b]Particles.

[c]Total suspended particles (TSP).

[d]PM_{10}.

[e]Mean values. The location is not available.

LCA methods differ in their boundary setting approaches. The boundary of the process-based method is flexible and is typically selected at the discretion of the analyst, whereas the boundary of input-output based LCAs is determined by the economic system that yields the data.

Process-based guidelines, developed by the Society for Environmental Toxicology and Chemistry and the U.S. Environmental Protection Agency (67), are usually adopted for process-based LCA. The framework divides each product or service into individual process flows and strives to quantify their upstream environmental effects. The assessment has the following four major components:

1. Goal and scope phase, definition of the objective of the analysis and the criteria that best represent the performance of the assessed alternatives to accomplish the objective defined;
2. Inventory phase, identification of the major material and energy inputs associated with the production of each component in the supply chain, and quantification of the stressors of interest (e.g., energy, pollution, toxic releases, water consumption, and waste generation);

TABLE 5 Emission factors for criteria pollutants and CO_2 for various fossil-fueled technologies (lb/MWh) (64)

Technology	CO_2	PM_{10}	SO_2	NO_x
Distillate oil-fired turbine	1196	0.09	0.251	4.27
Landfill gas-fired turbine	682	0.31	0.614	1.91
Digester gas-fired turbine	NA[a]	0.11	0.058	1.43
Pulverized coal	2119	2.58	0.317	7.32
Microturbine	1596	0.09	0.008	0.40
Small simple-cycle turbine	1494	0.08	0.008	1.10
Medium simple-cycle turbine	1327	0.07	0.007	0.60
Large simple-cycle turbine	1281	0.07	0.007	0.99
Large combined-cycle turbine	776	0.04	0.006	0.10
Advanced technology turbine	1154	0.07	0.006	0.30
Solid oxide fuel cell	950	0.00	0.005	0.01
Phosphoric acid fuel cell	1078	0.00	0.006	0.03
Gas-fired engine, lean burn	1108	0.03	0.006	2.20
Gas-fired engine, 3-way catalyst	1376	0.03	0.007	0.50
Diesel engine	1432	0.78	0.450	21.80
Diesel engine, selective catalytic reduction	1432	0.78	0.450	4.70

[a]NA means not applicable.

3. Impact assessment phase, quantification and aggregation of effects arising from the use of each component to yield life-cycle impacts of the object assessed; and
4. Final phase, interpretation of results by means of comparisons, rankings, sensitivity analyses, and simulations.

In contrast, one popular economic input-output analysis (EIO-LCA) utilizes a 500×500 commodity by commodity transaction matrix of the U.S. economy. In this model, economic transactions are used to identify interdependencies between all sectors in the economy (68). The method is more inclusive, and the boundary of the assessment is the national economy. Various commodities, such as steel, coal, and sugar, are represented by characteristic sectors. The association of the total economic output of each sector with a set of environmental indicators, such as energy consumption, water use, and pollution, produced by the respective sectors, yields environmental intensity factors that may be used in environmental analyses. The information currently available is based on transactions for 1997 (69). The environmental intensity factors have been applied to a number of product assessments (68, 70).

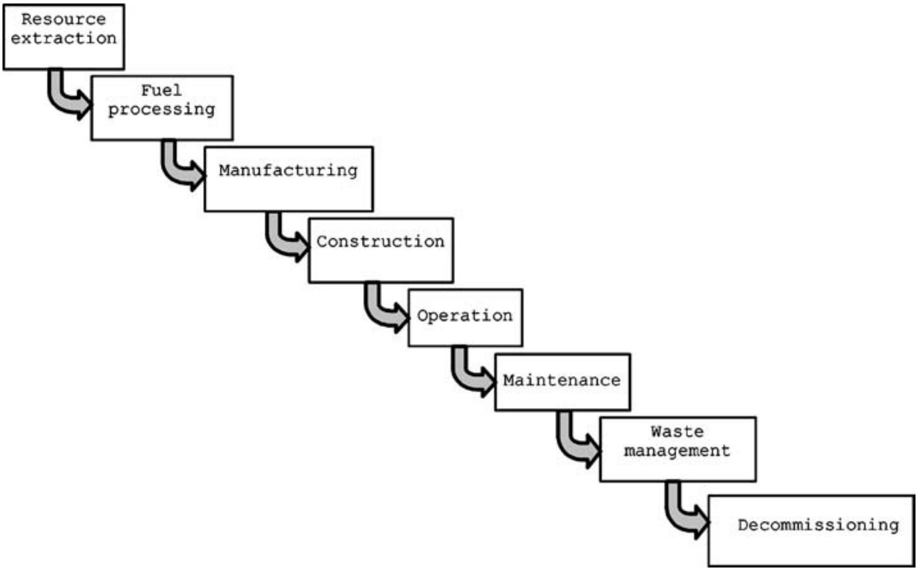

Figure 13 Life-cycle phases of a power plant.

