Electricity: Market Challenges 6

A large amount of electricity-generating capacity will have to be built over the coming years to replace retiring units and meet new demand. Renewable energy technologies (RETs) are already competitive for some of this capacity, and further technical development and commercialization support (see chapter 5) could expand their share. However, the rate of growth for RETs will also depend on factors such as economic and regulatory changes within the electricity sector, availability of financing, taxes, perceptions of risk, and the rate of change in conventional technologies. This chapter discusses those factors and approaches for further commercializing RETs for electricity generation.

ELECTRICITY SECTOR CHANGE

Structural and regulatory changes in the electric utility industry have, in the past, encouraged the development of today's renewable energy industry and are likely to play a key role in how the renewable energy industry develops in the future. Many of these changes were set in motion by increasing strains on the utility industry in the 1970s.

Utilities generally enjoyed stable growth and declining costs of electricity production until the early 1970s. Then these histori-

[1] The Energy Information Administration estimates that utilities will build a total of about 110 GW (and retire 60 GW) and nonutility generators (not including cogenerators) will build 72 GWe by 2010. See U.S. Department of Energy, Energy Information Administration, *Supplement to the Annual Energy* Outlook, *1994*, DOE/EIA-0554(94) (Washington, DC: March 1994), p. 183.

cal trends were reversed due to reduced economies of scale[2] for new large coal-fired plants,[3] the oil shocks, inflation and high apparent costs of capital, sharp reductions in demand growth, increased environmental regulation, and problems with advanced technology such as supercritical boilers and nuclear plants.[4] These and other problems led state regulatory agencies to disallow (i.e., not include in the rate base) more than $10 billion worth of utility investment during the 1980s.[5] Regulators and utilities became interested in alternative approaches in order to avoid heavy capital investment in new generation facilities.

One such approach was to encourage independent entrepreneurs and companies other than utilities to generate power. Another was to tap alternative resources, renewable in particular. Federal policy addressed these issues through the Public Utility Regulatory Policies Act (PURPA) of 1978. Title II of PURPA established a class of electricity suppliers—"qualifying facilities" (QFs)—based on cogeneration and renewable, and outside conventional profit regulation. It required utilities to purchase power generated by QFs at a rate based on the utility's *incremental* cost[6]---more commonly termed *avoided* cost--of power.'

For a variety of reasons, the response to PURPA was mixed, especially for RETs, as described in box 6-1. Price was a key factor. Where the avoided cost level was high, the industry was deluged with offers; where low, no offers were made. Another factor was the terms under which electricity was to be purchased. Some states simply set tariffs for electricity purchase depending on the current avoided cost level. Since these could change frequently, private investors were unwilling to risk their capital on long-term projects whose return could vary dramatically. Other states allowed long-term contracts, which provided the more certain financial climate developers needed

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[2] Laurits R. Christensen and William H. Greene, "Economies of Scale in U.S. Electric Power Generation, "*Journal of Political Economy*, vol. 84, No. 4, pt. 1, 1976, pp. 655-676; Thomas G. Cowing and V. Kerry Smith, "The Estimation of a Production Technology: A Survey of Econometric Analyses of Steam-Electric Generation," Land *Economics, vol.* 54, No. 2, May 1978, pp. 156- 186; Edward Kahn and Richard Gilbert, Universitywide Energy Research Group, University of California, Berkeley, "Competition and Institutional Change in U.S. Electric Power Regulation," Report PWP-011, May 2, 1993; Richard F. Hirsh, *Technology and Transformation in [he American Electric Utility Industry* (Cambridge, England: Cambridge University Press, 1989); and David E. Nye, *Electrifying America: Social Meanings of a New Technology, 1880-1940* (Cambridge, MA: MIT Press, 1990), p. 32.

[3] One study found that going from a 400 MW to an 800 MW unit reduced cost per kW installed by just 5 percent (or 10 percent on the additional kW). See "How Much Do U.S. Powerplants Cost?" *Electrical World,* March 1985, reporting on a study of 491 recently completed and commercially operating fossil and nuclear plants by University of Tennessee's Construction Research Analysis group for Edison Electric Institute.

[4] Paul L. Joskow and Nancy L. Rose, "The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units, " *Rand Journal of Economics,* vol. 16, No. 1, spring 1985, pp. 1 -27; and Martin B. Zimmerman, "Learning Effects and the Commercialization of New Energy Technologies: The Case of Nuclear Power," *Bell Journal of Economics, vol.* 13, No. 2, autumn 1982, pp. 297-310.

[5] Oak Ridge Nationa] Laboratory, "Prudence Issues Affecting the U.S. Electric Utility Industry," 1987, and "Prudence Issues Affecting the U.S. Electric Utility Industry: Update, 1987 and 1988 Activities," 1989; and Ed Kahn, University of California, Berkeley, personal communication, May 1994.

[6] See *section* 210 of the Public Utility Regulatory Policies Act of 1978.

[7] The term incremental *cost* of power has been interpreted in different ways by various utilities, leading to varying payments to QFs. See, e.g., Daniel Packey, "Why Does the Energy Price Increase When Cheaper-Than-Avoided-Cost DSM Is Added," *Utilities Policy,* vol. 3, 1993, pp. 243-253.

BOX 6-1: Lessons Learned in State Renewable Energy Development

States vary dramatically in their development of renewable energy technologies (RETs) in the electricity sector California has more than 6 GW of installed RET capacity, Maine is second with about 850 MW, and Florida is third with about 820 MW The top 10 states account for nearly three-quarters of U S RET development This development is often largely unrelated to state renewable resource endowments For example, the Midwest has very large wind energy resources but little wind energy development Instead, most wind development has taken place in California where wind resources are relatively limited although there are a few particularly good sites

Key factors determining RET development include the planning, contracting, and procurement policies of the states These were well described in a recent report published by the National Association of Regulatory Utlity Commissioners Of particular value were the following

Standard contracts with (or guidelines for) the terms and conditions for capacity and energy sales to utilityies This greatly reduces the expense and delay of negotiations, reducing transaction costs and the time required to obtain a financeable contract

Long-run contract price based on avoided new utility plants. Long-run contracts (extending for 15 to 30 years) based on the cost of new resources are more likely to provide a sufficient revenue base for nonutility generat ion development than contracts based on short-term energy and capacity.

Both capacity and energy values paid. It is difficult for new projects to recover costs unless they receive payment for their capacity value

Fixed or predictable payment stream This is critical for any nonutility developer to obtain financing

Availability of /eve//zeal or front-loaded payments This allows developers of capital-intensive renewable energy projects to pay debt service on the loan, which is generally 10 to 15 years, compared to 30 years for utilities

No *dispatchability or minimum capacity factorscreens* This meant that renewable resources having an irtermittent/low capacity factor (hydro wind, solar) and nondispatchable resources (geothermal) were not excluded from participating Regulatory mechanisms reflected the benefits that these resources provide to the consumer

Special rates set for renewab/es Two of the states created special rates through legislation (New York for all qualifying facilities and Connecticut for municipal solid waste)

SOURCE Jan Hamrin and Nancy Rader Investing in the *Fufure A Regulators Guide to Renewables* (Washington DC National Association of Regulatory Utility Commissioners February 1993)

to raise capital and develop a project. Standard offers, or contracts, contributed to this confidence and also reduced the transaction costs of developers.[8] In California, the combination of PURPA, federal and state tax credits, and/or standard offers together with favorable renewable resources led to substantial development of several RETs. including biomass, geothermal, solar thermal, and wind, beginning in the early 1980s.

PURPA introduced a degree of competition into the electric ity sector. In the mid- 1980s, rcgulators and utilities investigated competitive bid-

[8] Standard offers define the terms and conditions+. g., energy and capacity payments, dispatch ability, and reliability —under which utilities will buy power. They set the transaction price at the avoided cost determined by the state regulatory authority. Some of the standard contracts entered into in the early 1980s resulted in prices for QF power that were above utilities" actual avoided costs when oil and gas prices crashed in the mid- to late 1980s. On this basis some argue that it was inappropriate to provide long-term—e.g.,10-year—standard contracts. That energy prices might decline was, of course, a risk when these contracts were entered into. At that time, however, energy prices were expected to rise and contracts reflected that expectation. Investment in natural gas-fueled powerplants today similarly faces risks should natural gas prices escalate more rapidly than expected in a decade. These fuel cost risk issues suggest the need for resource diversity and f'or proper allocation of risk and reward. This is discussed below.

ding as a way to control costs of new plants. Utilities in some 25 states have conducted competitive bidding. Nonutility generators (NUGs) responded to these opportunities by building about 57 GW of generation capacity through 1992, including some 16 GW of RET capacity.[9] The record of low cost, rapid construction, and reliability of many of these projects has encouraged further opening up of the electricity sector to competition.

The Energy Policy Act of 1992 (EPACT) continued this policy direction by creating a new class of power producers known as Exempt Wholesale Generators that are exempted from certain traditional utility requirements.[10] EPACT also addressed a variety of related transmission access issues (see below). Finally, California and several other states are considering an investigation of the possibility of "retail wheeling" to determine the feasibility of creating an even more competitive market.[11] Whatever form these varied actions ultimately take, it is likely that there will be substantial further structural changes in the electricity sector, in particular, higher levels of competition in electricity generation.

The impact of increased competition on RETs is uncertain. Greater competitive pressures may reduce investment in research, development, and demonstration (RD&D) and could diminish interest in capital-intensive, long-term generating technologies such as RETs. The low cost and high performance of combustion turbines fired with natural gas have great appeal in a competitive market. To the extent that market competition ignores benefits such as lower environmental impact or reduced exposure to fossil fuel cost increases, RETs may be disadvantaged. Furthermore, separation of generation from transmission and distribution (T&D) could increase the difficulty of implementing applications that benefit the system as a whole, such as the distributed utility. On the other hand, increased market competition may help differentiate energy markets by value, potentially opening up new higher value market niches for which particular RETs can effectively compete.

Competitive bidding for electric power supply typically proceeds in three steps. First, the utility projects the need for new electricity supply, including how much new capacity (MWS), what kind (baseload, load following, peaking), and when it will be needed. Second, a solicitation for competitive bids is made. Third, the tendered bids are screened and/or ranked on the basis of several factors, usually beginning with price and followed by operational issues, cost structure, and environmental impacts.

In practice, there has been less development of renewable energy under the competitive bidding approach than had occurred under earlier PURPA avoided cost/standard offer methods. As of 1990 (before a significant number of competitively bid projects came online), renewable fueled 6.6 GW out of a total of 9.1 GWNUG noncogeneration ca-

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9 U.S. Department of Energy, Energy Information Administration, *Annual Energy Review, 1993*, DOE/EIA-0384(93) (Washington, DC: July 1994). p. 251. About 32 GW were under PURPA and 25 GW under competitive bidding and other means.

10 As governed by the Public Utility Holding Company Act of 1935.

11 Retail wheeling is proposed t. allow individuals the opportunity to purchase their electricity from any utility or independent power producer—thus allowing them to shop around for the lowest price or for other features that they value. This has been characterized as similar to the individual customer's ability to shop around for a long distance telecommunications company. In fact, retail wheeling of electricity is not well - defined and cannot be described by so simple an analogy. For a discussion of these issues, see, e.g.: *The Electricity Journal,* April 1994, entire issue; Richard J. Rudden and Robert Homich, "Electric Utilities in the Future," *Fortnight/y,* May 1, 1994, pp. 21 -25; and Public Utilities Commission of the State of California, "Order Instituting Rulemaking and Order Instituting Investigation," Apr. 20, 1994. In addition to California, Nevada has a limited program in place, and Michigan and New Mexico have called for rulemaking on more limited programs to introduce greater competition. See, e.g., Peter Fox-Penner, "Critical Trends in State Utility Regulation, ''Natural Resources & *Environment/,* winter 1994, pp. 17-19,5 l -52.

pacity (73 percent) .12 In contrast, just 12 percent of successful competitive bids to date have been based on renewable, totaling a little over 2 GW.[13]

Several factors may have contributed to this difference. QFs were limited to RETs and cogeneration, unlike competitive facilities that can use any fuel. In addition, fossil fuel prices have dropped to near historic lows, reducing the incentive for choosing RETs. Some have also suggested, however, that the low rate of adoption of renewable under competitive bidding practices may in part be due to the screening/ranking factors not adequately reflecting the substantial benefits of renewable.[4]

These changes are exposing what some perceive to be a fundamental conflict between two different philosophies for utility regulation: 1) using regulatory interventions in the utility sector to advance social goals such as a cleaner environment through greater investment in and use of efficient and/or renewable energy technologies, and 2) reducing and/or changing regulation in the utility industry to allow greater competition in generation and consequently more efficient and lower cost provision of electricity.[15] These are not necessarily conflicting goals, and means of realizing both are discussed below.

Other changes will also affect RETs. Increasing concern over the environmental impacts of fossil fuel use has led to consideration of RETs in policy initiatives such as the Clean Air Act Amendments of 1990,[16] EPACT, and the Climate Change Action Plan. Half the states now incorporate environmental externalities in their electricity sector planning and operations either qualitatively or quantitatively, and other states are considering this. Such environmental concerns are likely to increase over time, and will generally benefit most RETs.

Some RETs may also have a significant influence on the structure of the electricity sector. In particular, as photovoltaics (PVs—or other small-scale technologies such as fuel cells) are developed, they may be distributed throughout a T&D net work. That could lead to substantial] y different T&D requirements and might affect the technical and financial structure for the electric utility. '7 Accommodating this change will require much better models and understanding of actual power flows so that the corresponding costs can be unbundled and assigned appropriately to ensure efficient use of the T&D system.[18]

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[12] Energy Information Administration, Op. cit., footnote 1.

[13] Blair G. Swezey, National Renewable Energy Laboratory, "The Impact of Competitive Bidding on the Market Prospects for Renewable Electric Technologies," draft, January 1993.

[14] Ibid.

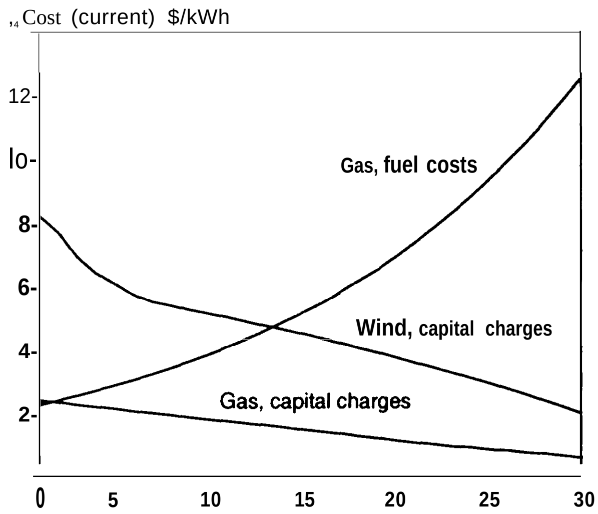
[15] This issue has recently been highlighted by the California order instituting an investigation and rulemaking on retail wheeling. For a flavor of some of the debate, see *The Electricity Journal*, April 1994, entire issue.

[16] See, e.g., U.S. Environmental Protection Agency, *Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act*, EPA 430-R-94-001 (Washington, DC: February 1994).

[17] For example, who might own rooftop PV systems: utilities, homeowners, or third parties? If distributed power is a significant fraction Of the system, the answer to this question could influence the structure of the electricity sector.

[18] A variety of different means are being explored to achieve better understanding of and workable models and contracts for unbundling transmission services. Steven L. Walton, "Establishing Firm Transmission Rights Using a Rated System Path Model, " *The Electricity Journal*, October *1993*, pp. 20-33; W. Hogan, "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics*, vol. 4, No. 3, 1992, pp. 21 I -242; and Kahn and Gilbert, op. cit., footnote 2.

FIGURE 6-1: Capital Carrying Charges and Fuel Costs for Conventional and Capital-Intensive Renewable Energy Projects



NOTE: The capital carrying charges for the utility-owned wind powerplant modeled here are initially about four times those of the modeled natural gas combined-cycle powerplant, and drop to about three times after the period of accelerated (five-year) depreciation for the wind equipment. This illustrates the high front-loaded costs for capital-intensive RETs. In contrast, the natural gas system has high fuel costs and operates more in a "pay-as-you-go" manner. Overall, the wind system modeled here has a slightly lower lifetime levelized cost of electricity at 5.22¢/kWh than the natural gas system at 5.47¢/kWh.

The capital carrying charges include the return on debt, the return on equity, federal and state income taxes, book depreciation, property taxes, and insurance. The methodology used here followed that of the Electric Power Research Institute. All costs are in current dollars in order to appropriately value tax benefits. Parameters used are wind capital costs of $900/kW, capacity factor of 28 percent, and natural gas combined-cycle capital costs of $650/kW, capacity factor of 70 percent, and heat rate of 7,700 Btu/kWh. Other parameters are as indicated in tables 6-1 to 6-3.

SOURCE: Office of Technology Assessment, 1995.

POWERPLANT FINANCE[19]

A typical fossil fuel project—such as a natural gas-fired combined-cycle powerplant-will have a relatively low capital cost per unit power output compared with a typical nonfuel-based[20] renewable project, but faces continual (and potentially increasing) fuel costs. A typical renewable energy project will have high capital costs but little or no fuel cost (see figure 6-1). Over the lifetime of the project, the low operating (fuel) costs of the RET can more than make up for its high capital costs—depending on factors such as the cost of capital, fuel, operations, and plant life. Nevertheless. the RET can cost more than the fossil plant during the first years of the project under common financial accounting methods.

Effectively, the RET power is paid for in advance through the capital charges, in contrast to the pay-as- you-go nature of fossil fuel. The higher front-end cost of the renewable poses the risk of overpaying for power should the project fail prematurely (see figure 6-2). Conversely, costs of the non-fuel-based RET could be lower in the future than for a fossil fuel system, particularly if fuel prices escalate as projected (figure l-A-4).

| Utility Finance[21]

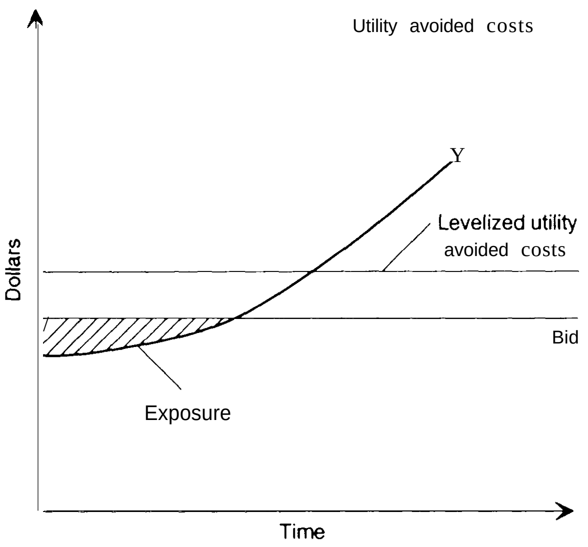
Electric utilities are monopolies regulated primarily by states. The retail price at which the utility sells electricity is set through a regulatory review process that allows the utility to recover all operating expenses, including taxes, and to earn a "fair" return for its *prudent* investments. The review typically consists of two stages: 1) a review of utility capital investments that can be a lengthy, arduous process (especially if questions are raised

19 Analysis of the financial situation of the electricity sector more broadly, including market-to-book value ratios, price/earnings ratios, and other measures of financial health are beyond the scope of this study; they can be found elsewhere. See, e.g., Edward Kahn, *Electric Utility Planning and Regulation* (Washington, DC: America nCouncil for an Energy Efficient Economy, 1991); Leonard S. Hyman, *America's Electric Utilities: Past, Present, and Future* (Arlington, VA: Public Utilities Reports, Inc., 1983); and Harry G. Stoll, *Least-Cost Electric Utility Planning* (*New* York, NY: John Wiley and Sons, 1989).

20 Biomass-fueled renewable energy projects are likely to have capital and fuel costs similar to those of fossil fuel projects, unlike capital-intensive nonfuel-based RETs such as geothermal, hydro, solar, and wind.

21 Only investor-owned utilities will be discussed here, as public utilities are exempt from federal taxes and tax incentives.

FIGURE 6-2: Potential Rate-Payer Exposure with Front-Loaded Cost Structures



NOTE The front loaded cost structure resulting from typical carrying charges shown in figure 6-1 can result in" rate-payer exposure" in that they pay for the plant upfront but run the risk that the plant does not operate for as long or al the performance level expected Proper structuring of the contracts can reduce this risk

SOURCE Ed Kahn et al Lawrence Berkeley Laboratory, Evaluation Methods in Competive Bidding for Electric Power, ' LBL-26924 June 1989

over the prudence of investments); 2) and much less detailed reviews of automatic adjustment of fuel costs.

The cost of owning and operating a utility-generating plant is affected by a variety of federal and state/local tax provisions as discussed below. Current federal tax policy variously provides investor-owned utilities[22] (IOUs) 5-, 15-, and 20-year accelerated depreciation, and a 10-year 1.5¢/kWh renewable electricity production credit (REPC) according to the particular technology, as listed in table 6-1. State and local governments may also levy income, sales, property, and other taxes.

The impact of federal and state/local taxes at the generating plant (not including, for example, fuel mining and transport) can be calculated using standard financial models .23 Representative taxes carried by different powerplants are shown in figure 6-3, based on the parameters in tables 6-1,6-2, and 6-3. (A more detailed analysis of taxes over the entire fuel cycle for two specific regions in the United States is given in the following section.)

Current law (which provides five-year accelerated depreciation for many RETs) sets the federal tax burden per kWh of generated electricity for RETs and most fossil technologies in the range of roughly 0.1 ¢- 1.0¢/kWh, depending on the particular technology, its capital cost, and other factors. This does not include the REPC[24] or upstream taxes from, for example, fuel mining or transport (see below). Within this range there is considerable variation between technologies in taxes paid per kWh generated. Coal-generated electricity (which receives 20-year tax depreciation) carries a federal tax burden in this scenario of about 0.4¢kWh, as illustrated in figure 6-3a.

If capital-intensive RETs instead had the same depreciation schedules as coal-fired plants, they would generally pay significantly higher taxes per kWh generated than fossil fuel plants (for the generating plant itself, not including fuel mining and transport costs—see below). The reason is that federal taxes are based on income, utility income is based in part on capital investment—for example, the rate base, and RETs require a higher capi-

22 Investor-owned utilities generate about three-quarters of U.S. electricity and will be the focus of this discussion. Other types of utility ownership include public utilities, cooperatives, and federally owned facilities. These other types are not discussed here as they are generally exempt from federal and state taxation.

23 This analysis was done by OTA using a model similar to that of the TAG™ method of the Electric Power Research Institute. This spreadsheet model was also compared with and validated by several other standard methods such as those in: U.S. Congress, Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s, OTA-E-246* (Washington, DC: U.S. Government Printing Office, 1985); and Harry G. Stoll, *Least-Cost Electric Utility Planning (New* York, NY: John Wiley & Sons, 1989).

24 The REPC, part of EPACT, credits wind and closed-loop biomass facilities placed in service between 1994 and 1999 with 1.5¢/kWh.

