# Renewables Portfolio Standards in the United States

## A Status Report with Data Through 2007


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April 2008


BERKELEY LAB

Lawrence Berkeley
National Laboratory


LBNL-154E

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# Executive Summary

As the popularity of renewables portfolio standards (RPS) has grown, so too has the need to keep up with the design, early experience, and projected impacts of these programs. This report – the first in a regular series – seeks to fill this need by providing basic, factual information on RPS policies in the United States. Key findings of this inaugural edition are as follows:

- Mandatory RPS policies have been created in 25 states and Washington D.C.; four additional states have non-binding goals
- In 2007, four states established new RPS policies, 11 states significantly revised pre-existing RPS programs (mostly to strengthen them), and three states created non-binding renewable energy goals
- Forty-six percent of nationwide retail electricity sales will be covered by the mandatory state RPS policies established through the end of 2007, once these programs are fully implemented
- RPS policy designs vary widely among states, and a "common" design has not yet emerged
- Resource eligibility in state RPS programs has expanded beyond traditional renewables, with three states now allowing demand-side energy efficiency to meet at least a portion of their RPS requirement; additional states have stand-alone mandatory energy efficiency portfolio standards
- Eleven states now have four or more years of operational experience with an RPS, though many other state programs are just getting underway
- Though not an ideal metric, over 50% of the non-hydro renewable capacity additions in the U.S. from 1998 through 2007 occurred in states with RPS programs (~8,900 MW); 93% of these additions came from wind power, 4% from biomass, 2% from solar, and 1% from geothermal
- Assuming that full compliance is achieved, current mandatory state RPS policies will require the addition of roughly 60 gigawatts (GW) of new renewables capacity by 2025, equivalent to 4.7% of projected 2025 electricity generation in the U.S., and 15% of projected electricity demand growth
- Solar-specific RPS designs are becoming more common, with 11 states and Washington D.C. adopting solar or distributed generation (DG) set-asides so far; these policies have already supported 102 MW of photovoltaics and 65 MW of solar-thermal electric capacity, and a total of roughly 6,700 MW of solar capacity would be needed by 2025 to fully meet existing set-aside requirements
- The early-year renewable energy targets in the majority of state RPS policies have been fully or almost-fully achieved through the application of renewable electricity or renewable energy certificates (REC) towards RPS targets; the overall average level of RPS "compliance" in 2006 was 94%, and nine states achieved renewable energy deliveries, as a proportion of RPS targets, of above 95%
- Several states have struggled to meet early-year RPS targets, however, and alternative compliance payments of more than $18 million were paid in 2006; financial penalties have been applied in two states
- Renewable energy certificate tracking systems continue to expand and, as of the end of 2007, all but four RPS states allowed unbundled RECs to count towards RPS compliance
- Renewable energy certificate markets remain fragmented, and prices have varied dramatically across states, and over time, reflecting variations in RPS design
- The electricity rate increases associated with existing state RPS policies, for those states in which such impacts are readily calculable, generally equal 1% or less so far; in several states, the renewable electricity required by these policies appears to be priced competitively with fossil generation
- States are increasingly recognizing lack of transmission investment as a key barrier to achieving RPS targets, and at least five states – Texas, Colorado, California, Minnesota, and New Mexico – took important steps in 2007 to mitigate this barrier
- The U.S. House of Representatives passed a Federal RPS in 2007, but the bill was unable to pass out of the U.S. Senate

# Introduction

Renewables portfolio standards (RPS) have proliferated at the state level in the United States since the late 1990s.[1] In combination with Federal tax incentives, state RPS requirements have emerged as one of the most important drivers of renewable energy capacity additions. The focus of most RPS activity in the U.S. has been within the states. Nonetheless, the U.S. House of Representatives and Senate have, at different times, each passed versions of a Federal RPS; a Federal RPS, however, has not yet been signed into law.[2]

The design of an RPS can and does vary, but at its heart an RPS simply requires retail electricity suppliers (also called load-serving entities, or LSEs) to procure a certain minimum quantity of eligible renewable energy. An RPS establishes numeric targets for renewable energy supply, applies those targets to retail electricity suppliers, and seeks to encourage competition among renewable developers to meet the targets in a least-cost fashion. RPS purchase obligations generally increase over time, and retail suppliers typically must demonstrate compliance on an annual basis. Mandatory RPS policies are backed by various types of compliance enforcement mechanisms, and many – but not all – such policies include the trading of renewable energy certificates (RECs[3]).

Renewables portfolio standards are a relatively recent addition to the renewable energy policy landscape, and these policies continue to evolve. Keeping up with the design, early experience, and projected impacts of these programs is a challenge. This report seeks to fill this need by providing basic, factual information on RPS policies in the United States. It focuses on state-level initiatives, though a later section briefly discusses Federal developments as well. The report does not cover municipal-level renewable energy goals, unless required by state law. Similarly, this report focuses on *mandatory* state RPS requirements, though it also touches on *non-binding* renewable energy goals, especially when those goals are developed by state law or regulation. This report is the

**ACRONYMS**

| | |
|---|---|
| ACP | alternative compliance payment |
| CPCN | certificate of public convenience and necessity |
| CREZ | competitive renewable energy zone |
| DG | distributed generation |
| ERCOT | Electric Reliability Council of Texas |
| ERZ | energy resource zone |
| ESP | competitive electric service provider |
| GATS | PJM Generation Attributes Tracking System |
| GIS | New England Power Pool Gen. Info. System |
| GW | gigawatt |
| GWh | gigawatt-hour |
| IOU | investor-owned utility |
| LSE | load-serving entity |
| MISO | Midwest Independent System Operator |
| M-RETS | Midwest Renewable Energy Tracking System |
| MSW | municipal solid waste |
| MW | megawatt |
| MWh | megawatt-hour |
| PJM | PJM Interconnection |
| POU | publicly owned utility |
| PRC | public regulation commission |
| PSC | public service commission |
| PUC | public utilities commission |
| PV | photovoltaics |
| REC | renewable energy certificate |
| RPS | renewables portfolio standard |
| SEP | supplemental energy payment |
| TWh | terrawatt-hour |
| WECC | Western Electricity Coordinating Council |
| WREGIS | Western Renewable Energy Gen. Info. System |

[1] RPS policies are sometimes called "Renewable Energy Standards," "Quota Systems," or "Renewable Obligations."
[2] Mandatory RPS requirements also exist in Australia, Japan, Belgium, Sweden, Italy, the United Kingdom, and Poland. Certain provinces in India and Canada have also developed RPS instruments, and renewable energy purchase obligations of a somewhat similar form are used in China.
[3] Sometimes referred to as a "Tradable Green Certificate" or "Green Tag", a REC is created when a megawatt-hour of renewable energy is generated, is a purely financial product, and can be traded separately from the underlying electricity generation. REC transactions create a supplemental revenue stream for renewable generators, and allow retail suppliers to demonstrate compliance with an RPS by purchasing RECs in lieu of directly purchasing renewable electricity.

first of what is envisioned to be an ongoing series; as such, it concentrates on key recent developments, while also providing basic information on historical RPS experience and design.

The report begins with an overview of state RPS policies: where they have been developed, when, and with what design features. Though most RPS programs are still in their infancy, the report summarizes the early impacts of these policies on renewable energy development, and provides a forecast of possible future impacts. It then turns to the implications of the growing trend towards solar and/or distributed generation set-asides within state RPS programs. Next, the report highlights state RPS compliance levels, enforcement actions, and cost impacts, as well as key developments in REC markets. Finally, the report provides a brief overview of Federal RPS proposals.

## Four States Added RPS Policies in 2007, Raising the Total to 25 States and Washington D.C.

The popularity of mandatory state RPS policies has grown in recent years. Four states – Illinois, New Hampshire, North Carolina, and Oregon – established new RPS programs in 2007 alone (the details of which are described further in Table A-1 in the Appendix). At the end of 2007, 25 states and Washington D.C. had a mandatory RPS (see Figure 1). Figure 2 shows the rate of state RPS adoption over time, presenting both the year of initial enactment and the years in which major changes to state RPS policies have been made. Of the 26 programs in existence at the end of 2007, half had been created since the beginning of 2004.

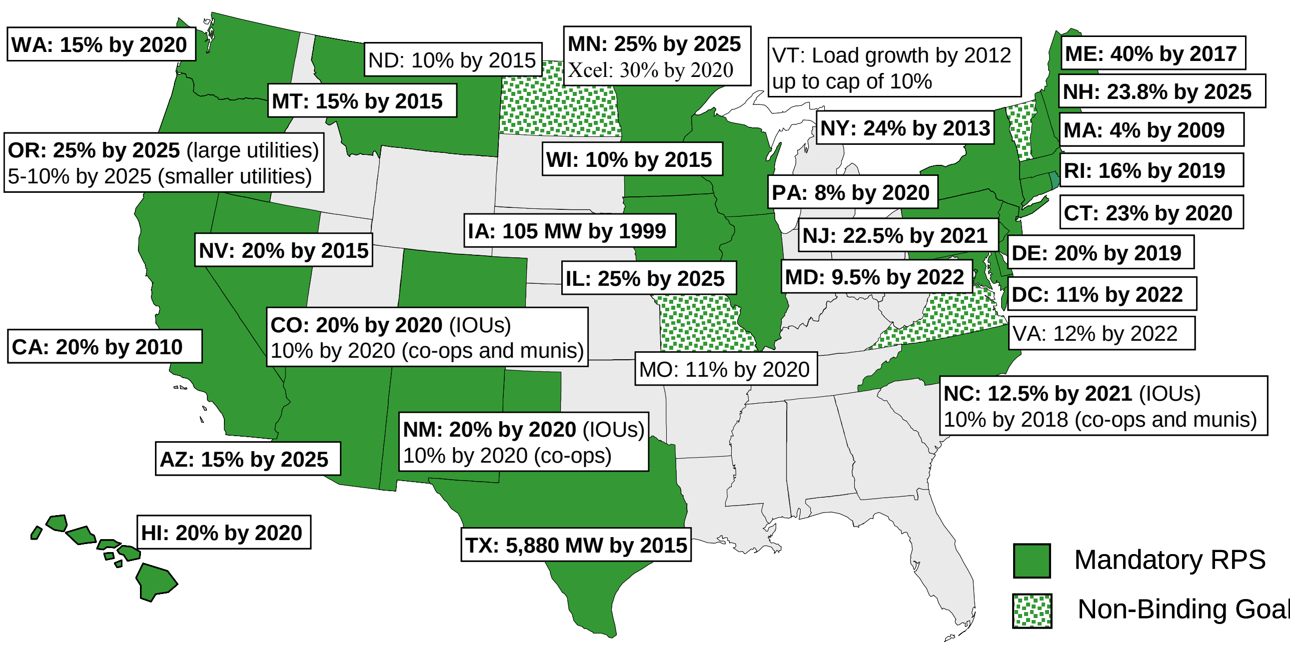


**Figure 1. State RPS Policies and Non-Binding Renewable Energy Goals**

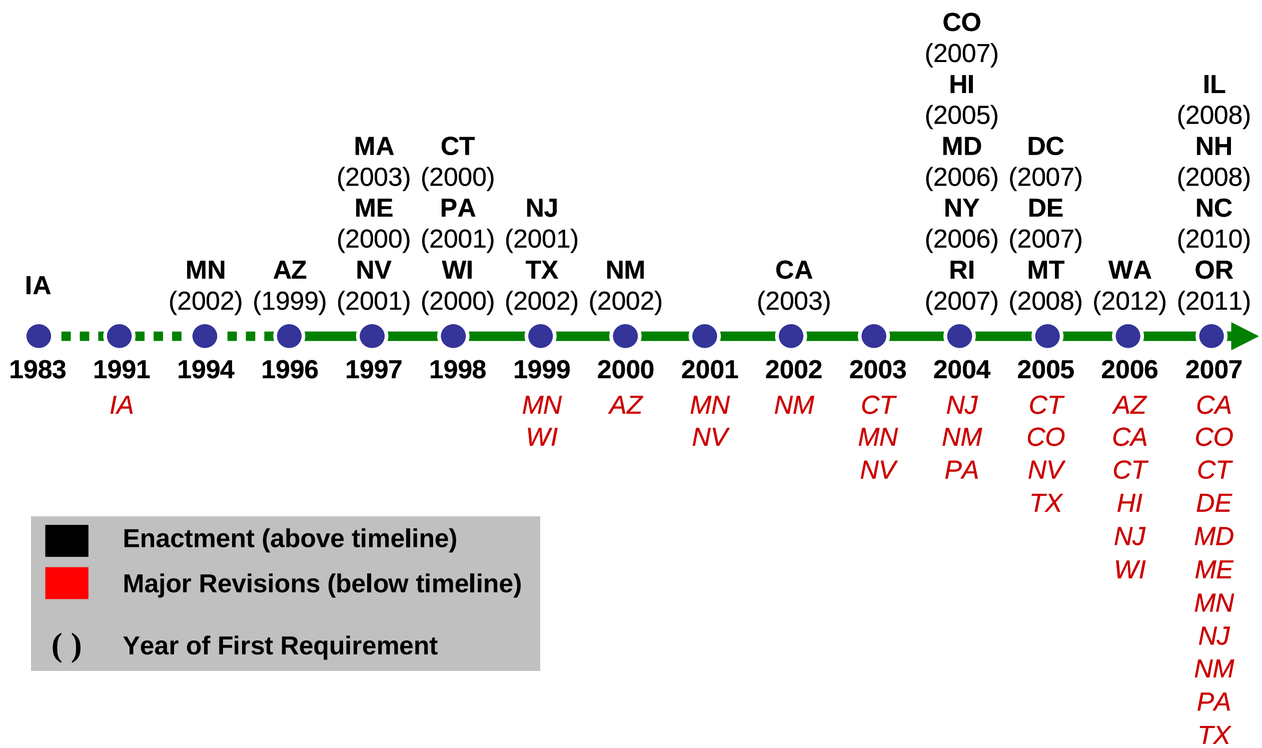


**Figure 2. The Adoption and Revision of Mandatory State RPS Policies**[4]

Most state RPS policies, including all four new programs created in 2007, have been established by legislative action. Alternatively, two states (New York and Arizona) developed their programs through regulatory channels, and two other states (Washington and Colorado) did so via voter-approved ballot initiatives.[5] In the 1990s, state RPS policies were generally incorporated into much broader state electricity restructuring legislation. More recently, these policies have been adopted through stand-alone legislation. In most cases, RPS programs are implemented by state utility regulatory agencies (i.e., public utilities commissions, variously referred to as PUCs, PSCs, PRCs, etc).