The LCA can be a powerful tool to evaluate the performance of energy systems. In most classical economic analyses, the ratio of subsidies per energy output of different energy technologies is based on the energy output during the operation of the systems. In contrast, an LCA tracks all energy inputs over the life cycle of a power plant and includes its decommissioning and waste management. For example, in an LCA analysis of the cost of electricity from a photovoltaic system, the true cost reflects not only the bus bar cost, but also the cost of the materials and the manufacture of the panel, as well as any costs associated with the disposal of the panel at end of its operational life. In the same vein, subsidies of nuclear energy are higher if energy consumed to manage and store used fuel is taken into account. Other useful places for this type of analysis are the production of ethanol fuel and its comparison with other liquid fuels (71).

On the environmental side, LCA can be useful because different electricity generation technologies may produce a variety of impacts during different phases of their life cycle. Indeed, different life-cycle stages are dominant in the impacts of different electricity generation technologies (71, 72). The challenge is how to translate emissions that vary over spatial and temporal dimensions into meaningful dollar figures (72).

Full-cost accounting attempts to translate impacts that arise from the entire life cycle of a process or product into economic values. In the case of electricity production, the cost accounting consists of an LCA and evaluation of the resulting damage caused by pollutants and toxic releases. Next, the damages are are further aggregated, and the ratio between the total damage, which is expressed in monetary units, and the total electricity produced by the power plant renders the full environmental cost of the electricity.

Costs and Value Judgments

The comparison of the costs of externalities is further complicated because of the need to find ways to reflect human perceptions and value judgments. It is difficult to compare the "small chance of a big disaster against a persistent routine impact that is significant but not overwhelming" (72).

Nuclear accidents and global warming also share a common feature with respect to economic valuation and discounting: The impact of each could persist in the environment for centuries, well beyond the time that our conventional methods of economic valuation provide useful methods of comparison. There is a weak connection between the generation who benefits from the energy produced and the generation suffering the harm; consequently, the estimation of the present value of such impacts using market discount rates is inadequate (74, 75).

The damages caused by the operation of a power plant sometimes manifest over long time horizons, and therefore, benefit cost analysis must describe future effects in terms that help current policy makers choosing appropriate approaches for environmental protection. Global warming may remain a problem for centuries and may affect people who received little or no benefit from the electricity produced that caused the problem. That is, a power plant, which produces electricity for the current generation, also emits carbon dioxide, which accumulates in the atmosphere and has potential to trigger future environmental impacts. When time horizons associated with an environmental externality are long enough that impacts manifest over different generations, the problem is characterized as an intergenerational discounting issue. In this case, the choice of a social discount rate for practical applications requires inputs from disciplines other than economics to produce a sensible answer.

Therefore, the calculation of the present value in monetary terms of the future damage caused by CO_2 emitted today would need to include a discount rate that reflects such long-run impacts. An appropriate discount rate should at least reflect the fraction of CO_2 remaining in the atmosphere after its release. One approximation to this value is based on the pulse response function that results from a carbon cycle model used by the Intergovernmental Panel on Climate Change (76). Similarly, the costs of a nuclear accident should reflect the persistence of isotopes in the environment instead of a present value discounted by a market discount rate. Figure 14 shows the fraction of CO_2 and the fraction of strontium 90 as a function of time compared to discounting using a 4%, 7%, and a 12% discount rate.