TABLE 6-1: Current Tax Factors for Selected Electricity Sources

	Investor-owned utilities					Nonutility generators				
	Book life	Tax life	Method	ITC percent	REPC[a] ¢/kWh	Book life	Tax life	Method	ITC percent	REPC ¢/kWh
Coal	30	20	150YODB		—	30	20	150%DB	.	—
Gas turbine	30	15	150%DB	—	—	30	15	150%DB		
Nuclear	30	15	150%DB	—	—	30	15	150%DB	—	
Biomass-plantation	30	20	150%DB		1.5	30	20/5[b]	150/200%DB		1 5
Biomass-waste	30	20	150%DB		—	30	20/5	150/200YoDB	—	
Geothermal	30	5	200%DB	—	—	30	5	200YODB	10C	
Hydro	50	20	150YODB	—	—	50	20	150%DB		—
Solar-PV	30	5	200%DB		—	30	5	200%DB	10	—
Solar thermal	30	5	200%DB		—	30	5	200%DB	10	—
Wmd	30	5	200%DB	—	1.5	30	5	200%DB	—	1.5

[a] This credit was enacted by EPACT section 1914 The REPC of 15¢/kWh is limited to wind and closed-loop biomass facilities placed in service during the period 1994 to 1999; it is provided only during the first 10 years of plant operation, it is phased out linearly as costs increase from 8¢/kWh to 1 1¢/kWh it is adjusted for inflation and it is reduced by other grants and credits

[b] Five-year 200%DB tax depredation is available only for qualifying facilities under the Public Utility Regulatory Policies Act

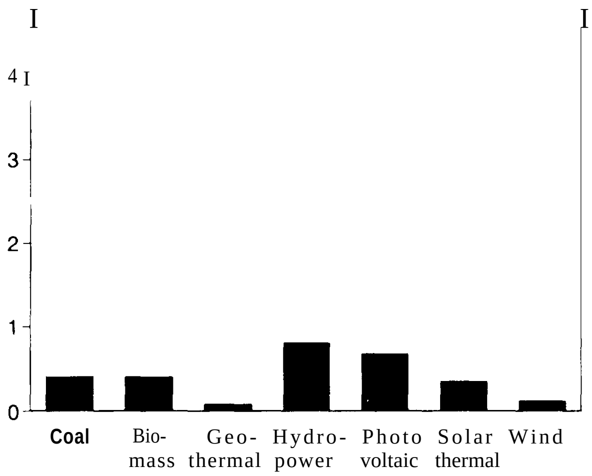
[c] The 10 percent ITC for solar and geothermal property was made permanent by EPACT, section 1916 It applies only to nonutility generators, however, as utilities were previously made ineligible fOr the credit

NOTES DB=declining balance ITC-investment tax credits for 10 percent of cost of qualified solar and geothermal property and was permanently extended under the Energy Policy Act of 1992 (EPACT); REPC= renewable electricity production credit of 1 5¢/kWh for energy produced by wind and closed-loop biomass facilities

SOURCES E Bruce Mumford and Blake J Lacher, "The Equity Stake " *Independent Energy,* March 1993, pp 8-10, 16 Stanton W Hadley et al *Report on the Study of the Tax and Rate Treatment of Renewable Energy Projects,* Report ORNL-6772 (Oak Ridge, TN Oak Ridge National Laboratory December 1993), and Internal Revenue Service, IRS Code, Sec 168(e)(3) Rev Proc 88-22, 1988-1 CB 785, IRS Code Sec 168(b)(l)

FIGURE 6-3A: Levelized Federal Tax Burdens on Various Technologies Owned and Operated by an Investor-Owned Electric Utility

FEDERAL

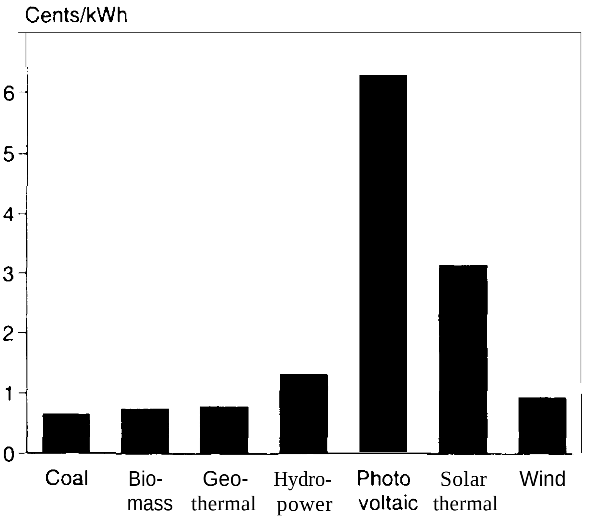


NOTE: On a per kWh basis, the federal tax burden carried by various technologies under utility ownership varies considerably between technologies. Without accelerated depreciation for RETs, their tax burden would generally be significantly higher than that for conventional coal- or gas-fired powerplants. The calculations used a revenue requirement methodology following that of the Electric Power Research Institute, and were based on the parameters listed in tables 6-1, 6-2, and 6-3. The analysis includes the effect of accelerated depreciation; it does not include the impact of energy production credits as provided by the Energy Policy Act of 1992.

SOURCE: Office of Technology Assessment, 1995.

FIGURE 6-3B: Levelized State Tax Burdens on Various Technologies Owned and Operated by an Investor-Owned Electric Utility

STATE AND LOCAL



NOTE On a per kWh bass state and local taxes carried by various technologies also vary significantly of these, property taxes can be particularly significant determinants of overall tax burders. The calcula tions used the same methodology and parameters as figure 6-3A The bass for calculating property taxes can vary significantly befween states and localities depending on how the cap [al is assumed to depreciate in value over time how inrflation in capital values is treated and other factors The scenario modeled here assumed that the property bass would Increase with inflation the share of that property on which the tax is levied is assumed to deprecate at a straight- me book life rate

SOURCE Off Ice of Technology Assessment 1995

tal investment per power output than fossil plants.[25] Accelerated depreciation for capital-intensive RETs only partially compensates for basing taxes on capital investment rather than kWh generated.

Although further reducing federal taxes—which total less than 1 ¢/kWh (not considering the REPC)—might correspondingly provide a small competitive boost for technologies such as biomass, geothermal, hydro, and wind that are now competitive or nearly so, it would have little competitive benefit for solar thermal or photovoltaics (chapter 5).

This analysis shows a gap in policy instruments between RD&D and tax policy to support largc-scale commercialization. RD&D is often the first factor that reduces the cost of a technology. As commercial manufacturing increases with ncar-

[25] In practice, utility rate regulation is far more complex than this, and utilities have incentives for choosing low total cost, rather than high capital cost options.

TABLE 6-2: Assumed Financial Parameters for Investor-Owned Utility Powerplant Financial Analysis

Global parameters	Rate	
Inflation	3%	
Insurance	1	
Property tax	3	
State sales tax on fuel	5	
State sales tax on equipment	5	
State income tax	6[a]	
Federal income tax	35	
	Rate	**Share**
Debt	5% real	45%
Preferred stock	5	10
Common stock	8	45

[a]State tax is deductible from the federal return.

SOURCE: Office of Technology Assessment, 1995

competitiveness, economies of scale become the primary factors in driving costs down further, and tax credits can expedite this process. Before a technology can get to this stage, however, it must establish a manufacturing base while it is yet uncompetitive except for niche markets. Mechanisms to support manufacturing scaleup may be an important intermediary step in some cases if costs are to be reduced to more widely competitive levels. The TEAM UP proposal discussed in chapter 5 is such a step. It is important to assure that any such policies actually stimulate investment in large-scale manufacturing, or manufacturers could simply use this assistance to prop up prices for products from existing capacity.

State and local property taxes can impose a heavy tax burden on capital-intensive RETs because they are levied as a percentage of capital[26] and because they are levied annually. Sixteen states exempt some renewable energy equipment from property taxes (see table 6-4) and some provide tax credits; this can reduce the state tax burden. The basis for such property tax exemptions in part depends on how taxes are viewed—as a tax on "wealth" or to pay for "benefits," serving effectively as a user's fee. Viewed as a benefits tax, for example, property taxes provide on average roughly three-quarters of local tax revenues and serve to cover the costs of roads, schools, and other public services for the employees of the facility being taxed. The level of such public services required, however, varies significantly with the type of powerplant. Conventional powerplants may require substantial infrastructures for fuel transport and water supply, as well as schools and hospitals for many employees. In contrast, some RETs may require little or no transport of fuel and may operate with relatively fewer personnel at the powerplant per unit of capital investment than conventional powerplants.[27] Detailing these differences would be a useful next step for making decisions about taxing RET property at the state and local level.

Nonutility Generator Finance

NUGs typically finance generation expansion through *project* finance in which the lender is repayed and the loan secured through the cash flows

26 How capital is determined varies from state to state, depending on how the capital is assumed to depreciate in value over time, how inflation in capital values are treated, and numerous other factors. The scenario modeled assumed that the property basis would increase with inflation; the share of that property on which the tax is levied is assumed to depreciate at a straight-line book life rate.

27 This does not necessarily imply that the renewable energy system might generate less employment. In fact, several studies suggest that some RETs may generate more employment. The difference, however, is where this employment is distributed across the fuel cycle. Capital-intensive RETs may have more employment associated with manufacturing and less associated with fuel production or power-plant operations and maintenance than do fossil fuel systems.

TABLE 6-3: Baseline Cost and Performance Parameters for Utility Powerplant Financial Analysis

Coal	10	70	1,500	1.6	1,0	1 0	0 5
Gas turbine	13	15	400	2.5	3.0	1 0	0.5
Biomass-plantation	10	70	1,500	2,5	0.0	1.0	0.5
Biomass-waste	10	70	1,500	2.0	0,5	1.0	0.5
Geothermal	—	80	2,400	—	.	2.0	0.5
Hydro	—	40	2,000	—	—	0.5	0.5
Solar-PV	—	25	6,000	—	—	0.5	0.5
Solar thermal	—	25	3,000	—	—	2,0	0.5
Wind	—	28	1,000	—	—	1.0	0.5

NOTE All values have been rounded off reflecting uncertainties due to substantial technological advances taking place and uncertain future fuel prices Values represent 1994 technology status and current fuel cost projections, and do not incorporate the projected performance improvements indicated in chapter 5.

[a]Both fixed and variable operating costs are combined here as capacity factors are assumed to be fixed.

SOURCE: Office of Technology Assessment, 1995.

TABLE 6-4: State incentives for Solar Technologies

	Tax credit	Sales tax exemption	Property tax exemption	Industry recruiting	Loan	Grant	Other
Arizona	—	✓	—	✓[a]	✓	—	—
California	10%	—	—	—	✓[b]	✓[c]	—
Hawaii	35%[d]	—	✓[e]	✓	—	—	—
Idaho	—	—	—	—	✓[f]	—	Income tax[g]
Indiana	—	—	✓	—	—	—	—
Iowa	—	—	✓[h]	—	✓	—	—
Massachusetts	15%[i]	✓	✓	—	—	✓	Corporate tax
Minnesota	—	✓	✓[j]	—	—	—	Accelerated depreciation
Mississippi	—	—	—	—	✓[k]	—	—
Montana	—	—	✓	—	—	—	—
Nevada	—	✓[l]	✓				
New Hampshire	—	—	✓[m]	—	—	✓[n]	—
New Jersey	—	✓	—	—	—	v	Permit fee exemption
New York	—	—	✓	—	—	—	—
North Carolina	25%[o]	—	—	✓[p]	—	—	—
North Dakota	15%	—	✓	—	—	—	—
Ohio	—	—	✓	—	—	—	—
Oregon	35%	—	✓[q]	—	✓[r]	—	—
Pennsylvania	—	—	—	—	—	✓[s]	
Rhode Island	—	v	—		—	—	—
South Dakota	—	—	✓	—	✓[t]	—	—
Tennessee		—	—	—	✓	—	—
Texas	—	—	✓	—	—	✓[u]	Accelerated depreciation
Utah	25%[v]	—	—	—	—	—	—
Virginia	—	—	✓[w]	✓[x]	—	—	—
Wisconsin	—	—	✓	—	—	✓[y]	—
Wyoming	—		—			✓[z]	

[a]Offers a 10-percent tax credit for construction costs of "qualifted enwronmental technology facilities, " including renewable energy plants

[b]offers 5-percent loans to small businesses.

[c]Grants to local governments, schools, and hospitals.

[d]Maximum credit of $1750 for single family homes and $350 for multifamily units

[e]For systems installed between 1976 and 1981

[f]Offers loans of up to $50000 for six years at 5 percent interest

[g]The entire cost of residential solar system can be deducted up to a maximum of $20000

[h]Exempt for five years

[i]Maximum credit of $1,000

[j]Photovoltaic (PV) systems are exempt

[k]Maximum loan is $200,000 and term is seven years

[l]Deferred up to five years

[m]Offered at the discretion of individual towns

[n]Grants of up to $10,000 for up to 100 percent of innovative projects

[o]Residential and commercial active or passive solar systems with a maximum credit of $1 000

[p]Offers 20-percent tax credit to any PV manufacturing facility

[q]For passive and active solar water and space heating

[r]Maximum loan is $20 million over 10 to 15 years at 7 to 10 Percent Interest

[s]Up to $100000 for residential, commercial, and institutional solar projects

[t]Loans at 3 percent interest for RETs with a payback of less than 10 Years

[u]Matching grants

[v]Maximum credit of $1,500

[w]Offered at the discretion of individual towns

[x]Credit of 75¢/W for PV modules manufactured in Virginia and sold between 1995 and 1999

[y]Grants of 10 to 20 percent of the cost of solar projects with a payback of less than 10 years, up to $75,000

[z]Up to $2,500 for PV projects

NOTE Many of these state incentives apply to residential and/or commercial use of passive architecture, solar thermal space or water heating, and other such building applications

SOURCE Larry E Shirley and Jodie D Sholar, "State and Utility Financial Incentives for Solar Applications," *Solar Today,* July/August 1993, pp 11-14 and the assets of the individual project.[28] This is the form of financing used in many wind (see box 6-2) and solar thermal projects (see box 6-3), for example. In contrast, utilities typically finance generation expansion through *corporate* finance in which the loans are secured by all the corporation's assets.[29] NUGs also typically carry higher debt,[30] in part because of overall lower perception of risks [31] These differences in financial structure and taxes affect NUG investment in RETs in several ways.

First, NUG project finance is typically limited by lenders to 15 years or less-compared with project lifetimes of perhaps 30 years—and may have reopener clauses that require renegotiation of terms if utility avoided costs or other factors change sufficiently. This may make it more difficult for NUGs to invest in long-term, capital-intensive RETs.

Second, lenders must be assured the economic viability of the NUG project, including that the cash flow will always cover debt service payments. Project finance loans then often require financial reserves to ensure that debt service can be covered and may have a variety of other restrictions on cash flow.[32] These requirements may be particularly stringent for capital-intensive RETs, and may result in NUGS being required to post additional financial security or have greater demands placed on other components of the project bid.[33]

Third, as for utilities, NUG finance may be influenced by a variety of tax considerations (see table 6-1). The impact of accelerated depreciation and state/local taxes is similar to the case of utilities, as discussed above. In addition, recent analyses for the U.S. Department of Energy suggest that the 10-year 1.5¢/kWh REPC for closed-loop biomass and wind has the potential to improve NUG rate-of-returns, and may thus encourage investment in these technologies. The Alternative Minimum Tax (AMT)[34] may, however, limit a NUG from taking full advantage of these tax incentives. While the Office of Technology Assessment (OTA) has not analyzed this issue, at least one study found that "if a NUG is subject to the AMT, . . . [it] becomes a barrier to the adoption of renewable technologies. "[35] Such factors may be particularly important for renewable; as a fledgling industry, it is viewed as having higher risk and can

28 Edward P. Kahn et al., Lawrence Berkeley Laboratory, Energy and Environment Division, "Analysis of Debt Leveraging in Private Power Projects," Report LBL-32487, August 1992.

29 Existing debt covenants, however, limit management's ability to obligate ex isting assets further. Coverage ratios, for example, help protect existing bondholders.

30 A project may have as much as 80 percent debt, 16 percent subordinated debt, and just 4 percent equity in the project. See, e.g., Daniel A. Potash, "For What It's Worth . . .," *Independent Energy,* September 1991, pp. *37-40.*

31 The financial community recognizes that NUGs have strong incentive to succeed because otherwise they do not get paid. In addition, NUG projects usually begin with long-term power purchase agreements with utilities, so they do not face demand risks. In such a case, the utility bears the demand risk and may have to buy its way out of an expensive contract if demand is lower than expected. Therefore, even though the NUG pledges only the assets of the specific project, it can carry higher levels of debt than a utility.

32 E.P. Kahn et al. op cit, footnote 28; Roger F. Naill and William C. Dudley, "IPP Leveraged Financing: Unfair Advantage?" *Public Utilities Fortnightly,* Jan. 15, 1992; and Roger F. Naill and Barry J. Sharp, "Risky Business? The Case for Independents," *Electricity Journal,* April 1991, pp. 54-63.

33 Blair G. Swezey, National Renewable Energy Laboratory, "The Impact of Competitive Bidding on the Market Prospects for Renewable Electric Technologies," Report No. NREL/TP-462-5479, September 1993.

34 For a discussion of how the AMT works, see Stanton W. Hadley et al., *Report on the Study of Tax and Rate Treatment of Renewable Energy Projects, ORNL-6772* (Oak Ridge, TN: Oak Ridge National Laboratory, December 1993), p. 1-12.

35 Ibid.

BOX 6-2: Wind Energy Development in California

Until recently, the development of the U.S. wind Industry had taken place primarily in California due to particularly favorable tax and rate treatment there in the early to mid-1980s In addition to the federal 10-percent Investment tax credit, a 15-percent business energy investment tax credit,[1] and five-year accelerated depredation for wind systems,[2] this included a state energy Investment tax credit of 25 percent,[3] and favorable power purchase agreements with California utilities under the Public Utility Regulatory Policies Act. In particular, California Standard Offer *4* locked in escalating energy prices for a period of 10 years,[4] based on the expectation that conventional energy prices were also going to escalate The advantage of this form of contract was that 10-year debt financing could then be obtained from various institutional investors who were assured of the necessary income stream to retire the debt This price lock-in reduced Investor uncertainty and led to a "stampede of potential power producers signing contracts with utilities "[5]

These tax benefits were generous. By one estimate, "most Investors could recover about two-thirds of their Investment through the reduction of their taxes in less than three years, even with no sales of electricity "[6] Consequently, these returns attracted a wide range of manufacturers, financiers, and wind farm developers of varying capabilities and motivations, By one estimate, more than 40 wind energy developers installed turbines between 1982 and 19847 In 1980, the California Energy Commission set a goal of having 500 MW of wind capacity online by 1987, 1,436 MW were actually online in that year.

There was, however, relatively little base of supporting wind technology research, development, and demonstration (RD&D), much of the previous federal technology RD&D had been focused on very large (1 MW or larger) systems and little on the relatively lower risk and lower cost Intermediate scale (50 to 250 kW) systems that were put in by private developers Consequently, many early wind systems failed to perform as expected. For example, wind systems produced just 45 percent of industry electricity generation projections in 1985 This poor performance of many U. S.-made turbines opened the door for the entry of large numbers of Imported turbines, totaling some 40 percent of the cumulative Installed capacity as of 1990 These foreign turbines—largely Danish in origin—were noted for their heavier and high-quallty construction and their high reliability.

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[1] The business investment tax credit for certain energy properties was enacted under the Energy Tax Act of 1978 (Public Law 95-61 8)

[2] This was established under the Economic Recovery Tax Act of 1981

3 As state taxes are deductible the effect of this tax credit is reduced

4 This was followed b, a drop to perhaps 90 percent of avoided cost over the remaining (20) years of the contract At the end of the 10 years avoided cost payments covered operations and maintenance and other costs and returns

[5] Alan J Cox et al Wind Power in California A Case Study of Targeted Tax Subsidies, " Regulatory Choices *A Perspective on Developments in Energy Policy,* Richard J Gilbert (ed) (Berkeley, CA University of California Press 1991), p 355

6 Ibid p 349

[7] Susan Williams and Kevin Porter, *Power Plays Profiles of America's Independent Renewable Electricity Developers* (Washington DC Investor Responsibility Research Center 1989) Estimates of the number of manufacturers and developers active at some level vary widely and are sometimes much higher For example some estimate that more than 50 manufacturing companies and 200 development companies were involved in wind development in the early 1980s See Jan Hamrin and Nancy Rader, *Investing in the Future A Regulator's Guide to Renewables* (Washington, DC National Association of Regulatory Utility Commissioners, February 1993) p B-27

(continued)

BOX 6-2 (cont'd.): Wind Energy Development in California

Federal and state tax credits were significantly reduced beginning in 1986, This led to a winnowing of wind system manufacturers and developers and sharply slowed the rate of installation. Just eight developers Installed wind turbines in 1988, for example, and about two dozen are now active at some level. Six of these—Cannon Energy, FloWind, Kenetech-U.S. Windpower, New World Power, SeaWest, and Zond—account for about three-quarters of total installed wind capacity in the United States.[8] Manufacturers went through a similar winnowing process, with just one large U.S. manufacturer—Kenetech-U.S. Windpower—and several smaller manufacturers/project developers—including Zond, FloWind, Cannon Energy, and Advanced Wind Turbines—now producing or developing utility-scale turbines.[9] Work continued throughout this period, however, with continuing gains in cost and performance, Federal RD&D support, in partnership with private firms, have enabled U.S. wind companies to take the global lead in wind turbine technology, cost, and performance, but these firms continue to struggle in international markets, where most sales are now occurring.

Overall, the history of the development of the wind power industry has both negative and positive aspects. On the negative side, at least one detailed analysis Indicates that more was spent to develop wind technology during this period than was necessary or efficient.[10]" Using tax and rate incentwes, in effect, to support RD&D, and Installing many poor performing machines was not an efficient means of developing and commercializing wind energy technology. Tax-based financing also sometimes resulted in year-end Investment decisions, making planning and manufacturing difficult, On the positive side, a cost-effective and environmentally friendly technology has been developed and a viable industry is beginning to take shape, in part due to favorable tax and rate treatment that allowed the industry to get started,

8 Randall Swisher, American Wind Energy Association, personal communication, Aug 25, 1994

9 Others include Atlantic Orient, Wind Eagle, and Wind Harvest

10 Cox et al Op cit footnote 5

have more difficulty attracting capital than well-established competitors.

UTILITY FULL FUEL-CYCLE TAX FACTORS

An analysis done for OTA examined taxes—including both federal and state income taxes, sales taxes, fuel taxes, property taxes, and taxes on labor—across the entire fuel cycle of fuel extraction and supply, fuel transport, and utility generation.[36] It included the embedded taxes on capital, labor, and land directly involved within each of these activities. Capital, labor, and land taxes in secondary industries were not separately considered. This analysis included modeling of the financial structure of each of these entities and consideration of construction costs and how they are included in the ratebase.

Two utilities were modeled using data provided by specific east and west coast investor-owned utilities. Table 6-5 summarizes the results of this analysis for each of the fuel cycles. This table highlights several issues. First, taxes on upstream coal and the development and transport of the natural gas supply are a relatively small portion of the total fuel-cycle taxes; most of the taxes occur at

36 This section primarily draws on the work of Dallas Burtraw and Pallavi R. Shah, Resources for the Future, "Fiscal Effects of Electricity Generation Technology Choice: A Full Fuel Cycle Analysis," report prepared for the Office of Technology Assessment, March 1994.

BOX 6-3: The Rise and Fall of Luz International, Ltd.

Between 1984 and 1991, Luz International, Ltd. installed 354 MW of parabolic trough solar thermal electric-generating capacity in California's deserts. The technology demonstrated increasing reliability and performance and decreasing costs with each generation. For example, the levelized cost of electricity dropped by roughly a factor of three between the first and last generations. Nevertheless, these parabolic trough systems are not cost-competitive given the drop in energy prices beginning in the mid-1980s, particularly compared to using natural gas in advanced gas turbines.

Financing of solar thermal plants was possible due to a combination of federal and state tax incentives and favorable utility power purchase rates (just as for wind power; see box 6-2). Tax benefits for solar thermal investment consisted of a 10-percent federal investment tax credit, a 15-percent federal business energy investment tax credit, and five-year accelerated depreciation; and a 25-percent California energy investment tax credit[1] and exemption from property taxes. Power purchase rates were initially under California Standard Offer 4 (SO4) contracts and included 10-year fixed rates at high levels based on the expectations for conventional fuels.

Luz developed, manufactured, and operated (through subsidiaries) the parabolic trough systems, with support from large institutional and corporate investors through project financing. As a consequence, Luz financing was highly leveraged—it owned little of the powerplants; most of the funding came from outside. This made it vulnerable to small changes in the investment climate. For example, when the attractive SO4 contracts were suspended by the California Public Utilities Commission, investors in the Luz plants demanded an increase in their projected aftertax internal rate of return from about 14 to 17 percent.