In addition to *mandatory* RPS policies, several states have developed *non-binding* renewable energy goals. As of the end of 2007, four states without a mandatory RPS had instead created non-binding targets through legislative action. Three of these states – Missouri, North Dakota, and Virginia – created their targets in 2007 (see Table A-3 in the Appendix), while Vermont established its target in 2005.[6] Other states, such as Illinois and Maine, previously had non-binding renewable energy goals that have subsequently been changed to mandatory RPS programs. Finally, some states with a mandatory RPS also have more-aggressive non-binding goals, including California (33% renewable energy by 2020, established by the Governor and the state's energy agencies), Iowa (1000 MW of wind capacity by 2010, recommended by the Governor's Energy Policy Task Force in 2001), and Texas (10,000 MW by 2025, established through legislation).

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[4] Some states have adopted annual RPS compliance periods that do not coincide with calendar years. Throughout this report, RPS compliance periods are referred to based on the starting year of the annual compliance period.
[5] The Colorado RPS passed based on a voter initiative in 2004, with 53% support. The Washington state RPS passed in 2006 with 52% of the vote.
[6] Though not reflected in this report, Vermont passed legislation in March 2008 establishing a new, non-binding goal that 20% of statewide electricity sales be derived from renewable generation by 2017.

## Eleven States Significantly Revised their RPS in 2007

Figure 2 illustrates the growing tendency for states to revise existing RPS policies. Eleven states made substantial modifications to their RPS programs in 2007, as described further in Table A-2 in the Appendix.[7] These changes have generally been to strengthen pre-existing RPS requirements, often by increasing renewable energy targets, removing supplier exemptions, or adding resource-specific set-asides.

Examples of legislative weakening of state RPS policies exist, but are generally more-modest in scope (e.g., minor expansions to resource eligibility, exempting publicly owned utilities from solar set-aside requirements, etc.) than are the examples of a strengthening of those policies. No state RPS policy has yet been repealed by later legislative action.

## Forty-Six Percent of Load in the U.S. Will Ultimately Be Covered by Existing RPS Policies

Mandatory state RPS programs created through the end of 2007 will, once fully implemented, apply to load-serving entities that, in aggregate, supply roughly 46% of nationwide retail electricity sales (see Figure 3). If the four states with non-binding renewable energy goals are also included, then the amount of nationwide load ultimately covered by an existing RPS (once fully implemented) increases to almost 51%.

Not all RPS policies establish renewable energy purchase obligations that take effect immediately upon enactment, however. As a result, in 2007, LSEs serving 31% of U.S. electrical load had an active RPS compliance obligation, up from 30% in 2006, 24% in 2005, and just 3% in 2000. By 2012, existing RPS policies will be nearly in full force, and active compliance obligations will extend to LSEs serving almost 46% of nationwide electrical load.

Of the LSEs serving the 31% of U.S. electrical load with RPS obligations in 2007, investor-owned utilities (IOUs) represent the largest share (19%), followed by competitive electric service provides (ESPs, 10%), and then by publicly owned utilities (POUs, 3%).[8] After 2007, the percentage share by each type of electricity supplier cannot be easily projected, due to potential customer switching between IOUs and ESPs in states with retail choice.

The fact that 100% of U.S. load is not covered by a state RPS reflects two factors. First, and most obviously, not all states have developed RPS programs. Secondly, as described in Table 2, a variety of states offer RPS exemptions to particular types of LSEs and/or customers. Both factors are incorporated into Figure 3.

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[7] Less-significant revisions to RPS policies in 2007 were made in the following states: (1) Hawaii (in implementing 2006 statutory revisions to the RPS, the PUC established a framework for – among other things – reporting and non-compliance penalties); (2) Massachusetts (regulatory revisions were made to biomass eligibility); (3) Montana (added competitive ESPs serving small customers to those LSEs that must meet RPS obligations); and (4) Nevada (added geothermal heat as an eligible energy efficiency source).

[8] The term publicly owned utility, or POU, is broadly used in this report to include public power and cooperatives. IOU, ESP, and POU contributions do not sum to 31% due to rounding.

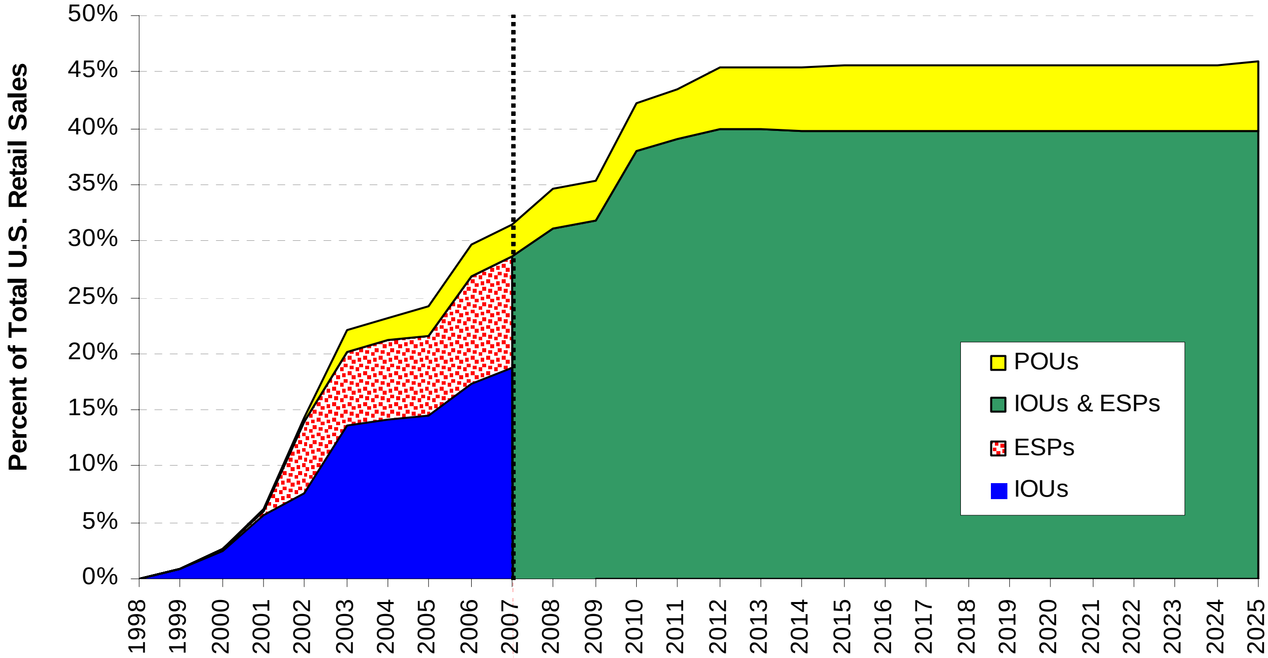


**Figure 3. U.S. Electrical Load with Active State RPS Obligations**

## The Design of State RPS Policies Continues to Differ Widely

State RPS programs share the common goal of encouraging renewable energy supply, but design variations among states are so stark that there is even some debate over what exactly constitutes an RPS, and whether certain states qualify as having one.[9] The tailoring of RPS designs to satisfy particular state objectives and political exigencies is a typical aspect of state policy making, ensuring that U.S. states serve as "laboratories" for RPS policy experimentation.

Table 1 illustrates a small subset of the important design differences among existing mandatory state RPS programs and non-binding state renewable energy goals. Variations exist in terms of the renewable energy purchase targets and timeframes, which renewable energy technologies are eligible[10], and whether existing projects can qualify. Importantly, some states have established "tiered" targets or set-asides, consisting of different targets for different resource types or resource vintages, frequently with different schedules and compliance frameworks. Tiers and set-asides are often used to ensure that an RPS supports certain "preferred" resources, not just the least-cost renewable energy options. Alternatively, or in addition, some states have sought to support preferred resource types through credit multipliers of various designs.

One important structural difference among state RPS policies relates to how compliance is achieved. Three distinct RPS compliance models have thus far emerged:

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[9] New York, for example, has established a policy that it calls an RPS, but that involves ratepayer collection of funds and incentive payments from a state energy authority. New York is identified in this report as a state with an RPS, though such a classification is debatable.

[10] Though wind, solar, landfill-gas, and geothermal energy are eligible under most of the policies, eligibility criteria for biomass, municipal solid waste (MSW), and hydropower vary considerably across states. Some states also allow resources such as energy efficiency and gas-fired fuel cells to qualify (see later section).

1. in states with retail electric competition, electricity suppliers are typically given broad latitude to comply with RPS requirements as they see fit;
2. in states with still-regulated utility monopolies, electricity regulators oversee – to varying degrees – utility procurement and contracting under the RPS; and
3. in two states, New York and Illinois, a state agency/instrumentality has direct responsibility to conduct procurements under the RPS.

As alluded to earlier, state RPS policies also differ in terms of which entities are obligated under the program. Many states have exempted certain LSEs or end-use customers from meeting RPS reqiurements (see Table 2). In particular, states often exempt some or all POUs from formal RPS obligations, or instead allow POUs to develop their own renewable energy standards. Various other types of permanent or temporary exemptions have also been adopted, for example, exemptions for small utilities, large customers, or customers in utility service territories with a rate freeze. *Force majeure* clauses and cost caps, which are common, can also effectively function as exemptions by reducing the amount of load subject to RPS obligations.

States have also adopted different eligibility rules related to geographic location and electricity delivery. States that enact RPS policies typically do so with the expectation that the requirement will stimulate new resource development in their state or region. If renewable electricity is used for compliance, and that electricity must be delivered to the LSE under the RPS obligation, a practical limitation is placed on the distance of renewable projects from the state in question. Unbundled RECs, on the other hand, could potentially satisfy an RPS without any geographic constraint. Because state interests in encouraging in-state or in-region development vary, because interpretations of the requirements of the Interstate Commerce Clause vary, and because wholesale electricity market structures differ, a variety of approaches have been used to limit the geographic eligibility of renewable energy projects, and to establish electricity delivery requirements. Table 3 describes the geographic eligibility and electricity delivery requirements for the main "tier" of each state's RPS (certain sub-tiers, for example solar or DG set-asides, often have different standards).

Other differences in the design of state RPS policies, some of which are described in later sections of this report, pertain to what kind of enforcement is applied, whether and what types of cost caps exist, whether unbundled RECs are allowed, what level of compliance flexibility is provided, whether discretionary or non-discretionary regulatory waivers are offered, the degree to which contracting requirements are applied, and the role of state funding mechanisms.

Tables A-1 through A-3 in the Appendix provide more-detailed textual descriptions of the key design elements of the new mandatory state RPS programs, major RPS program revisions, and new non-binding state renewable energy goals adopted in 2007. Key policy design trends among those states that created or revised RPS programs in 2007 include the following:

- The stringency of renewable energy targets increased both through revisions to existing programs and through implementation of new RPS policies.
- The use of resource-specific set-asides dramatically expanded, especially for solar, but also for other favored renewable resource options, such as wind power.
- The applicability of RPS policies continued to expand to cover POUs, with three of four new state policies broadly applicable to all electricity suppliers, and revisions to existing policies also increasingly requiring POUs to meet renewable energy purchase objectives.
- Though RPS policies increasingly apply to POUs, it has also become common to offer greater leniency and impose lower RPS targets to those supplies.

## Table 1. Select Design Elements of State RPS Policies

| State | First Compliance Year | Current Ultimate Target | Existing Plants Eligible[1] | Set-Asides, Tiers, or Minimums | Credit Multipliers |
|---|---|---|---|---|---|
| **Mandatory RPS Obligations** | | | | | |
| Arizona | 2001 | 15% (2025) | No | Distributed Generation | None[2] |
| California | 2003 | 20% (2010) | Yes | None | None |
| Colorado | 2007 | 20% (2020): IOUs<br>10% (2020): POUs | Yes | Solar | In-State, Solar, Community-Ownership |
| Connecticut | 2000 | 23% (2020) | Yes | Class I/II Technologies | None |
| Delaware | 2007 | 20% (2019) | Yes | Solar, New/Existing | Solar, Fuel Cells, Wind |
| Hawaii | 2005 | 20% (2020) | Yes | Energy Efficiency | None |
| Illinois | 2008 | 25% (2025) | Yes | Wind | None |
| Iowa | 1999 | 105 MW (1999) | Yes | None | None |
| Maine | 2000 | 40% (2017) | Yes | New/Existing | None |
| Maryland | 2006 | 9.5% (2022) | Yes | Solar, Class I/II Technologies | Wind, Methane |
| Massachusetts | 2003 | 4% (2009) | No | None | None |
| Minnesota | 2002 | 25% (2025)<br>30% (2020): Xcel | Yes | Wind for Xcel; Goal for Community-Based Renewables | None |
| Montana | 2008 | 15% (2015) | No | Community Wind | None |
| Nevada | 2003 | 20% (2015) | Yes | Solar, Energy Efficiency | PV, DG, Eff., Waste Tire |
| New Hampshire | 2008 | 23.8% (2025) | Yes | Solar, New, Existing Biomass/ Methane, Existing Hydro | None |
| New Jersey | 2001 | 22.5% (2021) | Yes | Solar, Class I/II Technologies | None |
| New Mexico | 2006 | 20% (2020): IOUs<br>10% (2020): Co-ops | Yes | Solar, Wind, Geothermal or Biomass, Distributed Generation | None[2] |
| New York | 2006 | 24% (2013) | Yes | Distributed Generation | None |
| North Carolina | 2010 | 12.5% (2021): IOUs<br>10% (2018): POUs | Yes | Solar, Swine Waste, Poultry Waste, Energy Efficiency | None |
| Oregon | 2011 | 25% (2025): Large<br>5-10% (2025): Small | No[3] | Goal for Community-Based and Small-Scale Renewables | None |
| Pennsylvania | 2001 | 8% (2020) | Yes | Solar | None |
| Rhode Island | 2007 | 16% (2019) | Yes | New/Existing | None |
| Texas | 2002 | 5,880 MW (2015) | Yes | Goal for Non-Wind | All Non-Wind |
| Washington | 2012 | 15% (2020) | No | None | Distributed Generation |
| Washington, DC | 2007 | 11% (2022) | Yes | Solar, Class I/II Technologies | Wind, Solar, Methane |
| Wisconsin | 2000 | 10% (2015)[4] | Yes | None | None |
| **Non-Binding Renewable Energy Goals[6]** | | | | | |
| Missouri | 2012 | 11% (2020) | Yes | None | PSC Authorized To Do So |
| North Dakota | 2015 | 10% (2015) | Yes | None | None |
| Vermont | 2006 | Up To 10% (2012)[5] | No | None | None |
| Virginia | 2010 | 12% (2022) | Yes | None | Wind, Solar |

[1] Some RPS policies allow existing facilities, but only if built after a certain date, e.g., 1995 or 1999. For the purpose of this table, these states are identified as not allowing existing resources, because they do not allow older existing facilities. In other states, such as Texas, existing facilities may qualify towards the RPS, but with restrictions not identified in the table. Note also that even those states that do not broadly allow existing facilities to qualify under their RPS often allow incremental generation from such facilities to qualify.
[2] Credit multipliers were once used extensively, but are now being phased out and replaced by set-asides.
[3] Only plants placed in service on or after January 1, 1995 are broadly eligible, except that certain small-hydro facilities owned by Oregon utilities and placed in service prior to 1995 are also eligible (such facilities must be certified as "low impact", however, and there are limits to the amount of hydro generation that is allowed to qualify). Incremental efficiency and capacity upgrades on pre-1995 renewable facilities are also eligible.
[4] Targets vary by utility, but the statewide goal is 10% by 2015.
[5] Target equals load growth between January 2005 and January 2012, capped at 10% of 2005 load. The target becomes mandatory in 2013 if the non-binding goal is not achieved. Though not reflected in this report, Vermont also passed legislation in March 2008 establishing a new, non-binding goal that 20% of statewide electricity sales be derived from renewable generation by 2017.
[6] In addition to the four non-binding state renewable energy goals noted here, California, Iowa, and Texas have both mandatory RPS policies and more-aggressive non-binding goals.