In addition to the variability on temporal and spatial scales, who is impacted affects the way risks are perceived. Impacts from energy production have become a focus of environmental justice. Social conflicts resulting from environmental

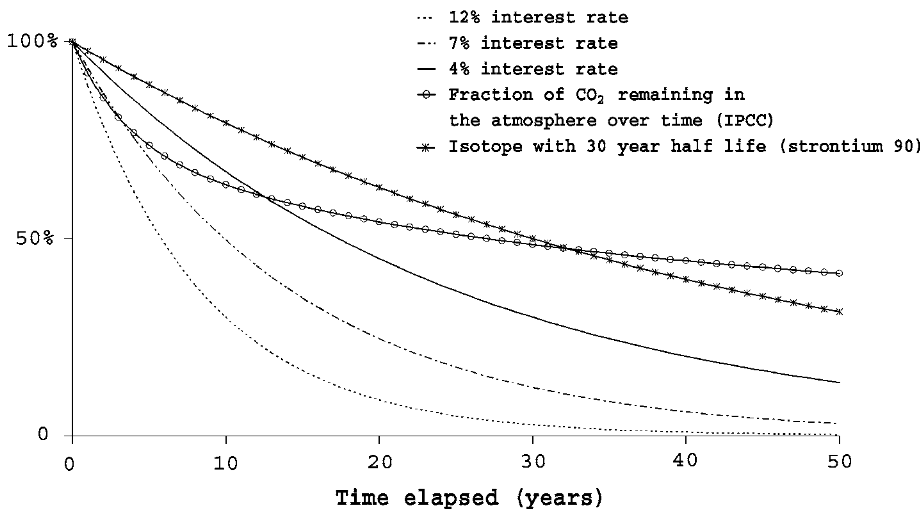

Figure 14 Decay rates for CO_2 and strontium 90 compared to discount rates. IPCC is the Intergovernmental Panel on Climate Change.

justice conflicts exist in many languages, and the economic valuation of damages is only one language. Who has the power to impose particular languages of valuation? Who rules over the ways and means of simplifying complexity, deciding that some points of view are out of order? Who has power to determine which is the bottom line in an environmental discussion (77)? Goals and values of analysts are embedded in the valuation methods. Finally, the valuation of an externality is also affected by the degree of control or adaptability for any given impact and by the degree of irreversibility of a given impact (78). Some people argue that there is an opportunity cost for climate change mitigation actions because in the future the cost to adapt to changes is going to be lower than present mitigation costs. However, if climate change leads to permanent losses, such as species extinction, this irreversible damage arguably has infinite costs.

Valuation Strategies

The cost of air pollution and greenhouse gas (GHG) emissions can be estimated either using the economic valuation of the damage caused by pollution, or they can be assessed using the cost of alternatives to reduce emissions, such as new technologies or fuel switching. Estimations based on quantification of damages are contentious because different electricity generation sources pose different forms of impacts, which vary over spatial, temporal, and social dimensions. Monetary quantification aspires to translate different impacts into a comparable and objective unit (79), but the task is not simple. The valuation of externalities draws on several components, such as emission inventory, transport and deposition modeling, environmental impact and risk assessment, and finally economic valuation. Thus, environmental costing incorporates the uncertainties of these complimentary assessments (24). Alternatively, environmental costs could be quantified on the basis of abatement costs used to mitigate health or environmental damage, e.g., control costing method.

A variety of methods is available to control air emissions from fossil-fueled power plants. For example, in the case of SO_2 emissions, which is a precursor for acid rain, reductions may be accomplished either through the installation of scrubbers or fuel switching to a lower sulfur content coal. The existence of concurrent opportunities, scattered over the United States, and the belief that a market trading scheme could achieve low cost emission reductions led to the creation of the Acid Rain Program. The program was proposed as an amendment to the 1990 U.S. Clean Air Act to reduce 1995 total air emissions of acid rain precursors from power plants back to 50% of their 1980 levels (80).

The market for SO_2 emissions, or allowances, establishes property rights on SO_2 emissions and specifies a marginal abatement cost for SO_2. This in turn allows polluters to purchase emission permits rather than implementing technologies to reduce their own emissions. Every year an emitter needs enough allowances to match his emissions over the same period. If the market operates efficiently, pollution reduction is achieved at a lower cost than through traditional command and control regulations (81, 82). Emissions control obligations of the first group of electricity generators started in 1995, but some transactions occurred prior to that year. Figure 15 shows the cost per ton of SO_2 derived from the Acid Rain Program. The same scheme is could be applied to other air emissions, such as GHGs (83).