Energy prices dropped in the mid-1980s; at the same time, the federal investment tax credit of 10 percent was phased out, the federal energy investment tax credit was reduced from 15 to 10 percent, and the California Solar Energy Tax Credit was reduced. Improvements in technology cost and performance just managed to keep up with these tax changes, which were imposed independently of the needs of technology development or to counterbalance swings in the price of energy. Annual extension of the tax credits severely constrained planning and construction schedules for the plants, requiring Luz to wait until the tax credits were extended and then rush to construct the powerplant within the year. This also significantly raised the cost of obtaining finance and building the plants. Extension of the California property tax exemption was delayed into 1991, during which one of the investors pulled out. Low energy prices and uncertain extension of tax credits subsequently prevented other potential investors from entering and ultimately contributed to the bankruptcy of Luz in 1991. The plants Luz built continue to be operated under separate operating companies.

Thus, federal and state policy created the conditions necessary to launch commercialization of solar thermal electric generation but were then withdrawn independently of the needs of developing a commercially viable technology.

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[1] As state taxes are deductible, the net effect of this credit was reduced to roughly 13.5 percent.

SOURCES: Michael Lotker, *Barriers to Commercialization of Large-Scale Solar Electricity: Lessons Learned from the Luz Experience*, Report SAND91-7014 (Albuquerque, NM: Sandia National Laboratory, November 1991); and Newton D. Becker, "The Demise of Luz: A Case Study," *Solar Today*, January/February 1992, pp. 24-26.

TABLE 6-5: Full Fuel-Cycle Taxes

	Location				
	west	540	0.16	108	1.24
	east	6.43	0.06	1.27	1 33
Gas	west	4.36	0.16	0.54	070
	east	3.52	0.07	0.44	051
Renewable energy technologies					
Biomass	west	6.01	0.39	1.08	1 47
	east	4.69	0.52	1.00	1 51
Hydro	west[a]	13.43	0.00	3.84	3.84
	east	907	000	208	208
Solar thermal	west[b]	14.33	0.00	1.68	1.68
	east	16.06	0.00	3.05	3.05
Wind	west[c]	6.16	0.00	1.28	1.28
	east	5.55	0.00	1.11	1.11
Renewable energy technologies with the renewable electricity production credit (REPC)[d]					
Biomass/REPC	west	475	0.39	033	0.72
	east	3.44	0.52	0.25	0.77
Wind/REPC	west[c]	4.91	0.00	0.49	0.49
	east	404	000-	023	023

[a]The hydro west plant had an exceptionally high capital cost in data provided by the utility, which led to the high levelized cost of energy and higher taxes listed here.

[b]The solar thermal west plant does not include natural gas cofiring; the solar thermal east plant is for a natural gas hybrid.

[c]The original utility-provided data for the wind west case was significantly outdated. Consequently, the values presented here are updated with current cost data.

[d]The difference in taxes between the no-REPC and with-REPC cases is not the same as the difference in the levelized cost of electricity. The cause of this is that the regulated utility receives a fixed rate of return; providing a tax credit reduces the overall revenue requirement and the cost of electricity even more.

NOTES: This analysis should be considered preliminary. Values listed are based on utility-provided data and may vary significantly from other projects. For details of the assumed parameters, see table source. Values have been rounded off to two decimal places. Fuel costs include state fuel taxes, and embedded mining and transport taxes directly on the corporation as well as on capital and labor income. Plant taxes include federal and state income taxes, state sales taxes, and property taxes directly on the corporation and on capital and labor income.

SOURCE: Dallas Burtraw and Pallavi R. Shah, "Fiscal Effects of Electricity Generation Technology Choice: A Full Fuel Cycle Analysis," report prepared for the Office of Technology Assessment, June 1994.

the powerplant either directly or as embedded taxes on, for example, labor. Second, RETs generally face somewhat higher taxes per kWh of electricity generated than either coal or gas,. if the benefits of the REPC[37] for wind and closed-loop biomass arc not included. With the REPC. taxes for closed-loop biomass and wind are reduced to levels in the range of those now enjoyed by natural gas (see table 6-5). The REPC, however, is scheduled to end in 1999, after which facilities will again face higher taxes. Renewable such as hydro and solar thermal also face much higher taxes per

[37]There arc no AMT limitations in these cases.

kWh than coal or natural gas in some cases. (Photovoltaics would face much higher taxes than conventional systems as well. but were not modeled here.) Third, there is considerable variation between the eastern and western cases in individual tax components and the overall tax rate, and between particular technologies.

DIRECT AND INDIRECT SUBSIDIES

Two recent studies of direct and indirect federal and state subsidies of the energy industry are summarized in table 6-6.[38] The studies agree on most subsidies.[39] Many of the disagreements result from differences in defining a "subsidy," as noted in table 6-6.[40] Subsidies may influence the choice of generation technology in the short term and over the long term.[41]

The direct and indirect federal supports across all energy systems. including electricity, may total somewhere between $10 billion to $20 billion per year. On a unit energy basis these levels of support may make a difference in the choice of technology only within a narrow range of costs. For example. the Alliance To Save Energy estimates that about 60 percent of their total listed in table 6-6 goes to the electricity sector or—assuming a median value of $20 billion—roughly $12 billion. Dividing by the 2.8 trillion kWh generated in 1992[42] gives a total of about 0.4¢/kWh.[43] or about 10 pcrcent or less of the cost of electricity generated by new gas and coal units (see table 6-5). This subs id} may affect the choice of generation technology within this narrow band of costs, but will probably not have much direct impact on the choice of technologies that are outside this range.

The single-year snapshot of supports shoun in table 6-6 does not reflect the historical importance of such supports in creating an industry over time. It also ignores the high leverage that RD&D-spccific supports can have on technological development. Such supports have a cumulative impact. encouraging a host of private as well as other public investment and contributing to a cycle of increasing performance and decreasing unit costs. This strengthens a technology's compctitive advantage. Cumulative direct supports for conventional energy technologies are in the hundreds of billions of dollars.[44] Over time this has had and could continue to have a substantial influcncc on the course of the energy industry.

RISK AND UNCERTAINTY

There are many risks and uncertainties in powcrplant finance, construction, and operation. Some of these are explicitly considered as part of the powerplant financing process and arc incorpo-

[38] U.S. Department of Energy, Energy Information Administration, *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*, Report SR EMEU 92-02 (Washington, DC: November 1992); and Douglas N. Koplow, *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts* (Washington, DC: Alliance To Save Energy, April 1993). Earlier reports include Battelle Pacific Northwest Laboratory, *An Analysis of Federal Incentives 1'seal To Stimulate Energy Production*, Report PN'L-2410 REV.I 1 (Richland, W'A February 1982).

[39] Note however [hat d] fferent base years are used.

[40] There is much debate as [o whether accelerated depreciation is a subsidy. Regardless of how it is defined, it does represent a large tax expenditure. Section 3015 of EPACT directed the National Academy of Sciences to analyze energy subsidies, but action has been delayed and alternative efforts arc being considered. This work will hopefully resolve some of these lingering differences.

[41] whether a particular factor is defined to be a subsidy is not of concern here.

[42] U S Department of Energy, Energy Information Administration, *Annual Energy Review. /992*, Report DOE EIA-0384(92) (Washington, DC: June 1993).

[43] This may be substantially more significant if, in fact, most of the subsidy goes to a narrow set of fuelcycles or If the particular fuel cycle supported has captured little of the market—such as the embryonic photovoltaics industry. In fact, however, most of this support goes to conventional fossil and nuclear fuel cyc les which generate most of the power. Consequently, this is a reasonable average value for the discussion here, without resorting to differentiating the specific fuel cycles to which funding is applied.

[44] For example, one detailed analysis found direct supports alone for coal. oil, natural gas, nuclear, and electricity to be $440 billion (1992$) between 1918 and 1978. See Battelle Pacific Northwest Laboratory, op. cit., footnote 38.

TABLE 6-6: Direct and Indirect Federal Supports of the Energy Sector

Type of support	EIA, 1992 $billions	ASE, 1989 $billions	Principal disagreements[a]
Accelerated depreciation	NA	2.8-9.6	Not considered to be a subsidy by EIA as the Accelerated Cost Recovery System is available to all business.
Price-Anderson Act	3.0[b]	0.8-2.8	EIA estimated the value listed from the literature but included it separately as a regulatory cost rather than a subsidy. Several other regulatory costs such as unleaded gasoline and oil storage tank safety are not included in this table, nor are their health or other benefits.
DOE energy R&D	2.0	2.0-2.1	
Strategic petroleum reserve	NA	1.7-2.1	EIA considered it a security measure rather than an energy subsidy.
Investment tax credits	NA	0.8-2.0	Not included in EIA estimates as most were eliminated in 1986. They were continued for business investment in solar and geothermal property, however, and this was made permanent by the Energy Policy Act of 1992.
Low-income home energy assistance and DOE conservation assistance	1 4	1.5	
Tax-exempt bonds for public power	1.1- 7	1 1-1 4	
Rural electrification administration	0.8- 2	1 1-12	EIA values are based on the differences between government and market Interest rates
Uranium enrichment enterprise	03- 5[b]	0.3-1.0	EIA used current outlays and quantified, but did not include in their summary tables, amortization of historic investment. Federal outlays in 1992 were $200,000, but amortizing historic investment raises the level of subsidy to $0.3 billion to $1.5 billion, as listed here.
Utility normalization of excess deferred taxes	NA	00-1.0	Not Included by EIA
Social Security and Department of Labor Black Lung Trust Fund	0 3	1 1-13	EIA includes only current outlays in excess of trust fund receipts from taxes on coal production. Roughly $600 million of black lung disability payments is collected as a production tax on coal; between $300 million to $400 million comes from general Treasury revenues and is included here.
Office of Surface Mining Reclamation and Enforcement	0.1	09	
BLM and Minerals Management Serwce	03	NA	
Army Corps of Engineers CMI program	05	06	

Bureau of Reclamation power projects	01	NA	
DOE waste management	NA	06	
Power Marketing Administrations/TVA	08-42	04-06	EIA estimate of *$800* million is for current outlays over receipts the value $42 billion corresponds to recapturing historic investment at market rates of interest
Tax exclusion for electric coops	NA	04-06	
Tax-exempt bonds for pollution control equipment	NA	05-06	
Percentage depletion benefits	07-10	04-05	
Alternative fuel credit (methane from coal seams)	07	NA	
Alcohol fuels excise tax exemption	05	**03-05**	
Alcohol fuels tax credits	01	**NA**	
Passive loss restriction exemptions for 011 and natural gas	01	**01-03**	
Tax-exempt pubilcly owned utlities	01-02	03	
Total for those listed here	129-197	177-321	The total listed here for EIA does not subtract excise taxes in excess of current liabilities as done by EIA in their summary total They are Included here because these can be thought of as prepayments of future liabilities. Also, several categories, such as the Price-Anderson Act and Uranium Enrichment Services Investment costs are included here but are not Included in the EIA total EIA summary estimates of subsidies are $5 billion to $10 billion, which is approximately the same as that listed here when the Price-Anderson Act, Uranium Enrichment amortization, and other subsidies are subtracted and when excise taxes m excess of current liabilities are subtracted
Adjusted total	5-10	212-360	The EIA estimate of $5 billion to $10 billion does not Include amortizing historic uranium enrichment or other investment, the Pnce-Anderson Act, and others as noted above, and subtracts excise taxes going to general revenue

[a]Principal disagreements are primarily the result of defining what is and what is not a subsidy

[b]Values that were quantified, but not included in the overall estimate of subsidies by EIA

KEY ASE Alliance To Save Energy, BLM - Bureau of Land Man.]gement DOE U S Department of Fnergy EIA Energy Information Administration NA 'not available or not considered a subsidy within the report R&D research and development TVA Tennessee Valley Authority

NOTE Export-Import Bank supports for the export of energy technologies were Included by ASE bu! F 1A considered them to be a trade measure Although these help support U S energy technology manufacturers they were not included here For other differences see the source materials Also note that no estimate of the energy subs idy component of M iddle East military d ipl omatic or aid support is included No costs for the regulatory controls associated with public health and safety are Included Fstimates of these values range widely

SOURCES U S Department of Energy Energy Information Administration Federal Energy Subsidies Direct and Indirect Interventions in Energy Markets SR EMEU/92-02 November 1992 and Douglas N Koplow Alliance To Save Energy' Federal Energy Subsidies Energy Environmental and Fiscal Impacts April 1993 rated in the cost of capital and various financial arrangements. These include the risks of not completing construct ion on time or on budget, and poor technological performance. These arc considered in the financial packages negotiated by NUGs and affect their access to and cost capital .[45] For utilities, cost overruns may not he recovered if the investment is not deemed prudent and can affect their cost of capital.

Certain other risks and uncertainties, however, may not be fully considered in utility planning or electricity costs. These inciudc the risk of fuel cost incrcascs, which arc largely passed through to ratepayers by fuel adjustmcnt clauscs;[46] long-term liabilities for waste disposal or large-scale accidents;[47] and the risk of capacity not matching demands. The utility planning process and electricity markets can be distorted in favor of generat - ing options that entail risks passed directly to ratepayers and taxpayers rather than being incorporated in powerplant planning or the cost of generated electricity. Conversely, to the extent that other technologies—such as certain RETs—are not credited for their ability to avoid these risks, the planning process and electricity markcts can be distorted against them.

RETs also face various risks. depending on the technology. These include premature technical failures due to the relative immaturity of the technology, day-to-day variability in wind find solar resources, and rare but significant shortfalls in resources due to natural disasters. Technological risks and the day-to-day variability of the renewable resource arc generally fully considered in the design, construction. and financing of renewable energy plants. These risks, however, are generally born by the technology developer (if a NUG) rather than being passed through to the ratepaycr or taxpayer.

Rare events may not be adequately accounted for, however. For example, the volcanic eruption of Mt. Pinatubo injected large quantities of sulfur dioxide into the atmosphere, reducing beam raditition to the Earth. Coupled with other weather effects, overall power production from the solar trough thermal power-plants at Kramer Junction in southern California was reduced by 30 percent in the winter and spring of 1992. Total insolation (direct plus diffuse) such as would be used by non-concentrating flat plate photovoltaics, however, was affected much less---declining roughly 5 percent.[48] EI Niños or other weather events may simi - larly change wind patterns and reduce the output of wind powerplants.[49] The Midwest floods during the summer of 1993 might likewise have reduced the harvesting of biomass energy crops. And, of course, droughts may affect hydropower plants or biomass growth.

Such events are rare and the maximum impact in these cases occurred over no more than a year or so. In the most sensitive cases. they r-educed pow-

[45] For a detailed discussion, see Kahn and Gilbert, op. cit., footnote 2; Edward P. Kahn, "Risks in Independent Power Contracts: An Empirical Survey," *The Electricity Journal*, November 1991, pp. 30-45; Mason Willrich and Walter L. Campbell, "Risk Allocation in Independent Power Supply Contracts," *The Electricity Journal*, March 1992, pp. 54-63; and Naill and Sharp, op. cit., footnote 32.

[46] On the other hand, that fuel cost risks are passed through may lower the cost of capital to utilities somewhat, in part compensating for this risk.

[47] Risks of nuclear accidents are explicitly covered under the Price-Anderson Act. See table 6-6.

[48] J.J. Michalsky et al., "Concentration System Performance Degradation in the Aftermath of Mount Pinatubo," presented at the 1993 Annual Conference of the American Solar Energy Society, Washington, DC, Apr. 25-28, 1993; J.J. Michalsky et al., "Mount Pinatubo and Solar Power Plants," *Solar Today*, July/August 1993, pp. 21-22; and Roland Hulstrom, National Renewable Energy Laboratory, personal communication, April 1993.

[49] See, e.g., Cutter Information Corp., "Pinatubo, Weird Weather Challenges California's Wind and Solar Thermal Electric Industries," *Energy, Economics, and Climate Change*, July 1992, pp. 2-5. Very few prospective windpower sites have sufficient detailed data to evaluate such variations. For a discussion, see R.W. Baker et al., "Annual and Seasonal Variations in Mean Wind Speed and Wind Turbine Energy Production," *Solar Energy*, vol. 45, No. 5, 1990, pp. 285-289.

er output by just 30 percent over a few months. If long-term climate change due to the use of fossil fuels occurs, however, these shifts in weather patterns could persist and interfere with the operation of RETs located according to current weather patterns. In contrast, fossil fuel prices have varied much more—by roughly three to eight times[50] in real terms over the past three decades—than renewable resource availability, and price increases can remain for years.

Techniques developed for analyzing the value of risks in financial markets are now being applied to evaluate risks in the electricity sector. Developing such analytical tools would help determine how RETs should be valued compared with conventional technologies.

Fuel Cost Risks

Fuel costs will continue to be variable.[51] Gas prices may bc strongly influenced in coming years if there is an economy wiclc-electric utilities, industry, buildings. transport---move toward gas as a clean fuel. Fossil fuel costs might also be affected should certain environmental taxes—such as on carbon emissions—be established.

The Capital Asset Pricing Model (CAPM)[52] has been the principal analytical tool considered for determining the value of the risk of fuel cost variability.[53] It guides the selection of a diversified portfolio which reduces risks. While the application of CAPM to fuel cost risks is intriguing, it may require a stronger analytical foundation if it is to provide detailed quantitative guidance.[54] Other techniques being examined include options valuation[55] and arbitrage pricing theory.[56] Fuel cost risks may become important in the future, but additional work is needed on the analytical tools to value these various risks.

Liability Risks

Although explicit liability-related policies (such as the Price-Anderson Act) provide important benefits to their respective industries, there are many other liabilities that may be implicitly as-

[50]Coal has varied from 60¢/MMBtu (million Btu) in 1968 to $1.71/MMBtu in 1975, oil has varied from $1.50/MMBtu in 1972 to $6.94/MMBtu in 1981, and natural gas has varied from 30¢/MMBtu in 1951 to $2.65/MMBtu in 1982. This ignores the impact of various regulatory and price controls. See Energy Information Administration, op. cit., footnote 42.

[51]Little oil is now used in the electricity sector, so fluctuations in its price are of less direct interest.

[52]Ernst R. Berndt, *The Practice of Econometrics: Classic and Contemporary* (Reading, MA: Addison-Wesley Publishing Co., 1991); and Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance*, 4th Ed. (New York, NY: McGraw-Hill, Inc., 1991).

[53]Shimon Awerbuch, "Risk Adjusted IRP: It's Easy," presented at the NARUC-DOE Fifth National Conference on Integrated Resource Planning, Kalispell, MO, April 1994; Shimon Awerbuch, "New Utility Thinking Creates Opportunities for Solar Energy," *Solar Industry Journal*, 3rd quarter, 1992, pp. 21-26; Shimon Awerbuch, "Testimony Before the Public Utilities Commission, State of Colorado," Docket No. 91R-642EG, Feb. 14, 1992; Shimon Awerbuch, "Measuring the Costs of Photovoltaics in an Electric Utility Planning Framework," *Progress in Photovoltaics*, vol. 1, No. 3, April 1993, pp. 153-164.

[54]For reviews of some of the analytical difficulties of the CAPM model, especially when discount rates are negative, see, e.g.: William L. Beedles, "Evaluating Negative Benefits," *Journal of Financial and Quantitative Analysis*, vol. 13, 1978, pp. 174-176; R.H. Berry and R.G. Dyson, "On the Negative Risk Premium for Risk Adjusted Discount Rates," *Journal of Business Finance and Accounting*, vol. 7, 1980, pp. 427-436; Moshe Ben-Horim and Narayanaswamy Sivakumar, "Evaluating Capital Investment Projects," *Managerial and Decision Economics*, vol. 9, 1988, pp. 263-268; Timothy J. Gallagher and J. Kenton Zumwalt, "Risk-Adjusted Discount Rates," *The Financial Review*, vol. 26, 1991, pp. 105-114; and Bernard Schwab, "Conceptual Problems in the Use of Risk-Adjusted Discount Rates with Disaggregated Cash Flows," *Journal of Business Financing and Accounting*, vol. 5, 1978, pp. 281-293.

[55]Robert S. Pindyck, "Irreversibility, Uncertainty, and Investment," *Journal of Economic Literature*, vol. 29, September 1991, pp. 1110-1148; and Avinash K. Dixit and Robert S. Pindyck, *Investment Under Uncertainty* (Princeton, NJ: Princeton University Press, 1994).

[56]J. Fred Weston and Thomas E. Copeland, *Managerial Finance*, 9th Ed. (Fort Worth, TX: Dryden Press, 1992)

sumed by taxpayers but are largely unrecognized. These include the potential liabilities from site contamination and the associated cleanup Costs.[57]

Since these concerns affect conventional fossil and nuclear fuel cycles to a much greater extent than most RETs. taking them into account could benefit RETs when energy technology choices are made.

Demand Risks

Demand risk is that associated with constructing a powerplant that turns out to be unnecessary for a long time after completion due to slower than projected demand growth. This risk is particularly significant when constructing large, long lead-time powerplants. Unless the investment is deemed imprudent, the costs to the utility (even if the plant is built by a NUG) are largely passed through to ratepayers.

A variety of analytical methods are being developed to determine the value of demand risks. Of these, options valuation appears to be one of the best suited at this time.[58] Some leading utility executives expect it to be an important planning tool.[59] Options valuation is an analytical technique used to value the costs and benefit of waiting to make a large irreversible investment. During the delay, additional information on the need for capacity expansion, fuel costs, technology performance, and other important variables may change the economics of a particular choice.

Including these costs may significantly alter the choice of generation technology. RETs benefit from such considerations as they tend to be small, modular, and quickly installed. They can therefore be added as needed to meet demand growth.

Conventional technologies and strategies are also being adapted to such demand risks. For example, gas turbines tend to be relatively small (100 MW), modular, and quickly installed. Further, construction can be phased, in which a simple-cycle gas turbine is first installed, followed by construction of a combined-cycle system as demand grows. Ultimately, an integrated gasification system may be added so that low-cost coal or biomass can be used.

ENVIRONMENTAL COSTS AND BENEFITS

Crediting the environmental benefits of RETs compared to fossil fuels in energy planning and pricing could better reflect some advantages of RETs compared to fossil fuels. Recent efforts to

[57] For example a report by the Subcommittee on Oversight and Investigations, House Committee on Natural Resources found that tens of thousands of sites—including mine sites, oil and gas wells, and waste disposal sites (many not energy-related)—do not now comply with environmental standards and may be contaminating surface and/or groundwater. The federal government may carry the risk of cleanup if the operator defaults or declares bankruptcy. U.S. Congress, House of Representatives, Committee on Natural Resources, Subcommittee on Oversight and Investigations, "Deep Pockets: Taxpayer Liability for Environmental Contamination," Majority Staff Report, July 1993.

[58] For demand-side applications, see Eric Hirst, "Do Utility DSM Programs Increase Risk'?" *Electricity Journal*, May 1993, pp. 24-31; and Eric Hirst, "Flexibility Benefits of Demand-Side Programs in Electric Utility Planning," *The Energy Journal*, vol. 11, No. 1, January 1990. For supply-side applications, see Enrique O. Crousillat, World Bank, "Incorporating Risk and Uncertainty in Power System Planning," Industry and Energy Department Working Paper, Energy Series Paper No. 17, June 1989; Enrique Crousillat and Spires Martzoukos, World Bank, "Decision Making Under Uncertainty: An Option Valuation Approach to Power Planning." Industry and Energy Department Working Paper, Energy Series Paper No. 39, August 1991.

[59] "New England Electric CEO Calls for Competitive Measures, Environmental Edge," *Electric Power Alert*, Jan. 5, 1994, p. 26.

TABLE 6-7: Estimates of the Value of Environmental Externalities for the Electricity Sector (1989 $/lb)

	SO_x	NO_x	CO_2	CH_4	Particulates
Energy Power Research Institute	$0.20-$1.30	$0.02-$0.23	—	—	—
California Energy Commission	5.80	5.80	$0.01	—	$3.90
Chernick	0.90	1.60	0.042	$0.37	2.60
Hohmeyer	0.20-0.90	0.30-1.50	0.010	0.35	0.20-1.20
Ottinger	2.00	0.80	0.007	—	1.20
Schilberg	0.50-9.20	1.40-12.30	0.03	0.20	—

NOTE: All values have been rounded off. The ranges listed depend in part on the region considered within the particular study, typically urban versus rural.