**Table 2. State RPS Exemptions**

| State | % of State Sales Covered | Treatment of POUs | | Other LSE Exemptions | Customer Exemptions |
|---|---|---|---|---|---|
| | | Munis | Coops | | |
| AZ | 59% | ○ | ● | Political subdivisions; utilities with >50% of out-of-state customers | None |
| CA | 98% | ⦿ | ⦿ | POUs obligated to develop own RPS | None |
| CO | 94% | ● | ● | Munis with < 40,000 customers | None |
| CT | 100% | ⦿ | na | Munis obligated to develop own RPS | None |
| DE | 75% | ○ | ○ | POUs have requested/received exemptions | Industrial customers > 1.5 MW load |
| HI | 100% | na | ● | None | None |
| IA | 75% | ○ | ○ | Applies only to MidAmerican and IPL | None |
| IL | 56% | ○ | ○ | IOUs with < 100,000 customers; all competitive ESPs | IOU retail supply customers not with fixed-price service |
| MA | 86% | ○ | na | None | None |
| MD | 98% | ● | ● | Coops served by existing purchase agreement | Industrial process load > 300 GWh/yr; resid. load in area subject to rate freeze |
| ME | 93% | ○ | ○ | None | Sales to certain businesses, until 2010 |
| MN | 100% | ● | ● | None | None |
| MT | 63% | ⦿ | ⦿ | Coops and existing munis with > 5,000 customers must develop own RPS; other coops exempt; ESPs and new munis that serve large customers exempt | None |
| NC | 100% | ● | ● | None | None |
| NH | 100% | ● | ● | None | None |
| NJ | 97% | ○ | ○ | None | None |
| NM | 88% | ○ | ● | None | None |
| NV | 88% | ○ | ○ | None | None |
| NY | 73% | ○ | ○ | LIPA, NYPA, munis encouraged to establish RPS | None |
| OR | 100% | ● | ● | Multiple clauses offer possible exemptions to certain suppliers (esp. POUs) in certain years | None |
| PA | 97% | ○ | ○ | None | Load in area subject to rate freeze |
| RI | 99% | ○ | na | None | None |
| TX | 75% | ○ | ○ | Utilities under a rate freeze | Certain large customers upon petition |
| WA | 83% | ● | ● | All utilities with < 25,000 customers | None |
| D.C. | 100% | na | na | None | None |
| WI | 100% | ● | ● | None | None |

Notes: The percent of state sales figures represent the fraction of statewide load ultimately obligated by existing RPS policies. The percentage totals include POUs required to meet an RPS of their own design (e.g., CA and CT) and LSEs temporarily exempted from the RPS. In addition to the specific exemptions listed here, Federal power marketing agencies and state-owned electric utilities are assumed to be exempt in all cases.

● Must generally meet RPS (in some cases, percentage targets are lower or limited exemptions apply)
⦿ Must meet an RPS of their own design
○ Fully exempt from obligatory RPS
na No entities of that type exist in the state

**Table 3. Geographic Eligibility and Electricity Delivery Requirements (Main Tier of Each State's RPS)**

| Geographic Eligibility and Delivery Requirements | States | Notes |
|---|---|---|
| In-state generation requirement | HI, IA | IA: also allows location in broader utility service area |
| In-region generation requirement | MN, OR, PA | MN: RECs originating within M-RETS; OR: WECC for unbundled RECs, U.S. portion of WECC and delivered to LSE for renewable electricity; PA: PJM projects for all LSEs, MISO projects for some LSEs |
| Electricity delivery required to state or to LSE | | |
| Direct transmission inter-tie between generators and state | NV, TX | NV: allows limited sharing of transmission inter-tie with other generators; TX disallows such sharing |
| Broader delivery requirements to state or to LSE | AZ, CA, MT, NM, NY, WI | CA: relaxed scheduling allows shaped/firmed products; NY: strict hourly scheduling to state and strong preference for in-state resources in solicitation process; WI: projects must be owned by or under contract to LSE |
| Electricity delivery required to broader region | | |
| Generators anywhere outside region must deliver electricity to region | DE, ME, NJ, WA | DE: also provides credit multipliers for in-state wind installed before 2013; NJ: resources outside PJM must be "new"; WA: if outside Pacific Northwest, requires delivery to state |
| Generators in limited areas outside region must deliver electricity to region | CT, DC, MA, MD, NH, RI | All: renewable facilities must be located in control areas adjacent to state's ISO; DC & MD: LSEs may also purchase unbundled RECs (without electricity delivery) from states that are adjacent to PJM |
| In-state generation encouragement | | |
| In-state multipliers | CO | No restriction on location of RECs creation, but credit multiplier for in-state projects (DE also provides in-state encouragement through multipliers) |
| Cost-effectiveness test | IL | In-state unless insufficient cost-effective resources, then from adjoining states, then from other regions; after 2011, equal preference to in-state and adjoining states |
| Limit on RECs from out-of-state generators | NC | Up to 25% compliance can be met with unbundled RECs from outside state (no limit for one LSE, Dominion); remainder must be in-state or delivered to LSE |

## Resource Eligibility Is Expanding Beyond Traditional Renewable Sources to Include Energy Efficiency and Other Supply-Side Technologies

Among those states with mandatory RPS policies, three – Hawaii, Nevada, and North Carolina – allow demand-side energy efficiency to qualify for a portion of the stated *renewables* portfolio standard requirement, enabling LSEs to substitute energy efficiency for renewable energy for some portion of RPS compliance (see Table 4). Other states, including Colorado, Connecticut, Illinois, Minnesota, New Jersey, New Mexico, Pennsylvania, and Texas, have established (or have authorized the development of) mandatory energy efficiency portfolio standards that are separate from, and additional to, any targets for renewable resources.[11]

Some states also allow certain supply-side efficiency technologies or non-renewable energy technologies to meet a portion of their RPS standard, including the electricity and/or heat from combined heat and power and/or waste heat recovery facilities (e.g., Colorado, Connecticut, Hawaii, Illinois, Maine, Nevada, North Carolina), and fuel cells using fuels derived from non-renewable energy sources (e.g., Connecticut, Maine, Minnesota, New York, Pennsylvania). Still other states, such as Pennsylvania, include portfolio standard requirements for non-renewable energy sources that are *additional* to the standards applied for renewable electricity.

**Table 4: States with Demand-Side Energy Efficiency Included in Mandatory RPS Requirements**

| State | Proportion of RPS that Can Be Met with Energy Efficiency | Notes |
|---|---|---|
| HI | Up to 50% | Heat pump water heating, ice storage, ratepayer-funded efficiency programs, and use of rejected heat from cogeneration and combined heat and power systems |
| NV | Up to 25% | Utility-subsidized efficiency measures installed after 1/1/05, and district heating powered by geothermal hot water; at least 50% of savings must come from the residential sector; utilities can purchase energy savings credits from third parties; energy efficiency receives standard multiplier of 1.05, and 2.0 for peak savings |
| NC | IOUs: Up to 25%; up to 40% after 2021<br>POUs: Unlimited for main RPS target | Efficiency measures after 1/1/07, including waste heat from combined heat and power systems powered by non-renewable fuels; POUs may also rely on demand-management/load-shifting |

[11] For additional information on energy efficiency portfolio standards in the United States, see: (1) Nadel, S. 2006. Energy Efficiency Resource Standards: Experience and Recommendations. Washington, D.C.: American Council for an Energy-Efficient Economy. (2) Hamrin, J., E. Vine, and A. Sharick. 2007. The Potential for Energy Savings Certificates as a Major Tool in Greenhouse Gas Reduction Programs. San Francisco, Calif.: Center for Resource Solutions.

## Operational Experience Remains Limited

State RPS programs are a relatively new addition to the renewable energy policy landscape, with most programs enacted since the late 1990s. Consequently, many RPS states have few years of operational experience during which active compliance obligations have been in force. As shown in Figure 4, six states with RPS policies had no operational experience with those policies, as of year-end 2007 (i.e., the first compliance period is 2008 or later), and six additional states had just one year of such experience. Eleven states have four or more years of operational experience, though in some instances these policies began with modest renewable energy purchase obligations, so early-year targets were not particularly challenging to achieve.

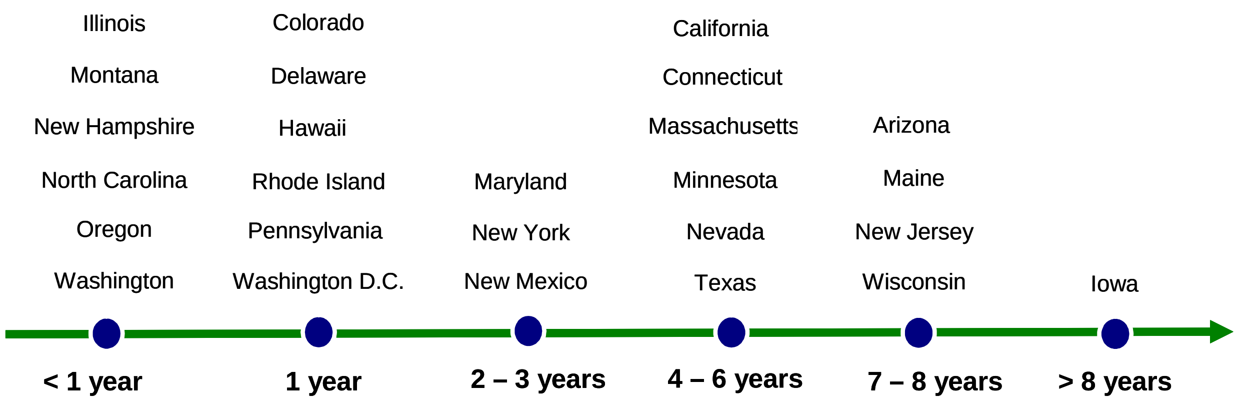


**Figure 4. Experience with State RPS Policies (Years Since First Major Compliance Period)**

## Renewables Portfolio Standards Are Increasingly Motivating Renewable Energy Development

Though experience remains somewhat limited, state RPS policies are already beginning to have a sizable impact on the amount and location of renewable project development. These policies are one of a number of drivers for renewable energy. Other significant factors include Federal tax incentives, state renewable energy funds, voluntary green power markets, the specter of future greenhouse gas regulations, and the economic fundamentals of certain forms of renewable energy relative to conventional generation. Disentangling these various drivers is – to put it mildly – challenging.

As one indicator of the role of state RPS programs in renewable resource development, over 50% of non-hydro renewable capacity additions in the U.S. from 1998 through 2007 occurred in states with active, mandatory RPS policies, totaling roughly 8,900 MW (see Figure 5). Since 2002, this percentage rises to over 60%. In 2007 alone, approximately 76% of all non-hydro renewable capacity additions came from states with active RPS programs. By this metric at least, it appears that state RPS policies are already playing a major role in renewable resource development in the United States.

These numbers should be viewed with some caution, however, because they do not assess whether any given facility was constructed *because of* a state RPS or was, in fact, even eligible for a given state's RPS. On the one hand, in some RPS states, such as Texas and Iowa, a substantial amount of renewable energy capacity has been added in recent years that has not been directly motivated by those states' RPS policies. Moreover, because RPS policies have often been established in states with reasonably strong renewable resource potential, it is perhaps not surprising that a good fraction of the renewable energy development in the U.S. has occurred in those states. Given these considerations, the data presented in Figure 5 would tend to overstate the importance of RPS programs. On the other hand, most states allow out-of-state generation to count toward their RPS, so renewables capacity built in a non-RPS state may be used to meet another state's mandate; the data presented in Figure 5 do not account for this effect, which would tend to understate the importance of state RPS policies. As a result, it is somewhat unclear whether and to what degree the data presented here under- or over-estimate the importance of state RPS policies.

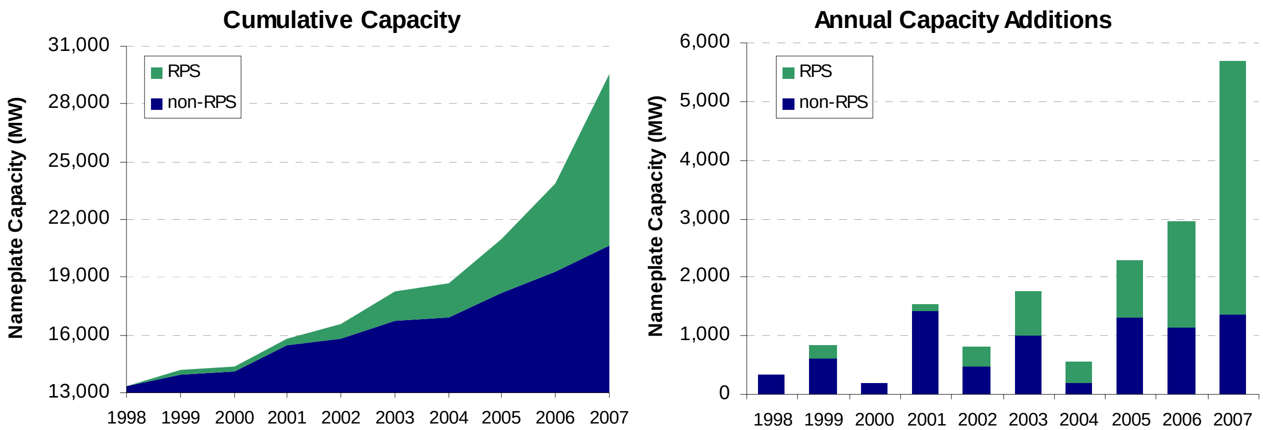


**Figure 5. Cumulative and Annual Non-Hydro Renewables Capacity in RPS and Non-RPS States**[12]

Regardless of these details, it is nevertheless evident that existing state RPS policies have already had a sizeable impact on new renewable resource development.[13] Moreover, because many of these policies have only recently been enacted, and renewable energy contracting has just begun, renewable capacity additions to date do not fully capture the impact of existing state RPS policies. In California alone, for example, the state's investor- and publicly owned utilities have contracted for more than 7,000 MW of new renewables capacity since the RPS was enacted in 2002, but just 1,100 MW of this capacity was online at the end of 2007.