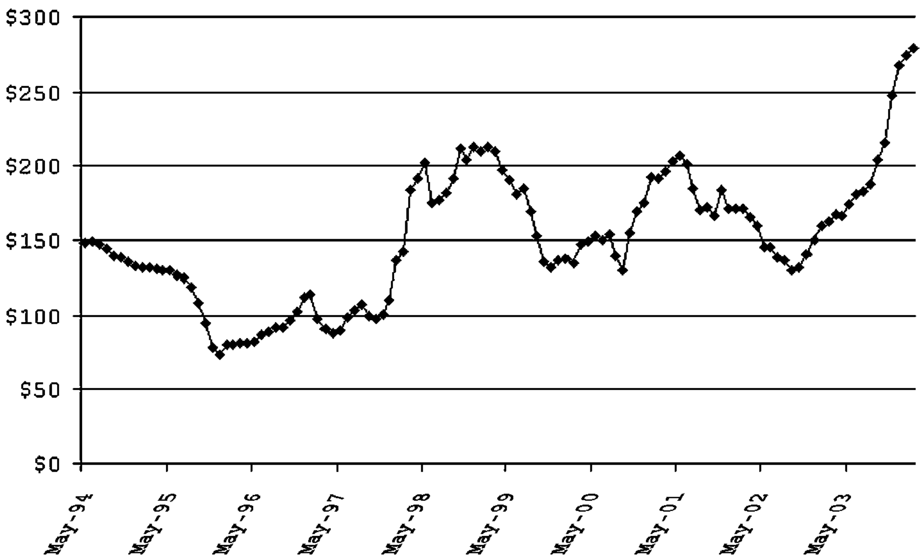

Figure 15 Abatement cost for SO_2 (82).

TABLE 6 Energy Modeling Forum marginal abatement cost of carbon emissions determined by various models in 1990 US$/tC[a]

Model	No trading				Annex I trading	Global trading
	United States	OECD-E[b]	Japan	CANZ		
ABARE-GTEM	322	665	645	425	106	23
AIM	153	198	234	147	65	38
CETA	168	—	—	—	46	26
FUND	—	—	—	—	14	10
G-Cubed	76	227	97	157	53	20
GRAPE	—	204	304	—	70	44
MERGE3	264	218	500	250	135	86
MIT-EPPA	193	276	501	247	76	—
MS-MRT	236	179	402	213	77	27
Oxford	410	966	1074	—	224	123
RICE	132	159	251	145	62	18
SGM	188	407	357	201	84	22
WorldScan	85	20	122	46	20	5
Administration	154	—	—	—	43	18
EIA	251	—	—	—	110	57
POLES	135.8	135.3	194.6	131.4	52.9	18.4

[a]The marginal cost of carbon abatement corresponds to the cost of the last tonne of GHG reduced between 1990 and the commitment period (2008–2012) in order to meet the Kyoto target, which implies emission levels for several countries 5% below their 1990s levels (85).

[b]Abbreviations used are Organization for Economic Cooperation and Development—Europe (OECD-E), Canada, Australia, New Zealand (CANZ), Australian Bureau of Agricultural and Resource Economics (ABARE) global trade and environment model (GTEM), Asian integrated model (AIM), carbon emissions trajectory assessment model (CETA), climate framework for uncertainty negotiation and distribution model (FUND), global relationship to protect the environment (GRAPE), model for evaluating the regional and global effects of greenhouse gas reduction policies (MERGE), Massachusetts Institute of Technology emissions predictions and policy analysis (MIT-EPPA), multi-sector multi-region trade (MS-MRT), regional dynamic integrated model of climate and the economy (RICE), second generation model (SGM), U.S. administration's economic analysis—council of economic advisors (Administration), U.S. Department of Energy—Energy Information Administration (EIA), prospective outlook on long-term energy systems (POLES).

A diverse set of models have been used to examine the effects of trading on the marginal abatement cost of carbon emissions (Table 6).

METHOD IV: CLIMATE CHANGE AND ENERGY COSTS

From an economic point of view, climate change potentially affects both individual and social welfare, and its effects are measured either by means of cost-benefit frameworks or sustainability approaches. Cost-benefit analysis weighs future damages versus adaptation costs, whereas sustainability approaches attempt to prevent unacceptable harm to future generations. [However, adaptation costs would be high if an abrupt climate change occurs (84)]. One computational strategy is to use a cost-benefit analysis—assuming a set cost or benefit to reduce emissions—to then determine the financial cost of a given level of climate protection (Table 6). These values combined with CO_2 emissions may be added to the social costs of electricity as an environmental fee in the same way costs from local/regional impacts from pollution are added.