SOURCE: Jonathon Koomey, Lawrence Berkeley Laboratory, "Comparative Analysis of Monetary Estimates of External Environmental Costs Associated with Combustion of Fossil Fuels," LBL-28313, July 1990 (original sources are cited in this report); and Richard L. Ottinger et al., *Environmental Costs of Electricity* (New York, NY: Oceana Publications, 1990).

quantify some of these environmental costs (see table 6-7) have been examined by OTA in a separate report.[60]

Some 25 states now consider environmental costs in their electricity sector planning and operations either qualitatively or quantitatively, and other states are considering doing So.[61] At the federal level. section 808 of the Clean Air Act Amendments of 1990 requires the Federal Energy Regulatory Commission and the Environmental Protection Agency to quantify and report to Congress the net environment] benefits of RETs compared to nonrenewable energy and to model regulations for incorporating such benefits in the regulatory treatment of RETs.[62]

Federal policy has established minimum standards to protect species and ecosystems. Recently, interest has developed in the use of market mechanisms to most efficiently allocate resources to meet these standards, even creating mtirkcts—such as SO_x tradeable emissions permits under tht Clean Air Act Amendments of 1990---wherc necessary. Such approaches may also be applicablc to other environrnental costs associated with energy use.

Global warming. however, presents additional difficulties. Although there is growing scientific consensus that global warming will occur. it is not known with precision when the impacts will occur, what form they will take, or how they will be

[60] These issues are explored separately in a background report done within this assessment of RETs. U.S. Congress, Office of Technology Assessment, *Studies of the Environmental Costs of Electricity*, OTA-ETI-134 (Washington, DC: U.S. Government Printing Office, September 1994). See also: Oak Ridge National Laboratory and Resources for the Future, "U.S.-EC Fuel Cycle Study Background Document to the Approach and Issues," ORNL/M-2500, November 1992; D.E. Jones, *Environmental Externalities: An Overview of Theory and Practice* EPRI CU EN-7294 (Palo Alto, CA: Electric Power Research Institute, May 1991); Richard L. Ottinger et al., *Environmental Costs of Electricity* (New York, NY. Oceana Publications, Inc., 1990); Olav Hohmeyer, *Social Costs of Energy Consumption* (New York, NY: Springer-Verlag, 198X}. J, Koomey, Lawrence Berkeley Laboratory, .'Comparative Analysis of Monetary Estimates of External Environmental Costs Associated with Combustion of Fossil Fuels," LBL-28313, July 1990; and Andrew Stirling, "Regulating the Electricity Supply Industry by Valuing Environmental Effects How Much Is the Emperor Retiring')" *Futures*, December **1992,** pp. 1024-1047.

[61] Office of Technology Assessment, ibid.

[62] See, e.g., Federal Energy Regulatory Commission, *Report (m Section 808: Renewable Energy and Energy Conservation Incentives of the Clean Air Act Amendments of 1990* (Washington, DC: December 1992); and Mar-k Chupka and David Howarth, *Renewable Electric Generation: An Assessment of Air Pollution Prevention Potential* (Washington. DC, U.S. Environmental Protection Agency, March 1992).

distributed at the local and regional level. Global warming thus represents the kind of environmental externality that policy makers are least able to deal with: it is very long term---occurring over many decades to hundreds of years; the impact is very uncertain even though potentially severe;[63] and it involvcs things that are difficult to value, such as the survival of particular species.

For the most part, RETs are benign environmentally. In particular, their operation does not emit regulated pollutants or greenhouse gases.[64] Development of RETs might be viewed as a low-cost policy against serious environmental uncertainties, especially since many RET applications will also be economically beneficial.

APPROACHES TO COMMERCIALIZING RETS

A variety of supports has been provided over the past two decades to accelerate commercial adoption of RETs. These have contributed to the relatively rapid increase in the use of certain technologies such as biomass, geothermal, and wind (see box 6-2). Federal commercialization supports for RETs currently include accelerated depreciation, investment tax credits. and the REPC. These are summarized in table 6-1. These supports can help relatively mature technologies, but have much less impact on the commercialization of technologies that are higher cost. Even with these supports, RETs are not expected to make a major contribution to U.S. electricity supplied in the next two decades if present trends continue. For example, the Energy Information Administration projects RET electricity generation will increase from 11 percent of the total in 1990 to 13 percent in 2010 (see chapter 1).[65] If commercialization of RETs is a goal, the following steps could help deal with some of the challenges discussed above.

Competitive bidding and green competitive set-asides

As generation markets continue to open, competitive bidding is likely to play a more important role in these markets. As currently practiced, however, bid selection criteria may not fully credit some of the benefits of renewable. All-source bidding selection criteria could be modified to value more carefully such factors as the risk of fuel cost increases and environmental impact.

In evaluating some of these factors, however, it may not be possible to assign precise values that are widely accepted, or to design a single set of all-source bidding selection criteria that fairly cons iders all technologies. It may therefore be preferable for utilities to solicit bids specifically for certain technologies.

Such technology-specific set-asides could be designed to provide an increasing market demand for each set of technologies over a period of years, providing developers a more certain market and allowing them to scale up manufacturing and reduce prices. The growth in such set-aside capacity could be chosen to bring a particular RET down its cost curve to a fully competitive market position. It would be necessary to ensure that such technology and manufacturing improvements and price reductions actually occurred, however, and that the set-aside did not simply provide higher margins to manufacturers.[66] It is also necessary to ensure that utilities are not encumbered with a large number of high-cost contracts, especially if retail wheeling is introduced. Thus, technology-specific set-asides can support commercialization of even less mature RETs without excessively bur-

[63] See, e.g., U.S. Congress, Office of Technology Assessment, *Preparing for an Uncertain Climate*, OTA-O-567, OTA-O-568 (Washington, DC: U.S. Government Printing Office, October 1993).

[64] The combustion of biomass does release carbon dioxide, but that is balanced by the uptake of growing plants. Thus, the full biomass cycle can be operated on a sustainable basis.

[65] This does represent, however, an increase in nonhydro generation from roughly 50 billion kWh in 1990 to 170 billion kWh in 2010.

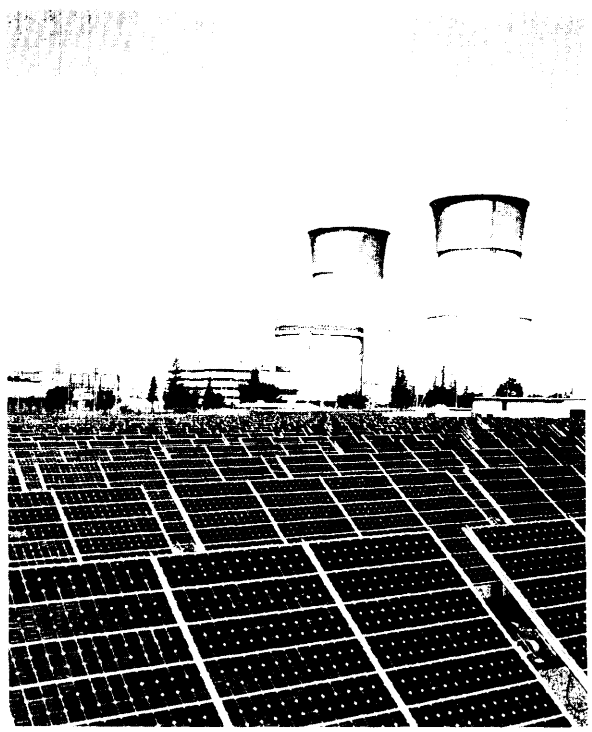
[66] Donald W. Aitken, "Sustained Orderly Development," *Solar Today*, May/June 1992, pp. 20-22.

dening ratepayers and utilities. Both will benefit in the long term as RETs become fully competitive.

Technology-specific set-asides could also provide experience to regulators and utilities in preparing/evaluating future proposals and bids for renewables and would help balance their long experience and comfortable familiarity with conventional systems. It would also offer developers and utilities alike the opportunity to train personnel and to establish effective regimens of communication and interconnection supports.

There are several initial efforts with competitive set-asides. California, for example, has mandated renewable energy capacity purchases by utilities. Technologies, however, are not specified and this initiative is not likely to provide support for less mature technologies. The bidding and bid selection processes have also been controversial and the future of the program is in doubt.[67] The New England Electric System made a "green request for proposals" in 1993, but all seven of the selected bids were rejected by the Rhode Island Public Utilities Commission (PUC) in April 1994 as too expensive.[68] Nevertheless, various options to move this program forward are being considered. Other competitive set-asides for RETs include those by the Bonneville Power Administration and the New York State Energy Plan.[69]

Congress could consider directing the Department of Energy to work with the states to establish appropriate levels of technology-specific set-asides for RETs. This could be done first as pilot projects and then on a larger scale—coordinated on a national basis—in order to best capture fuel diversity and environmental benefits while supporting the manufacturing scaleup of their respective industries and thus reduce costs as rapidly and efficiently as possible.



GEORGE TURNER SMUD

The Sacramento Municipal Utility District (SMUD) 2-MW photovoltaic plant is installed at the site of the now closed Rancho Seco nuclear powerplant

Green pricing

Green pricing[70] proposals to support RETs typically place a surcharge of perhaps 10 percent on the monthly utility bill of *voluntarily* participating customers. The surcharge funds are then used to

[67]This approach is a component of a larger strategy that has become known as Sustained Orderly Development. "Wind Receives Large Share of BRPU Preliminary Bid Auction," *Wind Energy Weekly*, vol. 12, No. 577, Dec. 20, 1993, pp. 1. The set-aside has been called into question by the California Public Utilities Commission (PUC) and the Federal Energy Regulatory Commission (FERC). Under its call to investigate retail wheeling, PUC asked the legislature to explicitly reconsider the requirement placed on them to establish set-asides for renewables. In a February 1995 draft decision, FERC ruled that California cannot set avoided costs for QFs above the cost of any source of power, including low-cost purchases. This decision could preclude any preferential treatment of RETs.

[68]Daniel Kaplan, "State Regulator, Renewables Proponents Clash," *The Energy Daily*, Apr. 13, 1994, p. 3.

[69]For details on these and other programs, see Jan Hamrin and Nancy Rader, National Association of Regulatory Utility Commissioners, "Investing in the Future: A Regulator's Guide to Renewables," February 1993.

[70]David Moskovitz, " 'Green Pricing': Customer Choice Moves Beyond IRP," *The Electricity Journal*, October 1993, pp. 42-50.

pay the difference in cost between the renewables and conventional utility power. This provides greater choice to consumers and fits in well with the structural changes now taking place in the electricity sector. Several efforts of this sort have been launched, including the "PV Pioneer" program by the Sacramento Municipal Utility District with a 15-percent price premium for PVs,[71] Public Service of Colorado,[72] Traverse City Light & Power,[73] and a program by Southern California Edison (SCE).

The SCE program is with Kenetech-U.S. Windpower, Inc. They recently announced a preliminary agreement for 500 MW of wind power, the first 250 MW of which would be contingent on sufficient utility customers enrolling in a green pricing plan.[74] This wind capacity would fill about 60 percent of SCE's renewable energy purchases mandated under the California renewable energy set-aside, if that program moves forward.

Green pricing is attractive because it is voluntary, but it is unlikely to achieve the level of support for RETs that set-asides could. In addition, ratepayers who volunteer will be paying for the environmental and risk benefits gained on behalf of everyone in the region.

Incentives to purchase RETs

Most utilities have little or no incentive to purchase RETs or to purchase RET-generated electricity from NUGs rather than conventional fossil power: whatever source of power is used, the utility earns the same return. Regulatory changes to allow a slightly higher rate of return for the use or pur-chase of reasonably cost-effective rcnewables would provide incentive and help utilitics gain experience with RETs while reducing fuel cost risks to ratepayers and environmental impact.[75] As an example, the Wisconsin Public Service Commission recently granted regulated utili ties the right to provide their shareholders an additional return of 0.75¢/kWh for power generated by wind, photovoltaics. or solar thermal plants over 20 years for projects brought online between 1993 and 1998.[76] Although this is primarily a state regulatory issue, federal policy might play a supporting role.

Although they appear to have significant potential to support RETs, these strategies—green competitive set-asides. green pricing, or stockholder incentives---arc too new for any significant conclusions to be drawn as to their effectiveness in practice.

Federal taxes

Current federal tax incentives for RETs, such as accelerated depreciation, investment tax credits, and pduction credits, reduce federal tax burdens on RETs depending on the particular incentives and RET. As discussed above, however, the tax burden per kWh on many RETs remains higher than that for coal- or gas-powered electricity generation. For wind and biomass, which are competitive or near-competitive with fossil systems, tax incentives may have a significant influence on their market viability. However, the REPC of 1.5¢/kWh is limited to facilities in operation by 1999, which does not allow time for most biomass systems. with their 3- to 7-year growth cycles (for woody crops) to get established.

Tax policy has had a significant influence on the development of RETs such as wind (see box 6-2). Government incentives intended to help renewables, however, have also on occasion had the perverse effect of hurting them. For example, un-

[71] Sacramento Muni Aims To Have 50 MW of Photovoltaics on System by 2000," *Electric Utility Week*, June 27, 1994, pp. 16-17.

[72] "PSCO 'Green Pricing' To Fund Renewable Energy Projects," *Wind Energy Weekly*, Dec. 6, 1993, pp. 5.

[73] "Michigan Muni Turns to "Green Pricing" To Finance Wind Turbine," *Wind Energy Weekly*, May 30, 1994.

[74] Daniel Kaplan, "SCE, Kenetech Announce Wind Power Deal, Green Pricing Plan," *The Energy Daily*, vol. 22, Mar. 17, 1994, p. 1.

[75] See, e.g., David Moskovitz, *Renewable Energy: Barriers and Opportunities; Walls and Bridges* (Washington, DC: World Resources Institute, July 1992).

[76] "Minnesota Utility Eligible To Receive Wisconsin Incentive," *Wind Energy Weekly*, Nov. 8, 1993, pp. 4-5.

certainty over incentives raises risks for private developers and makes financing more difficult, as in the bankruptcy of the largest solar thermal company (see box 6-3). Ways to reduce the impact of this uncertainty are to make proposed incentives retroactive and to increase their duration.

Front-loaded capital costs of RETs

High investment costs for RETs can result in a NUG paying as much or more for debt and other costs than it receives from the sale of its power during the first critical years of a project. Ways to mitigate this problem might include: 1) innovative financial mechanisms to redistribute loan repayments over the project lifetime so as to better meet the cash flow constraints of the developer; 2) changes in the schedule for energy and capacity payments (i.e., to front-load payments); 3) interest rate buydowns (in which public entities provide a one-shot upfront payment of interest to reduce this front-loading);[77] and 4) longer contract periods to put NUG financing on a more level basis with the financing utilities implicitly receive from ratepayers.

For example, the senior debt of some recent NUG projects has been divided into two separate components, one with a shorter term and a variable interest rate, the other with a longer term and a fixed interest rate. Such financing structures have arisen because banks have increasingly been unwilling to lend for periods longer than 15 years, while insurance companies and other institutions are sometimes willing to lend for terms of 20 years or more. In addition, banks and other institutions increasingly prefer to diversify their portfolio and prefer to not underwrite an entire project alone.[78] Such mechanisms may allow some restructuring of the front-loaded cost structure of RET projects but also require careful negotiation to properly allocate risk among the participants, particularly for the longer term debtholder. A detailed analysis is needed of mechanisms to assist development of long-term loans for RETs through private capital markets. There may be a federal role in matchmaking and/or leveraging such arrangements.

Changing contract payment schedules to better match the cash flow requirements of RET developers raises the risk of paying in advance for a powerplant that later fails. If, however, payments are structured so that they are always sufficient to cover operating and other costs and also provide a reasonable margin for the operator, it will always be profitable for someone to keep the plant operating. This can reduce the risk of premature failure and abandonment.

Transaction costs

High transaction costs can be a significant barrier for small renewable energy developers. Among the lessons drawn from past experiences (see box 6-1) is the value of standard contracts. Providing standard contracts is usually a state regulatory issue.

Direct and indirect subsidies

To improve the competitiveness of RETs, a more detailed and ongoing accounting of subsidies and related supports such as tax expenditures in the electricity sector might be made for each fuel cycle. Explicitly identifying subsidies and related supports for each fuel cycle on an ongoing basis could provide policymakers with a better sense of federal tax and budget expenditures so they could determine if taxpayers are getting their money's worth, and if any change is warranted.

Risk and environmental costs

Potential fuel price changes and environmental liabilities may not be adequately accounted for in the planning of new electricity-generation capac-

[77] Interest rate buydowns may often be preferable to such public finance instruments as loan guarantees, as buydowns leave the commercial lender at risk and thus maintain market incentives to perform, while minimizing federal exposure. On the other hand, interest rate buydowns do require specific federal outlays.

[78] John H. Kenney, "Financing with a Dual-Tranche," *Independent Energy*, September 1992, pp. 16-22.

ity or in the cost of electricity, Therefore, the potential of RETs to offset these risk pass-throughs may not be adequately valued by planners, reducing the likelihood that these RETs will be chosen when new capacity is planned. More analysis could help understand these risks, determine means of valuing them, and understand how risk pass -throughs influence financial markets and the choice of generation technologies.

The federal government could work with states to examine fuel adjustment clauses in particular and the impact these have on the choice of generation technologies. Mechanisms to adequately account for the risk of future fuel price increases in generation capacity planning could be developed and implemented. Initial work on this is under way in Colorado[79] and elsewhere. Environmental cleanup bonds, trust funds, or other funding mechanisms could be examined to determine their ability to recover long-term environmental cleanup costs from energy industries and companies.[so] Tax benefits that could affect the choice of a fuel cycle could be based on minimizing environmental impact.

State governments could incorporate environmental externality costs in their utility planning efforts or direct] y in electricity y costs, and state regulators could encourage utilities to consider environmental impacts when deciding which generating units to operate.[81] Although these are primarily state issues, the federal government could support such efforts through information programs, the development of appropriate analytical tools, and further analysis of the social costs of energy use. Proposals to base state and/or federal electric sector taxes on emissions. potentially including greenhouse **gas** emissions, rather than profits or sales could be examined for potential effectiveness, costs and benefits. equity impacts, or other consequences. Some studies have indicated that shifting from corporate income taxes may have positive benefits in the longer term.[82]

Structural change

The potentially negative impact of changes in the electric power sector on RETs, discussed at the beginning of this chapter, might be addressed by the use of sectorwide policy tools, rather than utility-specific regulatory interventions. For example, the valuation of fuel cost risks and environmental costs, and corresponding use of technology-specific set-asides for both utilities and NUGs, may ease some of the conflict inherent in limiting such costs or controls to regulated utilities alone. Such electricity sectorwide policy tools could be considered at both the state and federal levels.

CONCLUSION

This chapter has outlined a variety of challenges—structural, financial, tax, risk, and competitive-–that face commercialization of RETs in the electric sector. These challenges will likely preclude many cost-effective applications of RETs under current policies. A significant RET industry is beginning to develop with a portfolio of maturing as well as immature but promising technologies. The considerable experience that has been gained builds confidence for the industry's future. Policy experience is also developing. More effective commercialization, if done wisely, can lead to increased growth and widespread benefits.

[79] Shimon Awerbuch, "Direct Testimony," *Investigation Into the Development of Rules Concerning Integrated Resource Planning*, Colorado Public Utility Commission Docket 91R-642EG, February 1992.

[80] See, e.g., House Committee on Natural Resources, op. cit., footnote 57.

[81] Steve Bernow et al., "Full-Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," The *Electricity Journal*, March 1991, pp. 20-33.

[82] Moskovitz, op. cit., footnote 75; Robert Repetto et al., *Green Fees: How a Tax Shift Can Work for the Environment and the Economy* (Washington, DC: World Resources Institute. November 1992); and Dale W. Jorgenson and Kun-Young Hun, "The Excess Burden of Taxation in the United States." *Journal of Accounting, Auditing, and Finance*, vol. 6, No. 6, fall 1991.

Government Supports and International Competition 7

U.S.-owned and U.S-based manufacturers have led the world in the research, development, and commercialization of many renewable energy technologies. Today, these manufacturers are facing strong competitive challenges both at home and abroad. Compared with U.S. firms, foreign competitors are often more strongly supported by public research, development, and demonstration (RD&D) and commercialization programs, protected by tariff or nontariff trade barriers, and assisted in their drive to enter foreign markets. At stake is a potentially large international market and the U.S. jobs and other economic benefits that might come from serving it.

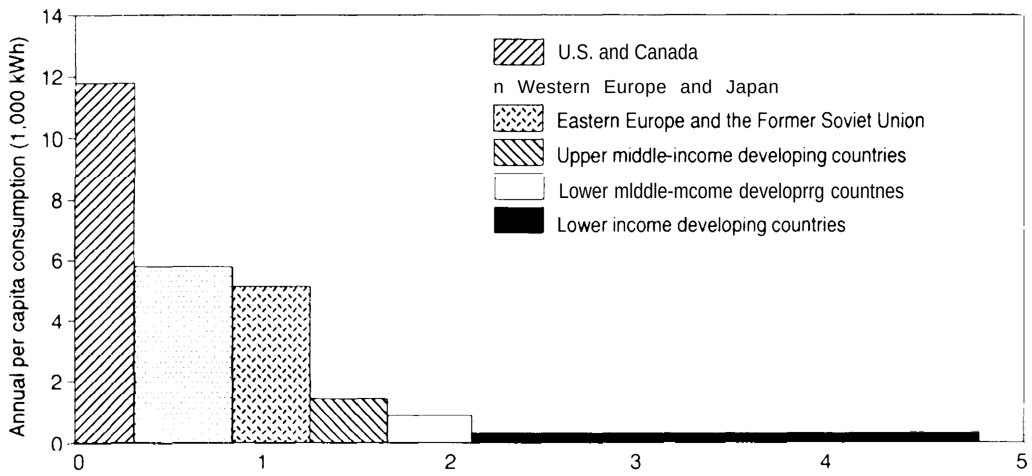
What Has Changed?

International interest in renewable energy technologies (RETs) has increased over the past decade. Environmental concerns-due to acid-rain damage to forests in Europe, the Chernobyl nuclear accident in the former Soviet Union, and possible global warming, as well as ongoing concerns about future fossil fuel prices and supply reliability—have generated a strong push in Europe to find alternatives to nuclear- and fossil-based electricity generation. Recently, the "Declaration of Madrid" called for RETs to provide 15 percent of primary energy demand in the European Union by 2010.[1]

At the same time, many power markets in Europe are going through substantial structural change. Some utilities in Europe (e.g., in the United Kingdom) have undergone large-scale priva-

[1] European Commission, Directorates-General XII, XIII, XVII and European Parliament, STOA Programme et al., "Declaration of Madrid," Conference on an Action Plan for Renewable Energy Sources in Europe, Madrid, Spain, Mar. 16-18, 1994.

FIGURE 7-1: World Electricity Consumption, 1987



The distribution of electricity use among different population groups around the world is shown. Lower income developing countries have very low levels of electricity consumption and are likely to be an important and rapidly growing market for renewable energy technologies over the next several decades.

SOURCE: Adopted from United Nations. *Energy Statistics Yearbook 1990* (New York, NY: 1992).

tization: others arc searching for ways to cooperate across many aspects of their operations. Whatever form European utilities take,[2] there are likely to be additional opportunities for using RETs within them.

In developing countries, current levels of electricity use are very low (figure 7-1) and the demand for electricity is growing rapidly.[3] Estimates of the market for power generation equipment in developing countries are typical] y in the $1 -trillion range over the next 10 years, or an average of $100 billion per year;[4] the market could grow much larger in the longer term. Investment and operational expansion at this level poses great difficulties for many inefficient or heavily subsidized state-owned electric utilities. In response, many developing countries are opening up their electricity sectors and beginning to encourage private investment. Use of RETs in distributed utility applications may offer opportunities to improve power sector performance.