## State RPS Policies Are Primarily Supporting Wind Power, Though Some Resource Diversity Is Apparent

Of the more than 8,900 MW of new non-hydro renewable energy capacity that has come on line in RPS states from 1998 through 2007, roughly 93% has come from wind power, with biomass (4%), solar (2%), and geothermal (1%) playing lesser roles (see Figure 6).

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[12] Non-solar data for 1998-2006 were sourced from EIA Form-860; wind data for 2007 were from AWEA; biomass and geothermal data for 2007 were from Ventyx; and solar data for all years were from Larry Sherwood (Interstate Renewable Energy Council) and known installations of solar thermal electric facilities. Renewable capacity additions are designated as having occurred in an RPS state if the facility came online in the year before the first compliance date or later.

[13] Research at Berkeley Lab confirms this to some degree. In particular, Berkeley Lab estimates – based on project-specific considerations – that, from 2001 through 2007, roughly 65% of the total wind additions in the U.S. were motivated, at least in part, by state RPS policies.

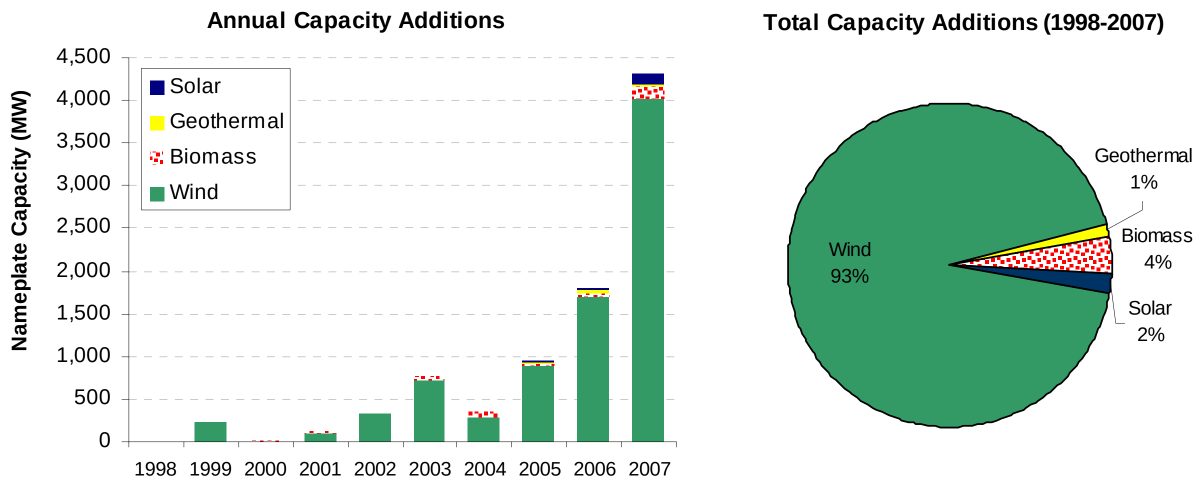


**Figure 6. Non-Hydro Renewable Energy Capacity Additions in RPS States, By Technology Type**[14]

Though renewable resource diversity has so far been limited, there is some evidence that diversity may increase over time as RPS policies expand, at least in some states. In California, for example, of the more than 7,000 MW of contracts for new or repowered renewable energy projects signed from 2002 through 2007 by the state's IOUs and POUs, 58% of the total capacity is wind, 23% solar, 12% geothermal, 7% biomass/MSW, and less than 1% is small hydro and ocean energy, demonstrating a greater level of diversity than historical trends, both nationally and in California.[15] Additionally, largely because of technology tiers that exist in a number of states, a growing amount of solar energy is being motivated by RPS obligations, as discussed further in a later section of this report.

## The Future Impacts of Existing State RPS Policies Are Projected To Be Relatively Sizable

The impacts of state RPS programs on renewable resource development are expected to expand in the long term as renewable purchase obligation increase, though the magnitude of that growth will depend on how RPS policies are implemented, whether cost caps are limiting, whether entities elect to make alternative compliance payments, and whether new renewable energy projects would have come on line absent the support of state RPS policies.

Ignoring these complexities, and simply assuming that full compliance is achieved, Berkeley Lab estimates that over 60 GW of cumulative, new renewable energy capacity may be needed by 2025 to fully meet existing state RPS policies (see Figure 7), including 4 GW already required by 2007, a cumulative 14 GW by 2010, and a cumulative 32 GW by 2015. The 60 GW figure increases to over 62 GW if one also includes the non-binding renewable energy targets legislatively established in Missouri, North Dakota, Vermont, and Virginia, and to nearly 77 GW if one includes the longer-term, non-binding renewable energy goals in California, Iowa, and Texas.

[14] Non-solar data for 1998-2006 were sourced from EIA Form-860; wind data for 2007 were from AWEA; biomass and geothermal data for 2007 were from Ventyx; and solar data for all years come from Larry Sherwood (Interstate Renewable Energy Council) and known installations of solar thermal electric facilities. We designate renewable capacity additions as having occurred in an RPS state if the facility came online in the year before the first compliance date or later.

[15] Of the more than 1,100 MW of renewable capacity added in California from 1998-2007, approximately 75% was wind, 12% biomass, 8% geothermal, and 4% small hydro.

The largest markets, in terms of capacity growth requirements, are projected to be California, Illinois, Minnesota, Texas, New Jersey, and Arizona, each of which would require over 3,000 MW of new renewable energy capacity by 2025 to achieve full compliance. As a proportion of expected statewide retail sales in 2025, however, leading states are somewhat different, and include Minnesota, Oregon, Connecticut, New Jersey, New Hampshire, New Mexico, and Delaware, each of which would require that more than 15% of statewide load in 2025 come from new renewable generation. Some of the leading states in terms of required capacity additions, such as Texas, require rather modest additions on a percentage-of-load basis.

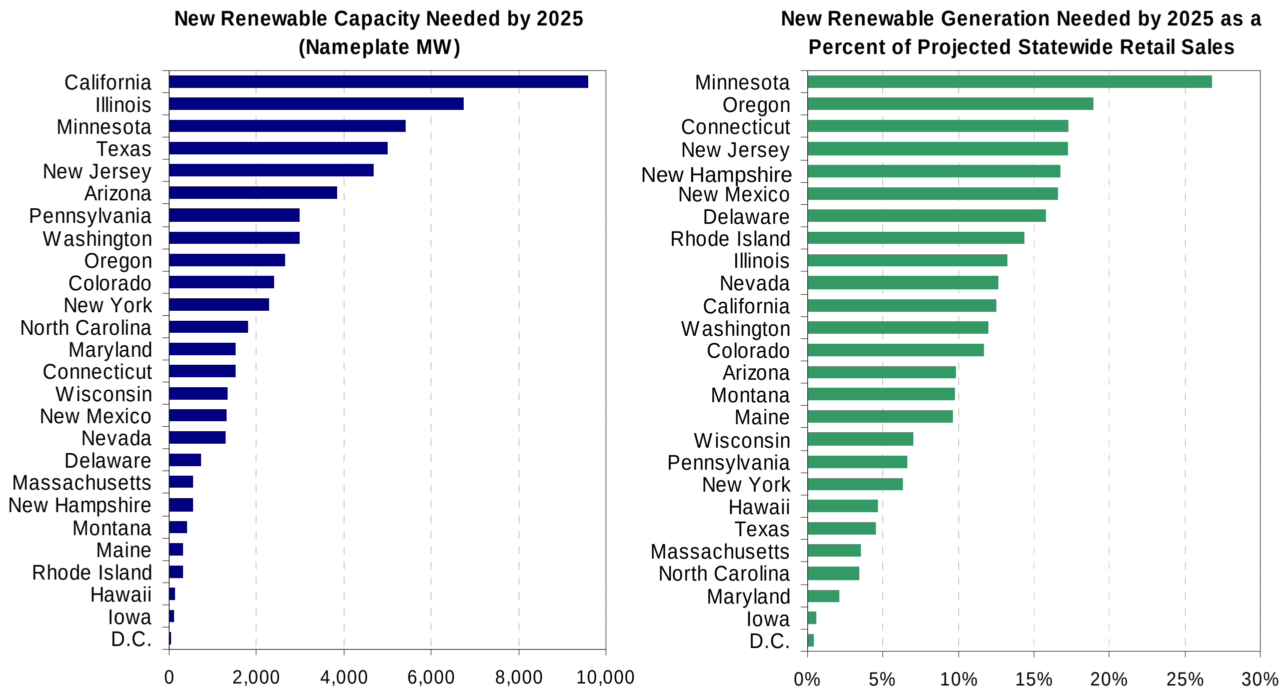


**Figure 7. New Renewable Energy Required to Meet Existing State RPS Policies**[16]

Though the eventual market impacts of existing state RPS policies are uncertain, and will depend critically on design and implementation details, there is little doubt that the aggregate amount of new renewable energy generation *required* under these policies is significant. The estimated 60 GW of new renewables capacity equates to an *additional* 4.7% of total projected nationwide electricity generation in 2025, compared to a non-hydro share of 2.1% in 1999 and 2.4% in 2006. Roughly 15% of the projected growth in retail electricity sales from 2000 though 2025 would come from new renewable generation required under existing state RPS policies. Even with this growth, however, non-hydro renewables would continue to provide a relatively modest contribution to U.S. electricity supply: adding the estimate of new renewable generation required by existing state RPS programs from 2000 to 2025 to the 1999 base amount of non-hydro renewables sums to just 6% of total projected electricity generation in the U.S. by 2025.

[16] Data used to generate this figure were derived by applying RPS percentage obligations in each state to our projection of obligated retail sales, and deducting expected contributions from existing renewable generation. The figure may overstate new renewables needed to fully meet state RPS policies to the extent that more-aggressive energy efficiency programs reduce load growth, or if LSEs use out-of-state existing renewable generation to a greater extent than assumed here. Note that the new renewable generation required under the Maryland and Washington, D.C. RPS policies is assumed to come exclusively from those states' solar set-asides, with all remaining RPS requirements in those two states projected to be met by existing resources.

## Solar-Specific RPS Designs Are Becoming More Prevalent

Because of concerns that traditional RPS programs – in which all eligible renewable technologies compete – are likely to benefit only the least-cost projects, an increasing number of states have begun to design their RPS policies to provide differential support to promising but (currently) higher-cost renewable technologies or applications. Typically, this support has been provided either through *credit multipliers*, in which favored renewable technologies are given more credit towards meeting RPS requirements than are other technologies, or through *set-asides*, in which some fraction of the RPS must be met with favored technologies.

As suggested by Table 1, set-asides and credit multipliers have been used to support an array of favored technologies, applications, project locations, and vintages. The most popular use of these mechanisms, however, has been to support central and distributed solar energy specifically, and customer-sited distributed generation (DG) more generally.[17]

Set-asides for solar or DG exist within 12 of the 26 U.S. RPS programs (see Figure 8). Four of these states combine credit multipliers of some form with these set-asides. Credit multipliers have become somewhat less popular in recent years, and only two states – Texas and Washington – now use credit multipliers without an accompanying mandatory set-aside. The popularity of set-asides for solar or DG, on the other hand, has increased dramatically in recent years. In 2007 alone, new solar or DG set-asides were created in Delaware, Maryland, New Hampshire, New Mexico, and North Carolina, and the previously-established solar set-aside in Colorado was effectively expanded though an increase in that state's overall RPS target.

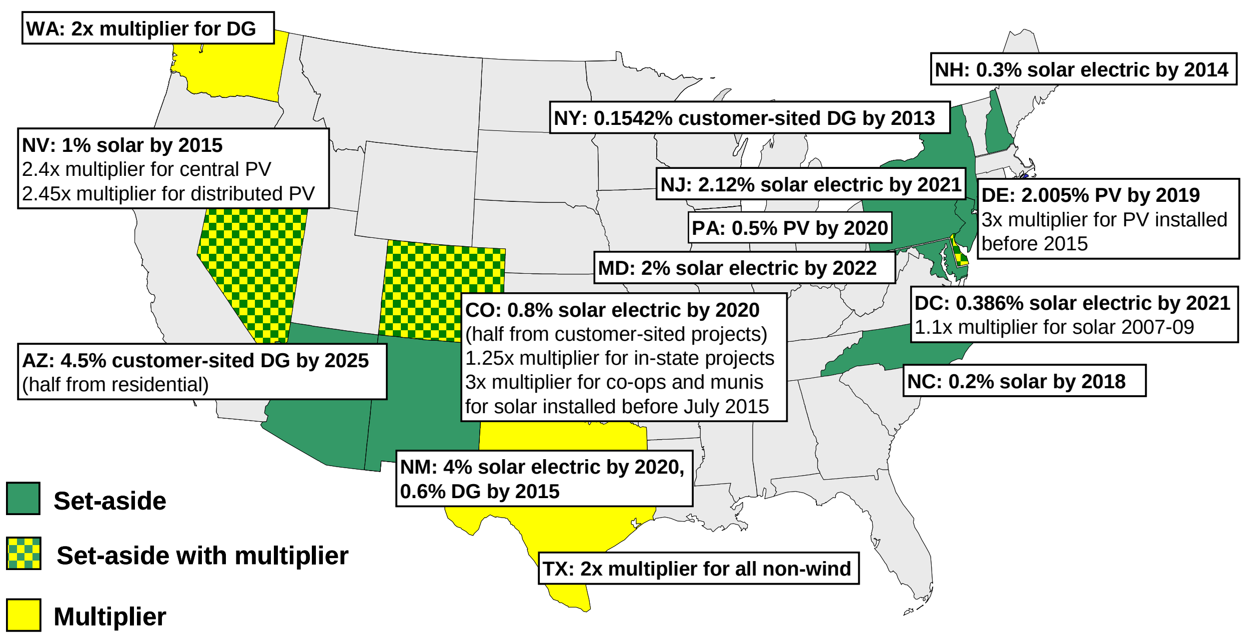


**Figure 8. Differential Support for Solar Energy in State RPS Policies**

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[17] In addition to deciding which of these mechanisms to use, states seeking to support solar within an RPS must also address issues of eligibility (Are all forms of solar electricity eligible? Are customer-sited generators eligible?); measurement (Are metering and tracking systems in place?); and REC ownership and trading (Do owners of solar systems own their RECs? Do mechanisms exist to trade small quantities of RECs?).

Among those states with solar or DG set-asides, two are restricted to photovoltaic (PV) applications, nine also allow solar-thermal electric technologies to qualify, three allow solar heating and/or cooling to qualify[18], and three states have DG set-asides in which solar PV can compete with other forms of renewable DG (see Table 5). The policies also differ in their targets and timeframes, geographic scope of project eligibility, use of cost caps and alternative compliance mechanisms, and degree of regulatory oversight over solar contracting. Many of these set-asides have yet to take effect; only Arizona, Nevada, and New Jersey have three or more years of operational experience.

