

RENEWABLE ENERGY POLICIES AND MARKETS IN THE UNITED STATES

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The United States led the world in renewable energy development for many years. In the 1990s, that leadership passed to Europe and to a lesser extent Japan for solar photovoltaics. However, the diversity of policy and market experience, coupled with a policy resurgence at the state level in the late 1990s, continued to make the U.S. experience highly relevant to policy-making in China and other countries. By 2003, the installed renewable electricity capacity of the United States had reached 19 GW, about 13% of worldwide renewable capacity, excluding large hydropower (Table 1).

This chapter provides an overview of the history of renewable energy policies and markets in the United States and how they evolved over time. There have been three distinct phases in that history (Table 2). The first phase, from 1978 to 1990, was the so-called “PURPA era.” Prior to 1978, electric utilities had no obligation to purchase power from third parties and were not interested in investing in non-hydro renewable energy themselves. (Geothermal in California was a notable exception, developed commercially by a utility during the 1960s and 1970s.) That situation changed with the introduction of the Public Utilities Regulatory Policy Act (PURPA) of 1978, which required utilities to purchase power from qualifying third parties at the utility’s “avoided cost.” The definition of “avoided cost” and implementation of the law varied from state to state. In several states, implementation of PURPA represented the first use of the “feed-in” policy, a concept that later caught hold in Europe. Primarily as a result of California’s interpretation of PURPA and favorable tax incentives, 12,000 MW of renewable power was constructed in the United States during the 1980s.

The second phase following the PURPA era was not so favorable, however. Several factors caused renewable energy markets to stagnate, including a long period of electric power sector restructuring, repeal of federal and state incentives, and sharply lower natural gas prices. Very little capacity was added. This “stagnation era” lasted until around 1997.

The third phase, starting around 1997, represented a new era for renewable energy in the United States. By then, some of the uncertainty surrounding electricity reform had begun to lessen, and state renewable energy policies that were enacted during restructuring started to take effect. These state policy innovations included:

- “Renewables portfolio standards” (RPS), which require utilities to generate or purchase minimum levels of renewable energy, were enacted in 18 states and Washington DC.
- “Public benefit funds” (PBF) were enacted in 14 states. These funds typically collect a small surcharge on electricity sales. The funds were expected to collect more than \$4 billion for renewable energy through 2017 and were investing over \$300 million annually on renewable energy in 2004.
- “Net metering” policies were enacted in 33 states between 1996 and 2004, bringing the total number

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of states with net metering to 39. These policies allow two-way power exchange between a utility and individual homes and businesses with their own renewable power sources.

- Programs to subsidize rooftop solar photovoltaic systems for households and businesses in California, supported by the state’s public benefit fund, resulted in 15,000 homes and government and commercial installations of grid-connected solar photovoltaics, totaling more than 90 MW by 2004.
- Voluntary “green power” purchases began through a variety of state and utility programs. Between 1999 and 2004, more than 500 utilities in 34 states began to offer their retail customers the option to buy green power. Mandates that required utilities to offer green power products were enacted in 5 states between 2001 and 2003.
- Tax credits, rebates, low-interest loans, and many other financial incentives came into force at the state and local levels.
- During this third phase, federal policies also contributed to renewable energy development. These policies included a favorable production tax credit (PTC) for wind and other renewable resources, initially set at 1.5 cents/kWh. Indexed to inflation, the tax credit rose to 1.8 cents/kWh by 2004. There was also a 10% investment tax credit for solar and geothermal, favorable tax depreciation schedules, and new biofuels policies.

This chapter first discusses these three policy phases in greater detail. Then it shifts to a market and technology perspective and reviews progress with individual technology markets and industries. Finally, the chapter offers lessons relevant to China and other countries interested in promoting renewable energy.

TABLE 1: RENEWABLE ELECTRICITY GENERATION CAPACITY AS OF END-2003 (GW)

Technology	World total	China	US
Small hydropower*	56.0	30.0	2.7
Wind power	40.0	0.6	6.4
Biomass power	35.0	2.0	6.7
Geothermal power	8.8	> 0.1	2.4
Solar thermal electric power	0.4	0	0.4
Solar photovoltaic power (grid)	1.1	0	0.1
Total renewable power capacity**	142	33	19
<i>For comparison:</i>			
Large hydropower	730	90	80
Total electric power capacity	3,700	410	740

* Definitions of small hydropower vary by country, typically up to 10 MW but in a few cases up to 30 MW.

** Excluding large hydropower.

TABLE 2: MAJOR RENEWABLE ENERGY POLICY MILESTONES

1978	Public Utilities Regulatory Policy Act (PURPA) enacted.
1978	Energy Tax Act provided personal income tax credits and business tax credits for renewables.
1980	Federal R&D for renewable energy peaked at \$1.3 billion (\$3 billion in 2004 dollars).
1980	Windfall Profits Tax Act gave tax credits for alternative fuels production and alcohol fuel blending.
1992	California delayed property tax credits for solar thermal power, which caused investment to stop.
1992	Energy Policy Act provides tax credits for ethanol fuels for vehicles.
1994	Federal production tax credit (PTC) takes effect as part of the Energy Policy Act of 1992.
1996	Net metering laws started to take effect in many states.
1997	States began establishing policies for renewables portfolio standards (RPS) and public benefits funds (PBF) as part of state electricity restructuring.
2001	Some states began to mandate that utilities offer green power products to their customers.
2002	Federal production tax credit (PTC) expired and was not renewed until later in the year, causing the wind industry to suffer a major downturn. This happened in 2000 also, and again in 2004.
2004	Five new states enacted renewables portfolio standards (RPS) policies in a single year, bringing the total to 18 states plus Washington DC; public benefit funds (PBF) were operating in 15 states.

BEGINNINGS: THE PURPA ERA

The birth of today’s modern renewable energy industry can be traced largely to the Public Utilities Regulatory Policy Act of 1978 (PURPA), which was the earliest form of feed-in law. The policy required utilities to purchase power from small renewable generators and cogenerators (combined heat and power), known as “qualifying facilities.” The primary difference between PURPA and contemporary European feed-in laws is how the feed-in tariff was determined. European feed-in prices have typically been based on a specified percentage of the average retail electricity price or, more recently, fixed by law for each renewable energy technology, taking into account prevailing technology costs. The PURPA tariff was based on the projected wholesale cost of conventional (fossil-fuel) power to the utility, and was intended to approximate the “avoided costs” to the utilities.

PURPA faced early legal challenges that delayed its implementation until 1981. But once it was underway, and where it was implemented aggressively, PURPA enabled an environment in which renewable developers could secure financing for their projects because they could sell their output under attractive contracts. Implementation of PURPA was most prominent in California. California’s implementation of PURPA offered long-term (15-30 year) contracts at a fixed tariff for the first 10 years of facility operation. These were the so-called “Standard Offer 4” contracts.

During its early years in California, PURPA’s main effect was to increase industrial and commercial on-site cogeneration. But slowly renewable energy project developers began to emerge and flourish in the state. The wind industry saw the greatest benefits, led by the company US Windpower, which was headquartered in California and Texas. This growth was aided by a 25% California state tax credit for investments in wind

power from 1980-1983 and an equivalent federal tax credit. As a result of Standard Offer 4 contracts, a sizable market and manufacturing capacity developed for wind, geothermal, biomass, small hydro and solar technologies in California. These developments were aided by California's diverse and abundant renewable energy resources. And California has remained one of the leaders in installed renewable energy capacity.