Despite large investments. many people in many rural areas of developing countries are unlikely to be served by conventional electric utility grids for many years; the cost of transmission and distribution grid extension is too great. Similarly,

[2] Andrew Holmes, "E\ olution and De-Evolution of a European Power Grid," *Electricity Journal*, October 1992, pp. 34-47. See also Edward Kahn and Richard Gilbert, "International Comparisons of Electricity Regulation." 17th International Con ference of the International Associa-(ion o! Energy Economists, Stavanger, Norway, May 1994.

[3] For a detailed review of energy use in developing countries, see U.S. Congress, Office of Technology Assessment, *Fueling Development: Energy Technologies for Developing Countries*, OTA-E-516 (Washington, DC: U.S. Government Printing Office, April 1992).

[4] The market is likely to be smaller in the near term and grow larger with time. See, e.g., Edwin A. Moore and George Smith, "Capital Expenditures for Electric Power in the Developing Countries in the 1990s," World Bank, Industry and Energy Department Working Paper No. 21 for the Energy Series, February 1990.

transport of fuel for diesel electric systems is expensive and often unreliable. In many cases, the choice is either to purchase remote RET systems or continue to do without electricity. RETs have the potential to cost-effectively provide electricity to people in areas outside the utility grid. The benefits of electricity, such as lights, water pumps, and modern communications, can help transform these traditional societies. This can contribute to political stability as well as provide trade benefits and jobs for the United States.

Both within Europe and in developing countries, RETs are thus increasingly seen as key power technologies in the future, with potentially huge markets. These factors have resulted in much more activist government policies in support of RETs in recent years and pose a significant competitive challenge to U.S. firms.

Potential Roles

Foreign markets offer a promising opportunity for using RETs. Many of these applications are higher value uses, for example, remote applications where RETs such as photovoltaic (PV), small solar thermal, and small wind have strong competitive advantages. These markets thus offer the potential to scale up manufacturing and drive down prices through economies of scale and learning.

The United States is now doing well in some RET export markets. For example, about 70 percent of U.S. photovoltaic production was shipped abroad in 1993; about 37 percent of world production of PVs was in the United States.[5] Nearly two-thirds of U.S.-based PV production, however, is by firms recently purchased by foreign interests. To lose foreign market share could then greatly reduce U.S. firms' economies of scale and learning; ultimately, this could lead to a loss of competitiveness even in our own markets.

As discussed elsewhere in this chapter, several countries appear to have earmarked the PV industry for special support. Such support could threaten U.S. firms in both domestic and export markets, especially since the PV industry is one where economies of scale and rapidly improving technology, along with steep technical and financial barriers to entry, give the first in the field a strong advantage.

Principal Themes

Rather than a broad overview of U.S. and foreign RD&D, commercialization, and trade programs—such reviews and related policy discussions are well covered elsewhere[6]—this chapter makes a detailed comparison of international activities in two specific areas—photovoltaics and wind. Other renewables, such as biomass energy technologies,[7]

[5] "U.S. PV Shipments Climb Sharply as Thermal Collector Numbers Drop," *Solar Letter*, June 10, 1994, p. 134.

[6] Interagency Environmental Exports Working Group, *Environmental Technologies Exports: Strategic Framework for U.S. Leadership* (Washington, DC: U.S. Department of Commerce, U.S. Department of Energy, and Environmental Protection Agency, November 1993); U.S. Department of Energy, *National Energy Strategy, Technical Annex 5: Analysis of Options To Increase Exports of U.S. Energy Technology*, US-DOE/S-0096P (Washington, DC: National Technical Information Service, 1992); Trade Promotion Coordinating Committee, "Toward a National Export Strategy," Report to Congress, September 1993; Office of Technology Assessment, op. cit., footnote 3; U.S. Congress, Office of Technology Assessment, *Industry, Technology, and the Environment: Competitive Challenges and Business Opportunities*, OTA-ITE-586 (Washington, DC: U.S. Government Printing Office, January 1994); U.S. Congress, Office of Technology Assessment, *Development Assistance, Export Promotion, and Environmental Technology—Background Paper*, OTA-BP-ITE-107 (Washington, DC: U.S. Government Printing Office, August 1993); and Andrew Barnett, "The Financing of Electric Power Projects in Developing Countries," *Energy Policy*, vol. 20, April 1992, pp. 326-334.

[7] For a review of biomass energy technology development, financial support, and its relationship to agriculture in Europe, see European Parliament, Scientific and Technological Options Assessment, Directorate General for Research, *Energy and Biomass: Potential for Cultivation and Prospects for Utilization from the European Community's Perspective*, Project Paper No. 1 (Luxembourg: April 1993); *Energy and Biomass: Country Profiles: Agriculture and Forestry Biomass Production—Operations Achieved*, Project Paper No. 2 (Luxembourg: August 1993); and *Energy and Biomass: Liquid Biofuels*, Project Paper No. 3 (Luxembourg: August 1993).

have recently been[8] or are currently being reviewed elsewhere.[9]

This comparison of PV and wind programs shows a wide range of supports among various nations of the Organization for Economic Cooperation and Development (OECD), including government-supported RD&D; direct funding of, or tax credits for, investments in RET equipment; supports for the purchase of generated renewable energy; and a variety of legislative—including environmental—supports for renewables.

The bulk of this chapter is focused on national PV and wind programs in Japan, Europe, and the United States. Following this discussion is a brief crosscutting summary and discussion of possible policy options to respond to this competitive challenge. How U.S. firms do in this international competition will depend on the groundwork that is laid today.

Finally, it should be noted that PV and wind technologies are advancing rapidly and government programs are changing quickly in response to new opportunities and shifting public concerns.

INTERNATIONAL ACTIVITIES IN PV AND WIND TECHNOLOGIES[10]

Competition in RETs is increasing rapidly as industrial countries recognize the growth potential of these environmentally friendly and currently or potentially cost-effective energy technologies. The PV and wind energy technology activities of nine OECD countries are reviewed and compared here.

All of the renewable energy programs reviewed have three complementary strategies: 1) RD&D to increase the cost-effectiveness of the technology and thus broaden its scope of economically attractive market applications: 2) market development to accelerate acceptance of RETs in currently cost-effective or newly emerging applications; and 3) market priming to support the use of RETs where they are not yet cost-effective but could become so with further development and large-scale manufacturing.

The link between increased cost-effectiveness and market development is critical. The potential market relies heavily on price (without considering risk or environmental costs, see chapter 6), particularly compared with the mature energy technologies that RETs compete against. Prices for RETs are determined by technical performance as determined by RD&D, economies of scale and learning realized by mass production, and the requirement to recoup certain fixed RD&D, manufacturing, and marketing costs through sales. Thus, costs can be reduced if sales volumes are increased, but sales volumes may not increase until prices are reduced. This "chicken-and-egg" problem is a central challenge for RETs.

RD&D for Increased Cost-Effectiveness

Photovoltaics

The general routes to improved PV cost-effectiveness are increased energy conversion efficiencies, improved balance of systems, and reduced manufacturing and installation costs. Increasing conversion efficiencies will make each square centimeter of PV surface more productive, increasing the utilization of available solar energy while making the cell less costly on a materials basis per unit output. A reduction in manufacturing costs per unit of cell area makes each square centimeter of cell less costly. The combination of reduced cost and increased efficiency is expected to

[8] For a broad review, see James & James Science Publishers, *European Directory of Renewable Energy Suppliers and Services, 1992* (London, England: 1992).

[9] A detailed competitive assessment of international renewable energy technology, policy, and activities is currently under way at Sandia National Laboratory for the Department of Energy. It covers biomass, geothermal, ocean, photovoltaic, solar thermal, wind, and advanced batteries.

[10] This section is drawn primarily from Ted Kennedy and Christine Egan, Meridian Corp., "International Activities Supporting Wind and Photovoltaic Energy," report prepared for the Office of Technology Assessment, Nov. 8, 1993.

TABLE 7-1: Publicly Funded Photovoltaic R&D, by Country (current U.S. dollars in millions)

Year	United States	Japan	Germany	Italy	France	European Union	Switzerland	United Kingdom
1979	118.8	13						
1980	148.6	35	6	9				
1981	151.6	32	10	9				
1982	61.6	40	33	9				
1983	57.9	41	30	9	6.3			
1984	50.2	41	30	9	5.2			
1935	54.5	46	31	20	6.1	6		
1986	37.8	48	31	20	4.6	6		
1987	40.0	38	32	20	3.8	6		
1988	34.6	37	35	20	3.1	6		
1989	35.1	42	50	20	2.8	4		
1990	34.7	54	65	27	4.4	4	5.2	
i991	46.3	54	65	41	4.5	4	6.0	0.5
1992	60.4	62	65	41	4.5	4	8.6	1.0

SOURCE: Morton Prince, Office of Solar Energy Conversion, U.S. Department of Energy; Paul Maycock, Photovoltaic Energy Systems, Inc.; and Fred J. Sissine, Congressional Research Service, "Renewable Energy: A New National Commitment," IB93063, Feb. 10, 1994.

result in dramatic declines in system capital costs as well as energy costs per kilowatt-hour produced (see chapter 5). Most countries with PV programs include a variety of activities to improve performance and reduce manufacturing costs.

Incorporation of PVs into building structures is a concept that is being pursued by most of the major programs, including those of the United States (PV-Bonus Program), Japan (superhigh-efficiency cell applications), Germany ("1,000 Roof" program), and Great Britain (Study of PV Applications in Buildings).

Improvements in balance of system (BOS) components and system reliability and lifetime are two additional areas addressed by most programs. BOS components include batteries, power conditioning equipment, system interconnections, and support structures. The Japanese, Italian, and Swiss programs specifically target BOS components either as budget line items or as discrete program areas.

System reliability and lifetime research is directed at several critical areas, including subsystem components such as the PV modules, batteries, and inverters; system configurations and interconnections; and operations and maintenance requirements. These concerns are addressed either as specific program areas or as components of broader program initiatives by virtually all countries examined.

Table 7-1 provides data on national annual PV RD&D budgets, and table 7-2 lists production levels by country from 1976 to 1993.

Wind

Improvements in the cost-effectiveness of wind energy technologies (see chapter 5) have been pursued through advanced engineering and manufacturing improvements. For example, improvements in blade design through public-private U.S. efforts are now resulting in rotors that increase energy capture by 10 to 30 percent, while reducing inefficiencies caused by fouling due to insects and airborne particles (see chapter 5). Virtually all of the country programs addressed in this report are investigating such improvements, as well as improvements in power system components—including variable-speed operation with advanced power electronics and expert control systems to

TABLE 7-2: Photovoltaic Production, by Region

	World	United States		Japan		Europe		Rest-of-World	
Year	MW	MW	%	MW	%	MW	%	MW	%
1976	0.42	0.32	76						
1977	0.45	0.42	93						
1978	0.96	0.84	88						
1979	1.46	1.24	85						
1980	3.30	2.50	76	0.50	15	030	9		
1981	5.40	3.50	65	1.10	20	080	15		
1982	8.40	5.20	62	1.70	20	1.40	17	010	1
1983	21.70	13.10	60	5.00	23	330	15	030	1
1984	25.00	11.50	46	8.90	36	360	14	080	3
1985	22.80	7.70	34	10.60	45	340	15	140	6
1986	26.00	7.10	27.3	12.60	485	400	154	230	9
1987	29.20	8.70	29.8	13.20	45..2	450	154	280	10
1988	33.80	11.30	35.1	12.80	353	670	197	300	9
1989	40.20	14.10	35.1	14.20	353	790	197	400	10
1990	46.50	14.80	31.8	16.80	361	1020	219	470	10
1991	55.30	17.10	30.9	19.90	360	13.40	242	500	9
1992	57.90	18.10	31.3	18.80	325	1640	283	460	8
1993	60.69	22.44	36.9	17.30	285	1655	273	440	72

MW = megawatts

NOTE: World total for 1976-79 does not add up, because data from those years was not broken out by region.

SOURCE: Morton Prince, Office of Solar Energy Conversion, U.S. Department of Energy, and Paul Maycock, Photovoltaic Energy Systems, Inc.

increase power output, improve power quality, and reduce mechanical loads.

The development of large-scale turbines to reduce unit costs per kilowatt and address siting constraints is being pursued by the European Union (EU), Danish, Italian, and German programs with specific budget line items or discrete program areas. The development of offshore turbines—land-use restrictions such as the location of population centers may prevent wind energy development in some prime areas—is being investigated in many of the country programs, particularly Denmark and the Netherlands, as a mid-term option.

Increases in system reliability and lifetime are addressed in most national programs. In the United States, for example, design improvements and better operations and maintenance regimes have resulted in availabilities of up to 97 percent, compared with 20 percent in 1981 (see chapter 5). Turbines have been simplified and the numnber of moving parts has been reduced. This has cut down on maintenance requirements and has enhanced lifetimes while reducing manufacturing costs.

overall, Europe appears to be gearing up for largc-scale deployment of wind turbines in the war term. Plans for installing some 4,000 MW of wind capacity by the year 2000 have been announced. [11] The large-scale deployment of turbines will permit further economics of scale in manufacturing and operations.

[11] J.C. Chapman, *European Wind Technology*, EPRI TR-101391 (Palo Alto, CA: Electric Power Research Institute, March 1993).

Market Development Initiatives

Various OECD nations have undertaken activities to support the commercialization of RETs. By encouraging commercialization of RETs, larger scale production can be initiated, allowing economies of scale to be realized. In turn, these economies lower the costs of RETs and allow still larger market opportunities to be tapped. This cycle will ultimately allow the creation of a large and cost-effective RET industry. Commercialization strategies now in use for wind and PV technologies include removing regulatory and institutional barriers; information programs to better inform key decisionmakers regarding renewables; demonstrating technically appropriate and cost-effective applications of the technology; and stimulating market demand through market conditioning demonstrations, large-scale government purchases, subsidies, low-interest loans, tax incentives, and other supports.

Photovoltaics

Market conditioning is specifically identified in the U.S. photovoltaic program as a key strategy element. Activities include education; technical assistance and training; market, economic, and financial analyses; technology characterizations; regulatory and value analyses; and codes and standards assessment and development. Efforts to improve the policy and regulatory framework include evaluation of transmission issues affecting PVs, development of integrated resource planning methodologies, and integration of environmental considerations into utility planning. There are similar market conditioning activities in other countries, including efforts by the Photovoltaic Power Generation Technology Research Association in Japan and the Future Energies Forum in Germany.

Demonstrations are intended to encourage market participation through example, proving a new technology application in the critical areas of appropriateness, reliability, cost-effectiveness, ease of maintenance, integration with existing systems, and so forth. The major PV evaluation program in the United States is the PV-USA project. Major demonstration projects in other countries include the "1,000 Roof" PV program in Germany, promoted with the use of subsidies; "model" facilities in Japan, which are supported through subsidies; and the PLUG modular 100-kW grid-connected PV systems in Italy.

Market subsidies[12] are intended to foster market development and growth to the point at which the market can operate without them.[13] In the United States, supports are limited to tax incentives, including five-year accelerated depreciation and a 10-percent investment tax credit for nonutility generators. At the current state of cost and performance in PVs, these provide only modest incentive for additional investment.

Italian subsidies support up to 80 percent of installation costs or provide buyback rates for peak periods of up to 28¢/kWh. In Japan they range up to two-thirds of the cost of residential systems, and buybacks rates for PV-produced electricity are reported to be as high as 24¢/kWh. Japan also offers a 7-percent tax credit for PV systems and low-interest loans with rates as low as 4.1 percent. Germany offers subsidies for system capital costs of up to 70 percent.

Wind

For wind energy development, the U.S. experience in the 1980s was with targeted investment tax credits. In effect, these favored installation of turbines over the production of power. They were phased out in the mid-1980s. The Energy Policy

[12] An important note with regard to subsidies is that they can translate into significant additional government support of PV technology beyond RD&D budgets. Determining the level of this support ranges from difficult to nearly impossible. Since most of the budgets described here include only on-budget line items, subsidy expenditures for hardware installation and power production (whether they take the form of cash support or tax relief) may provide a significantly higher level of support than could be fully described in this report.

[13] Of course, programs may take on a life of their own and live on after their intended purpose has been met.

Act of 1992 provides a 1.5¢/kWh production tax credit for wind-generated electricity, Subsidies have been used by Denmark and Germany in the form of stable power purhase prices, paying 85 and 90 percent of the retail price of electricity, respectively. In England. power purchase rates have been set at very attractive levels for certain periods, which has accelerated installations dramatically.

Country Programs and Market Share

Photovoltaics

The market for PV modules has been rapidly increasing and is expected to continue to do so for the foreseeable future (see table 7-2). Global market share trends indicate that U.S.-based production, after experiencing a decline through the mid-1980s, remained at 30 to 32 percent during 1990-92 and then jumped to nearly 37 percent in 1993.[14] Japan, which had 15 percent of the market in 1980, rose to 49 percent in 1986, and declined to 28.5 percent in 1993. The gains during 1980-86 were largely related to expanded sales of amorphous silicon technologies introduced through a number of consumer products. After 1986, the PV market began to shift from consumer product opportunities to power sector applications. European producers gained more of the market between 1986 and 1992, largely at the expense of Japanese firms. The combined market share of producers in the rest of the world has remained relatively constant since 1986.

Some of these PV firms have an international presence, with RD&D, manufacturing, sales, and other activities taking place in many countries. A number of foreign firms have also recently purchased U.S. PV producers. In March 1990, for example, Siemens A.G. of Munich purchased Atlantic Richfield Company's ARCO Solar.[15] This gave Siemens nearly 50 percent of U.S. photovoltaic shipments in 1992. In March 1994, Ebara Corporation of Japan purchased majority control of Blue Ridge Industrial Development Group, a spinoff from Westinghouse Electric that was commercializing dendritic web silicon PV.[16] In July 1994, Mobil Solar Energy Corporation, a Massachusetts-based producer of ribbon silicon PV cells, was sold to Angewandte Solarenergie GmbH of Germany, a joint venture whose parent companies include Daimler-Benz A.G. and the largest electric utility in Germany,[17] In November 1994, Solec International] was purchased by Sumitomo and Sanyo of Japan.[8] Together, these companies accounted for about 63 percent of the PVs manufactured in the United States in 1993 (see table 7-3).

The issue of "who is us" has appeared repeatedly in discussions of international competitiveness. Closely related is the question of the extent to which benefits-jobs, earnings, training, intellectual property-of federal assistance go abroad. whether transferred by a U.S. firm operating or sourcing offshore or by a foreign firm operating in and receiving benefits from the United States.[19] Maintaining U.S.-based production of PVs will likely require significant RD&D and investments in *advancd* automated production facilities, particularly as PV-production increasingly becomes a commodity production process.

[14]Paul D. Maycock, Photovoltaic Energy Systems, Inc., "International Photovoltaic Markets, Developments, Trends: Forecast to 2010," 1994.

[15]The agreement was announced In mid1989. See Richard McCormack, "Siemens Snare\ Arco Solar," *New Technology Week*. Aug. 7. 1989.

[16]"Japanese Firm, Westinghouse, Investors To Commercialize Dendritic Web PV," *Solar Letter*, vol. 4, No. 7, Apr. 1, 1994, pp. 76-77.

[17]"Mobil Announces Sale to ASE Americas, Venture of Deutsche Aerospace Nukem," *Solar Letter*, vol. 4, No. 17, Aug. 5, 1994, p. 186.

[18]"Sumitomo, Sanyo Acquire Solec: Financing and Marketing Aid Set," *Solar Letter*, vol. 4, No. 25, Nov. 11, 1994, p. 284.

[19]For a detailed discussion of these issues, see U.S. Congress, Office of Technology Assessment, *Multinationals and the National Interest: Playing by Different Rules*, OTA-ITE-569 (Washington, DC: U.S. Government Printing Office, September 1993).

TABLE 7-3: Photovoltaic Cell and Module Shipments, by Company (megawatts)

Company	1987	1988	1989	1990	1991	1992	1993
United States							
Siemens Solar	4 2	5 5	6 5	7 0	9 0	9 0	125
Solarex	2 9	3 2	5 0	5 4	5 6	5 7	6 5
Solec International	0 3	0 6	0 9	0 9	1 2	1 3	1 3
Advanced PV Systems					0 2	0 8	0 5
Astropower		01	0 2	0 4	045	0 6	0.9
Ussc	0 3	0 4	0 5	0 6	0 2	0 3	0 5
Mobil Solar/ASE GmbH	005	01	005	005	0 2	0 3	0 2
Entech			0 3	003	003	005	001
Other (Chronar)	0 9	1 2	065	042	0 2	01	
Total	865	11.3	141	148	171	182	22-1
Japan							
Sanyo	4 8	4 8	4 8	4 9	6 0	6 5	6 2
Kaneka	165	2 2	2 4	2 5	31	3 0	2 2
Kyocera	1 3	1 7	2 5	4.5	5 8	51	4 8
Talyo Yuden	12	1 3	1 5	1 6	1 6	1 6	1 6
Sharp	1 5	0 8	1 0	1 0	1 0	1 0	1 0
Hoxan	1 5	0 8	1 0	0 8	0 8	0 6	0 4
Fuji	0 5	0 5	01	01	01		
Matsushita				0 6	0 8	1 0	1 0
Other	0 7	0 7	0 9	0 8	0 6	oil	0 0
Total	132	128	142	168	198	188	173
Europe							
Deutsche Aerospace	0 8	1.3	1 2	1 7	21	2 6	2 6
BP Solar Systems	1 3	1 3	14	1 4	2 2	3 5	4 5
Naps France		1 0	0 7	0 6	1 0	0 6	0.5
Cnronar Wales		0 9	0 7	0 6	0 2	0 0	01
Photowatt (France)	1 0	0 8	0 8	1 5	1 8	2 0	1 7
Eurosolaire (Italy)	0 4	0 4	0 8	1 0	1 5	2 6	3 2
Helios (Italy)	0 3	0 3	0 8	12	1 5	2 0	1 0
Isophoton (Spain)	0 2	0 2	0 3	0 5	0 5	0 6	0 5
Siemens (Germany)	0 2	0 2	0 4	0 6	0 8	0 6	0 5
RES (Netherlands)			0 4	0 5	0 5	0.8	0 5
Other	0 3	0 4	0 4	0 6	1 3	11	12
Total	4 5	6 7	7 9	102	134	164	166
Rest-of-World							
CEL (Indua)	1 2	1 3	1 3	1 4	1.4	1 5	1 8
Sinonar (Taiwan)				0 6	0.4	0 4	NA
Heliodinamica (Brazil)	0 5	0 5	0 6	0 6	1 0	0 5	0 5
Reil (India)			0 5	0 5	0 5	0 5	NA
Bharat (India)	0 4	0 4	0 4	0 4	0 4	0 8	1 0
UDTS/HCR Algiers	—		0 3	0.3	0 3	0 3	NA
Venergia (Venezuela)			0 3	0 3	0 3		NA
Other	0 7	0 8	0 8	0 8	1 0	1 0	NA
Total	2 8	3 0	4 0	4 7	5 0	4 6	4.4

NA not avaiable

SOURCE: Paul Maycock, Photovoltaic Energy Systems, Inc., *Photovoltaic News*, vol. 12, No. 2, February 1993, and Paul Maycock, Photovoltaic Energy Systems, Inc., "International Photovoltaic Markets, Developments and Trends Forecast to 2010," 1994.

BERGEY WINDPOWER CO.

Six 10-kW wind turbines from Bergey Windpower, an 11.2-kW photovoltaic array from Siemens Solar, and a diesel power backup provide power for 150 homes in the village of Xcalac in Quintana Roo province, Mexico.

In general, the major PV RD& D programs have similar goals. all of which are aimed at producing PV modules and equipment that are cost-effective in the broadest array of' applications. In addition, activitits that faci1itatc PV tcchnology and market developmcnt have been adopted. many of which arc not included in a country RD&D budget. These include demonstrations. government purchases, market subsidies. low-interest loans, and tax incentives. Such facilitating support activities differ widely among countries and are examined below. Japan, Germany, Italy, and others offer more aggtrddivr supports than does the United States in many respects.

Wind

In 1992, European utilities and developers installed some 225 MW of wind capacity, while only 5 MW was instulled in the United States.[20] Europeans, either privately or through electric utilities, are investing $300 million to $500 million per year in wind cquipment and associated services, not including research and development (R&D).[21] More recently. several U.S. utilities have shown increased interest in wind energy.