**Table 5. Design Elements of State Solar and DG Set-Asides**

| State | First Compliance Year | Resource Eligibility | | | |
|---|---|---|---|---|---|
| | | Photovoltaics | Solar Thermal Electric | Solar Heating and/or Cooling | Non-PV Dist. Generation |
| Arizona | 2001 | ● | ● | ● | ● |
| Colorado | 2007 | ● | ● | | |
| Delaware | 2008 | ● | | | |
| Maryland | 2008 | ● | ● | | |
| Nevada | 2003 | ● | ● | ● | |
| New Hampshire | 2010 | ● | ● | | |
| New Jersey | 2004 | ● | ● | | |
| New Mexico | 2011 | ● | ● | | ● |
| New York | 2006 | ● | | | ● |
| North Carolina | 2010 | ● | ● | ● | |
| Pennsylvania | 2006 | ● | | | |
| Washington D.C. | 2007 | ● | ● | | |

Despite their nascent state, solar and DG set-asides, in combination with state and Federal incentives, have already begun to have a significant impact on the grid-connected PV market in the United States, as shown in Figure 9. Overall, New Jersey has been the largest solar set-aside-driven PV market in the United States since 2000, although Nevada and Colorado emerged as equally-significant solar set-aside markets in 2007. Additional contributions to grid-connected PV additions in states with solar set-asides have come from Arizona and, more recently, New York. In total, from 2000 through 2007, 102 MW of grid-connected PV capacity was added in states with solar set-asides, representing 22% of all grid-connected PV installations in the U.S. over this period, and 75% of all grid-connected PV additions outside of California, the country's largest market.[19]

The impact of solar and DG set-asides is not restricted to PV. In fact, the nation's only two solar-thermal electric plants built since 1991 – a 1 MW facility in Arizona commissioned in 2006 and a 64 MW plant in Nevada commissioned in 2007 – have been motivated by solar set-asides. More generally, solar-thermal electric development does not, in some states, appear to require a solar set-aside. In California, for example, a number of such projects are in development, driven by a more-traditionally designed RPS, without a solar set-aside (see Table 6).

[18] In addition to Arizona, Nevada, and North Carolina, which allow solar heating and/or cooling to qualify for their solar/DG set-asides, a number of other states allow solar heating and/or cooling to qualify for their overall RPS target, including: Delaware, Hawaii, Illinois, New Hampshire, Pennsylvania, and Texas.

[19] California's RPS, which lacks a solar set-aside, has resulted in 15-29 MW of utility-scale PV contracts for projects not yet constructed (range reflects expansion options). Separately from the RPS, California has also enacted aggressive financial incentive programs that intend to support 3,000 MW of customer-sited solar PV by 2017, and that have already spurred more than 300 MW of grid-connected PV capacity from 2000-2007.

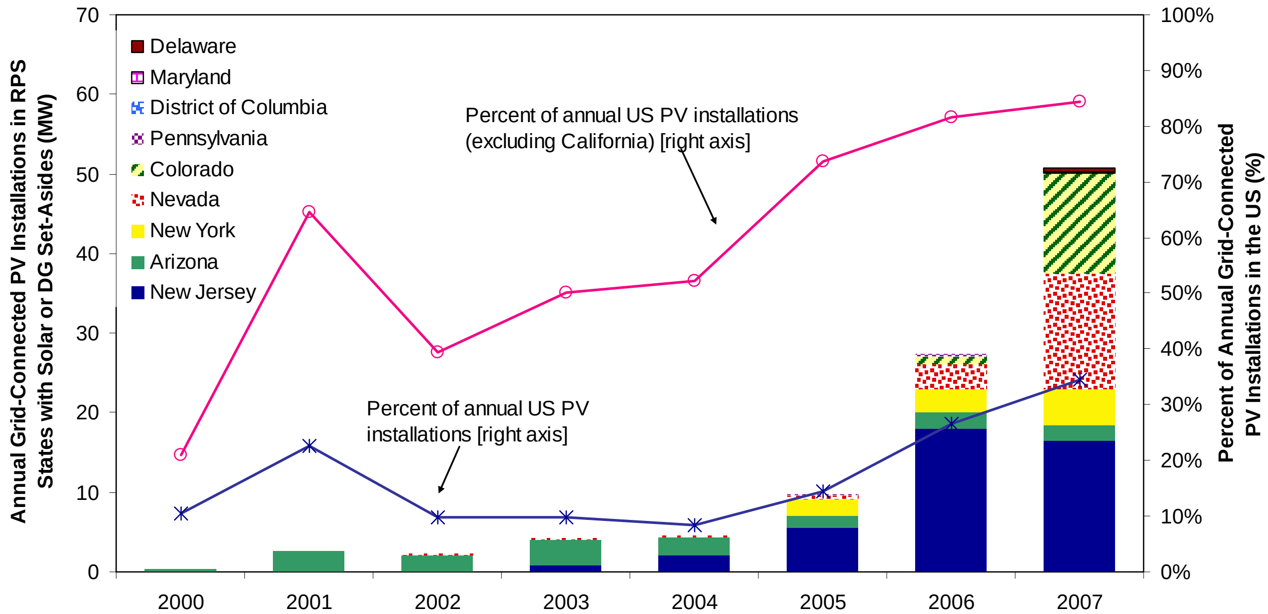


**Figure 9. Annual Grid-Connected PV Installations in RPS States with Solar or DG Set-Asides[20]**

**Table 6. Status of Utility-Scale Solar-Thermal Electric Facilities Proposed in the U.S.**

| Power Purchaser | Developer | State | Project Size | Status | Motivation |
|---|---|---|---|---|---|
| Nevada Power | Acciona | Nevada | 64 MW | Operational | Solar set-aside |
| Arizona Public Service | Acciona | Arizona | 1 MW | Operational | Solar set-aside |
| Pacific Gas & Electric | Solel | California | 554 MW | Contracted | General RPS |
| Pacific Gas & Electric | Ausra | California | 177 MW | Contracted | General RPS |
| Pacific Gas & Electric | BrightSource | California | 500 – 900 MW | Contracted | General RPS |
| Southern California Edison | Stirling Energy Systems | California | 500 – 850 MW | Contracted | General RPS |
| San Diego Gas & Electric | Stirling Energy Systems | California | 300 – 900 MW | Contracted | General RPS |
| San Diego Gas & Electric | Bethel | California | 49 MW | Contracted | General RPS |
| San Diego Gas & Electric | Bethel | California | 49 MW | Contracted | General RPS |
| Arizona Public Service | Abengoa | Arizona | 280 MW | Announced | General RPS |
| Florida Power & Light | Ausra | Florida | 10 – 300 MW | Announced | Not stated |

Notes: Table does not include facilities announced by developers, unless a purchaser of the power has been identified. In addition to the specific facilities listed here, a number of utilities in the Southwest have issued a 250 MW RFP for central station solar power, and Colorado's major IOU (Xcel Energy) has announced preliminary plans for a 200 MW facility.

The impacts of RPS solar set-asides on solar development will continue to grow as a greater number of the existing set-asides take effect and as targets increase over time. Figure 10 and Table 7 present Berkeley Lab estimates of the solar electric capacity (including PV and solar thermal electric) that would be required to fully achieve existing state solar and DG RPS set-aside policies. Changes in Federal tax incentives, binding RPS cost caps, *force majeure* events, and other barriers will – in reality

[20] PV installation data from 2000-07 were provided by Larry Sherwood (Interstate Renewable Energy Council). For the purpose of assigning state PV installations to set-asides, the data above include installations in the year before the first set-aside compliance date. Data are presented in direct-current units, at Standard Test Conditions.

– challenge the full achievement of these policies.[21] As such, the estimates presented here should be considered a reasonable, if uncertain, estimate of the potential impact of these set-asides under an aggressive assumption of full compliance.

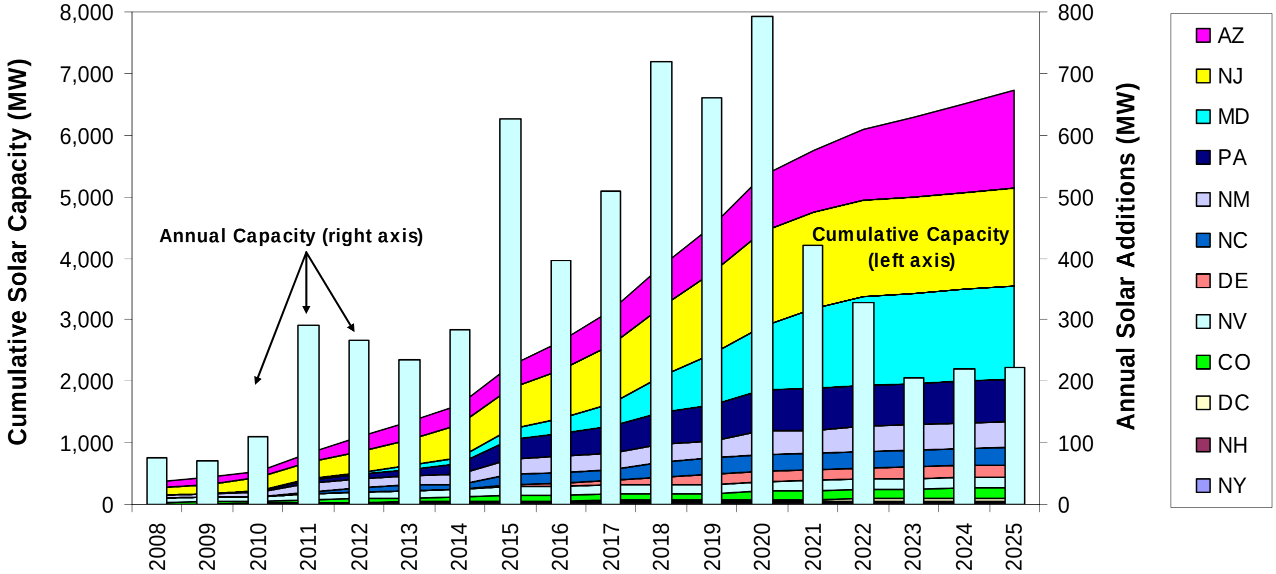


**Figure 10. Solar Capacity Required to Meet Existing State RPS Solar and DG Set-Asides[22]**

Even with these caveats, the estimates presented here demonstrate the potential importance of these set-asides for the solar market in the coming decades. As shown, a cumulative 550 MW of solar capacity may be required by these policies by 2010, growing to approximately 2,200 MW by 2015, 5,300 MW by 2020, and 6,700 MW by 2025. Annual solar additions on the order of 100 MW may be required from 2008 through 2010, rapidly ramping up to nearly 300 MW a year from 2011 through 2014, and then to over 500 MW a year from 2015 to 2021, if full compliance is to be achieved.

The largest set-aside driven solar markets in the long-term, based on required capacity to fully meet state targets, are projected by Berkeley Lab to include Arizona, New Jersey, Maryland, and Pennsylvania. In the next several years, however, significant growth in solar capacity will also be required in New Mexico, Nevada, and Colorado. Finally, as a proportion of expected statewide load in 2025, these set-aside policies are projected to require solar generation shares as high as 3.1% in New Mexico, and 2% or more in Arizona, Maryland, and New Jersey again assuming that full compliance is achieved.

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[21] Actual impacts will be affected not only by whether full compliance is achieved, but also by future load growth, the competitiveness of solar energy in broader DG set-asides, the relative contribution of different types of eligible solar technologies, and other factors.

[22] Berkeley Lab developed these estimates using a number of input assumptions regarding expected load growth, capacity factors, compliance exemptions, the share of solar used to meet broader DG obligations, the share of PV and solar-thermal electric used to meet solar requirements, and other factors. Data are presented in direct-current units, at Standard Test Conditions.

Achieving these targets is not assured, however, and a number of policy design issues may constrain the market's growth. States have developed various types of cost caps, for example, many of which may ultimately become binding, thereby limiting future solar market expansion to levels below those estimated here.

**Table 7. Cumulative Solar Required to Meet State RPS Solar and DG Set-Asides**

| State | 2010 Capacity | 2025 Capacity | 2025 Solar Generation as a % of State Load |
|---|---|---|---|
| Arizona | 110 MW | 1,600 MW | 2.0% |
| Colorado | 29 MW | 160 MW | 0.4% |
| Delaware | 0.5 MW | 190 MW | 1.4% |
| Maryland | 14 MW | 1,500 MW | 2.0% |
| Nevada | 76 MW | 180 MW | 0.6% |
| New Hampshire | 4 MW | 35 MW | 0.3% |
| New Jersey | 210 MW | 1,600 MW | 2.1% |
| New Mexico | 64 MW | 420 MW | 3.1% |
| New York | 10 MW | 15 MW | 0.0% |
| North Carolina | 5 MW | 280 MW | 0.2% |
| Pennsylvania | 25 MW | 690 MW | 0.5% |
| Washington D.C. | 0.5 MW | 54 MW | 0.4% |
| **Total** | **550 MW** | **6,700 MW** | **n/a** |

Note: Data are presented in direct-current units, at Standard Test Conditions

Additionally, some states – especially those in which retail electric competition exists – continue to struggle with how to encourage appropriate contracting for solar generation, given the political risk of future policy changes. In 2007, New Jersey sought to address this concern by developing plans to transition away from a rebate-based solar market and towards a market primarily supported by solar renewable energy credits. To provide some encouragement for longer-term REC contracting, New Jersey established, in advance, an eight-year schedule for solar alternative compliance payment (ACP) levels, thereby removing at least some market uncertainty. Other states, such as Maryland, North Carolina, Colorado, and Nevada, simply require long-term contracting for solar energy or RECs. Alternatively, or in addition, some states have mandated or encouraged the use of up-front financial incentives, at least for smaller-scale PV systems (and sometimes for larger commercial installations as well); this is true in Colorado, Nevada, Arizona, New Jersey, New York, and Maryland.

## Compliance with State RPS Mandates Has Been Strong in General, Though Important Exceptions Exist

So far at least, early-year renewable energy targets in the majority of state RPS policies have been fully or almost-fully achieved. "Compliance" is defined here as the application of renewable electricity or RECs towards RPS targets, including the use of available credit multipliers, but excluding any use of ACPs.[23] Using this definition, of the 14 states with RPS compliance obligations

[23] Note that the definition of "compliance" used here is not the same as that used by individual states. This report focuses on the delivery and retirement of renewable electricity or RECs for use in a given compliance year (including RECs that are delivered in previous or subsequent years, as long as they are used to meet current-year compliance, as well as credit

in 2006 for which data were available, nine states achieved compliance levels of greater than 95%, (see Table 8). These states include California, Iowa, Maryland, Maine, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin. Moreover, the weighted-average compliance level (weighted by the level of compliance obligation) across all 14 states for which data were available was 94% in 2006, compared to 96% in 2005 (12 states), 94% in 2004 (11 states), and 86% in 2003 (9 states).