Other states also brought significant renewable capacity into operation during the 1980s, notably New York and Maine. In 2003, over 45% of Maine's electricity supply came from renewable energy sources (most from biomass and hydro), much of which was developed under the early PURPA contracts.

Primarily as a result of state interpretation of PURPA as well as favorable tax incentives, 12,000 MW of geothermal, small hydro, bio-power, solar thermal, and wind power generation facilities were constructed in the United States during the 1980s. Of this capacity, 6,100 MW were installed in California alone—including 1,600 MW of wind, 2,700 MW of geothermal, 1,200 MW of biomass.

A PERIOD OF STAGNATION

In the early 1990s, several things happened to cause renewable energy markets to stagnate. First, power demand slowed in key markets like California, just as large nuclear plants that had experienced long delays finally came into operation. Second, natural gas prices dropped dramatically, making renewable energy less attractive when compared to natural gas-fueled generation. This was a very significant change; real natural gas prices plunged from \$7/MBTU in the early 1980s to less than \$1.50/MBTU by 1993 (in constant 1980 dollars). Third, most of the favorable state and federal tax incentives were rescinded. And fourth, government funding for renewable energy R&D peaked in 1981 and began a significant decline.

In addition, the electric power sector began to undergo vast institutional restructuring at the state and federal levels, including the development of competitive wholesale markets; unbundling of generation, transmission, and distribution; and ultimately, retail power competition. Renewable energy often benefited from some provisions of state restructuring efforts (which frequently included certain policy provisions to encourage renewable generation), but these provisions did not take effect immediately, and renewable investments had to wait for restructuring to be completed. Indeed, during the period of restructuring, and the period directly preceding it, power markets were plagued with uncertainties, dampening investments of all forms. Many players decided to wait until the situation stabilized and the final "rules" were in place.

These trends made continuing contracts under PURPA unattractive or unnecessary. Early PURPA avoided-cost calculations in the most active states were based on the projected costs of new coal or nuclear facilities proposed in utility resource plans, which often assumed rapidly escalating fossil fuel prices. As a result, contract prices to qualifying facilities were quite attractive in the early years. Later, however, as fossil fuel prices plummeted, tariffs based on avoided costs also declined. By 1990, energy prices had not risen as originally expected. Also, a large number of natural-gas fired plants came on-line in California at low prices. Power surpluses emerged, wholesale power prices declined, and declining avoided cost rates led to reduced competitiveness of renewable energy. By the early 1990s, as Komar (2004) notes, "utilities

and regulators were unwilling to sign long-term contracts at high buy-back prices. The State of Idaho, for example, changed its PURPA rules from requiring utilities to sign twenty-year contracts with certain renewable generators to requiring five-year contracts. As a result of these changes, the 1990s saw a marked slowdown in PURPA-based new renewable energy capacity” (p. 138).

As PURPA’s influence faded in the 1990s, however, a number of innovative state-level policies emerged. These are discussed next.

STATE-LEVEL POLICY INNOVATIONS DRIVE RESURGENCE

As utility restructuring was completed and some clarity returned to power markets about the future “rules of the game”, and as various state renewables policies that were enacted in the process of restructuring took effect, a new era began for renewable energy in the United States. Increasing environmental concerns also played a role and, to an even greater extent, concerns about increasingly high natural gas prices, which began to increase by the late 1990s. These concerns coupled with a desire to stimulate economic development became major motivators for policies to promote renewable energy.

During the period 1999-2004, installed wind power capacity grew from 1500 MW to 6800 MW. Grid-connected solar photovoltaic capacity rose to 90 MW. Annual ethanol production grew from 4 billion liters/year in 1996 to 13 billion liters/year in 2004. Voluntary green power purchases rose from 380 GWh in 1998 to 1,900 GWh in 2002, and to 3,900 GWh in 2003. By 2004, an estimated 400,000 customers nationwide had voluntarily chosen green power. Private companies competed for green power customers in competitive retail power markets and in all markets nationwide, sales of “renewable energy certificates” to companies and public agencies began. Most of these developments were due to state and local policies, but federal support in the form of the production tax credit (PTC) and ethanol tax credits also played a key role. The growth was also fueled by a reduction of renewable energy costs (especially wind power) due to technology advances and economies of scale in production and learning.

After the PURPA era, fixed-price feed-in laws were no longer considered a politically viable approach to renewable energy development in the United States. Policymakers increasingly preferred mechanisms that stimulated market competition and minimized cost. (In Europe, feed-in approaches remained but evolved to effectively account for similarly changing political circumstances.) In the US, favored policies became renewables portfolio standards, public benefits funds, net metering, and other tax and subsidy policies. These policy mechanisms, along with the increasing role of voluntary green power markets, are discussed in detail below.

1. Renewables Portfolio Standards (RPS)

Renewables Portfolio Standards (RPS) have become the most-popular state-level policy to support renewable energy in the United States. Under an RPS, retail electricity suppliers are required to purchase a growing amount or percentage of renewable energy over time. Of all of the state-level policies discussed

here, the RPS is also proving to be the most important in stimulating large amounts of renewable energy additions, although design pitfalls have been experienced in numerous states. To date, most capacity installed under RPS laws has been wind, which is the cheapest option.

By early 2005, 18 states and Washington, D.C. had RPS policies. Renewable energy purchase obligations ranged from just 1% to as high as 30%. (Note, however, that the highest-target states sometimes include hydropower in the electricity share and already have substantially met their targets; Maine's 30% target is already achieved and New York is already at 19% of its 24% target). By 2004, approximately 40% of the U.S. electrical load was covered by state RPS policies. Many of the existing RPS policies have been enacted in states that have restructured their electricity markets. However, a growing number of state RPS policies have been established in traditional monopoly electricity markets. Table 3 shows the states with RPS policies and their renewable energy purchase obligations. The U.S. Congress has considered applying an RPS on the federal level, for the entire United States, but the legislation has not yet succeeded in the legislative process and, as of 2005, all RPS policies were enacted at the state and local levels.

Massachusetts was one of the very first states to enact an RPS, in 1997. However, implementation of Massachusetts' law did not start until 2002. Connecticut has the distinction of having one of the earliest effective dates for any RPS, January 1, 2000. Early RPS laws enacted in 1997-2000 often had modest targets of less than 10% and the design of these policies was sometimes poor. However, starting in 2001, more ambitious targets in the 15-20% range began to appear in states like California, Nevada, and Rhode Island. The newer RPS requirements were also often more effectively designed than some of the earlier policies. The year 2004 saw a major RPS policy expansion, with five new states enacting RPS policies.

The amount of new renewable generation expected from these standards varies widely depending on the design of the policy, and the treatment of pre-existing renewable energy capacity. For example, Maine has historically generated over 40% of its power from eligible renewable resources, so its 30% standard is unlikely to result in any new renewable generation. In contrast, California's goal to increase renewable sales from 10.5% in 2001 to 20% by 2010 will require a significant amount of new in-state renewable energy generation.

Texas implemented an RPS in 2000 that required the installation of 2000 MW of new renewable capacity by 2009. A combination of factors put Texas substantially ahead of schedule, with half of the targeted capacity already in place by 2002. These factors included the federal production tax credit, favorable transmission access rules, good wind resources, and the availability of long-term 10-25 year power purchase contracts from utilities. Moreover, to the surprise of the utilities, when Texas consumers took part in opinion surveys, there was overwhelming support for renewables being added to the utilities' supply portfolios. This encouraged more rapid compliance with the new RPS law. Nearly all of the added capacity in Texas has been wind power.