The difficulty with economic quantification of climate change impacts arises from the chain of causality between emissions and the ultimate impact valuation in monetary values. First, emissions produce changes in atmospheric GHG concentrations, which affect the radiation budget of the earth and its average temperature, which causes a myriad of global and regional impacts, which are finally subject to various evaluation methods (85). Alternative assessments of each of these analytical phases may lead to different results. For example, various studies identified different effects on the global temperature due to a doubling of the CO_2 atmospheric concentration[2] (85). These studies attempted to quantify monetary damages to various systems of the U.S. economy (Table 7).

Because climate change is a global problem, it is natural to extend the damage evaluation beyond national boundaries. For example, an estimated 160,000 persons die owing to side effects of global warming in tropical regions (86). Assuming that anthropogenic annual carbon emissions amount to 6.5 peta-grams (Pg) of C (23.8 Pg of CO_2) (87), multiplying the number of deaths by the value of a statistical life and dividing by total annual emissions render a \$33.6/Mg of CO_2 value. Interestingly, the first tradable emission permits negotiated by the Chicago Carbon Exchange were traded at \$1/Mg (83).

Alternatively, the value of CO_2 emissions may be calculated using the cost of a technology that releases fewer emissions or captures and sequesters CO_2 from the atmosphere. For example, energy conservation technologies reduce the consumption of energy without compromising the level of service. Therefore, the ratio between emissions associated with the displaced energy supply and the cost of the conservation measure yield the cost of the avoided GHG emissions (Figure 16). Because some conservation measures, such as replacing incandescent light bulbs with compact fluorescent and replacing fluorescent tubes with efficient fluorescent tubes, already yield positive revenues, the cost of the avoided carbon may be negative.

Virtually every energy technology involves some carbon release over its lifetime, even if only during the manufacturing stage. As an example, the marginal cost of renewable electricity generation may indicate the marginal abatement carbon cost. There is a considerable potential for renewable energy in the United States, and the feasibility of a particular technology varies according to its

[2]A doubling in CO_2 concentration means twice as much as the preindustrial level, from 270 ppmv to 540 ppmv.

TABLE 7 Monetized estimates of the effect of doubling the CO_2 concentration with respect to the preindustrial revolution level (resulting in increased average global temperature) to the present U.S. economy in billions of dollars (85)[a]

Damage category	Cline (2.5°C)	Fankhauser (2.5°C)	Nordhaus (3°C)	Titus (4°C)	Tol (2.5°C)
Agriculture	24.1	11.5	1.5	1.6	13.7
Forest loss	4.5	1.0	Small	59.9	—
Species loss	5.5	11.5	0.0	—	6.9
Sea level rise	9.6	12.4	16.8	7.8	11.7
Electricity	15.4	10.9	1.5	7.7	—
Nonelectric heating	−1.8	—		—	—
Human amenity	0.0	—		—	16.5
Human morbidity	0.0	—		—	—
Human life	8.0	15.7		12.9	51.4
Migration	0.7	0.8		—	1.4
Hurricanes	1.1	0.3		—	0.4
Construction	0.0	—	↑	—	—
Leisure activities	2.3	—	Estimated	—	—
Water supply	0.0	0.0	at 0.75%	0.0	0.0
Availability	9.6	21.4	of GDP[b]	15.7	—
Pollution	0.0	—	↓	44.8	—
Urban infrastructure	0.1	—		—	—
Air pollution	0.0	0.0		0.0	0.0
Tropospheric O_3	4.8	10.0		37.4	—
Other	0.0	—		—	—
Mobile air conditioning	—	—		3.4	—
Total	84.0	95.5	55.5	191.3	102.0
% of GDP[b] in 1990	1.5	1.3	1.0	1.0	2.5

[a]Base year 1990 converted to 2002 values using the consumer price index.

[b]GDP means U.S. gross domestic product.

location. Figure 17 shows the renewable energy resource availability in the United States and the technologies that are the most promising for each state (88).

An increasing arrray of options exist to reduce carbon emissions or to sequester the carbon equivalent of those emissions. For many of these options, such as as geologic sequestration, the costs are at best estimates of what they might become if the technology is scaled-up to offset megatons or gigatons of emissions.