Nonetheless, it is also evident that a number of states have struggled to meet even their early-year RPS targets. In Arizona, for example, compliance has been well below 50% since 2003, even after accounting for credit multipliers. This is because RPS targets in that state have historically had to be met only to the extent that pre-specified funding amounts were sufficient to achieve compliance; in point of fact, funding levels have been insufficient. In Massachusetts, on the other hand, eligible RECs have been in short supply, in part because of a difficult project development climate in the New England region. For similar reasons, Connecticut also experienced a slight REC shortage in 2006, though much less severe than in Massachusetts due to different resource eligibility rules. Minnesota's statewide RPS, which began in 2005, achieved 94% "compliance" in that year, but because Xcel's mandate for additional biomass and wind capacity (beyond that required for the statewide RPS) was not strictly achieved on schedule, overall compliance levels (including both the statewide RPS and Xcel's incremental renewable capacity mandates) averaged 61-81% from 2002 through 2005. Nevada has struggled with RPS compliance for a variety of reasons, including contract failures and project delays, as well as changing regulatory treatment of REC transfers among the state's two major utilities. Finally, New York's first-year RPS target was missed by a wide margin, in large part because of a modest delay in the on-line date of one of the state's largest new renewable energy facilities, and in part due to REC prices that were higher than initially anticipated and budgeted.

The few states with obligatory solar set-asides in 2006 or earlier have had mixed success in meeting those requirements (see Figure 11). In Arizona, for example, just 23% of the solar set-aside in 2006 was met by solar energy deliveries (even after accounting for credit multipliers), due in large measure to insufficient funding levels. In Nevada, solar REC retirements in 2006 were only 9% of the solar target (again, accounting for multipliers), an increase from just 2% in 2004 and 2005. The addition of a 64 MW solar-thermal electric project and nearly 15 MW of PV in 2007 should dramatically improve the compliance of Nevada's utilities in the years ahead. New Jersey, meanwhile, achieved 96% compliance with its solar set-aside in 2006 through solar deliveries, down from 98% in 2005, but up from just 54% in 2004. Pennsylvania achieved 100% compliance with its first-year solar set-aside in 2006, but that requirement was so small as to be effectively meaningless (the solar REC retirement obligation in the 2006 compliance year was equivalent to just 5-10 residential PV installations, due to the limited amount of load with RPS obligations in that period).

multipliers). In so doing, these data ignore the possible use of ACPs as well as certain other compliance flexibility mechanisms.

**Table 8. Application of Renewable Electricity and/or RECs Towards RPS Targets,**

| State | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|---|---|
| AZ | - | - | 89% | 64% | 31% | 31% | 26% | 25% |
| CA | - | - | - | - | - | 100% | 100% | 98% |
| CT | - | no data | no data | no data | no data | 100% | 100% | 93% |
| HI | - | - | - | - | - | - | 100% | - |
| IA | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| MA | - | - | - | - | 100% | 65% | 64% | 74% |
| MD | - | - | - | - | - | - | - | 100% |
| ME | - | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| MN | - | - | - | 61% | 72% | 72% | 81% | no data |
| NJ | - | - | 100% | 100% | 100% | 100% | 100% | 100% |
| NM | - | - | - | - | - | - | - | 100% |
| NV | - | - | - | - | 31% | 30% | 95% | 39% |
| NY | - | - | - | - | - | - | - | 52% |
| PA | - | - | no data | no data | - | - | - | 100% |
| TX | - | - | - | 99% | 96% | 99% | 99% | 100% |
| WI | - | 40% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Weighted Average** | **100%** | **98%** | **100%** | **90%** | **86%** | **94%** | **96%** | **94%** |

blank cells = no compliance obligation existed in that year
no data = unable to obtain compliance data for that year

Notes:

- Arizona – data for 2001-2004 come from an ACC staff report and, after 2004, directly from compliance reports provided by the state's electric utilities; 2006 data were unavailable from one of the state's IOUs.
- California – data come from the CEC and from self-reported information, and include the state's major IOUs, and, starting in 2006, ESPs; data from small IOUs are excluded (because compliance rules have not been established) as are data from the state's POUs (because yearly RPS targets are often unstated).
- Connecticut – data were unavailable for 2000-2003, during which time RPS obligations applied only to non-standard-offer load, which represented less than 2% of statewide retail sales in those years.
- Hawaii – RPS obligations under previous legislation existed in 2005, but subsequent legislation removed the 2005 obligation and established a new RPS schedule that begins in 2010.
- Maine, Maryland, New Jersey – compliance figures are based on emails from state RPS administrators, not based on a review of compliance filings.
- New Jersey – compliance data for 2001-2003 are on a calendar year basis; beginning in 2004, compliance data are for annual periods beginning June 1st, which for the purpose of the table, are assigned to the starting year of the annual compliance period.
- Minnesota – prior to 2005, data presented here only include Xcel's wind and biomass mandates; in 2005, data include the overall statewide renewable energy obligation and Xcel's wind and biomass mandates, and 2005 compliance data are for the year beginning July 1, 2005; 2006 data are not yet available.
- Nevada – the large increase in compliance in 2005 resulted from the sale of excess non-solar RECs by Sierra Pacific to Nevada Power; Sierra Pacific has generated a substantially greater number of non-solar RECs in each year than required for its RPS target; the Nevada PUC allowed Sierra Pacific to sell excess non-solar RECs generated in 2004 and 2005 to Nevada Power, which the latter retired for compliance in 2005; in 2006, the utilities again requested that Sierra Pacific be allowed to sell non-solar RECs to Nevada Power, but the PUC did not grant this request, and thus Nevada Power fell far short of its RPS target.
- Pennsylvania – data were unavailable for 2001-2002, during which time RPS obligations applied only to Competitive Default Service load (default service provided by a competitive supplier), which represented less than 1% of statewide retail sales in those years; 2006 compliance data are for the compliance period beginning June 1, 2006.
- Wisconsin – before 2001, the RPS was a 50 MW renewables capacity requirement on a subset of electric utilities.

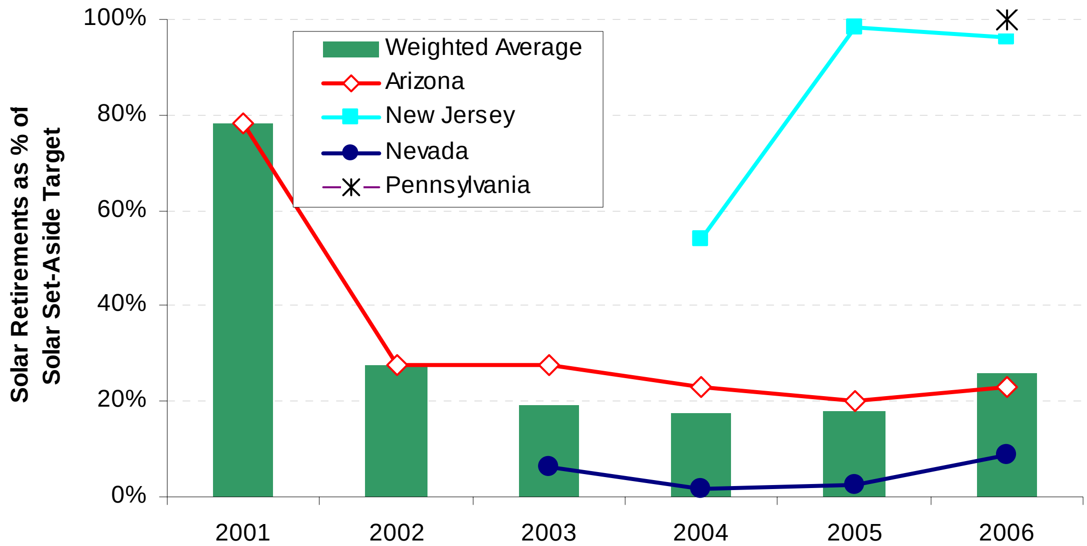


**Figure 11. Application of Solar Electricity and/or Solar RECs Towards Solar Set-Aside Targets**

Because states have developed differing compliance enforcement and flexibility mechanisms (see Text Box 1), one should not assume that lack of compliance, as defined here, automatically leads to enforcement actions. In some of the states listed as not achieving full compliance, alternative compliance payments (ACPs) are allowed and have been made to avoid enforcement action (funding collected from these payments is typically recycled to support renewable energy – and/or energy efficiency – through other means). This is true in Massachusetts and New Jersey (where the shortfalls in REC retirements have been fully met with ACPs) and, to a much lesser extent, in Maryland.[24] As a result, in 2006, $18.2 million was paid in the form of ACPs: 97.6% from Massachusetts, 2.2% from New Jersey, and 0.2% from Maryland.

In still other cases, such as California, opportunities to "make-up" purchase shortfalls exist, ensuring that any enforcement actions will not occur for several years after a given compliance year. In Arizona and New York, funding limitations can curtail compliance. Finally, a number of states offer compliance waivers on a discretionary basis; this is why, for example, Nevada's utilities have not been penalized, despite a long history of under-compliance, and Minnesota's utilities have likewise faced no penalties.

In part as a result of these factors, explicit enforcement actions have been taken in only two states so far: Connecticut and Texas. In Connecticut, lack of compliance in 2006 resulted in $5.6 million in penalties (though Connecticut uses the term ACP, these payments are defined as penalties here, because they are not automatically recoverable in rates). In Texas, two competitive ESPs were penalized a total of $4,000 in 2003 for lack of RPS compliance, while in 2005 two other ESPs were penalized $28,000.[25] In sum, enforcement actions have – up to now – been infrequent.

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[24] Though Table 8 suggests no REC shortfalls in Maryland and New Jersey in 2006, in fact renewable deliveries in these two states were 99.87% and 99.95%, respectively.

[25] Although not a non-compliance penalty *per se*, the two Nevada IOUs agreed to make a $30,000 donation to the Desert Research Institute, not recoverable in rates, as part of the stipulation to its 2005 RPS compliance filing.

**Text Box 1. State RPS Compliance Enforcement**

States use a variety of enforcement options to ensure that RPS targets are met. The most popular option in states that allow retail competition is an alternative compliance payment. If recoverable in rates, an ACP is a means of complying with an RPS – rather than procuring renewable generation or RECs – that effectively makes the need for explicit penalties moot (unless an LSE fails to comply through the ACP as well). In states that maintain vertically integrated electric utilities, on the other hand, enforcement most typically occurs through explicit or discretionary financial penalties. Other forms of RPS enforcement are also listed below. Though not shown here, it deserves note that a number of states allow LSEs to petition for an exemption from penalties under certain circumstances.

| Penalties for Non-Compliance | States | Notes |
|---|---|---|
| ACP, Automatic Cost Recovery | MA, ME, NH, NJ, RI | Payments generally go to a renewable energy fund; if failure to pay ACP, remedies can include license suspension or revocation and/or financial penalties; ME ACP applies only to new renewables target |
| ACP, Possible Cost Recovery | DE, MD, OR, DC | Cost recovery sometimes only allowed if ACPs are deemed to be the least-cost compliance option; payments generally go to a renewable energy fund; if failure to pay ACP, remedies can include license suspension or revocation and/or financial penalties |
| Explicit Financial Penalties, No Automatic Cost Recovery | CA, CT, MT, PA, TX, WA, WI | CA, CT, MT, PA, TX, WA: penalty in $/MWh applies to shortfall; WA: penalty may, in some circumstances, be recoverable in rates; WI: penalty ranges from $5,000 to $500,000; suppliers often given opportunity to petition for a waiver |
| Discretionary Financial Penalties, No Cost Recovery | AZ, CO, HI, MN, NV | Financial penalties assessed at the discretion of the PUC; penalties can be waived with sufficient cause; in MN, PUC can order renewable investment and can impose financial penalties |
| Enforcement at PUC Discretion | NC, NM | PUC has legislative authority to enforce compliance, but no rules have been established to document how this will occur |
| Not Applicable | IA, IL, NY | IL and NY rely on administrative agencies to procure renewables on behalf of LSEs; IA RPS has already been fully met |

# The Use of Renewable Energy Certificates and Certificate Tracking Systems Is Expanding

Reliance on unbundled RECs for state RPS compliance has often gone hand-in-hand with the development of regional certificate tracking systems. Although several states have allowed RECs and relied on (manual) attestations and contract audits, states are increasingly using electronic certificate tracking systems to issue, record, track, and retire RECs.

The year 2007 saw the completion of two new regional tracking systems—the Western Renewable Energy Generation Information System (WREGIS) and the Midwest Renewable Energy Tracking System (M-RETS). WREGIS serves the Western Electricity Coordinating Council (WECC), including 11 U.S. states, two Canadian provinces, and part of the Mexican state of Baja California. M-

RETS serves Wisconsin, Minnesota, Iowa, South Dakota, North Dakota, the province of Manitoba, and parts of Montana and Illinois.[26] New and existing tracking systems are shown in Figure 12.

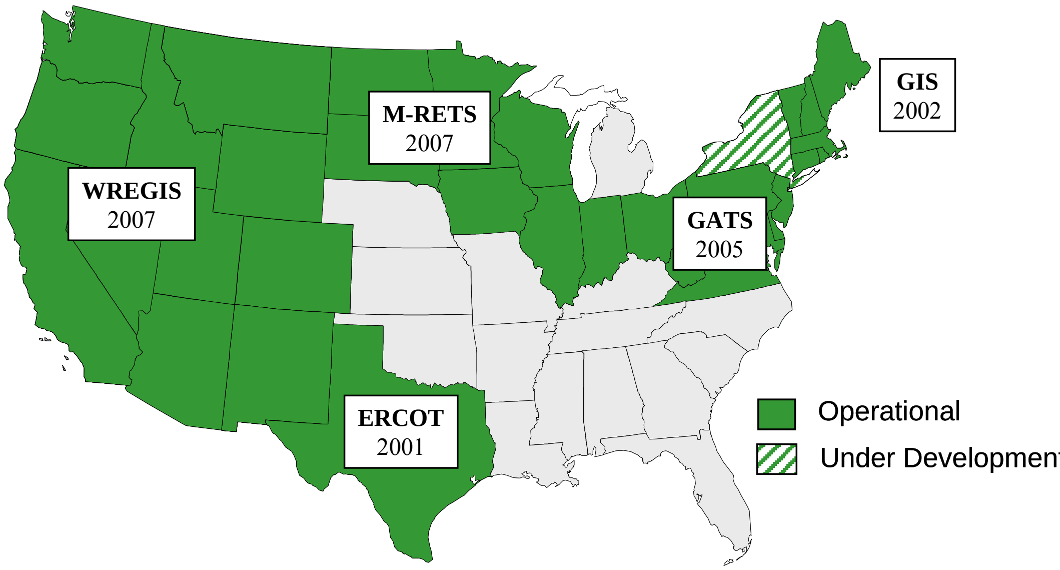


**Figure 12. Electronic Certificate Tracking Systems and Year of Initiation**

WREGIS and M-RETS are similar to the first electronic certificate tracking system developed by the Electric Reliability Council of Texas (ERCOT), in that they issue and track certificates only for renewable generation. In addition, WREGIS and M-RETS certificates may – in theory – be used at any time because they do not have an expiration date. This is in contrast to the New England Power Pool's Generation Information System (GIS) and the PJM Generation Attributes Tracking System (GATS), which both issue certificates to all generation and then settle those certificates on a regular schedule to support a variety of different policies. Prior to the operation of GATS, New Jersey developed, and continues to operate, a separate tracking system for Solar RECs and "Class I" RECs from onsite customer generation.