On November 2, 2004, Colorado voters approved Amendment 37, a proposed renewables portfolio standard (RPS). This was the first time in the nation's history that an RPS was put directly before voters rather than processed through a state's legislature.

While the number of states that have created RPS policies is large, experience with these policies remained somewhat limited. By 2005, few of the states had more than five years of experience with their RPS programs and some policies were established but not yet implemented. Nonetheless, the impact of these policies was beginning to be felt. According Petersik (2004), state RPS policies helped to motivate demand for 2,335 MW of new renewable energy capacity through 2003. The vast majority of this capacity, 2,183 MW, was wind power, with the most substantial demand for renewable resources coming from Texas (1,140 MW), Minnesota (476 MW), Iowa (237 MW), and California (175 MW). In fact, of the 4,300 MW of wind power installed in the US from 2001 through 2004, approximately half appeared to have been motivated in part by RPS requirements.

Though state RPS policies helped support these additions, it should be noted that federal tax policy also played a major role: federal production and investment tax credits, along with accelerated depreciation schedules, substantially reduce the cost of renewable energy supply used to comply with RPS policies. As such, success with RPS policies in some US states was being bolstered by federal tax policy.

Looking to the future, state RPS programs are expected to grow in significance. Assuming full compliance with existing policies (admittedly, an aggressive assumption), an estimated 25,000 MW of new renewable energy capacity would be required by 2017. The largest markets would be in California, New York, Pennsylvania, Minnesota, Texas, Nevada, and Massachusetts (Wiser et al 2004).

Due to the economic competitiveness of wind (thanks in part to federal tax incentives), wind power is expected to play a sizable role in meeting these requirements, but demand for biomass and geothermal resources may also be significant. Solar photovoltaic energy, though not a competitive resource compared to wind power, could contribute approximately 1,000 MW by 2020, as a result of solar set-asides within the RPS policies of 6 states and Washington, D.C.

While these projected additions are substantial compared to historic rates of growth, the aggregate amount of renewable generation required under these policies by 2017 equates to just 3% of total 2002 electric sales in the US, and to 7.2% of 2002 load in those states with RPS requirements. In addition, it deserves note that much of the impact to date has been restricted to just a few states, and there are a number of instances in which state RPS policies are not yet having their desired effect. The reasons for the poor performance in a number of US states are detailed below.

An important observation is that there is clearly no single way to design an RPS, and each of the US states has crafted its RPS policies differently, sometimes radically so. The percentage purchase obligation, for example, increases to just 1.1% in Arizona, but to 20% in California. While wind, solar, and geothermal energy are eligible under most of the RPS policies, criteria for the eligibility of biomass and hydropower vary considerably across states. Some states even allow non-traditional sources to qualify, including energy efficiency and gas-fired fuel cells. Differences also exist across states with respect to the duration of the policies, whether additional technology bands exist, how out-of-state renewable energy generators are handled, whether existing renewable energy plants are eligible, what kind of enforcement is possible, and what level of compliance flexibility is allowed. Importantly, most of the states have developed or are developing renewable energy credit markets to ease compliance burdens. This is not universally the case,

however, with some states requiring bundled renewable electricity purchases to meet the obligations. (See Wisser et al. (2004) for a more detailed discussion of the specific design of these different RPS policies.)

One example of the differences among the states is that many states have “tiered” or “split” RPS policies. This means that intermediate targets are set differently for different groups or types of technologies. For example, in the District of Columbia, “tier one” renewable resources include solar, wind, biomass, landfill gas, wastewater-treatment gas, geothermal, ocean (mechanical and thermal) and fuel cells fueled by “tier one” resources. “Tier two” renewable resources include hydropower (other than pumped storage generation) and municipal solid waste. The first set of intermediate targets for Washington, D.C., for the year 2007, sets 1.5% from “tier one” resources; 2.5% from “tier two” resources; and a minimum of 0.005% from solar energy.

Some states have also modified their RPS policies over time, typically to strengthen the standards and clarify the requirements. For example, Connecticut’s 1998 electric utility restructuring law created a renewable portfolio standard (RPS) that, due to poor design, had little effect. In 2003, however, the state legislature passed a new RPS that significantly improved the policy. Other states that have undertaken major revisions include New Jersey, Pennsylvania, and Minnesota.

One of the most important lessons from US RPS experience is the difficulty is designing and implementing an effective RPS. Where designed appropriately, as in Texas, an RPS can create a large and vibrant market for renewable energy and integrate renewable energy supply into the overall competitive electricity system. In this circumstance, an RPS can provide support for the least-cost eligible renewable energy sources and ensure the maximum degree of competition among renewable generators (overall diversity among renewable energy sources may be limited, however, because of the intense competition among project developers). And yet, RPS experience from the US has been decidedly mixed: some states have had success with the policy while others have struggled with poorly designed and implemented efforts.

A critical lesson from US experience is the need for policy stability and long-term contracting. Where short-term trade in renewable energy credits dominates over long-term contracting, RPS policies appear to be a costly and unstable way of achieving renewable energy objectives. Such problems have begun to be experienced in the New England region. Where long-term contracts are available, RPS policies have largely been successful.

Other important pitfalls experienced in the US include (Wisser et. al. 2004):

- *Poorly balanced supply-demand conditions.* Maine provides the quintessential example of a supply-demand imbalance, created by poor policy design. The Maine policy established a seemingly aggressive 30% RPS. Unfortunately, eligible resources include the vast majority of existing renewable energy and high-efficiency natural gas cogeneration in New England. Existing supply therefore far exceeds the standard itself and, as a result, the RPS will do nothing to support new renewable energy development.

- *Selective application of the purchase requirement.* Some US states have applied the RPS to only a small segment of the state’s electric market, muting the potential impacts of the policy. For example, in both Connecticut and Pennsylvania, initial RPS requirements applied to less than 5% of the total market (in both cases, subsequent revisions to the policies have rectified this problem). Not only does this violate the principle of competitive parity, it also ensures that the RPS will have only a marginal impact.
- *Insufficient enforcement.* Without adequate enforcement, electricity suppliers will surely fail to comply with the RPS. In this environment, developers will have little incentive to build renewable energy plants. The enforcement rules of a number of US RPS policies are vague in their application and, in some cases, adequate enforcement is seemingly lacking (e.g., Arizona and Nevada).

Other concerns, including poorly defined and unstable rules for resource eligibility and the eligibility of out-of-state generators, rigid verification mechanisms, and inadequate compliance flexibility, have also been experienced in some jurisdictions.

These experiences show that an effective RPS will generally be one in which: (1) strong political support and regulatory commitment exists, and that support is expected to continue over the duration of the policy, (2) clear and well-thought-out renewable energy eligibility rules are applied, (3) predictable long-term renewable energy targets are established that ensure new renewable energy supply, (4) standards are achievable given permitting challenges, (5) credible and automatic enforcement ensures that the penalties exceed the cost of compliance, and (6) the standard is applied to electricity suppliers that are credit-worthy and are in a position to enter into long-term contracts. Further, such design considerations can lead to an RPS in which long-term contracts are offered.

Despite the mixed experiences, state RPS policies are likely to remain the predominant form of support for renewable energy in the United States, at least in the near term. Existing policies will be re-designed to improve their effectiveness, and new states will be added to the RPS roster. Those policies that are already well-designed will begin to encourage significant – though not massive – growth in renewable energy capacity.