In general, the goals of the wind RD&D programs are similarly focused on cost-efective wind turbine development and deployment, but emphases vary. Japan, Sweden, Canada, Italy, and Belgium have financially supported exploitation of the wind resource primarily as an R&D activity. In contrast, the United Kingdom, Dcnrnark, the Netherlands. and Germany have attcmpted to stimulate the market by subsidizing turbine installations and paying a premium price for power produced. The U.S. program is balanced between both approaches. Wind energy RD&D budgets arc listed in tuble 7-4.

It is now useful to examine country-specific programs in more dctail. U.S. programs arc discussed in chapter 5.

JAPAN[22]

Japanese R&D of new and altermative sources of energy has taken place under the framework of the Sunshine Project initiated in response to the first oil crisis. In 1993, the Sunshine Project was combined with, among others, the Moonlight Project. which focused on energy conservation technologies, and the Research and Development Project on Environmcntal Technology, which focused on reduction of carbon dioxide (CO_2) and other emissions, to form the New Sunshine Project.

The New Sunshine Project includes three initfatives[23]:

[20] American Wind Energy Association, *1993 Wind Technology Status Report: Wind Energy on Verge of Expansion in U.S.* (Washington, DC: 1994).

[21] "European Wind Generation To Top Billion kWp Mark in 1993," *Wind Energy Weekly*, Sept. 28, 1992, p. 5.

[22] This section is primarily drawn from Kennedy and Egan, op. cit., footnote 10.

[23] Environment Agency, Government of Japan, *Establishing a Basic Law on the Environment* (Tokyo, Japan: Oct. 20, 1992); and Jacob M. Schlesinger, "In Japan, Environment Means an Opportunity for New Technologies," *Wall Street Journal*, June 3, 1992, p. A1.

TABLE 7-4: International Government-Funded Wind Energy RD&D[a]

Year	United States	Japan	Germany	Italy	CEC[b]	Denmark	Netherlands	United Kingdom
1983	31.4	15	18.0	1.5	6 2	1,0	3.3	5.3
1984	265	1.5	160	1 9	8.5	4.5	7 6	7.1
1985	316	1.5	129	2 3	9 6	8.0	12,0	9 0
1986	25.8	2 0	12,9	5 3	9 7	8.0	177	9 5
1987	167	3 2	12,9	9 6	13,0	8 0	236	9 5
1988	8 5	2 0	135	155	13.0	8 0	236	10.0
1989	8.8	2 0	250	245	155	8.0	236	100
1990	91	2 9	29.5	304	200	8 0	258	195
1991	11 1	31	295	30.4	20,0	7 6	27.3	255
1992	21.4	6 5	168	33 0[c]	19,6	6.0	289	15.8
1993	240	7.7	222	330	19.6	6.0	326	15,8

[a]Including test stations for Germany the Netherlands the United States, Italy, and Denmark

[b]CEC . Commission of the European Communities Includes budgets for both the Directorate General for Science, Research and Development and the Directorate General for Energy

[c]According to Dan Ancona o! the U S Department of Energy, these figures may include some double counting of funds due to projects falling behind schedule Thus, the actual budget may be overstated for 1992 and 1993

SOURCE Ted Kennedy and Christine Egan International Activities Supporting Wind and Photovoltaic Energy, " report prepared for the Office of Technology Assessment Nov 8 1993

1. the Action Plan for the Prevention of Global Warming-focused on CO_2 reduction and an increase in the pace of development and application of alternative energy technologies;[24]
2. research under the New Earth 21 Program—focused on technological development and international cooperation on energy and environmental issues;[25] and
3. the Applications in Neighboring Developing Countries Program—focused on collaborative research and application, including support for feasibility studies, design, installation, operation, and evaluation of renewable energy and environmental technologies in less developed countries.[26]

The total budget for the New Sunshine Project through 2020 is $11.5 billion.[27]

Photovoltaics have been a major focus of Japanese efforts. Although, the budget for PVS under the New Sunshine Project declined from $53.5 million in 1991 to $51.8 million[28] in 1992, the

[24]New Sunshine Program Headquarters, Agency of Industrial Science and Technology, "Comprehensive Approach to the New Sunshine Program Which Supports the 21 st Century—Sustainable Growth Through a Simultaneous Solution of Energy and Env ironmental Constraints," *Sunshine Journal, No. 4, 1993;* and Hisao Kobiyashi, "PV Status and Trends in Japan," paper presented at Soltech 1992, Albuquerque, NM, Feb. 10-12, 1992.

[25]New Sunshine Program Headquarters, op. cit., footnote 24.

[26]Nobuaki Mori, "Collaborative R&D Program on Appropriate Technologies—Contribution To Reducing Constraints on Energy and Environmental Technologies in Developing Countries," *Sunshine Journal. No. 4, 1993,*

[27]Yoshihiro Hamakawa, "New Sunshine Project and Recent Progress *in* Photovoltaic Technology in Japan, " UNESCO Solar Energy Summit, Paris, France, July 1993; and Ichiro Tansawa, "Broad Area Energy Utilization Network System Project—Eco Energy City Concept," *Sunshine Journal, No. 4,* 1993.

[28]One reviewer reports a separate estimate of $48.1 million, based on a budget of 6.1 billion yen for "solar power" quoted in Joint publications Research Service, Foreign Broadcast Information Service, JPRS-EST-92-037-L, May 7, 1992, p. 46, and a conversion rate of $0.007888 per yen in 1992. Linda Branstetter, Sandia National Laboratory, personal communication, April 1994.

overall PV budget will increase as a result of new spending by the Agency of Natural Resources and Energy of $9.7 million on initiatives to facilitate "public use." In recognition of the importance of reducing balance of system costs, roughly 16 percent of the 1992 budget is aimed at systems-level development, including BOS components such as inverters, batteries, and mounting systems. The world's most comprehensive dedicated testing facility for grid interconnection of distributed systems-consisting of at least 100 small (2-kW) arrays-is at a site on Rokko Island.[29]

The New Energy and Industrial Technology Development Organization (NEDO),[30] funded by the New Sunshine Project, established a Photovoltaic Power Generation Technology Research Association (PVTEC) in November 1991. This semigovernmental agency has 26 members representing a broad range of Japanese industries. PVTEC encourages collaborative R&D among member companies as well as with other private sector, government, and academic institutions. PVTEC's programs focus on production technology of advanced PV cells; production technology of amorphous PV cells; superhigh-efficiency PV cells; research and analysis on commercialization; and investigation of the trends of industry and technology in photovoltaic power generation, supporting research, and other activities. PVTEC also seeks to be a major base of effective R&D overseas, working in close cooperation with foreign organizations.[31]

Japan has implemented major financial subsidies for photovoltaics. A 7-percent tax credit has been established for enterprises installing PV systems.[32] MITI had a fund of $3.7 million in FY 1993 for individuals installing home PV systems to obtain loans at a rate of 4.55 percent for 5- or 10-year terms.[33] An installer of a "model plant" (interpreted to mean power installations, not manufacturing facilities) may receive a subsidy of up to 50 percent of the installation cost. In 1992, the government set up an institution to finance PV installations at public facilities such as schools at two-thirds of the total project cost. A budget of approximately $6.5 million was reported for FY 1992[34] and $3 million for FY 1993.[35] Japan has also announced a plan to install four model plants in developing countries.[36]

MITI is also planning to support up to two-thirds of the cost of residential systems. The program goal is 1,000 homes the first year and up to 70,000 by the year 2000.[37] Some $39 million of the MITI FY 1994 budget was requested for this program. The 3-kW systems will be grid con-

[29] Dan Shugar, Pacific Gas and Electric Co., personal communication, 1993.

[30] NEDO was initiated in 1980 in response to the second oil crisis. It is responsible for intensive and effective promotion of, and is subsidized by, the Sunshine Project. In 1991, NEDO'S responsibilities were expanded from a strict energy security focus to include environmental security. See Takashi Goto, "Photovoltaic R&D Program in Japan (Sunshine Project)," paper presented at the Sixth International Photovoltaic Science and Engineering Conference Proceedings, New Delhi, India, Feb. 10-14, 1992, p. 521.

[31] Photovoltaic power Generation Technology Research Association, "Aiming at a Major Base of Research and Development of Solar Cells," Summary Sheet, n.d.; Seiji Wakamatsu, Photovoltaic Power Generation Technology Research Association, slide presentation, n.d.

32. "NEDO Supports Field Test program," *NEDO Newsletter*, August 1992.

[33] Kiyoko Matsuyama, New Energy and Industrial Technology Development organization, personal Communication to Ted Kennedy and Christine Egan, Meridian Corp., June 1993.

[34] NEDO Supports Field Test Program, Op. cit., footnote 32.

35 Matsuyama, op. cit., footnote 33.

[36] Paul Maycock, "Japanese Plan for Global Warming Stimulates Major PV Initiatives," *PV News, vol.* 11, *No.* 5, May 1992.

[37] Foreign Broadcast Information Service, "MITI To Subsidize Household Solar Power Generation Systems," *Pacific Rim Economic Review, vol. 2, No. 18,* Sept. 8, 1993, p. 7, citing *Nihon Keizai Shimbun*, Aug. 22, 1993.

nected, with excess energy sold back to the utilities.[38] If the 70,000-home goal is achieved, it would represent four times current worldwide annual production. Firms with access to this market would benefit hugely from economies of scale and learning.

Beginning in April 1992, utility companies were directed by the Japanese government to allow grid interconnection[39] of systems such as photovoltaics, wind turbines, and fuel cells and to purchase their excess power. Privately generated renewable energy is purchased by the utility at the highest marginal price paid by the user for power. This ranges from approximately 16¢ to 24¢/kWh.[40] Utility companies have set a goal of 2.4 MW and 150 sites, including rooftops, offices, and technical centers, by 1995.

Japanese development of wind systems has not been as aggressive as that for PV. About 23 wind turbines, totaling 3.2 MW, were designed and installed from 1982 through 1991 in Japan. Total capacity additions for the country are expected to be about 3 MW by 1995, and another 7 MW between 1996 and the year 2000, for a total of 10 MW. Practical R&D is conducted by NEDO and more theoretical research is performed by the Mechanical Engineering Laboratory. Resource assessment work has identified more than 20 prime wind resource sites within the country. Mitsubishi has, however, exported about 700 of its 250-kW machines to the United States, most of which were installed in California.

EUROPEAN UNION[41]

The European Commission (EC) programs for RD&D in renewable energy are conducted by the Directorate General for Science, Research, and Development (DG XII) and the Directorate General for Energy (DG XVII). The major programs arc JOULE II (focused on R&D and emphasizing photovoltaics, wind, and biomass with a total allocation of $70.8 million[42] for 1991 -94) and THERMIE (focused on demonstration and with a budget allocation of $424 million from 1990 to 1992 and a proposed budget of $181.8 million from 1993 to 1994). The Commission provides direct financial support on a cost-shared basis of up to 50 percent of project costs for R&D and up to 40 percent for demonstration.[43] ALTENER is a recently proposed program under the direction of DG XVII intended to focus on barriers to the development of renewable energy .44

U.S. industry competition within the European Union has in the past been constrained by EU directives that allow public purchasers in four sectors (water, energy, transport, and telecommunicate ions) to reject bids that have less than half EU content by value. Furthermore. if purchasers consider non-EU bids. they are required to give a

38 Paul Maycock, "Japan Mount\ 27 Year Conservation and Energy Plan," *PV News*, vol. 1 I , No. 10, October 1992.

39 Kobiyashi, op. cit., footnote 24.

40 Matsuyama, op. cit., footnote 33.

41 Formerly the European Economic Community, the name was changed in November 1993. This section is primarily drawn from Kennedy and Egan, op. cit., footnote 10.

42 Commission of the European Communities, Directorate General XII for Science, Research and Development, "Non-Nuclear Energy (JOULE 11) 1991- 1994," Information Package, pp. 10-11; and Wolfgang Palz, "The European Community R&D program on Photovoltaics," paper presented at the 10th European Photovoltaic Solar Energy Conference, Lisbon, Portugal. Apr. 8-12, 1991, p. 1369.

43 "The European Community and Wind Energy," *Wind Directions*, vol. 1 I , No. 3, winter 1991-92.

44 "Renewables Could Benefit from EC Tax on CO_2 Output," *Wind Energy Weekly*, Aug. 24, 1992; "European Carbon Dioxide Target Needs To Triple Renewables Use," *Solar Letter*, vol. 2. No. 18, Sept. 4, 1992: and "Europe Gets Clean Away," *Wind Power Monthly*, vol. 8, No. 9 , September 1992.

SAM BALDWIN, OTA STAFF

A photovoltaic pumping system near Ziniare, Burkina Faso. This system provides clean drinking water, reduces the labor of lifting and hauling water, and can help break waterborne disease cycles.

3-percent price advantage to goods and services of EU origin.[45] The latest round of the General Agreement on Tariffs and Trade (GATT) addresses some of these issues and commits signatories to follow a set of rules specifying open, nondiscriminatory procurement practices. It should be noted that EU directives do allow for equal treatment to be negotiated bilaterally or multilaterally.[46]

DG VIII (Development Fund) implements an international development program with activities in developing countries. The projects have included photovoltaic water pumping and electrification with $1.7 million in funding from the EC.[47] Donor country contributions, primarily from Germany and France, have increased the value of this program to U.S. $10 million to $20 million. In 1989, a project was initiated within the THERMIE framework to install PV pumping systems and other small-scale applications for use in the Sahel region of Africa. More than 1,300 pumps powered by 600-W to 3.5-kW PV arrays with a total PV capacity of nearly 2 MW were to be installed beginning in 1992. The EC contributed $39 million for this program.[48]

The EC RD&D objectives with regard to wind energy are to identify the Union's resources and to develop design and testing methods with a focus on large machines. Current expenditures are about $4.85 million per year.

The EU is considering a Europe-wide carbon tax on fossil fuels in order to reduce CO_2 emissions. Thus far, only Denmark has passed legislation enacting this type of tax, although several other countries such as Germany, the Netherlands, and Italy have considered similar measures. The renewable energy industry in Europe could benefit from a tax on CO_2 emissions. It should be noted, however, that European prices for electricity are often substantially higher than those in the United States without any carbon tax. For example, the price for electricity in the industrial sector in 1991 was 8.8¢/kWh in Germany compared with 4.9¢/kWh in the United States.[49] This allows RETs to be fully competitive at a somewhat earlier point in their development path.

To preserve competition within the European Union, implementation of a carbon tax is contingent on the introduction of similar tax measures by other OECD member countries.[50] Oil export-

[45] U.S. International Trade Commission, *The Effects of Greater Economic Integration Within the European Community on the United States,* USITC Publication 2204 (Washington DC: July 1989).

[46] U.S. International Trade Commission, The *Effects of Greater Economic Integration Within the United States: Second Follow-up Report,* USITC Publication2318 (Washington DC: September 1990); U.S. International Trade Commission, *The Effects of Greater Economic Integration Within the European Community on the United States: Fifth Follow-Up Report,* USITC Publication 2628 (Washington DC: April 1993).

[47] Palz, op. cit., footnote 42.

[48] M.S. Imamura et al., *Photovoltaic System Technology: A European Handbook* (Brussels, Belgium: Commission of the European Communities, 1992).

[49] U.S. Congress, Office of Technology Assessment, *Industrial Energy Efficiency, OTA-E-560* (Washington, DC: U.S. Government Printing Office, August 1993).

5@' Renewables Could Benefit from EC Tax on CO_2 Output," op. cit., footnote 44.

ers to the EU have threatened retaliatory trade action if the community pushes ahead with this proposal.[51]

DENMARK[52]

In 1973, Denmark was 99-percent dependent on imported energy supplies, mainly oil. As a result of new energy policies, Denmark's annual gross energy consumption is lower now than in 1972, and its dependence on imported oil is less than 50 percent of the energy supply.[53] The Energy 2000: Plan of Action for Sustainable Development now serves as the foundation of Denmark's energy policy.[54] Its goal is to reduce energy use and atmospheric emissions by 2005 by reducing energy consumption by 15 percent, CO_2 emissions by at least 20 percent, sulfur dioxide (SO_2) emissions by 60 percent, and nitrogen oxide (NO_x) emissions by 50 percent. Use of renewable energy is expected to double. As part of this goal, the government has committed to further promotion of wind power. The plan estimates an installed capacity of 1,500 MW in 2005, corresponding to 10 percent of the expected electricity consumption.[55]

Installed wind power capacity in Denmark is currently between 670 and 730 MW; wind power supplies approximately 2.3 to 2.6 percent of its total electricity.[56] Wind energy development ' n Denmark has followed two paths: the development of small wind turbines through private initiatives on an individual or collective basis, and the development of large wind turbines and windfarms by Danish utilities.[57] PV is not a major focus of the Danish renewable energy program.

The Danish wind energy program was initiated in 1977. Government support for R&D has been limited. The RD&D program is funded by both the Ministry of Energy at $1.6 million/year and the Ministry of Industry at $2.4 million/year. Most of the support has gone to the Riso Test Station, with a small portion allocated to universities and miscellaneous RD&D projects. The overall Danish wind program during the 1980s cost about $95 million.[58] The Danish government has opted to pursue direct market stimulation in the form of subsidies rather than implement an extensive R&D program.

The private sector has contributed significantly to the development of wind technology, and rough estimates suggest that total private contributions toward wind development are of the same order of magnitude as government programs.[59] Additional support is provided by the utilities.[60] In December 1985, Danish utilities entered an agreement with the government to develop 100 MW of wind power capacity by the end of 1990; the 100-MW goal

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[51] "European Official Raps U.S. Stance on Carbon Dioxide," W/rid *Energy Weekly, vol. 11, No. 493,* Apr. 13, 1992, p. 4.

[52] This section is primarily drawn from Kennedy and Egan, op. cit., footnote 10.

[53] Finn Godtfredsen, "Wind Energy Planning in Denmark, " paper presented at the European Wind Energy Association (EWEA) Special Topic Conference on [he Potential of Wind Farms in Denmark, Denmark, Sept. 8-11, 1992.

[54] Danish Ministry of Energy, "Energy 2000--A Plan of Action for Sustainable Development," April 1990; and ibid.

[55] Jens Kr. Vesterdal, "Experience with Windfarms in Denmark," paper presented at the EWEA Special Topic Conference on the Potential of Wind Farms in Denmark, Denmark, Sept. 8-11, 1992.

[56] Birger T, Madsen, "The Danish Wind power Industry, " paper presented at the Wind Power 199 l Conference, 1991, p. 82; Godtfredsen, op. cit., footnote 53; and ibid.

[57] Vilhem Morup-Pedersen and Soren Pedersen, "Windfarm Projects Joint Ventures Between a Danish Utility and Private Cooperatives," paper presented at the EWEA Special Topic Conference on the Potential of Wind Farms in Denmark, Denmark, 1992.

[58] "Renewable Energy is Key Part of Global policy, Danes Say," *Wind Energy Weekly, vol. I* 1, No. 480, Jan. 13, 1992, pp. 3-4.

[59] Danish Ministry of Energy *Wind Energy in Denmark: Research and Technological Development* (Copenhagen, Denmark: 1990).

[60] Ibid.; Danish Ministry of Energy, "Development of Wind Energy in Denmark," paper presented at the World Renewable Energy Congress 11, Reading, England, Sept. 13-18, 1992.

was achieved by the end of 1992.[61] In March 1990, the Danish Parliament asked the utilities to develop an additional 100 MW of installed capacity by the end of 1993.

Until the end of 1990, Danish utilities bore 30 percent of the cost of grid connection for private wind turbines with a ceiling of $54.50/kW installed.[62] A new approach requires that the sometimes substantial costs of reinforcing the grid due to connection of new windmills be paid by the electric utility companies, while the cost of connecting to the grid be covered by the wind powerplant owner.[63] This has been controversial. For a time it appeared that the utilities would be successful in shifting more of the cost of grid connection back onto wind turbine owners, and requiring them to pay 65 percent of the costs of strengthening the grid, if necessary. It appears that the owners' association has prevailed in this battle since reports indicate that the cost of grid connection has been made the responsibility of the utilities.[64]

Danish wind energy incentives were introduced approximately 10 years ago. Initially each wind turbine erected by private companies received a government payment of 30 percent of capital costs. This subsidy was reduced gradually as the costs of wind energy declined, and it was discontinued in 1989. Under this payment program, approximately 2,500 wind turbines with a total capacity of 205 MW were installed.[65] In late 1992, a new subsidy program to stimulate investment in wind power was initiated. The program guarantees private turbine owners a buyback rate equivalent to 85 percent of the pre-tax price at which local electricity companies sell power to customers, and it obligates utilities to purchase the power.[66] The wind power purchase price ‘ill average 6¢/kWh.[67]

Denmark has an energy tax levied at 4.9¢/kWh. Until May 1992, this tax was refunded to renewable energy power producers in the private sector at a level of 4¢/kWh. The tax relief was structured so as to reflect avoided costs.[68] The value of the electricity tax was added to the payment that owners of wind turbines received for supplying wind-generated electricity to the grid.[69] Electricity produced by wind turbines owned by electric utilities was not exempted from taxation.

A private individual or group of individuals pays taxes only on income from the sale of those wind power kilowatt-hours generated in excess of domestic consumption of electricity with a 10-percent margin.[70] Private turbines receive a grant amounting to 4.3¢/kWh as part of a CO_2 tax package, replacing the refund of a standard electricity tax described above. According to a press release of the EC, the combined guaranteed buyback rate and the grant "will give windmill operators an average subsidy of around 55 percent of building and operating turbines." Altogether, $19.7 million was channeled to turbine operators by the program in 1992.[71]

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61 International *Energy Agency, Wind Energy Annual Report* (Paris, France: 1992).

62 Andrew Garrad, European Wind Energy Association, "Time for Action: Wind Energy in Europe," October 1991.

63 European Commission, "Commission Approves Price Support for Wind Power," press release, Sept. 30, 1992.

64 "Minister Rules Against Single Turbines and for Grid connection Charges," *Wind Power Monthly, vol. 8, No. 3,* March 1992.

65 American Wind Energy Association, "European Wind Energy Incentives," Feb. 19, 1992.

66 European Commission, op. cit., footnote 63.

67 "Developers Wait Anxiously for Brussels Approval Of New Regulations," *Wind Power Monthly,* vol. *8, No. 8,* August 1992.

68 Garrad, op. cit., footnote 6*.

69 Danish Ministry of Energy, Op. Cit., footnote 54.

70 Ibid.; and Garrad, op. cit., footnote 62.

71 European Commission, op. cit., footnote 63.

Shareholders in wind plants also reclaimed the value-added tax (VAT) paid on their power of 22 to 25 percent in 1992. Private owners of turbines supplying power directly to their properties could not reclaim the VAT.[72]

In 1990, the Danish government, in cooperation with Danish wind turbine manufacturers and two Danish financing companies, created a private company called Danish Wind Turbine Guarantee to offer long-term financing of large projects using Danish wind turbines. Financing periods depend on project value and run from 8.5 to 12 years. The Danish program will guarantee repayment of loans on Danish wind turbine projects for a 2.5-percent premium added to the interest on the debt, for up to 20 percent of the financed amount. The price of the guarantee is built into the cost of the wind project. The guarantees are underwritten partially by the government and partially by the limited-risk shareholder company set up to administer them. The company's share of the capital is $6.38 million, and is supported by a guarantee of U.S. $110 million from the Danish government and income from sale of the guarantees and interest earned on investment of the shareholder capital.[73]

This loan guarantee program significantly reduces the risk in selecting Danish units for a wind plant. If the units should become uneconomical to operate in the future, a company could shed the added debt service burden. It is an attractive tool to boost export sales and has been used by the American company Zond on a recently completed project in California.[74] This financing is not available within the EU, however, due to the EU decision that it was a form of unfair competition.[75]

In the early 1980s. wind turbine sales were based primarily on a subsidized home market. During this time, the Danish wind industry was characterized by more than 20 small companies producing 55-kW wind turbines. As of 1989, there were six significant manufacturers of wind turbines (see table 7-5). In the mid-1980s, exports became important. Danish wind turbines have been installed in 30 countries around the world. The market distribution of Danish wind turbine exports in 1990 was California, 64 percent; Germany, 19 percent; Spain, 5 percent; India, 4 percent; Netherlands, 3 percent; Sweden, 2 percent; and others, 3 percent.[76] By the end of 1991> 'ore than 8,300 Danish wind turbines with a total capacity of approximately 840 MW had been installed abroad.[77] Development assistance for wind energy projects, usually tied to Danish equipment, has been offered by DAN IDA (Danish International Development Agency) to various developing countries including India, Egypt, China, and Somalia.