New York, which manually tracks bundled energy and attributes, is currently working to develop an electronic system that will issue and track unbundled certificates. For the remaining states without a tracking system, APX, Inc., a private service provider, has announced that it will make available a certificate tracking system (not shown in Figure 12).

With the increased availability of formal certificate tracking systems, most RPS states have opted to allow – with restrictions – the use of unbundled RECs for compliance purposes.[27] As shown in Figure 13, the exceptions are: Iowa, which adopted its RPS long before RECs existed and which has satisfied its requirement; Arizona and Hawaii, which do not currently allow the use of unbundled RECs; and California, which will rely on WREGIS but has not yet approved the use of unbundled RECs.

[26] Because it is bisected by different control areas, Montana is served in part by WREGIS and in part by M-RETS. Similarly, Illinois is served in part by M-RETS and in part by GATS. Wisconsin previously operated its own tracking system for Renewable Resource Credits, but its program is now supported by M-RETS.

[27] See Holt, E. and R. Wiser. 2007. The Treatment of Renewable Energy Certificates, Emission Allowances, and Green Power Programs in State Renewables Portfolio Standards. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

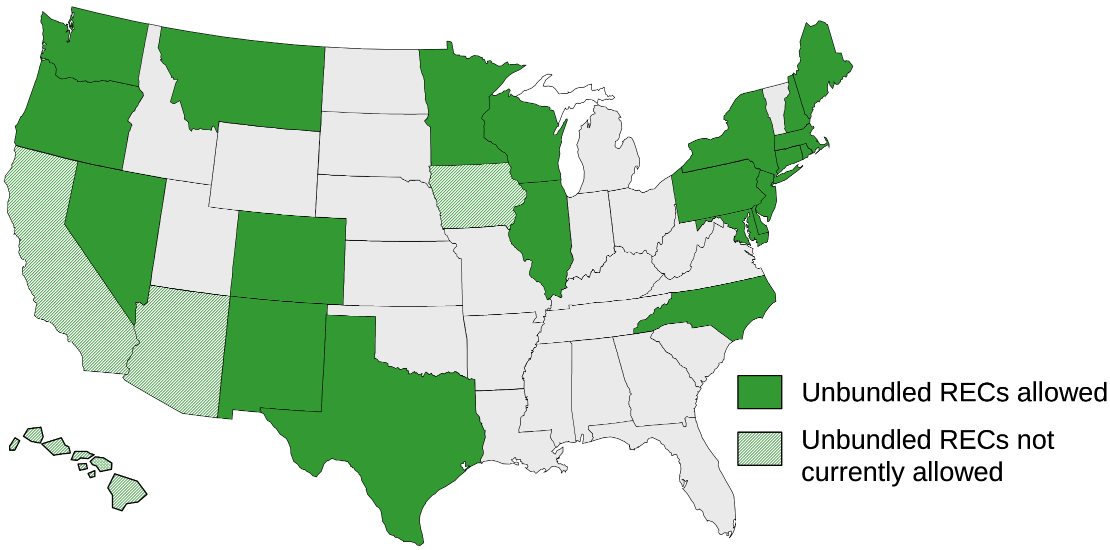


**Figure 13. Treatment of Unbundled RECs for State RPS Compliance**

Although RECs are now widely used as the preferred means of demonstrating RPS compliance, REC definitions are not uniform. States have defined RECs differently—based on differing eligible resource definitions, different generator vintages, limitations on generator location and electricity delivery, and whether or not emissions credits, if any, must be retired with the REC for RPS compliance. As a result, there are multiple state and regional markets for RECs, and fungibility across RPS markets is limited.

Typical REC contracting practices also vary considerably across states. Some state RPS markets have primarily encouraged short-term trade in unbundled RECs. This is most-often the case in states where retail choice is allowed and therefore the future load obligations of individual LSEs are more uncertain, and where electric utilities are no longer directly in the business of electricity supply. Other markets have relied on a mix of short-term and longer-term purchases, where long-term purchases might be for unbundled RECs or RECs bundled with the underlying electricity supply. Finally, in states in which retail competition is not allowed and regulators retain oversight over utility supply decisions, electric utilities largely rely on long-term contracts for RECs that remain bundled with electricity; such contracts are often required by state policy (see Text Box 2).

## REC Prices Have Been Highly Variable Across States

Renewable energy certificate markets remain fragmented in the U.S. Figure 14 and Figure 15 present indicative monthly data on spot-market REC prices in compliance markets, i.e., states in which RECs are sold to meet state RPS obligations. Figure 14 reports data on "main tier" or "Class I" REC prices, while Figure 15 reports data on REC prices under "Class II" or "existing tier" RPS requirements – typically consisting of existing hydropower, biomass, and MSW projects. These data were obtained from Evolution Markets, and exclude markets for which transparent spot-market REC pricing is not available.[28]

[28] Some care should be taken in using these data, however, because bilateral trade in RECs and longer-term REC contracts are not fully captured in the Evolution Markets data, and because liquidity is limited in many states.

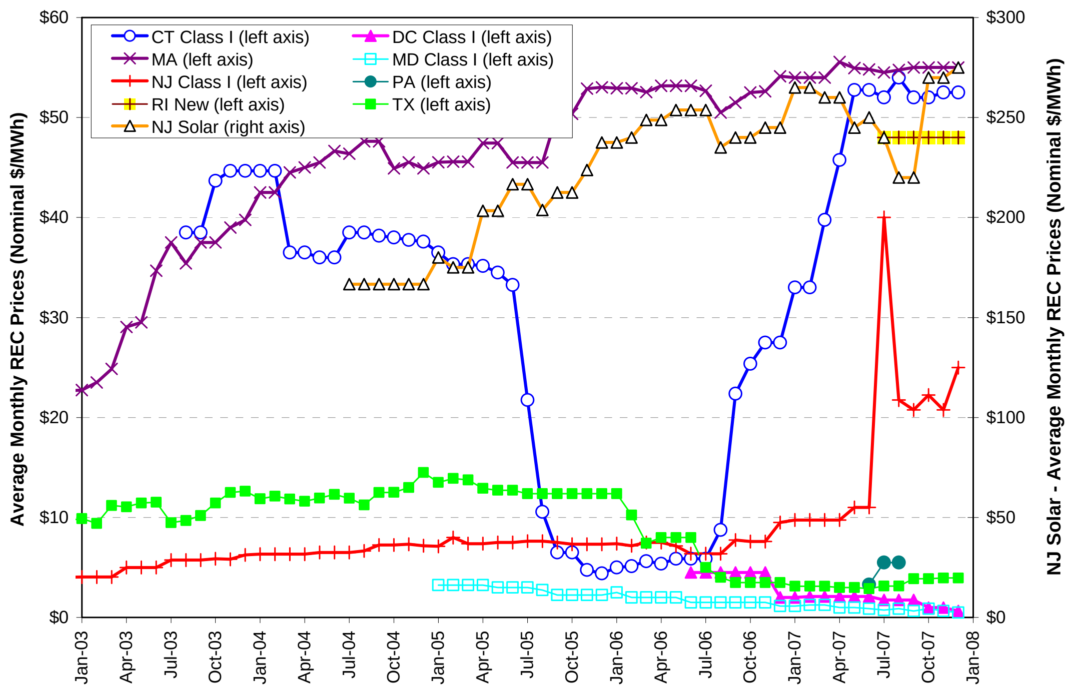


**Figure 14. REC Prices in RPS Compliance Markets (Main Tier and Class I)**

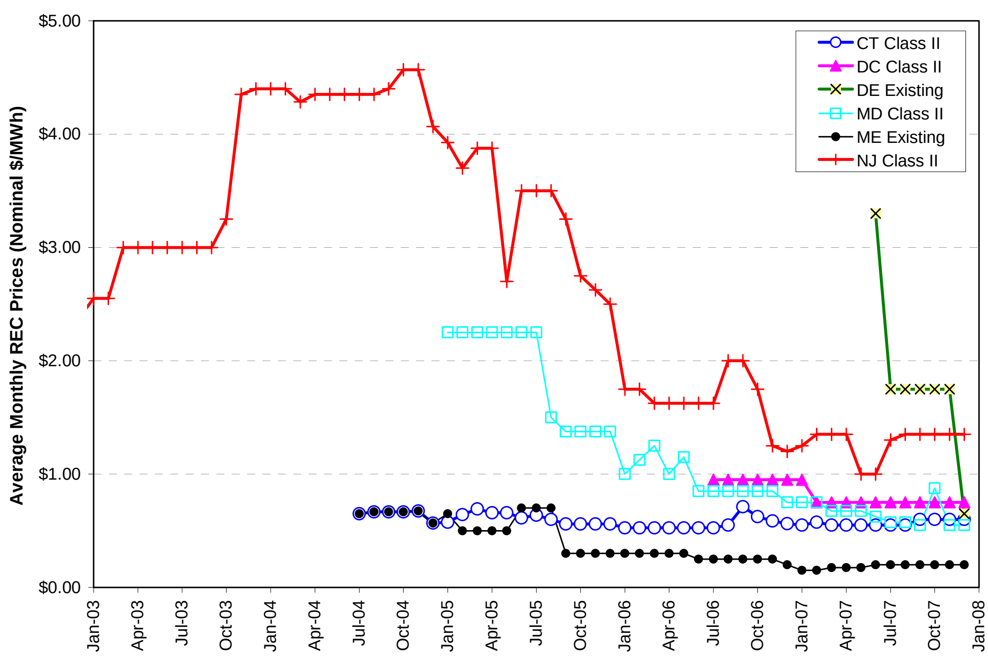


**Figure 15. REC Prices in RPS Compliance Markets (Existing Tier and Class II)**

Though not a comprehensive picture of all states, the figures clearly indicate that spot REC prices have varied substantially across regions and resource types, and that significant price fluctuations are even possible within a particular state over time. Key trends in 2007 include continued high prices to serve the Massachusetts RPS, dramatically increasing prices under the Connecticut Class I RPS and, more recently, a large spike in the price for Class I certificates under the New Jersey RPS. Class I REC prices in Connecticut have shown particularly striking swings, largely reflecting policy changes in resource eligibility rules over time. New Jersey's Class I REC prices rose partly because that state's renewable energy targets are increasing and partly because the growth in RPS requirements in the PJM region is placing greater competition on available supply. The sudden spike and then (more-modest) drop in prices may also have reflected, to some degree, an (incorrect) belief that supply was severely limited and/or hoarding of RECs by some parties. Prices trended downwards in Texas, Maryland (Class I), and Washington D.C. (Class I) due to a surplus of eligible renewable energy supply relative to RPS-driven demand in those markets. New Jersey's solar RECs, on the other hand, continue to fetch more than $200/MWh due to the underlying cost of solar electricity.

As shown in Figure 15, prices for "Class II" or "existing tier" RECs remained low, and trended downwards in most markets. Prices in these cases appear to largely reflect transaction (rather than supply) costs, since REC supply appears to far exceed REC demand in all of these markets.

Concerns have been expressed that REC price variability and uncertainty may limit the ability of RPS policies to support renewables investment decisions. As a result, a number of states have adopted RPS provisions to help projects secure financing. These efforts are summarized in Text Box 2.

**Text Box 2. Encouraging Project Financing**

Renewable projects are capital intensive, and investors therefore closely examine the long-term energy and REC cash flows of a project; projects that have locked-in or hedged their energy or REC prices for at least 10 years are often viewed more favorably. LSEs, on the other hand, have in some cases decided not to sign long-term contracts because they are discouraged or prevented from doing so by regulators (typical for default service providers in restructured markets); because their future load requirements are uncertain (competitive ESPs); or because their credit may not be strong enough to support such contracts (typically competitive ESPs). Uncertain energy and/or REC prices have – in some of these cases – impeded renewable project development. In other instances, development has occurred on a quasi-merchant basis, but arguably at higher ratepayer cost because investors in such projects require inflated returns to compensate for the added risk. To address these barriers, several states have adopted RPS provisions to help projects secure financing, as summarized below.

| | | |
|---|---|---|
| Contract Duration Requirement | CA | 10+ yrs |
| | CO | 20+ yrs |
| | CT | 100 MW, 10+ yrs |
| | IA | ownership or long-term contract |
| | MD | solar, 15+ yrs |
| | MT | 10+ yrs |
| | NV | 10+ yrs |
| | NC | solar, sufficient length to stimulate development |
| | PA | good faith effort includes seeking long-term contracts |
| | RI | PUC requires that default utility investigate long-term contracting |
| Central Procurement | NY | central procurement where NYSERDA purchases attributes under long-term contract |
| | IL | central procurement in which long-term contracts are likely to be offered |
| Credit Protection | NV | created program to protect payments to generators from utility credit concerns |
| | CA | initially exempted utilities from meeting RPS until they became creditworthy |
| Renewables Fund Support | MA | renewable energy fund created "green power partnership" that offers guaranteed REC purchase or option contracts of up to 10 years |

## The Price Impacts of State RPS Policies Are Not Always Observable, But Have Been Modest in Most Cases So Far

State RPS policies could have substantial impacts on electricity markets, ratepayers, and local economies. Unfortunately, the actual costs (and benefits) of state RPS policies have not been compiled in a comprehensive fashion, in part because of the early status of policy implementation and in part because of methodological complexities and data availability constraints. Despite these limitations, it is reasonably clear that the cost impacts of state RPS policies have varied by state but, at the same time, there is little evidence of a sizable impact on average retail electricity rates so far.

Translating unbundled REC prices, as well as the renewable electricity contracts that predominate in traditionally-regulated states, into retail rate impacts is challenging. Nonetheless, if one assumes (a) that REC prices represent the incremental above-market cost of renewable energy, (b) that the short-term REC prices presented in Figures 14 and 15 are representative of all RECs used for RPS compliance, and (c) that certain state-specific funding caps are binding, then 2007 RPS-induced retail rate increases, averaged over all obligated load in each state, can be estimated, as shown in Figure 16.[29]

Though the results vary across states, in most cases, rate increases are estimated at 1% or less in 2007. Moreover, the rate impacts shown here may, in some states, be biased upwards due to at least two factors: (1) longer-term REC contracts are likely to be priced below the short-term REC prices used for these calculations; and (2) the rate estimates presented here ignore the potential impact of renewable energy in reducing natural gas and wholesale electricity prices. At the same time, however, rate impacts will presumably grow over time as RPS obligations increase, unless REC prices or RPS funding levels simultaneously decline.