TABLE 3: U.S. STATE-LEVEL RPS POLICIES

First enacted	State	Final target	Includes large hydro?	Technology tiers/splits?	Types of utilities obligated
1997	Massachusetts	4% by 2009 and +1%/yr thereafter	No	No	All privately-owned retail suppliers
1998	Connecticut	10% by 2010	No	Yes	All privately-owned retail suppliers
	Wisconsin	2.2% by 2011	Up to 60 MW	No	Virtually all retail suppliers
1999	Maine	30% ongoing	Up to 100 MW	No	All privately-owned retail suppliers

	New Jersey	6.5% by 2008	Up to 30 MW	Yes	All privately-owned retail suppliers
	Texas	2000 MW by 2009	Yes	No	All privately-owned retail suppliers
2001	Arizona	1.1% by 2007-2012	No	Yes	Most retail suppliers
	Hawaii	20% by 2020	Yes	No	All retail suppliers
	Nevada	15% by 2013	No	Yes	All privately-owned retail suppliers
2002	California	20% by 2017	Up to 30 MW	Yes	All privately-owned retail suppliers
	New Mexico	10% by 2011	Yes	No	All privately-owned retail suppliers
2003	Minnesota	10% by 2015	Up to 60 MW	No	Major electric utility
2004	Colorado	15% by 2015	No	Yes	Utilities > 40,000 customers
	Maryland	7.5% by 2019	Yes	Yes	All privately-owned retail suppliers
	New York	24% by 2013	Yes	Yes	All privately-owned retail suppliers
	Pennsylvania	8% by 2020	Yes	Yes	All privately-owned retail suppliers
	Rhode Island	16% by 2019	Up to 30 MW	No	All privately-owned retail suppliers
2005	District of Columbia	11% by 2022	Yes	Yes	All privately-owned retail suppliers

Note: all targets are percentage of electricity sales (kWh) unless otherwise noted.

2. Public Benefit Funds

Public benefit funds (PBFs) are used to fund electricity-related public benefit programs such as renewable energy, research and development, energy efficiency, and low-income customer assistance. PBFs can be collected from a variety of sources, with the most common being a surcharge on end-use electricity rates (i.e., a “wires” or “distribution” charge).

Since 1997, 14 state PBFs have started operating to support renewable energy (Table 4). Many states also have PBFs that support energy efficiency, so the total number of states with a PBF is 23. These 14 PBFs are collecting and spending more than US\$300 million per year on renewable energy (Wiser et al 2003).

In those U.S. states with PBF funds, the combined funding for renewable energy and energy efficiency

often averages 1-3% of total retail sales revenue. At an average retail electricity rate of 10 (US) cents/kWh, this collection amount totals 0.1-0.3 cents/kWh. The renewable energy portion of these funds typically amounts to 0.1 to 0.8% of total retail sales revenue (see Table 4).

Bolinger et al. (2001) observe that PBF programs for renewable energy can be categorized into three different models: (1) The Project Development Model uses financial incentives such as production incentives and grants to directly subsidize and stimulate renewable energy project installation. Most PBFs use this model, at least to some degree. For the most part, these PBFs utilize production incentives, buy-downs/rebates, or other forms of grants as a means of distributing funds, rather than loans or other investment vehicles. (2) The Industry and Infrastructure Development Model uses business development grants, marketing support programs, R&D grants, resource assessments, technical assistance, education, and demonstration projects to build renewable energy industry infrastructure. (3) The Investment Model uses loans, near-equity and equity investments to support renewable energy companies and projects. The PBF programs in Connecticut, Pennsylvania, and Massachusetts have explored this approach.

States have developed a multitude of programs using PBF money. One common approach is to use funds to support large renewable energy projects, such as wind, biomass and geothermal. Support typically comes in the form of cash incentives for electricity production based on a dollar-per-megawatt-hour payment, though other approaches are also used (e.g., direct grants, low-interest loans, etc.). These incentives are often auctioned to those projects that need the lowest incremental amount of support to succeed. In aggregate, through 2004, state PBFs have obligated nearly \$350 million to support 2,290 MW of such projects; 707 MW of these projects are already on line, with 1550 MW in the planning stage. The vast majority of these projects are wind power facilities. Although they are not as important as RPS policies in this regard, state renewable energy funds are beginning to have some influence on large project installations.

States have also used PBFs aggressively in order to support distributed generation, especially solar PV. In fact, PBFs have been critical to the recent growth in the PV marketplace in the US and have become the nation's primary driver for PV expansion. A large number of states have developed rebate programs for rooftop, grid-connected solar installations. These rebates range from around \$2/watt to as high as \$5/watt. In total, state funds are obligating about \$200 million in support of solar PV on an annual basis, with the largest programs operating in California. In California, the state is obligating \$150 million per year in support of solar PV.

Although some success has been gained, political factors will greatly influence the effectiveness of PBF policies. For example, some jurisdictions have exempted large energy consumers from PBFs if they enter into voluntary, but binding, agreements to reach agreed-upon renewable energy or energy efficiency goals. More worrisome, some U.S. states are succumbing to short-term financial pressures, losing sight of the long term societal benefits, and re-appropriating public benefit funds for short-term governmental budget needs. In fact, given the difficulty in establishing new "taxes" in the US, few new PBFs have been created since 2001.

TABLE 4: U.S. STATE-LEVEL PUBLIC BENEFIT FUNDS

Start of fund operation	State	Annual funds spent on renewable energy (million \$)	Share of utility revenue spent on renewable energy
1997	Rhode Island	2	0.5%
1998	California	~235	1.4%
	Illinois	5	0.05%
	New York	14	0.13%
	Massachusetts	30	0.7%
1999	Delaware	0.3	0.05%
	Pennsylvania	(part of) 13	(part of) 0.12%
	Wisconsin	3	0.1%
	Montana	2	0.3%
2000	Minnesota	16	0.7%
	Connecticut	22	0.75%
2001	Oregon	10	0.6%
	Ohio	(part of) 15	(part of) 0.15%
	New Jersey	30	0.45%

3. Net Metering Laws

Net metering laws for on-site renewable energy are a type of state renewable energy policy that essentially allows the electric meter to run backwards when the on-site facility (usually a photovoltaic or small wind generator) is generating more power than is being consumed on-site. Most of these laws are written to allow the facility owner to get credit for any power generated and consumed for up to one year (essentially storing any excess power on the grid until needed). This type of policy sometimes allows the utility to keep any excess power left in the account at the end of the year without charge. It benefits the producer whose system may be generating power at different times of day from when power is needed. It also benefits customers with systems that produce excess power during some months of the year and insufficient power during other months by allowing them to optimize the generating equipment based on average annual consumption rather than average daily consumption.

Net metering is similar to some feed-in laws, although on a much smaller scale, because renewable energy producers essentially get the retail rate for the electricity they feed into the grid. However, net metering laws vary considerably from state to state, in terms of size of systems permitted, generating period, and payment rules and formulas. All of these details play role in determining the success of a law in any given state.

By 2004, 35 states had passed net metering statutes (Table 5). Four additional states had one or more

electric utilities that offered net metering, bringing to 39 the total number of states with net metering provisions for at least some of the population. As several highly populated states (including California) are included, this represents the vast majority of the U.S. population. As a result, by 2004, the great majority of homes and business in the US had the opportunity to generate their own renewable power and sell it into the power grid.