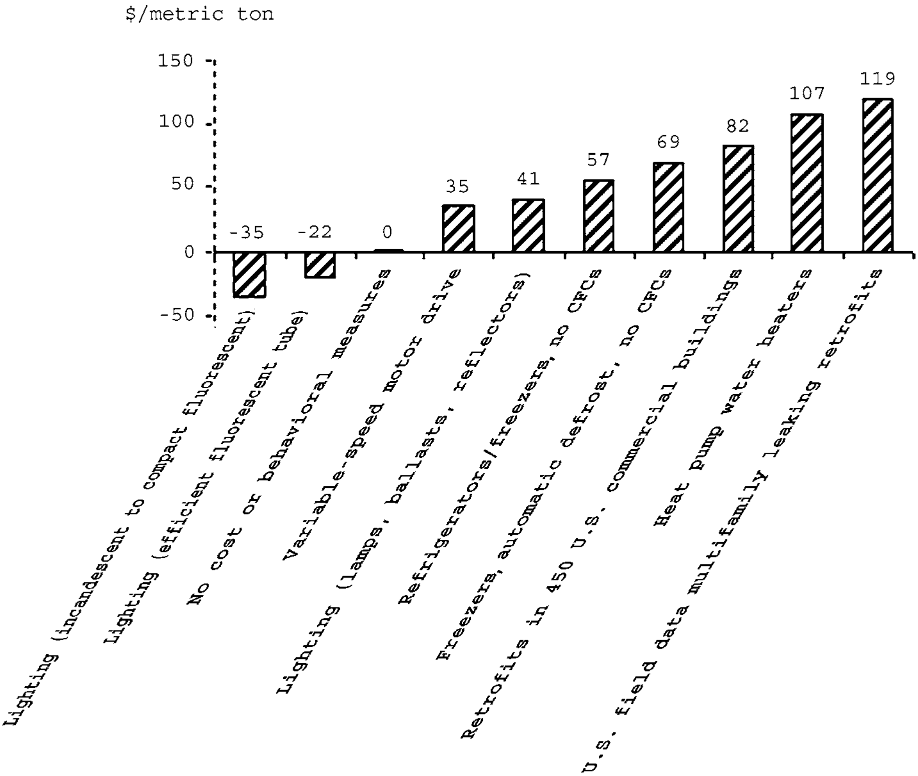

Figure 16 Cost of the avoided greenhouse gas emissions (85).

The use of top-down models is another alternative to calculate the cost of emitted carbon. These models are based on the relationship between macroeconomic parameters and the performance of economic sectors. Although top-down models present a high level of aggregation, they capture feedbacks between the energy sector and other sectors of the economy under a broad equilibrium framework at national and global scales. Table 7 presents a list of top-down models and their respective results in terms of dollars per metric ton of carbon.

The assessment of actual GHG reductions often necessitates an LCA. For example, although a photovoltaic module does not release GHGs during its operation, there is a significant contribution during manufacturing of the modules (89, 90). In contrast, the largest contribution of fossil-fueled power plants occurs during their operation (91). In the case of hydroelectric plants, an important impact is the loss of ecosystems displaced by reservoirs and the resulting loss of that ecological reservoir of carbon storage capacity (91–95). Emission factors produced from an LCA are more comprehensive than emission factors from just the operation of power plants, and thus LCA produces a more inclusive quantification of global climate change impacts. Nevertheless, monetization is not the only option to support decision making. Although the interpretation of aggregated emissions from power systems can be complex because of the spatial variations of local or regional impacts, careful application of these techniques has proven useful. In the case of global climate change, the location of GHG emissions does not affect potential impacts, which are instead more a function of the timing of the releases. The impact of emissions are then determined by the partitioning of carbon between atmospheric and other reservoirs, and the residence times. From there one can compare the airborne fraction of CO_2 emissions and the relative impacts of other GHGs over time; it is possible to compare various electricity generation options over different analytical periods and their relative impact on global climate change (Figure 18) (91). This sustainability approach attempts to judge the technologies over time against the natural system background, e.g., the global carbon cycle.

CONCLUSION

In this review, we have provided a qualitative tutorial in the methods used to determine electricity prices. In addition, we have highlighted the impacts of price fluctuations, subsidies, concealed health, and environmental impacts that may be valued and considered by energy analysts. In the case of electricity production, costs imposed to the environment, which usually are not part of the final tariff, are often found to be of more consequence. An important finding is that, in the literature today, the social and environmental externalities associated with our present energy economy are significant—in some cases larger—than the market prices for the resulting electricity. Using the current energy mix in the United States and the inventory of subsidies outlined in this review, the real cost of electricity is arguably between $0.09/kWh and 0.28/kWh.