FRANCE[78]

RD&D in renewable energy is the responsibility of the Agency for Energy and Environment Management (ADEME), which funds and coordinates R&D with programs undertaken by industrial partners and other public organizations. For example, in collaboration with the state-owned utility, Electricity de France (EdF), ADEME is sponsoring a program for 20 isolated homes to generate electricity from photovoltaic panels and/or wind turbines. The FY 1993 renewable energy

72 "Danes Use Carbon Tax To Pay for Wind," *Wind Power Monthly*, vol. 8, No. 6, June 1992.

73 Madsen, op. cit., footnote 56.

74 Ibid.

75 See ibid; and "If You Can't Beat Them Join Them," *Wind Power Monthly*, vol. 8, No. 1, January 1992.

76 Madsen, op. cit., footnote 56: Danish Ministry of Energy, Op. cit., footnote 59.

77 Godtfredsen, op. cit., footnote 53.

78 This section is primarily drawn from Kenned, and Egan, op. cit., footnote 10.

TABLE 7-5: Principal Manufacturers of Grid-Connected Wind Turbines

Manufacturer	Country	Turbines produced through end of 1989
US Windpower	United States	**3,500**
Mitsubishi	Japan	**500**
Vestas/DWT	Denmark	**2,800**
Micon	Denmark	**1,600**
Bonus	Denmark	**1,250**
Nordtank	Denmark	**1,100**
Danwin	Denmark	**300**
Windworld	Denmark	**102**
HMZ/Windmaster	Belgium/NL	**269**
Nedwind-Bouma	Netherlands	**58**
Nedwind-Newinco	Netherlands	**68**
Lagerwey	Netherlands	**125**
Holec	Netherlands	**19**
MAN	Germany	**321**
Enercon	Germany	**35**
MBB	Germany	**29**
Elektromat	Germany	**15**
HSW	Germany	**9**
WEG	United Kingdom	**27**
WEST	Italy	**35** (end of 1991)
Riva Calzoni	Italy	50 (end of 1991)
Ecotecnia	Spare	NA
Voest	Austria	NA

NA = not available

SOURCE A J M van Wik et al , *W/rid Energy Status, Constraits and Opportunities (L0ndon,England* World Energy Council, Study Group on Wind Energy, July 1992), sitxth draft

budget was $18.7 million, a 15-percent increase over the 1992 level of funding.

In France, PV is considered among the more promising of the renewable energy alternatives for rural electrification and remote offgrid applications. The year 1991 was a turning point for the French photovoltaic R&D program with the start of “PV20,” a new R&D program that has the following goals for the year 2000: a 20-percent conversion efficiency for crystalline silicon solar cells; $3.50/W (20 francs) as the installed price of a 100-kW grid-connected plant that is assembled and installed by the utility; a system lifetime of 20 years given basic maintenance; and 20 MW per year manufactured in France. Under the framework of PV20, an R&D program was initiated for the 1992-96 period.

France has some excellent wind resources, but its program is small. France expected to reach 5 MW of wind generation capacity by the end of 1993 and 12 MW by the end of 1994, and has set a target of 500 MW by the year 2005.[79] France has approved construction of the country’s first commercial wind powerplant. Electricity de France has agreed to buy wind-generated electricity from

[79] Paul Gipe, "The Race for Wind," *Independent Energy*, July/August 1993, pp. 60-66

independently owned turbines. EdF will now pay an average of 6¢/kWh. EdF will also assist ADEME in mapping the country's wind resource as well as identifying sites for future plants.

GERMANY[80]

Germany spends more on renewable energy than any other country in Europe. In 1992, its federal budget for renewable energy was approximately $216 million; this does not i include spending by the states, which is substantial for some technologies such as wind energy, The national renewable program is focused on solar, wind, and biomass energy technologies, with a strong bias toward PV. In 1992, the government spent $65.4 million on RD&D in PVs[81] compared with $17.6 million on wind. The government program is supplemented by substantial state (up to 30 percent of a project's total cost in Bavaria[82]) and utility support, as well as other financial support. This financial support includes credits/loans through the Energy Savings Program and the Credit Program To Promote Community Investment: and the "Law on Supplying Electricity to the Public from Renewable Energy Sources," which requires public purchase and compensation for electricity generated by small wind or solar systems at a rate of at least 90 percent of the consumer price.[83]

The Law on Supplying Electricity has had the effect of raising the national tariff for wind and PV paid by the utilities, from 7¢~ to 11 ¢kWh.[84] Compensation at these rates is not required if it can be proven to cause ".. . undue hardship or prevent the electric companies from meeting their federally mandated obligations. Undue hardship exists if the electric company must raise its prices significantly above the market rate."[85]

In November 1990, the federal government established a goal of decreasing CO_2 emissions by 25 to 30 percent from the 1987 level by the year 2000, which could stimulate the use of renewables.[86] A proposal has been introduced to initiate a CO_2 tax on conventional energy sources; this has been postponed pending development of related initiatives by the EU.[87]

The German PV program is strongly R&D-oriented but has begun to focus more on demonstration projects, which increased from 5 percent of the PV budget in 1989 to 16 percent in 1991. The " 1,000 Roof' program, initiated in 1990, is a demonstration project that is expected to result in 2,250 systems of 1 to 5 kW capacity on roofs of

80 This section is drawn primarily from Kennedy and Egan, op. cit., footnote 10.

81 A. Rauber and K. Wollin, "Photovoltaic R&D in the Federal Republic of Germany," paper presented at the 6th International Photovoltaic Science and Engineering Conference. New Delhi, India, Feb. 10- 12, 1992, p. 529.

82 "Bavaria Takes Up the Challenge," W/rid *Power Monthly*, vol. 8, No. 7, July 1992.

83 Compensation for hydropower, municipal solid waste, and agricultural and forestry residues must be at least 75 percent of the average rate per kilowatt-hour paid by consumers.

84 German Federal Ministry of Research and Technology, "Law on Supplying Electricity to the Public from Renewable Energy Sources (Electricity Supply Law)," translation in summary of German Government Document No. 66090, Oct. 5, 1990; American Wind Energy Association, op. cit., footnote 65; and P. Mann et al.. "The 250 MW Wind Energy Program in Germany," paper presented at the Wind Energy Technology and Implementation European Wind Energy Conference, Amsterdam, The Netherlands, 1991.

85 German Federal Ministry of Research and Technology, op. cit., footnote 84.

86 The citizens group Germanwatch (established to monitor German\'s action on environment and development issues) released a study on April 7, 1992. that stated that the country would fall short of stated goals for reduction of CO_2 emissions and predicting that Germany will achieve CO_2 emission cuts of only 10 percent by the year 2005. See "Germany Won't Achieve Goal Environmental Group Says," *Wind Energy Weekly*, vol. 1 I. No. 494, Apr. 20, 1992, pp. 5-6.

X7 Armin Rauber, Fraunhofer Institute of Solar Energy, personal communication to Ted Kennedy and Christine Egan, Aug. 18, 1992.

private homes. Participants receive a direct federal subsidy of 50 percent in the western states and 60 percent in the new eastern states. Approximately 20 percent of the cost of the system is subsidized by state govemments.[88] A limit has been set to a total subsidy of 70 percent of the system cost. This grid-connected application also allows owners to sell unused power to the utility at 12¢/kWh. The program is accompanied by a comprehensive measurement and evaluation program. The budget for the "1,000 Roof' program from 1990 to 1995 is approximately $55 million. This figure is incorporated in the Federal Ministry of Research and Technology (BMFT) annual budget figures. As of January 31, 1992, this program was opened to non-German manufacturers within the EU with the appropriate business permits.[89] Interest in the program was very high, but reportedly moderated in 1993.

The development of wind power has been supported by BMFT since 1975 through cost-shared wind-related RD&D. Germany has a national goal of 1,000 MW of installed wind power capacity by 2000. The installed wind power capacity at the end of 1991 was 110 MW, which had increased to 333 MW by January 1994.[90] BMFT provides approximately 50 percent of the total cost of all wind-related RD&D projects, with additional funding provided by the states and the EU.[91] These figures exclude the 250-MW demonstration program, which was reportedly allocated a total budget of$215 million.[92] Wind also receives a 10¢/kWh incentive for grid-connected machines and additional subsidies from several states. Other initiatives are expected.[93]

Under the "250-MW" demonstration program, wind installations are subsidized either through a price incentive of 3.7@ to 5¢/kWh[94] or a one-time capital investment grant of up to 60 percent of the facility cost.[95] By May 1991, more than 2,300 applications for 4,200 systems with a total capacity of 520 MW had been submitted.[9G] By the end of July 1992, 545 turbines representing an installed capacity of 89 MW were operating under the government program. Some 690 turbines had been installed as of December 1992 under the program, with a capacity of approximately 110 MW.[97] As of March 1993, expenditures for the 250-MW program totaled $24.6 million.[98]

Special low-rate bank loans from two central pools contribute significantly to wind power's fi-

88German Federal Ministry for Research and Technology, "Extension of Deadline for Applicants from the New German States for the 1000-Roofs Photovoltaics Program," press release, Jan. 31, 1991; and Rauber and Wollin, op. cit., footnote 81.

89Ibid.

90 Randy Swisher, American Wind Energy Association, personal communication, May 1994.

91International Energy Agency, *Wind Energy Annual Report* (Paris, France: 1991).

92International Energy Agency, op. cit., footnote 61; "Guidelines for the Promotion of Wind Turbines Under the 250 MW Program and Within the Framework of the Third Program for Energy Research and Technology," translation in summary of the German Government document, Feb. 22, 1991.

93"New Program in the Pipeline," *Wind Power Monthly, vol. 8. No. 7,* July 1992.

94An operator of a stand-alone machine receives 5¢/kWh for power consumed by the operator, and operators of grid-connected turbines receive 3.7¢/kWh, as well as the compensation paid by the utility equal to 10¢/kWh. Payment of this incentive ceases when the sum of the avoided electricity costs, electricity sales, and public subsidies (including those of the EC) reaches double what it cost to build the wind energy facility.

95Mann et al., op. cit., footnote 84.

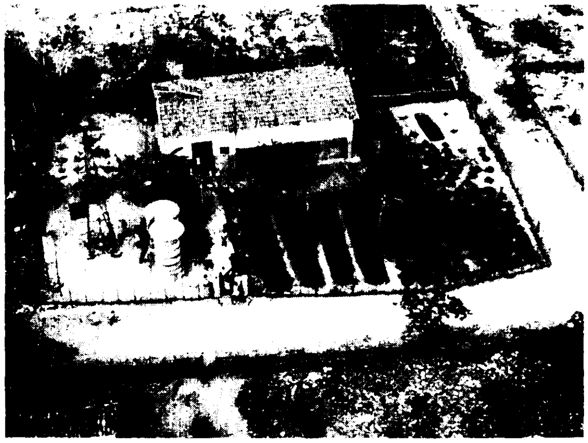
96Ibid.

97German Federal Ministry of Research and Technology, "Promotion of Wind Energy by the Federal Ministry of Research and Technology," translation in summary of the German Government document, March 1993.

98Ibid.

nancial support. Kredistanstalt fur Wiederaufbau and Deutsche Ausgleichsbank operate behind the scenes to offer credit schemes for wind power development, resulting in interest rates as low as 8 percent[99] compared with standard rates of around 15 percent (as of July 1992; assumed to be the nominal rate) or a rate subsidy of nearly half. Borrowing procedures are simple, and loans often come through faster than planning permission. The bank assumes the risk in exchange for the 1 percent interest rate it levies.[100]

International development is supported under the five-year Eldorado Program initiated in October 1991, which provides for wind and PV energy projects in developing countries through investment subsidies with a maximum of 70 percent of the equipment price. German-based manufacturers and suppliers of plants and systems are eligible.[101] The subsidies are granted directly to the manufacturer of the equipment rather than the project operator, with the hope that the manufacturer will be more likely to protect its reputation, and the reputation of the technology, by making sure the project succeeds.[102] Transportation from Germany to the site is subsidized 70 percent, and a scientific measuring and evaluation program is supported.[103] As of February 1993, six Eldorado Wind projects with a total capacity of 4.5 MW had been contracted with Chinese, Brazilian, Russian, and Egyptian counterparts and one Eldorado Sun project was supported in the Peoples Republic of China, including four PV pump systems of 4.8 kW, four battery chargers without inverters (1.1 kW), and 16 battery chargers with inverters (43.8 kW)



NATIONAL RENEWABLE ENERGY LABORATORY

In the state of Ceara in northeast Brazil, the village of Cardeiros has been the site of early PV deployments. The photo shows the village school with individual PV power systems for lighting and TV, refrigeration, street lighting, and water pumping.

ITALY[104]

In 1988, all the existing nuclear powerplants in Italy were shut down and all plans for the construction of new nuclear facilities were halted.[105] Renewable energy is viewed as the most plausible option for decreasing dependence on imported fossil fuels and protecting the environment. The Italian National Energy Strategy (PEN) sets national goals for the installed capacity of renewable energy. For PVs, goals of 25-MW installed capacity by 1995 and 50- to 75-MW

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[99] Rates are typically 7 to 7.5 percent, with a 1-percent loan origination fee.

[100] "Financial Packaging," *Wind Power Monthly, vol. 8, No. 7,* July 1992.

[101] German Federal Ministry of Research and Technology, "Guideline for the Promotion of Piloting Wind Power Plants Under Various Climactic Conditions," translation in summary of the German Government document, Oct. 23, 1991.

[102] "Seeking New Horizons," *Windpower Monthly,* vol. 8, No. 1, January 1992.

[103] German Federal Ministry of Research and Technology, "The Eldorado Test and Demonstration of Wind and Photovoltaic Systems Under Different Climactic Conditions," n.d.; "Staying Power Needed To Reach El Dorado," *Wind Power Monthly,* vol. 8, No. 9, September 1992; and "German Wind Power in Brazil," *Solar Energy Intelligence Report, vol. 19, No. 3,* February 1993.

[104] This section is drawn primarily from Kennedy and Egan, op. cit., footnote 10.

[105] The moratorium ended in December 1992, but it is unclear whether the industry will be revived. Branstetter, op. cit., footnote 28.

installed capacity by 2000 have been outlined. When the goals were established in 1991, the installed capacity was 3 MW. For wind power, PEN has established a target of 300 to 600 MW by the year 2000,[106] with an interim goal of 60 MW of installed capacity by 1995. [107] In December 1992, Italy's wind generating capacity was approximately 6 MW, another 14 MW were under construction, and nearly 20 MW were expected to be in operation by the end of 1993. [108]

The Italian renewable energy program is a joint effort of the Agency for Research and Development on Nuclear and Alternative Energies (ENEA) and the National Electricity Board (ENEL). In 1989, ENEL launched a demonstration program including two major initiatives: testing of Italian turbines and foreign turbines side by side in a marine environment at the Alta Nurra test site and in mountainous terrain at the Acqua Spruzza test site; and development of two full-scale windfarms (each equipped with 40 machines supplied by Italian manufacturers), one in Monte Arci in Sardinia and another at Acqua Spruzza. ENEA carries out the bulk of the PV R&D activities, with a focus on research into innovative materials and devices. ENEL works with ENEA on systems development and demonstration programs.

RD&D initiatives are supplemented by Law No. 10 passed on January 9, 1991, which determined the use of renewable energy to be in the "public interest" and provides for grants to public authorities, private companies, and state organizations. For wind turbines or windfarms with a capacity of 3 MW, investment subsidies of up to 30 percent of the capital expenditure are available. For PVs, subsidies of up to 80 percent of the capital expenditure are available for isolated houses. Demonstration plants in both technologies are eligible for a 50-percent subsidy. [109] A similar subsidy, limited to rural residences inhabited by those engaged in agriculture, was contained in a previous law instituted in 1982. Significant results came of this support, including the electrification of 4,100 rural dwellings and a total installed capacity of 1,850 kW of PV systems.

In June 1992, the Interministerial Committee on Prices passed a new law on the price paid by ENEL for electricity produced by renewable energy. New PV equipment can now receive 20@ to 28¢/kWh, and new wind equipment can receive 14@ to 17¢/kWh. Payment is determined by whether the power is dedicated to the grid or whether only excess capacity is provided, and is adjusted further for peak or offpeak production and capacity factors.

NETHERLANDS[110]

The wind energy program in the Netherlands includes RD&D supported by the Ministry of Economic Affairs through the Netherlands Agency for Energy and the Environment. It also includes direct funding of research institutions such as the Netherlands Energy Research Foundation.

The Integral Wind Energy Plan (IPW), which was in existence from 1986 to 1990, was the first government program to engage in direct market stimulation in the form of capital cost incentives based on installed kilowatts. In 1989, the investment subsidy was between 37 and 45 percent of the project cost, with a maximum of $600 to $740/kW installed. In 1990, the subsidy was reduced to 35 to 40 percent, with a maximum of $545 to $600/kW. In both cases, the percentage depended on the nonprofit or for-profit status of

[106] American Wind Energy Association, op. cit., footnote 65.

[107] "Italian Federal Wind Program Begins To Gather Momentum," *Wind Energy Weekly,* vol. 11, *No.* 525, Dec. 7, 1992, pp. 2-4.

[108] Ibid.

[109] G. Ambrosini et al., "Programs for Wind Energy Exploitation in Italy: A Progress Report," paper presented at the Windpower 1991 Conference, Palm Springs, CA, Sept. 24-27, 1991; "Renewable Energy Incentive Gets Approval," *Wind Directions,* winter 1991.

[110] This section is drawn primarily from Kennedy and Egan, op. cit., footnote 10.

the company. An environmental/low-noise-pollution subsidy was offered in the amount of $55/kW installed in 1989 and $27/kW installed in 1990. In 1990,$25 million was available through the IPW program.[111] A total of 127 MW of wind power capacity was installed under this program: 58 percent by utilities, 24 percent in commercial applications (including farming), 14 percent by private investors, and 4 percent by family cooperatives.[112] Total wind capacity in 1992 was expected to be 130 MW.

In January 1991, the Application of Wind Energy in the Netherlands (TWIN) program was initiated. TWIN is based on the official government position developed in the Energy Conservation Policy Paper and the National Environmental Policy Plan, which together set ambitious goals for energy conservation and supply diversification. These include the development of 1,000 MW of wind power by the year 2000, with $300 million allocated to the first 400 MW, to be followed by additional support for the remaining 600 MW. A goal of 2,000 MW of installed wind power capacity by 2010 is outlined. Most of the funds for wind power development are provided by the Ministry of Economic Affairs ($22.29 million in 1992), and the Ministry of Housing, Physical Planning and the Environment ($820,000 in 1992).

Technological development is conducted under TWIN to ensure continuing product development, with a goal of a 30-percent improvement in the price performance ratio and an electricity cost of 14¢/kWh. Wind turbine owners in the TWIN program receive a capital cost subsidy of up to 40 percent as determined by the rotor swept area. A bonus payment from the Environment Ministry is offered for low-noise wind turbines[113] and for turbines sited in specially approved, less environmentally sensitive areas. Additionally, 50 percent of the cost of feasibility y studies can be covered, up to $31,250. Information dissemination, outreach/education, assessment of the existing program against international and market developments, and promotion of international cooperation are also conducted under TWIN.

The utility sector has developed an Environmental Action Plan to install 250 MW of wind power in the Netherlands in 1991-95. The eight power distribution companies combined to form an organization called the Windplan Foundation with plans to construct most of the 1,000-MW goal of the TWIN program. The objectives of Windplan are the coordination of a combined investment program of 250 MW of windfarms within the next five years, coordination of a purchasing program for wind turbines, and support of the development of wind turbine technology.[114] In addition, the utilities pay tariffs to turbine owners ranging approximately from 6.8@ to 10.6¢/kWh depending on the province.[115]

The power distribution company for the Netherlands provinces of Gelderland and Flevoland, PGEM, has more than doubled the tariff it pays for wind power to private owners of turbines up to 3 MW. Beginning in 1993 for a period of 10 years the utility will pay new installations 8.8¢/kWh. The new policy of PGEM apparently offers support to the Association of Private Wind Turbine Owners (PAWEX). PAWEX is in the midst of a drawn-out conflict with the Association of Distribution Companies (VEEN) over the tariffs paid for wind power in the Netherlands. VEEN claims that 3.5@ to 3.7¢/kWh, the equivalent of the cost of fuel saved by the use of wind power, is a fair rate.

[111] Joe Beurskens, "Wind Energy in the Netherlands," compiled for the 1990 Annual Report of the International Energy Agency, Large-Scale Wind Energy Conversion Systems Executive Committee, 1990.

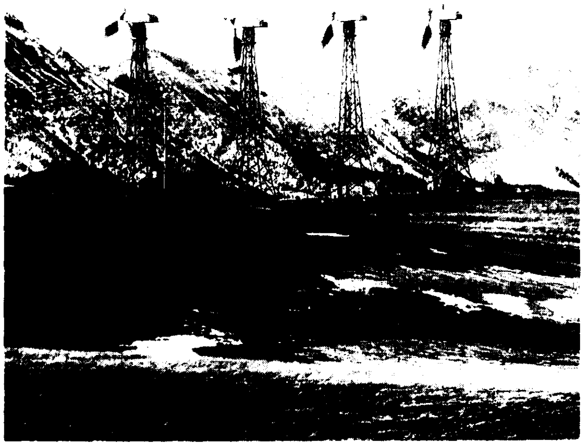
[112] American Wind Energy Association, op. cit., footnote 65.

[113] "Private Developers Granted Larger Share of Subsidy Cake," *Wind Power Monthly, vol. 8, No. 2,* February 1992.

[114] OTA has received word that the Windplan program had been substantially cut back, but details are not available.

[115] "One Thousand Extra Turbines in Four Years," *Wind Directions*, winter 1991.

KENETECH WINDPOWER INC



Kenetech Windpower, Inc., 33M-VS wind turbines on Cowley Ridge in Alberta, Canada.

PAWEX wants the utilities to also pay for the avoided cost of environmental damage and claims that a tariff of 10.6¢/kWh would be more reasonable. The conflict is now in arbitration. Until December 1991, PGEM followed the VEEN guidelines, but it has changed its policy to "express its appreciation for the environmental advantages of wind power." Members of VEEN in Friesland and PEN in Noors pay 6¢ and 8¢/kWh, respectively.[116]

An estimated 25 MW will also be installed by private investors in 1991-95.[117] Opportunities for wind turbine installation by private individuals were significantly improved in 1992, following changes in the regulations governing wind power subsidies.

Of the 250 MW of wind capacity Windplan intends to install, it invited non-Dutch manufacturers to bid for only 80 MW, providing Dutch companies a significant advantage. It is not clear how this action—with more than 2,600 turbines installed in the Netherlands, none imported as of 1991—fits within the framework of EU regulations.[118]

Kenetech-U.S. Wind Power, a privately held American company, has signed a contract to build and operate 25 MW of wind energy turbines for a utility in the Netherlands. U.S. Wind Power will finance, install, and operate the turbines and, under a power purchase agreement, will sell its output of 60 million kWh of electricity a year to NV Energiebedrijf, which serves the provinces of Gronigen and Drenthe. The machines are scheduled to be online by the end of 1994. Actual construction may be performed by a Dutch company rather than Kenetech's construction subsidiary, but no transfer of technology is presently planned.[119]

SWITZERLAND[120]

In September 1990, Switzerland's citizens voted for a three-pronged energy policy: a moratorium was declared on the construction of new nuclear plants for 10 years; existing nuclear plants were to continue to operate; and the Federal Ministry of Energy and the states (cantons) were given a mandate to pursue a more intensive energy policy promoting conservation and renewable. As a result, an action plan, "Energy 2000," was initiated. As of early 1993, funds had not been allocated specifically to the Energy 2000 program, and it is not yet clear what initiatives will be developed for PV or

116 "Utility Doubles Rate of Pay," *Wind Power Monthly, vol. 8, No. 1,* February 1992.