TABLE 5: NET METERING LAWS

Year first enacted	State (*)	Currently legislated capacity limit	Eligible technologies
1982	Massachusetts	60 kW	Renewables, fuel cells, MSW
1983	Minnesota	40 kW	Renewables, MSW, cogeneration
1987	Maine	100 kW	Renewables, fuel cells, MSW
1988	Oklahoma	100 kW	Renewables, MSW, cogeneration
1991	Iowa	500 kW	Renewables, MSW
	North Dakota	100 kW	Renewables, MSW, cogeneration
1992	Wisconsin	20 kW	Renewables, MSW, cogeneration
1996	California	1000 kW	Photovoltaics, Landfill Gas, Wind, Fuel Cells, Anaerobic Digestion
1997	Maryland	80 kW	PV, wind
	Nevada	30 kW	Renewables
	New York	10-400 kW	PV, wind, biomass
1998	New Hampshire	25 kW	Renewables
	New Mexico	10 kW	Renewables, landfill gas, MSW, fuel cells, cogeneration, microturbines
	Pennsylvania	50 kW, some less	Renewables
	Rhode Island	25 kW	Renewables, MSW, fuel cells, cogeneration
	Vermont	15 kW 150 kW farms	Renewables, fuel cells
	Washington	25 kW	Renewables, fuel cells
1999	Delaware	25 kW	Renewables
	Idaho (3 utilities)	25 kW residential 100 kW commercial	Renewables
	Ohio	100 kW microturbine no limit on others	Renewables, fuel cells, landfill gas, microturbines
	Oregon	25 kW	Renewables, fuel cells
	Virginia	10 kW residential 500 kW commercial	Renewables
2000	DC	100 kW	Renewables, fuel cells, microturbines
	Illinois (1 utility)	40 kW	PV, wind
2001	Arkansas	25 kW residential 100 kW commercial	Renewables, fuel cells, microturbines using renewable fuels

	Georgia	10 kW residential 100 kW commercial	PV, wind, fuel cells
	Hawaii	50 kW	Renewables
	Montana	10 kW	Renewables, fuel cells
	Wyoming	25 kW	Renewables
2002	Utah	25 kW	Renewables, fuel cells
2003	Louisiana	25 kW residential 100 kW commercial	Renewables, fuel cells, microturbines using renewable fuels
	Florida (1 utility)	10 kW	PV, wind
	Connecticut	100 kW renewables	Renewables, fuel cells, MSW, landfill gas
2004	Arizona (2 utilities)	10 kW	PV, wind
	Colorado	Not yet specified	not yet specified
	Indiana	10 kW	PV, wind, small hydro
	Kentucky	15 kW	PV
	New Jersey	4000 kW	Renewables, landfill gas, fuel cells using renewable fuels
	Texas	20 kW	Renewables, MSW

(*) net metering law is state-wide unless otherwise noted, in which case it applies to one or more individual utilities within the state.

4. Voluntary Green Power Sales

Since 1998, an increasing number of electricity consumers have been given the opportunity to voluntarily purchase green power. By 2004, more than one third of all U.S. consumers had the option to choose some form of renewable electricity product in addition to or instead of conventional power. Further, “renewable energy certificates” (RECS) have become available nationwide to all electric power consumers. Some of these choices have arisen due to competitive electricity markets, while others have appeared in continuing monopoly markets. Other types of voluntary purchases have also appeared. In general, green power sales fall into three main categories:

(a) Utility green pricing. In green pricing programs the utility’s electricity customers have the option of choosing to have a greater portion of their power supply come from renewable facilities. Such voluntary electric utility renewable electricity programs are experiencing rapid growth. The renewable electricity is typically marketed in three ways: (1) as blocks of electric power (e.g., 150 kWh blocks sold for \$2.50 each); (2) at a specified premium price for each kWh of renewable power purchased (e.g., 1.5 cents/kWh extra for renewables); or (3) as a separate electricity product sold on a fixed-price contract over some minimum period of time (e.g., 6 cents/kWh total electricity cost if the customer signs a five or ten-year contract). Utility green pricing programs have been growing for a number of reasons: (1) renewable electricity options became more and more popular with utility customers; (2) regulators in five states started requiring that utilities offer green pricing programs; and (3) tradable renewable energy certificates (TRC) make it easier to buy and sell renewable power both within and outside a utility’s service territory.

Through 2003, approximately 520 MW of renewable energy capacity was added through utility green pricing programs, 425 MW of which was wind power.

(b) Competitive retail green power sales. Competitive electricity markets are markets where multiple electricity service companies compete with one another to provide retail customers with electricity (i.e., no single electricity company has a geographic monopoly on retail electricity sales). Some of these markets contain companies that distinguish themselves by their supply of green, renewable power. As of early 2004, approximately 1130 MW of new renewable capacity had been built to supply competitive green power markets at the retail and wholesale levels, including TRC markets (described below). Virtually all of this new capacity is wind power though it is often mixed with biomass or small hydro in the final product offering. Significantly, large non-residential customers have begun to make significant purchases.

(c) Renewable energy certificates (TRC). Renewable energy certificates, also called tradable renewable energy certificates (TRC), capture or represent the environmental and social attributes associated with renewable electricity generation. The certificates are sold separately from the electricity itself. Thus a renewable energy producer sells the actual electricity to one customer at a competitive price, and then also sells an equivalent amount of TRC representing that electricity to another customer for an additional price. Starting in 2002, the renewable energy certificate market began to grow significantly. By 2003, there were 13 TRC marketers selling 17 certified products. New marketers were entering the market monthly. The certificates are purchased on a voluntary basis by non-profit organizations, commercial and industrial customers, universities and hotels, residential consumers, and government agencies.

Competitive retail markets have not guaranteed green power sales, however. In fact, competitive retail green power sales were declining in 2003-2004, while the sale of TRC in all retail markets increased twelve-fold between 2002 and 2003 and looked like they would double again in 2003-2004. Conversely, utility green pricing programs by both monopoly and non-monopoly utilities continued to grow because of their popularity with the general public. And in some cases, even if not required, monopoly utilities have established green pricing programs as a form of insurance, to keep their customer base from declining if restructuring is introduced in their state. These voluntary programs have supported an increasing amount of renewable energy, but their impact has been modest compared to that of state RPS and PBF programs. One prominent program, the US Green EPA Power Partnership, had 510 commercial partners who were purchasing 2,000 GWh of green power annually in 2004 (worth roughly \$120-150 million/year), marking a trend towards greater non-residential participation in the green power market.

Certification and verification of retail renewable electricity products for consumer protection has been an important element of green power markets. Certification is particularly important in the electricity market since electricity is such an abstract product. The main certification program in the United States has been Green-e, established in 1998. In part as a result of the market-shaping and verification activities of the Green-e program, the US renewable electricity market has gained a high level of credibility with the public in a fairly short period of time—about six years. Such credibility is important in the case of green power markets, which represent a completely new product type – differentiated electricity from renewable generators.

5. Other Regulatory Provisions and Financial Incentives

Numerous states have enacted additional regulatory provisions and financial incentives for renewable energy. The most common are:

- **Generation disclosure rules** require that utilities provide their customers with information about the energy they are supplying. This information often includes fuel mix percentages and emissions statistics.
- **Interconnection standards** provide technical protection requirements, equipment specifications, application procedures, analytical study requirements, and other rules and standards to ensure that renewables can be efficiently and safely interconnected to the grid.
- **Equipment-related standards and certification measures** have been applied to ensure uniform quality of equipment and installation.
- **Contractor licensing requirements** ensure that contractors have the necessary experience and knowledge to install systems properly.
- **Construction and design standards** include building-code standards for PV installations, design standards evaluated on life-cycle cost basis, and performance requirements. An example is Florida, which requires that all new educational facilities include passive solar design.
- **Personal tax credits or deductions** cover some of the expense of purchasing and installing renewable energy equipment. Some states offer personal income tax credits up to a certain percentage or predetermined dollar amount against the cost of purchasing and installing renewable energy equipment.
- **Corporate tax incentives** allow corporations to receive state tax credits or deductions for some portion of the cost of renewable energy equipment. In some cases, the incentive decreases over time. Some states allow the tax credit only if a corporation has invested a certain dollar amount into a given renewable energy project.
- **Sales tax incentives** typically provide an exemption from the state sales tax associated with the purchase of renewable energy equipment.
- **Property tax incentives** typically follow one of three basic structures: exemptions, exclusions, or credits. Some of the property tax provisions for renewable energy follow a simple model that provides that the added-value of the renewable device is not included in the valuation of the property for taxation purposes. That is, if a renewable energy heating system costs \$1,500 to install versus \$1000 for a conventional heating system, then the renewable energy system is assessed at \$1000.