The environmental impacts of energy conservation are negligible, so whenever such options are available, they should be seriously considered. Because the feasibility of available conservation technologies is a function of the energy supply cost, the use of higher energy costs, which include externalities, enables economic justification for conservation measures that were previously unfeasible. The inclusion of externalities in the final energy costs encourages technological innovations on the supply side as well.

The methods available today to assess and compare the cost of energy are beginning to capture the range of social and environmental costs of energy, as well as the risk premiums that we need to pay for different supply as well as conservation options. The next important steps are, first, to utilize life-cycle and other more integrative methods in our financial analyses and, second, to bridge the gap between engineering and financial assessments of the prices of energy services, and the wider social and environmental benefits, as well as costs of different power generation options.

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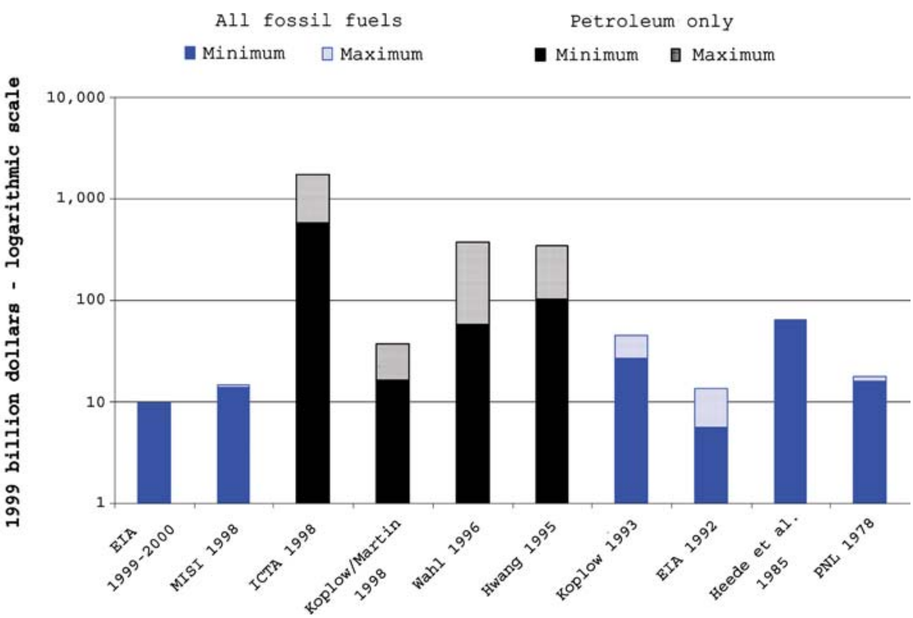

Figure 8 Total subsidies for fossil fuels according to various assessments (27).

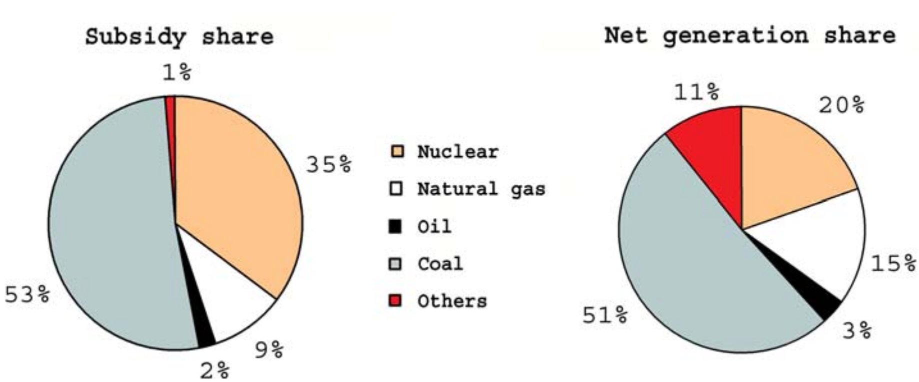

Figure 9 Share of subsidies and net generation in the United States for major electricity sources in 1999, based on (31, 32).