117 E. Luke and R. de Bruijne, Netherlands Agency for Energy and the Environment, "The Netherlands Wind Energy Stimulation Program: The Success of a Continuous Effort," paper presented at the Wind Energy Technology and Implementation European Wind Energy Conference, Amsterdam, 1991.

118 "One Thousand Extra Turbines in Four Years," op. cit., footnote 115.

119 "USW T. Supply Windpower to Netherlands Utility," *Solar Energy Intelligence Report,* vol. 18, No. 14, July 13, 1992.

120 This section is drawn primarily from Kennedy and Egan, *op.* cit., footnote 10.

wind power. The budget will be allocated annually by Parliament, and the necessary funding is estimated to be approximately $777 million. This is expected to be covered by the federal government in the form of incentives, as well as by the private owner. Subsidies of 30 to 50 percent of the capital cost of systems would appear to be necessary.

Switzerland stated goal is for renewable energy to provide 3 percent of the thermal energy and 0.5 percent of the electric energy the country needs by the year 2000. A complementary goal of 50 MW of installed PV capacity by the year 2000 has also been set. Photovoltaic R&D expenditures have risen from $5.2 million in 1990 to $8.64 million in 1992, but were expected to decrease to $5.05 million in 1993.

As a result of the energy utilization resolution passed by the Swiss Parliament in December 1990, public power companies are obliged to purchase the electrical energy produced by independent power producers using PV, wind, cogeneration. and micro-hydroelectric power stations and to reimburse them at an "appropriate rate. " For renewable energy power generation, the purchase price is based on the marginal cost of new domestic installations. Remuneration of between 21@ and 29¢/kWh "is possible. ''121 Scattered canton support in the form of attractive buybackrates and installation incentives has been reported, although there does not appear to be a uniform policy,

The government parties have reached a verbal agreement to impose a resource or energy tax to encourage the use of renewable. However, the rapid introduction of a CO_2-energy tax is restricted by the need to find a consensus with the EU. Consequently, it is unlikely to be introduced soon.

A fund exists for PV installations in government-owned buildings, such as military camps, railway stations, and post oftices. Since September 1992, the Swiss government has supported PV grid-connected installations for schools with a payment of $4,000/kW.[122]

UNITED KINGDOM[123]

The British Department of Trade and Industry has a series of regional planning studies under way to assist local authorities in identifying the renewable energy potential. Although the United Kingdom is considered to have the best wind resource in Europe, relatively few wind turbines had been installed until recently. High taxation on independent power production and low buyback rates throughout the 1980s hindered large-scale wind power development.[124] The completion of England's first commercial wind powerplant, a 2-MW installation at Delabole in the southeastern county of Cornwall, brought total wind capacity in the United Kingdom to 12 MW.[125] Proposals for 16 large-scale windfarms amounting to 130 MW were granted power purchase contracts and planning permission in mid-1992.126 By the end of 1992, 30 MW of wind power capacity were expected to be in operation,[127] and an additional 100 MW were under development, to be operational in

121 T. Nordman, "Photo\ voltaics Applications in Switzerland, " paper presented at the 11 th European Photovoltaic Solar Energy Conference, Montreux, Switzerland, Oct. 16, 1992.

122 Ibid.

123 This section is primarily drawn from Kennedy and Egan, *op.* cit., footnote 10.

124 Peter Musgrove and David Lindley, "Wind Farm Developments in [he U.K.," paper presented at the European Wind Energy Conference. Amsterdam, The Netherlands\, 1991,

125 "British Renewables Budget Frozen," *Wind Power Monthly, vol. 8, No. 3,* March 1992.

126 "Great Oaks from NFFO Acorns," *Wind Power Monthly,* vol. *8,* No. *5,* May 1992.

127 Andrew Garrard of Garrad Hassan, persona] communication with Ted Kennedy and Christine Egan, Meridian Corp., 1993.

1993,[128] making the British market the largest in the world in 1992.[129]

Photovoltaic efforts have not fared as well. A budget of about $4 million is dedicated to solar energy overall, but there is no official budget for PV. In 1989-90, an assessment of the prospects for PV power generation in the United Kingdom was undertaken by the Energy Technology Support Unit (ETSU). In response to this action, a number of leading authorities on PVs have setup the British Photovoltaic Association.

In 1990, the British power industry was privatized, and the government developed the Non-Fossil Fuel Obligation (NFFO), which required the purchase of specified amounts of power from nonfossil sources. This was done in part to ensure that the industry continued to buy output from the nuclear stations (despite their higher costs compared with fossil fuels), but it has also provided an impetus to the development of some renewable energy technologies such as wind.[130] At present costs, PV projects are not considered supportable under the obligation. The additional costs incurred by the regional distribution companies to satisfy the nonfossil fuel obligation are met by a tax on the electricity supplier (which is passed on to the consumer) of 10 to 11 percent on all revenue from coal-, oil-, and gas-generated power sales.[131]

Since NFFO was introduced, three calls for proposals have been made. The first phase of project solicitations took place in 1990 and resulted in 75 contracts totaling 152 MW of installed renewable energy capacity.[132] The 1991 call resulted in 122 contracts for 472 MW. By far the largest portion of the proposals were based on waste burning to generate power. Wind projects totaling more than 400 MW were submitted, and nine projects (a total of 28.4 MW) were selected.[133] Of these, four were existing prototype projects, and the remaining five were windfarm proposals each of greater than 1 -MW rated capacity.[134] The most recent call requires the purchase of an additional 300 to 400 MW of renewable power in contracts that run 15 to 20 years.[135]

Originally, power was to be purchased at 11 ¢/kWh, but by 1991 the price for wind was 21¢/kWh.[136] After 1998, payment will fluctuate and be based on a “pool price” of approximately 4.6¢kWh. This expiration date has been reflected in the availability of financing for this truncated period. Because of the planning, permitting, and construction time of 1 ½ to 2 years, the preferred rate will be available for only 6 to 7 years, and lenders have insisted on recovering their investment during the fixed price period.[137] British wind powerplants cost $2,300/kW installed capacity to build, with power costing about 18¢/kWh, as of 1992.

Throughout the 1990s, NFFO orders are expected to total about 1,000 MW, expanded from an original obligation of 600 MW. Wind is expected

128 "United Kingdom To Pass U.S. in the New Wind Installations," *Wind Energy Weekly*, vol. 11, No. 500, June 1, 1992, pp. 4-5.

129 "Great Oaks from NFFO Acorns," op. cit., footnote 126.

130 Musgrove and Lindley, op. cit., footnote 124.

131 "United Kingdom Moving To Slowly on Renewables Government panel Says," *Solar Letter*, vol. 3, No. 2, Jan. 22, 1993; D.I. Page and H.G. Parkinson, Energy Technology Support Unit, Harwell Laboratory, Didcot, U. K., "The Development of Wind Farms in England and Wales," n.d.

132 Page and Parkinson, op. cit., footnote 131.

133 Musgrove and Lindley, op. cit., footnote 124.

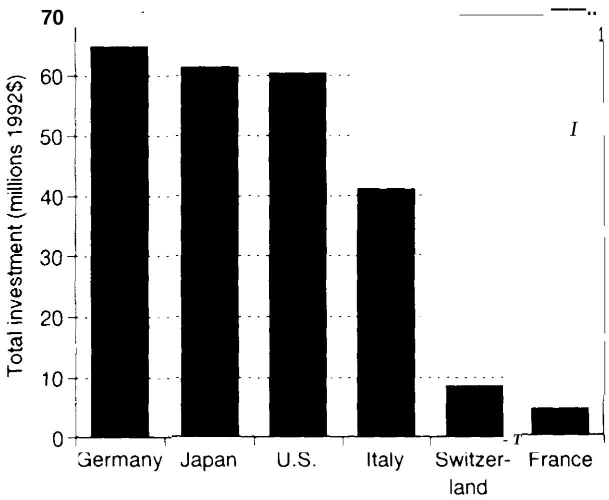
134 Page and Parkinson, op. cit., footnote 131.

135 Branstetter, op. cit., footnote 28.

136 Page and Parkinson, Op. Cit., footnote 131.

137 "UK Expected T. Expand Renewable Energy Program," *Wind Energy Weekly*, vol. 1, No. 499, May 18, 1992, p. 1.

FIGURE 7-2A: Total Federal RD&D in Photovoltaic Technologies, 1992



Total RD&D investment m PV techno/ogles is gwen for var/ous OECD counfnes By this measure the Umted States ranked a close third m investment beh{nd Germany and Japan

SOURCE Otice of Technology Assessment, 1995 based on table 7-1

to comprise about half of this amount.[138] By Sep. (ember 1992, f"lnal permission had been acquired for 49 percent of the NFF0.1[3g] Monitoring of these projects will be carried out by ETSU. A few projects will be singled out for more detailed mon - itoring by independent consultants, including two windfarrns under a three-year, $4.4-million, co-funded R&D program between National Wind Power and the Department of Trade and Industry. "

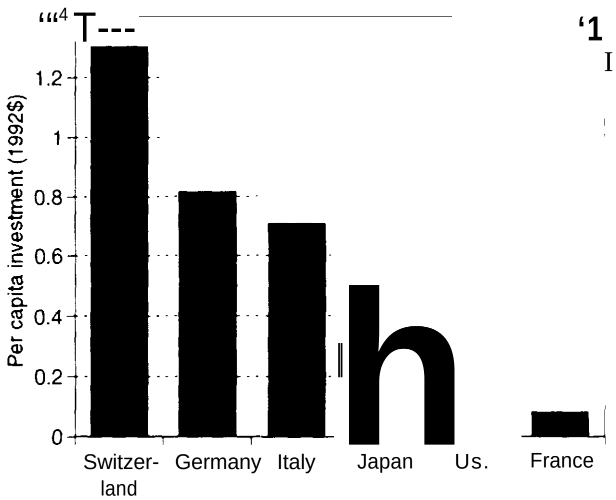
According to the American Wind Energy Association, several U,S. companies have placed bids through the NFFO program, including the Wind Harvest Company and a 4-MW project of Carter Wind Turbines. SeaWest Power Systems is the most active U.S. firm in the United Kingdom and is developing 40 MW of capacity there.

COMPARISONS

The preceding descriptions of national programs, and those of the United States as discussed in chapter 5, offer a snapshot of the wide array of supports that PV and wind technologies are receiving. It is useful here to briefly compare these supports.

Federal RD&D support for PVS is shown in total current dollars and in dollars per capita in figure 7-2. As noted in chapter 1, U.S. support for PVS has risen considerably since 1992, but that

FIGURE 7-2B: Per Capita Federal RD&D in Photovoltaic Technologies, 1992



Per capita RD&D investment In PV technologies IS gwen for various OECD counfrles By this measure, the Un/fed Slates ranks a dManf fifth behind Swli'edand, Germany /fa/y, and Japan

SOURCE Off Ice o! Tectmology Assessment 1995

i ~x. 'P.l Replrt Re~orllnlcnd~ Long-Term Market Incentl Ve$," *Wind Po\~er Monthl), vol. 8, No. 3,* March 1992.

1 l')p ~n~ parklns{>n, op. cit., footnote I ~ ~

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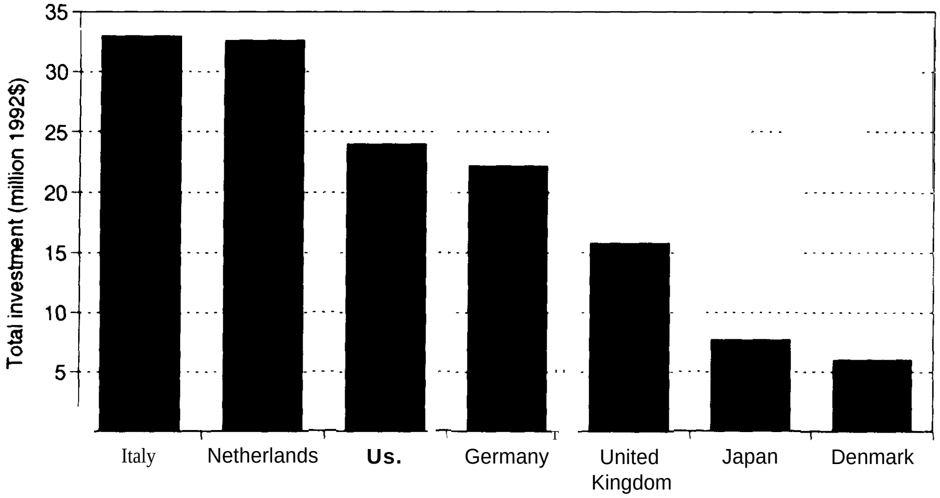
FIGURE 7-3A: Total Federal RD&D in Wind Energy Technologies, 1992



Total RD&D investment in wind energy technologies is shown for various OECD countries. By this measure, the United States ranked third in investment, well behind Italy and the Netherlands.

SOURCE: Office of Technology Assessment, 1995, based on table 7-4.

year was chosen for comparison because more recent data for several countries were not available on a consistent basis. The United States has a program roughly comparable in terms of total investment to those of Japan and Germany, and somewhat larger than that of Italy. In terms of per capita investment, however, the United States ranks far behind the leading countries.

Total and per capita federal RD&D support for wind technology is shown in figure 7-3. In terms of total investment, the United States ranks well behind Italy and Holland, and is roughly comparable to Germany. In terms of per capita investment, the United States ranks near the bottom of the list, for example, spending less than one-twentieth per capita of the amount spent by the Netherlands.

To encourage PV commercialization, the United States supports several major initiatives including the PV Manufacturing Technology Project and the PV for Utility Scale Applications, which are discussed in chapter 6. In addition, the United States provides five-year accelerated depreciation for PV systems as well as 10-percent investment tax credits for PV investments by nonutility generators. PV power must be purchased at the utility's avoided costs, but these are typically in the neighborhood of 3@ to 7¢/kWh, well below current PV costs.

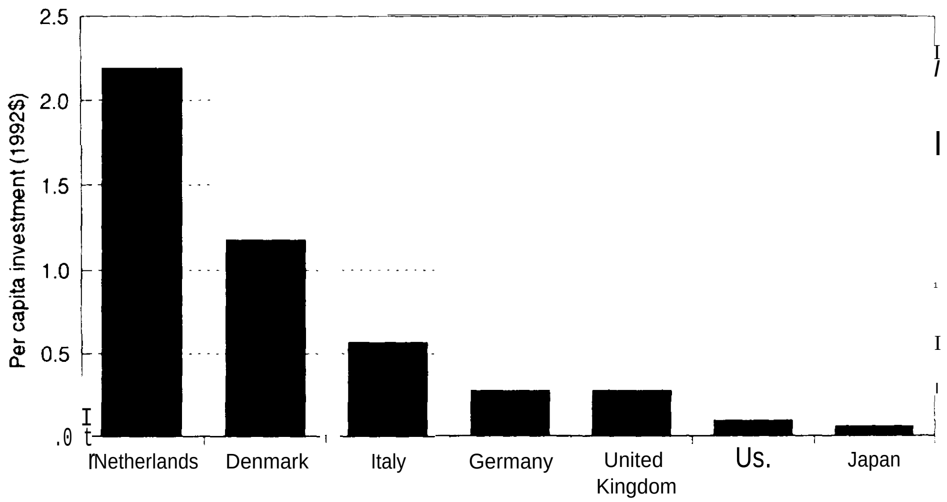
In comparison, Japan variously provides 7-percent investment tax credits, loans at interest rates of 4.55 percent, and subsidies of up to 50 percent on model plants, and it plans to subsidize up to two-thirds of the cost of residential systems. Further, the purchase price for privately generated power in Japan is 16@ to 24¢/kWh.

Germany provides 50 to 60 percent federal subsidies and roughly 20-percent state subsidies, with a limit of 70 percent, for PVs installed under its "1,000 Roof" program. Utilities purchase PV power at 12¢/kWh.

In Italy, remote houses can receive a PV subsidy of up to 80 percent of capital costs; grid-integrated PV systems receive 20@ to 28¢/kWh for power sold to the grid.

RD&D and commercialization strategies might rely on "deep-pocket" firms that can carry PV programs over the long term. ARCO and Mobil are large oil companies that were expected

FIGURE 7-3B: Per Capita Federal RD&D in Wind Energy Technologies, 1992



Per capita RD&D investment in wind energy technologies is shown for various OECD countries. By this measure, the United States ranks a distant sixth behind the Netherlands, Denmark, Italy, Germany, and the United Kingdom.

SOURCE Office of Technology Assessment 1995

to fill such a role in U.S. photovoltaic development. but both sold their PV division to German companies.

U.S. PV producers themselves, though technically strong, tend to be small firms. Other than U.S.-based production by Siemens (Germany) and Solec International (Japan), the United States has only one firm that produced 1 MW or more of PV power in 1992, compared with six Japanese firms,[141] five European firms,[142] and one firm in India.

The difficulties faced by small U.S. firms in accessing long-term financial resources are leading to arrangements with foreign producers in some cases. A recent example is the Energy Conversion Devices agreement with Canon (Japan) to build a production facility in Virginia (box 6-2).

This leads naturally to the question of the extent to which PV manufacturing might move offshore as it becomes more like a commodity production process. As discussed above. maintaining U. S.-based production of PVs will require maintaining a lead in RD&D as well as developing and investing in advanced automated production facilities.

POLICY OPTIONS

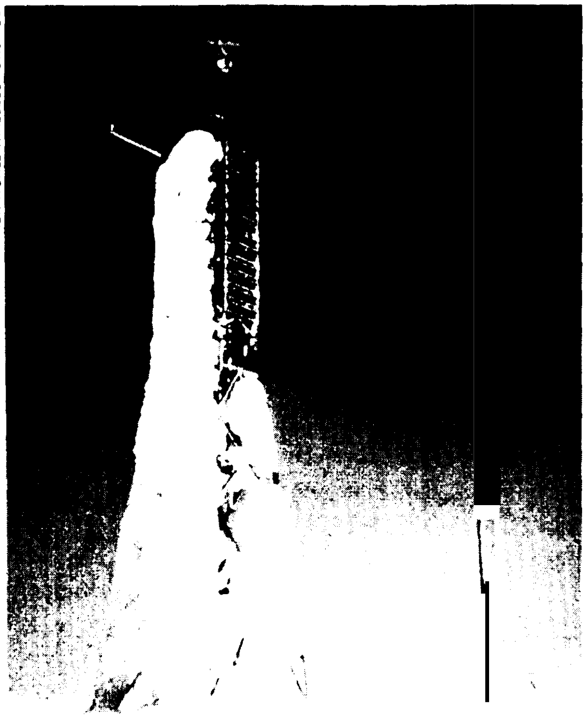
Given the rapid change in technologies and government programs, more current data and anal ysis are needed for effective decisionrnaking. Thus, Congress could direct both the Departments of Energy and of Commerce to expand recent work examining competitiveness.[143] Such work migh include a more detailed examination of the sup-

[141] Not including U. S.-based production by Solec International, now owned by Sumitomo and Sanyo.

[142] Not including U.S.-based production by Siemens-Solar.

[143] Work is currently being done at Sandia National Laboratory at the request of the Office of Intelligence, Office of Foreign Intelligence, U.S. Department of Energy.

NEW WORLD WIRELESS POWER CO



Above the arctic circle on Spitsbergen Island, Norway, this

port provided by foreign governments to their industries, including RD&D, tax. financial, and export assistance. This analysis could compare the effective level of subsidy provided to different technologies and firms within each country's accounting framework. It could also examine the firm-or industry-specific impact of these supports in terms of profitability, access to capital, ability to expand and capture market share, and other measures of vitality. Such analysis would seem particularly important in terms of small entrepreneurial U.S. firms, which may have difficulty adequately accessing capital even to match cost-shared R&D programs. Finally, the effectiveness of these supports could be compared on the basis of their long-term impacts on competitiveness; particularly important may be support for early scaleup of manufacturing that captures significant economies of scale and learning.

Correspondingly, specific strengths and weaknesses of the U.S. system could be examined to determine where it might be improved with respect to the international challenge. This analysis might include an examination of:

- RD&D and commercialization to develop adomestic industry (see chapters 5 and 6);
- the effectiveness and means of improving industry consortia and public-private partnerships for RD&D and market development;
- how RD&D can support U.S. exports;
- the access of small entrepreneurial firms to capital markets; [144] and
- gaps in support for developing export markets—particularly the lack of technology-specific knowledge or support, and weak market development support (especially public-private export project finance)-on the part of trade agencies.[145]

CONCLUSION

Renewable energy technologies could become a major growth industry in the 21st century. Competition in global renewable energy markets is likely to become increasingly intense, and the winners stand to dominate a lucrative international market. Several countries are vying for the lead in the world PV and wind markets with very aggressive programs. The U.S. is still a major player in the international marketplace and, given the opportunity, U.S. firms can continue to be competitive in international markets for renewable energy technologies. This may provide substantial long-term economic and environmental benefits at home and abroad.

[144] Michael E. Porter, "Capital Disadvantage: America's Failing Capital Investment System," *Harvard Business Review*, September-October 1992, pp. 65-82.

[145] For an analysis and discussion of U.S. export programs, see the references in footnote 6.

Appendix A: Units, Scales, and Conversion Factors

A

CONVERSION FACTORS

Area

1 *square kilometer* (km^2) =
0.386 square mile
247 acres
100 hectares

1 square mile=
2.59 square kilometers (km^2)
640 acres
259 hectares

| *hectare* = 2.47 acres

Length

| meter= *39.37* inches

| *kilometer*= 0.6214 miles

Weight

1 *kilogram (kg)*= 2.2046 pounds (lb)

1 *pound (16)= 0.454* kilogram (kg)

1 metric tonne (ml) (or "long ton") =
1,000 kilograms or 2,204 lbs

1 short ton = 2,000 pounds or 907 kg

Energy

1 Exajoule = 0.9478 quads

1 Gigajoule (GJ) = *0.9478* million Btu

1 MegaJoule (MJ) = 0.9478 thousand Btu

1 quad (quadrillion Btu) =
1.05x *10^{18}* Joules (J)
1.05 exajoules (EJ)
4.20x 107 metric tonnes, coal
1.72x 10^8 barrels, oil
2,34x10^7 metric tonnes, oil
2.56x10^{10} cubic meters, gas
5.8x10^7 metric tonnes dry wood
2.92x 10^{11} kilowatthours

1 kilowatthour =
3410 British thermal units (Btu)
3.6x10^6 Joules (J)

1 Joule=
9.48x10-^{4} British thermal unit (Btu)
2.78x10_^{7} kilowatthours (kWh)

1 British thermal unit (Btu) =
2.93x10-^{4} kilowatthours (kWh)
1.05x 103 Joules (J)

Volume

1 l *liter (1)=*
0.264 gallons (liquid, U. S.)
6.29x 1 0-^{3} barrels (petroleum, **U s.)**
1x 10-^{3} cubic meters (m^3)
3.53x1 0-^{2} cubic feet (ft^3)

1 *gallon (liquid, U.S.)=*
3.78 liters (1)
2.38x 10-^{2} barrels (petroleum, **U s.)**
3.78x 10-^{3} cubic meter (m^3)
1.33x10_^{1} cubic feet (ft^3)

1 barrel (bbl) (petroleum, U. S.) =
1 .59x 102 liters (1)
42 gallons (liquid, U. S.)

1 *cord wood=*
128 cubic feet (ft^3) stacked wood
3.62 cubic meters (m^3) stacked wood

Temperature

From Celsius to Fahrenheit:
((9/5) x ("C))+ 32 =°F

From Fahrenheit to Celsius:
(5/9) x (°F - 32) = °C

Temperature changes:

- To convert a Celsius change to a Fahrenheit change:
  9/5 x (change in °C) = change in °F

- To convert a Fahrenheit change to a Celsius change:
  5/9 x (change in °F) = change in °C

Example: a 3.0°C rise in temperature = a 5.4 °F rise in temperature