- **Rebate programs** are offered at the state, local, and utility levels to promote the installation of renewable energy equipment. Rebates are direct payments to purchasers of renewable equipment, either a fixed amount or a percentage of the cost of the equipment and installation. The majority of rebate programs are available from state agencies and municipally-owned utilities. Most programs support solar water heating or solar photovoltaic systems. Usually homes and small businesses are eligible to receive rebates, although rebates are sometimes available to industry, institutions, and government agencies.
- **Grant programs** are available primarily to commercial, industrial, utility, education, and government recipients. Some grant programs focus on research and development, while others are designed to help a particular project become economically viable.
- **Leasing/lease purchase programs** target remote power customers for whom line extension would be very costly. Customers may lease the technology (e.g., solar photovoltaics) from the utility. Or customers may choose to purchase the system after a given number of years at a reduced price.
- **Loan programs** offer low-cost financing for the purchase of renewable energy equipment. Low-interest or no-interest loans are available to residential, commercial, industrial, transportation, public, and nonprofit customers.

6. Local Government Policies

Another growing trend since the late 1990s is for municipal governments to purchase green power for use in municipal government buildings and infrastructure, or to establish RPS obligations for municipal utilities. A few cities have set city-wide political goals for power generated from renewables by fixed future dates. Table 6 details some of the communities that had taken these steps by 2004 and their goals. The two most common types of targets are: (1) power purchases by the municipal government only (e.g., municipal government buildings and infrastructure), and (2) power purchases for all customers in the city.

TABLE 6. CITY/MUNICIPAL GOVERNMENT POLITICAL TARGETS AND RPS

Enacted	City	Target/current renewables purchases	Notes
1999	Santa Monica (CA)	100% for municipal government	Political goal
1999	Austin (TX)	20% for entire city by 2020 (RPS)	Obligation on municipal utility
1999	Jacksonville (FL) and surrounding communities	7.5% for utility supply by 2015 (RPS)	Voluntary goal by utility JEA
2000	Chicago (IL)	20% for municipal government by 2006	Political goal
2001	Los Angeles (CA)	14% for municipal government	Political goal
2001	Portland (OR)	100% for municipal government	Political goal
2002	Salt Lake City (UT)	53 GWh/month for municipal	Political goal

		government currently	
2002	Davis (CA)	Power from 800 kW PV currently	From PVUSA solar plant
2002	Seattle (WA)	5% for entire city currently	Political goal
2003	Ft. Collins (CO)	15% for entire city by 2017 (RPS)	Political goal
2004	Columbia (MO)	15% for entire city by 2022 (RPS)	Obligation on municipal utility
---	Sacramento (CA)	20% for entire city 2011 (RPS)	Political goal
---	Minneapolis (MN)	10% for municipal government currently	Political goal
---	San Diego (CA)	23% for municipal government currently	Political goal
---	Aspen (CO)	50% for entire city currently	Political goal
---	Delaware municipalities	10% for entire community by 2015	Political goal

MARKET AND INDUSTRY HISTORIES

The wind, solar photovoltaic, solar thermal power, solar hot water, biofuels, and biomass power markets and industries have been influenced by the policy changes discussed above to different degrees at different times. This section examines these individual market and industry histories.

1. Wind Power

Several U.S. wind power companies in the 1980s were all developing technology, supported in part by public R&D programs through the National Renewable Energy Laboratory (formerly the Solar Energy Research Institute). California was their primary market because of California's Standard Offer 4 contracts under PURPA and favorable tax policies. In the mid-1980s, 95% of all wind capacity in the world was in California. By 1990, 1700 MW had been installed in the United States, virtually all in California. As late as 1996, California still had 95% of U.S. installed wind power capacity. The company US Windpower, based in Livermore, California, became the industry leader, and underwent several transformations over the years, finally becoming Kenetech Windpower. Zond Systems was another important California company that changed names several times: it became ENRON Wind and, in 2002, General Electric purchased ENRON Wind. In 2003, GE Wind had 50% of the US domestic market and 18% of the global market. (Footnote: The other half of the 2003 US wind market was primarily Vestas and NEG Micon of Denmark and Mitsubishi of Japan. European manufacturers have faced a difficult and costly battle in the US market due to patent disputes about variable-speed technology, which has so far prevented Germany's major manufacturer Enercon from selling in the US and raised costs to others.)

Public and private R&D was important to the early development of the wind industry. As the industry matured, production of 100-kW turbines gave way to variable-speed 330-kW turbines, and later to machines over 1 MW in size. But by the 1990s, markets dried up as the offer of new PURPA contracts was discontinued, fossil fuel prices fell, and federal R&D spending on wind power declined from \$60 million in

1980 (or \$140 million in 2004 dollars) to \$10 million annually. There was virtually no growth for several years. By 1998, only one major wind power company remained: ENRON Wind, which later became GE Wind.

The year 1999 was a turning point for wind power in the United States. Cumulative installed capacity increased by 40% as 730 MW of wind power capacity was added in an effort to complete wind projects before the federal production tax credit (PTC) expired in mid-1999. (The PTC was later extended through 2001, and then through 2003 and 2005). The PTC, enacted in 1992 and effective starting in 1994, provided a 1.5 cents/kWh subsidy for wind power generation (indexed to inflation and increasing to 1.8 cents/kWh by 2004). Many developers began to take advantage of the PTC in the late 1990s as wind power costs declined due to technological improvements. Investment in wind power was driven by other forces as well. Power sector restructuring led to a hiatus in power plant construction, and by the end of the 1990s, much of the country was in need of new power capacity. In addition, emerging state-level policies that supported renewable energy projects began to have an effect by 1999.

In the following years, renewables portfolio standards (RPS), public-benefit funds (PBFs) and other state-level policies, voluntary green power markets, and the PTC all continued to spur wind power investments in several states. Most notable was Texas, where an RPS coupled with the PTC had a major impact on wind power development; 1300 MW of wind power were installed between 2000 and the end of 2003. But the national market went up and down dramatically from year to year, as the PTC expired and was subsequently reinstated. For example, although 2003 was a boom year for wind power installations in the US, with 32% growth in cumulative installed capacity (1700 MW added), 2004 was a disaster for the industry. Only 390 MW was installed in 2004 due to a late extension of the PTC that year. “Stuck on red: the US wind sector waits for the PTC green light” proclaimed a typical renewable energy journal article (*Renewable Energy World* July-August 2004). (Footnote: Projects receive the credit provided they are commissioned during the period the credit is active. Although the renewal in 2004 was retroactive to January 1, 2004, many projects were not initiated during the year due to the uncertainty about whether the PTC would be renewed at all.) Similar lags in capacity additions occurred in 2000 and 2002, due to uncertainty about the extension of the PTC. Continued uncertainty over the federal PTC means that “state policies will likely be the most crucial mechanism to ensure the expansion of the wind industry in the coming years” concluded Lewis and Wiser (2005). Sawin (2001) similarly concluded that the PTC by itself did not play a major role in determining capacity additions during the 1990s, and that only in conjunction with state-levels policies was wind development accelerated.