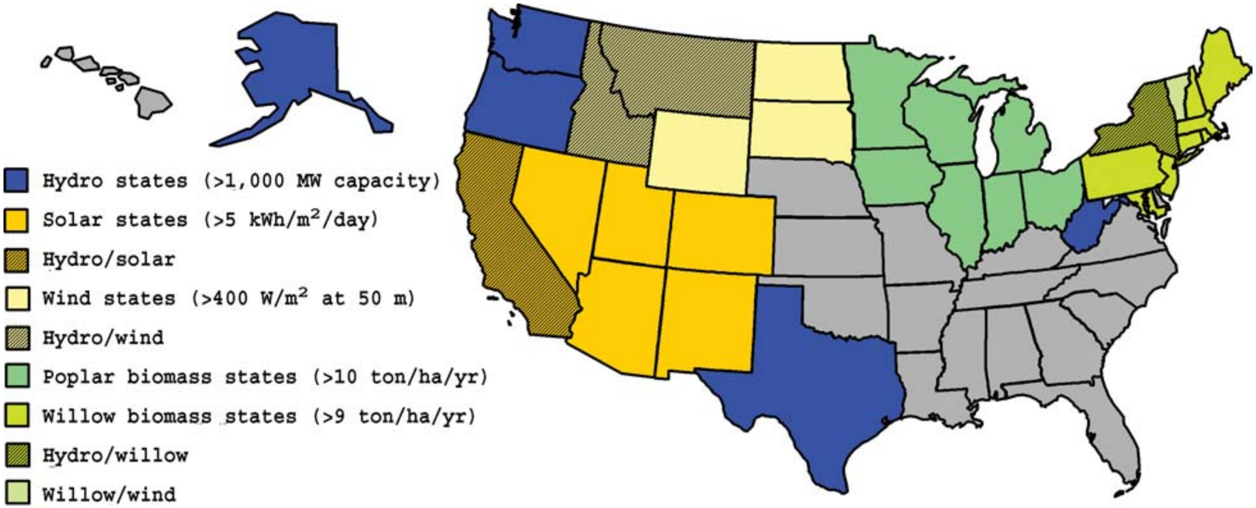

Figure 17 Renewable energy resource availability in the United States (88).

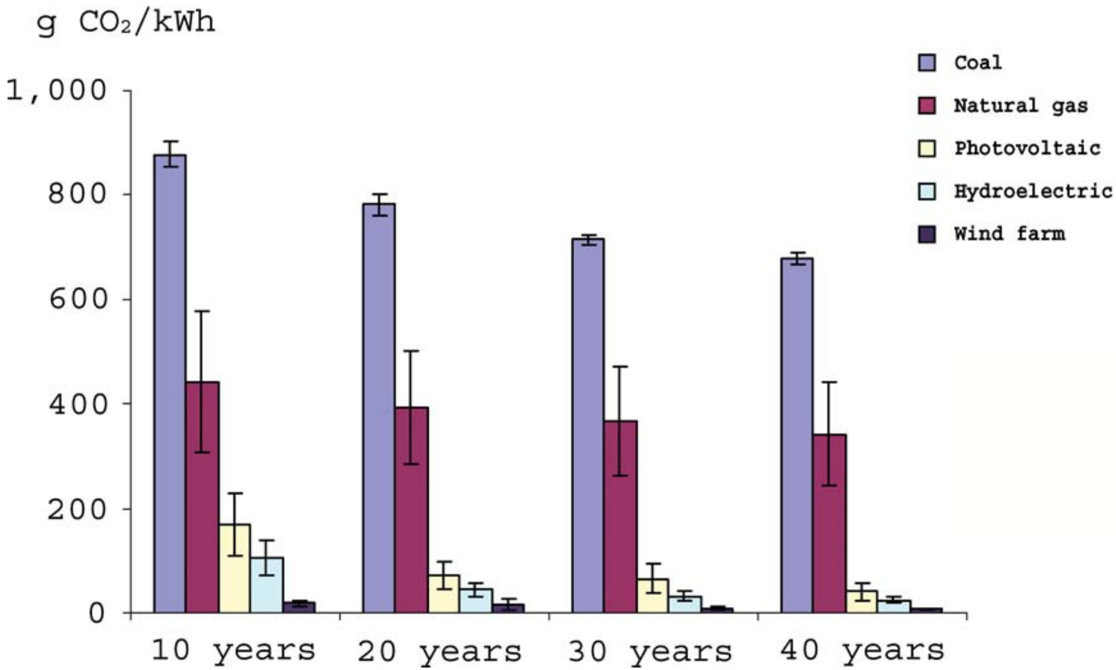

Figure 18 Life-cycle emissions for five electricity production technologies over four assessment periods (83).