The industry hiatus during the early 1990s, combined with the start-stop PTC expirations in 2000, 2002, and 2004, has hurt the long-term development of the wind industry in the United States (Figure 1) and has eroded the US position in the global wind power market. In 1990, the United States had 75% of cumulative installed wind power capacity worldwide. By 2003, the US share was reduced to 16%, as markets in Germany, Spain, Denmark, and even India surged due to electricity feed-in policies and active support by governments.

FIGURE 1 [Draw graph according to data below]

Title: Inconsistency in 1995-2004 annual wind power installations due to temporary expirations of the production tax credit (PTC)

Y-axis: MW added

X-axis: Year

Data:

X (text)	Y (numeric)
1995	40
1996	70
1997	30
1998	190
1999	730
2000	50
2001	1700
2002	430
2003	1700
2004	390

Finally, it deserves note that, as wind power capacity doubled from 2000 to 2004, and new geographic areas opened up in the Midwest and Great Plains, it became clear that wind power was becoming even more constrained by transmission access. New transmission planning and policies were becoming needed, and many experts expected the future of wind power in the US to be constrained by progress with such policies.

2. Solar PV

After industry shake-outs and losses during the 1980s, the U.S. PV industry continued to grow consistently from 1990 to 2002, expanding tenfold from 12 MW of production in 1990 to 122 MW of production in 2002, with most annual growth rates in the 20-35% range. Domestic demand remained small, however, so exports consistently accounted for around two-thirds of production during this period. Prior to 1998, virtually all production was for export or for domestic consumer products and off-grid commercial and industrial applications, including telecommunications, off-grid lighting, remote monitoring, and highway signals and signs. As with other renewable technologies, significant cost reductions followed production increases and continuing technology improvement (Maycock 2004).

Starting in 1998, the distributed grid-connected market began to accelerate, led by several key policy initiatives, most notably in California. Net metering laws were an essential pre-condition for grid-connected PV. Only a few states had net metering laws prior to 1995, and the use of net metering really began to accelerate in the United States beginning in 1996.

In addition, policies to subsidize the installation of grid-connected PV began to pick up steam in the late 1990s and early in the 2000s. The Sacramento Municipal Utility District (SMUD) (Phase II of the PV

Pioneer Program) and the Los Angeles Department of Water and Power provided up to \$3.50/watt and \$5.00/watt, respectively, for grid-connected PV. Meanwhile, California's state government began the most aggressive rebate program in the country, offering subsidies of up to \$4.50/watt for residential and commercial installations, with total public expenditures for PV rebates rising to well over \$100 million a year in recent years. Those subsidies declined to \$2.80-3.50/watt by 2004 as market prices declined.

A large number of other states and utilities have followed California, especially in those states with public benefit fund (PBF) programs, but the California programs still dominate the landscape. Six states with renewables portfolio standards (RPS) also began to develop solar-specific "set-asides" in 2002-2004. These set-asides require that a specific portion of capacity installed or electricity generated must come from solar PV. It is estimated that these set-asides will create demand for a cumulative 1000 MW of solar PV capacity by the year 2020.

As a result of these policies, 75 MW of grid-connected PV was installed during the period 1999-2003. The majority of this capacity was installed in California. Even though this represents the start of a strong trend in the United States, it still does not compare with the 960 MW of grid-connected PV in Germany and Japan, facilitated by their rooftop PV policies from 1994-2003.

Throughout the 1990s, five manufacturers dominated PV production in the US: Shell Solar (formerly Siemens Solar), AstroPower, BP Solar, United Solar Systems, and RWE Schott (formerly ASE). Siemens Solar dominated production during the 1990s, and continued to do so as it became Shell Solar. In 2003, Shell Solar accounted for 50% of U.S. production. During 2002-2003, at least three new players entered the US field: First Solar, Evergreen Solar, and Global Solar, which together accounted for about 8% of US production in 2003.

The year 2003 marked a downturn for the US PV manufacturing industry, although US installations of PV continued to rise. Domestic production dropped 15%, from 122 MW in 2002 to 103 MW in 2003. Several factors cited by Maycock (2004) for this include troubles at Astropower prior to its bankruptcy, drastically reduced production by BP Solar in the US following expansion of new plants in Asia and Europe, and process changes in the BP Solar plant (formerly Solarex).

Even though US PV production continued to grow (with 2003 being the exception) production in Japan and Europe surged even more during this period. Success in Japan and Europe was driven by an aggressive PV subsidy policy in Japan and an attractive electricity feed-in policy in Germany. Consequently, during the 1990s and the early 2000s, the US share of global production declined dramatically. By the end of 2004, US-based manufacturing produced only about 11% of global PV production, down from a peak of 46% in 1995. According to a Berger (1997) interview of a leading solar industry advocate of the time, Steven Strong, "the United States appears to have forsaken its world leadership role in photovoltaics and by default handed it to the Europeans and the Japanese. The Japanese have had a consistency of vision and a coincident public policy support to allow their photovoltaics program to move forward in incremental planned steps over a multiyear period with consistent funding." By 2003, Japanese manufacturers had captured half of global production.

3. Solar Thermal Electric Power

Solar thermal electric systems briefly flourished in California during the late 1980s when the LUZ company built nine solar thermal power stations totaling 350 MW in the Mohave desert. These stations were aided by federal and state tax credits, and favorable PURPA Standard Offer 4 (SO4) power purchase contracts. The cost of each successive plant was less than the previous one, as the technology steadily improved. However, LUZ was never able to gain a firm economic foundation because both the federal and state tax credits kept expiring at the end of each year. Each time the credits expired, they were renewed. But each new plant had to be started after the credits were renewed and then completed before the credits expired. (LUZ had less than one year to start and complete plants #1 to #8, and less than nine months to start and complete plant #9.) For several years, LUZ was always on the brink of failure but managed to continue building plants. In 1991, the California government delayed extending its property tax credit too long. The LUZ company, already weakened by years of hustling to meet tax credit expiration deadlines, went bankrupt. Since 1991, there has not been a commercial solar thermal plant built anywhere in the world. Yet the electricity costs from these plants were falling and technology performance was never a serious issue.

The period 2003-2005 marked the beginning of what may become a renaissance for solar thermal electric plants in the United States. Solar set-asides in state renewables portfolio standards, combined with declining costs began to contribute to new plans and projects. For example, a 50 MW parabolic-trough plant was soon to be constructed in Nevada, and facilities as large as 500 MW were being proposed in California.

4. Solar Hot Water

The solar hot water industry grew in the 1980s due to favorable tax policies at both state and federal levels. However, quality has always been an issue, and public education and awareness of solar hot water opportunities and competitiveness were never strong. In addition, low natural gas prices in the early 1990s discouraged solar hot water investments.

The U.S. solar hot water industry continues to benefit from state tax credits and direct rebates for investments in solar equipment, with many of these enacted in recent years. For example, California has exempted solar hot water from property taxes since 1999. Several other states have similar exemptions or allow municipalities to treat solar hot water differently for property tax purposes. In 1995, Arizona started to offer individuals a personal investment tax credit of 25% of the cost of solar hot water installations, up to a maximum of \$1000. Hawaii has a similar credit, of 35% of the value up to a maximum of \$1750, and 8 other states have similar credits. Ten states offered direct rebates for residential solar hot water, typically \$300 to \$700 per system (going up to \$2000 in Colorado). Despite these incentives, however, the US solar hot water market has remained fairly constant and low-level, with about 40,000-80,000 m² installed annually during the 1990s and 2000s. (This compares with an annual global market of more than 12 million m² in 2003, most of that in China.) The poor performance record of the 1980s continues to hinder

the market and industry.

5. Biofuels

The United States is the world's second largest producer of ethanol, after Brazil. The use of ethanol for transportation fuel is a recent phenomenon in the United States, with ethanol production increasing from 4 billion liters per year in 1996 to 13 billion liters in 2004. In comparison, Brazil's annual production was about 15 billion liters in 2004. There are 82 operating ethanol production plants in the United States and recent annual growth has been in the 15-20% range. By 2004, there were about 200 U.S. fueling stations (mostly in the Midwest) that sold E85, an 85% ethanol/15% gasoline blend.

Over the years, a number of biofuels tax policies and mandates were enacted at the state and federal levels. The Energy Security Act of 1979 created a federal ethanol tax credit of up to 60 cents per gallon for businesses that sell or use alcohol as a fuel. This applies to ethanol/gasoline blends as well, with the credit increasing in proportion to the share of ethanol in the fuel. Under the law, gasoline refiners and distributors can also receive an excise tax exemption of up to 5 cents/gallon for blending their fuels with ethanol. Several states also were offering incentives for ethanol production and sales.

The origins of these policies can be traced back to the 1980s, when Iowa established several policies to encourage ethanol consumption to promote use of its corn crop for energy. Iowa's policies included a mandate for government vehicles to use ethanol-blended fuel, and a one-cent-per-gallon fuel sales tax exemption for ethanol-blended fuels. In 1998, both the federal government and the State of Iowa extended their ethanol tax exemptions until the year 2007.

6. Biomass Power and Heat

Biomass is the primary renewable fuel used for non-electricity applications in the United States, with 95% of non-electricity renewable energy consumption coming from biomass in 2003. Two thirds of biomass energy consumption went to space, steam, and process heat, and one-third to electricity generation. The majority of biomass is thus consumed in industry.

Biomass power generation was one of the main beneficiaries of PURPA. By 1996, 7,000 MW of wood and wood waste facilities were generating power nationwide. California led this trend. The first small biomass power plants began operation in California in the early 1980s. In the early days, most biomass plants utilized sawmill residues exclusively. But as more biomass plants were constructed and the number of operating sawmills declined, biomass feedstocks broadened to include forest thinnings, agricultural byproducts, orchard removals, and urban wood waste. Another prominent state was Maine, where biomass provided 25% of the state's power during the 1980s.

Biomass for power generation increased at a fairly slow rate after 1995 and then declined in the period 2000-2002. Overall, biomass use remained fairly constant from 1996-2004 as heat-supply applications

declined slightly. State-level policies beginning in the late 1990s did not have significant impact on biomass power markets from agricultural waste. Plant shutdowns occurred in several states. In California, the industry peaked in 1994. With utility restructuring during the 1990s, one-quarter of existing biomass plants in California became uncompetitive and stopped operating. In Maine, biomass became the state's costliest power source (and Maine's RPS policy in 1999 was in part designed to "save" some of these facilities). The federal production tax credit, first established in 1992, initially applied only to "closed loop" biomass power projects, but then later to more traditional "open-loop" projects as well. The combination of the PTC and state-level RPS policies did not initially have the same impact on biomass power as they did on wind power. By 2004, some growth in biomass power capacity was beginning to occur, especially in New England in response to aggressive RPS policies, and in California and Wisconsin in response to increasing water quality problems from the organic waste of animal feedlots and dairy herds.

Landfill gas is also a major contributor to biomass power generation in the United States. Landfill gas facilities are relatively low cost and divert escaping methane gas (a harmful greenhouse gas) into use for power generation. Almost all landfills suitable for gas capture and power generation are doing so. Another growing biomass sector is the anaerobic digestion of animal waste, from dairy farms and animal feedlots, into biogas used for power generation.

CONCLUSIONS

The history of renewable energy policies and incentives in the United States points to a few clear lessons:

First, policy consistency is essential. US renewable energy policy has suffered from inconsistency as incentives have been repeatedly enacted for short periods of time and then suspended. This stop-and-go tendency has seriously hampered the development of markets and industries. As a result, the United States, once the world leader in renewable energy technologies and generation, now lags behind Europe and Japan in many respects. The up-and-down movement of the wind industry during 2001-2004 due to expiration of the production tax credit (PTC) is the best example of how inconsistent policies can affect an industry. The failure of the company LUZ in the late 1980s to continue developing solar thermal power stations is another. As Berger wrote in 1997, "federal aid has vacillated...National energy policy—especially as reflected in the tax code—changes its emphasis too quickly to provide the long-term stable planning horizon that major new renewable energy investments require. Foreign governments, meanwhile, give their renewable energy industries more generous and longer-term support than does the United States, therefore providing a more predictable operating environment, creating stiff competition for American renewable energy companies....For all these reasons, the public's long-term interests in swiftly bringing a renewable energy economy into being are neglected."

Second, the wind and solar industries are constrained by the fact that the major renewable energy markets are now overseas, particularly in Europe and Japan. It is more difficult to develop a strong domestic industry without a strong domestic market. The United States missed many opportunities in the 1990s to remain the world leader in the renewable energy industry and now is suffering the consequences.

Nevertheless, the domestic solar industry continues to grow, supplying both domestic and international markets. The domestic wind power industry could also continue to grow, but the domestic market is becoming increasingly constrained by regulatory problems with transmission access and continued uncertainty over the future of the federal production tax credit (PTC) beyond its expiration in 2005.

Third, US experience shows that state-level policies will likely be crucial in ensuring the expansion of renewable energy in the United States over the coming years, but that complimentary federal policies are also important. As the PURPA era gave way to stagnation in the early 1990s, electric power restructuring led to a boom in state policy innovations to support renewable energy. Those innovations, including RPS, public-benefit funds, net metering laws, voluntary green power markets, and a variety of financial incentives and regulatory provisions, have been gaining momentum since 1998. They now provide the bulk of encouragement for renewable energy in the United States, in combination with attractive federal tax incentives. Overall, however, the impact of these state-level actions is still modest relative to the potential impact of more aggressive federal policy. If anything, US experience illustrates the risk of relying too heavily on state-level support alone.

Fourth, for renewables to develop smoothly and efficiently, they need clear and equitable power transmission system rules and cost allocation methods. It is important to be clear about how transmission upgrade costs will be allocated and to incorporate renewable resource development into transmission planning. The transmission problems in the United States stem from the fact that the existing transmission system was designed to serve traditional, central station generation. Rules for who pays for what transmission costs were vague or non-existent and were dominated by the idea that any and all transmission upgrades required by renewable facilities had to be paid by those facilities. Transmission system planning that anticipates renewable resource development is just now being introduced and accepted.

Although government R&D and other technology development efforts are important, the history of the United States shows that renewable energy technologies and industries have developed fastest when policies have provided clear, consistent, and strong incentives for commercial market demand to grow. The PURPA era still stands as the most successful period of renewable energy development in the US, due to a confluence of factors and the strong support provided by the feed-in type of policy. In the future, state-level renewables portfolios standards will be the key to large-scale expansion, and some early RPS successes were being achieved. But design pitfalls have plagued some RPS programs and future design and implementation will need to proceed carefully. And even more aggressive policy action will be needed, comparable to aggressive policies in other countries, at both state and federal levels, in order for US markets to follow global trends.

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