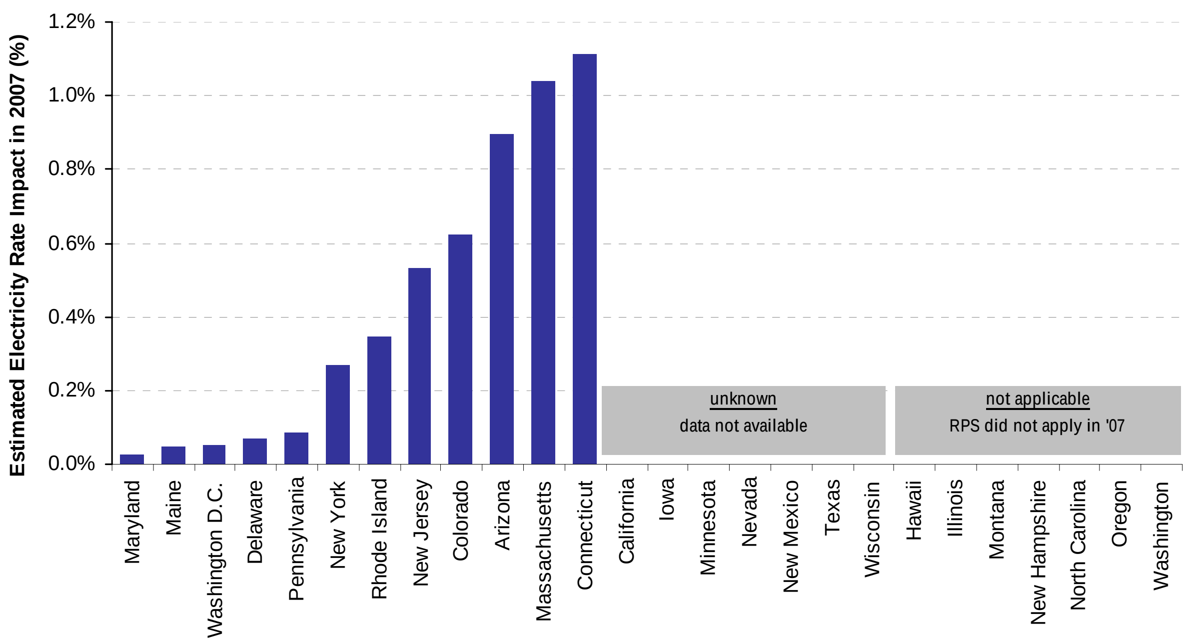


**Figure 16. Estimated Rate Impacts of State RPS Policies in 2007**

[29] Rate impacts are estimated on a calendar year basis, using the average compliance obligation during 2007.

In states where long-term renewable electricity contracts (rather than purchases of unbundled RECs) predominate as the mode of state RPS compliance, retail rate impacts are more difficult to estimate, due primarily to the confidentiality of contract terms. As such, these states are shown in Figure 16 as having "unknown" rate impacts in 2007 (those states listed as "not applicable" had no RPS obligation in 2007).[30] In a number of these states, however, there is at least some evidence that the renewable energy contracted in recent years has been priced competitively with conventional sources of generation. In California, for example, the majority of the renewable electricity brought under contract by the state's IOUs since 2002 has been signed at prices that are below the "market price referent" – the estimated cost of new gas-fired generation. Anecdotal evidence suggests historically low renewable energy prices in many of the other states listed as having "unknown" rate impacts in Figure 16 as well. In these instances, it is not clear whether state RPS policies are leading to higher, or lower, retail electricity prices.[31]

Notwithstanding these conclusions, it is also evident that renewable electricity prices have increased in recent years. Wind power contract prices for projects built in 2006, for example, were substantially higher than for projects built from 2000 through 2005.[32] At the same time, the cost of new gas and coal facilities has also been on the rise, making any long-term "incremental" cost of RPS programs difficult to estimate.

Given uncertainty about the future costs of RPS policies, state policymakers have developed a variety of approaches to limit the maximum impact of these policies on electricity rates, as shown in Table 9. Common approaches include alternative compliance payments that can be made in lieu of purchasing RECs, direct retail rate caps, renewable energy funding caps, renewable energy contract price caps, per-customer electric bill impact limits, and financial penalties that can serve as cost caps in certain circumstances. In addition, though not presented here, a number of states have established *force majeure* mechanisms that allow electricity suppliers to limit their renewable energy purchases if they are able to persuade regulators that those purchases would unduly raise electricity rates. Where calculable, Table 9 also translates the effective cost caps into the maximum possible incremental retail rate increase caused by RPS policies, for the year in which the state RPS achieves its highest percentage target. Though a sizable range exists, the majority of states have capped incremental rate impacts at well below 10%, and in eight states rate impacts are capped at or below 2%.

[30] Texas is included among these states. Though short-term REC pricing is transparent in Texas, many electricity suppliers have complied with their RPS obligations through long-term, renewable electricity contracts. Short-term REC prices are therefore not likely to be a good indicator of rate impacts in that state.

[31] Another approach to estimating impacts is to review state RPS cost-impact *projections*. A Berkeley Lab report completed in 2007, for example, provides a summary of 28 state RPS cost-impact projections. See: Chen, C., R. Wiser and M. Bolinger. 2007. "Weighing the Costs and Benefits of Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections." Berkeley, Calif.: Lawrence Berkeley National Laboratory.

[32] See Wiser, R. and M. Bolinger. 2007. "Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006." Berkeley, Calif.: Lawrence Berkeley National Laboratory.

**Table 9. Approaches Used to Cap the Maximum Cost of State RPS Compliance**

| State | ACP | | Retail Rate/ Revenue Req. Cap | Renewable Energy Contract Price Cap | Per-Customer Cost Cap | Renewable Energy Fund Cap | Financial Penalty May Serve as Cost Cap | Maximum Effective Retail Rate Increase |
|---|---|---|---|---|---|---|---|---|
| | Auto. Cost Rec. | Possible Cost Rec. | | | | | | |
| AZ | | | | | ● | ● | | to be determined |
| CA | | | | | | ● | | cap for portion of cost |
| CO | | | ● | | | | | 1.7% |
| CT | | | | | | | ● | 6.5% |
| DE | | ● | | | | | | 16.3% |
| HI | | | | ● | | | | 0.0% |
| IA | | | | | | | | no explicit cap |
| IL | | | ● | | | | | 1.4% |
| MA | ● | | | | | | | 1.4% |
| MD | | ● | ● | | | | | 2.1% |
| ME | ● | | | | | | | 4.8% |
| MN | | | | | | | | no explicit cap |
| MT | | | | ● | | | | 0.1% |
| NC | | | | | ● | | | 1.9% |
| NH | ● | | | | | | | 8.3% |
| NJ | ● | | | | | | | 10.6% |
| NM | | | ● | ● | ● | | | 1.8% |
| NV | | | | | | | | no explicit cap |
| NY | | | | | | ● | | 0.9% |
| OR | | ● | ● | | | | | 4.0% |
| PA | | | | | | | ● | no explicit cap |
| RI | ● | | | | | | | 6.4% |
| TX | | | | | | | ● | 2.1% |
| WA | | | ● | | | | | 4.0% |
| D.C. | | ● | | | | | | 2.5% |
| WI | | | | | | | | no explicit cap |

Notes: Maximum effective retail rate increase represents maximum incremental impact on average retail rates in the worst-case scenario, given various cost caps, and assumes that costs will be capped at the ACP, or financial penalty amount in states with active retail electric competition. It is averaged across all customers and utilities covered under each state RPS. In New York, the cap represents available funds collected from ratepayers to support renewable attribute purchases by NYSERDA, under that state's current regulations. California's RPS does have a cap insomuch as certain funding limitations exist, but these funding limitations do not allow a clear calculation of rate impacts in percentage terms. Maryland's retail rate cap only applies to that state's solar set-aside. Maine's ACP only applies to that state's new renewables requirement. New Jersey's maximum rate impact is estimated at current ACP levels, and does not reflect the BPU's recent decision to explore a 2% rate cap on solar incentives; if this 2% cap were considered, then the overall maximum rate impact in New Jersey would drop to 8.5%. Legislation in Texas allows the PUC to establish an ACP, but the Commission has chosen not to do so. Pennsylvania has a financial penalty, but because the penalty for solar set-aside non-compliance in 2x the market value of solar RECs, the penalty does not serve as a cost cap.

## States Are Increasingly Recognizing Transmission as a Key Limitation to Achieving RPS Targets

Transmission has quickly become recognized as among the most prominent barriers to the achievement of state RPS targets. The California Energy Commission, for example, has indicated that it does not expect the three California IOUs to meet the state's 20% RPS by 2010, in part because of insufficient transmission. Nevada Power has said that, in the long-term, it will not be able to meet the Nevada RPS without a transmission line to connect Nevada Power to Sierra Pacific Power Company, and a Governor's Advisory Committee in 2007 recommended that such a line be built and began the process of identifying transmission investments to support renewable energy. New Hampshire enacted legislation in 2007 requiring its PUC to conduct a study on expanding transmission in the state for renewable energy. And the North American Electric Reliability Corporation has indicated that state RPS requirements should be associated with investment in additional transmission.

In response to the transmission challenge, states and grid operators are increasingly taking more-proactive steps to encourage transmission investment, often within the context of growing state RPS obligations. Several examples of these initiatives are presented below.

- **Texas:** A revision of the state's RPS in 2005 directed the Public Utility Commission of Texas to create competitive renewable energy zones (CREZ), defined as areas of high-quality clean energy resources. The amended Texas RPS also authorized the PUC to order a utility to construct or expand transmission to meet the Texas RPS and required the PUC to approve RPS-related transmission applications expeditiously. In October 2007, the PUC issued an interim order designating five CREZ areas in west and north Texas that could stimulate the development of 22,806 MW of wind power. ERCOT has recently completed a transmission optimization study to determine the optimal transmission layout for the proposed CREZs. Once the CREZ designation is final, the utility or utilities servicing those areas have one year to file an application for new transmission with the PUC.[33]

- **Colorado**: Legislation was enacted in January 2007 modeled, to some degree, after the Texas CREZ approach. That legislation requires utilities to submit biennial reports designating energy resource zones (ERZs), identifying transmission plans for accessing the ERZs, and discussing potential strategies for using transmission to encourage local ownership of renewable energy projects. Along with the biennial reports, utilities must submit applications for certificates of public convenience and necessity (CPCN) for the identified ERZ areas. Subject to annual adjustment, utilities may recover planning, development, and construction costs for permitted transmission facilities via a rate adjustment clause. In October 2007, Xcel Energy identified four potential ERZ areas, and submitted a CPCN application for a 345 kV line in northeastern Colorado.[34]

- **California:** The ISO received FERC approval for a new transmission interconnection category for location-constrained resources such as renewable energy facilities in late 2007. Once a resource area has been identified, transmission would be built in advance of generation being developed, and costs would be initially recovered through the California ISO transmission charge.

[33] Non-incumbent utilities may also be allowed to be involved in transmission to CREZs.
[34] In February 2008, Xcel Energy reached a settlement with interveners to submit CPCN applications for new transmission facilities in all four ERZ areas by March 2009.

Once new generation comes on-line to use the transmission path, each generator would pay a pro rata share of the transmission costs. A variety of criteria would have to be met for an area to be treated in this fashion. Separately, California's RPS allows the PUC to approve transmission or generation tie-lines that are needed for LSEs to meet the RPS and for which cost recovery is not otherwise available. A variety of other transmission-related initiatives are also underway in the state, including: (1) development and construction of transmission facilities to access more wind power in the Tehachapi area; (2) evaluation of transmission options to access renewable energy in the Imperial Valley; (3) initiation of a multi-agency Renewable Energy Transmission Initiative to help define renewable energy zones in and around the state, and to prepare transmission plans for those zones; and (4) utility recovery of costs to study the feasibility of different transmission investments to access renewable energy, and to recover project-level interconnection study costs.

- **Minnesota:** The state has a relatively long history of planning for and developing new transmission for renewable resources, particularly wind. For example, in approving the merger of Northern States Power and New Century Energies that created Xcel Energy in 2000, the PUC ordered that four new transmission lines be placed into service by 2006 to access wind energy resources, and that an 825 MW requirement for wind be accelerated to 2006. Minnesota's RPS, meanwhile, requires utilities to file five-year transmission plans necessary to meet the state's RPS targets, and for those plans to be developed in conjunction with the Midwest ISO. In November 2007, the utilities filed a joint report stating that transmission is adequate to meet the RPS requirements through 2010 and, with some 115 kV additions, through 2012. More transmission will be necessary, though, to meet the 2016 RPS requirement.

In addition to these initiatives, seven states have formed transmission infrastructure authorities to issue revenue bonds for new transmission. New Mexico's transmission infrastructure authority, created in 2007, is authorized to support only transmission projects that transmit at least 30% renewable energy. Colorado's transmission infrastructure authority, also created in 2007, is intended to support projects for the production, transportation, transmission, equipment manufacturing, and storage of clean energy.[35] Though Colorado's authority is allowed to support non-clean energy projects, this allowance is severely limited; for a transmission project, the primary purpose must be to transmit clean energy. In the other five states of Kansas, Wyoming, North Dakota, South Dakota, and Idaho the infrastructure authorities have broad authority to help support transmission infrastructure, and are not limited to clean energy investments.

[35] Clean energy is defined as: biodiesel; biomass; landfill gas; ethanol; non-fossil-fueled fuel cells; zero-emissions generation technology; renewables including (but not limited to) solar, wind, and geothermal; and certain clean coal demonstration technologies.

## Federal RPS Policies Received Consideration in the U.S. Congress in 2007

The U.S. Congress has considered a number of Federal RPS proposals in the House of Representatives and the Senate. These proposals typically contain certain common design features, including: a renewable production target and schedule; a range of qualifying technologies; tradable RECs and price caps; exemptions for certain classes of retail electricity suppliers; and sunset provisions. Though the various proposals have had common design elements, the specifics vary significantly.

A Federal RPS has passed the U.S. Senate on three occasions since 2002. In August 2007, the House of Representatives passed a Federal RPS for the first time, as an amendment to a larger energy bill, by a 220-190 vote. The U.S. Senate, however, was unable to break a filibuster to include the RPS in the final energy bill. The House-approved RPS would have required certain retail electric suppliers to include 15% renewable resources in their electricity mix by 2020. Up to 4% of the requirement could have been met through energy efficiency investments.

## Conclusions

The popularity of state-level RPS policies has grown. With 26 RPS policies now in existence in the U.S., covering 46% of the nation's electrical load, the importance of these programs is expected to build over the coming decade. States without an RPS are continuing to consider its adoption, and if experience is any guide, even more states are likely to be added to the RPS roster in 2008.

In the meantime, it is clear that state RPS policies can be designed in a variety of ways, and that implementation experience has been mixed. Comparative experience from states that have and have not achieved substantial renewable generation growth highlight the importance of policy design details. As a result, as further experience and lessons learned are gained, states with existing RPS programs are likely to continue to tinker with their design. Some of this may occur through scheduled reviews of existing RPS policies, while other changes may proceed through the normal legislative process. An emerging challenge will be to make these changes without unduly destabilizing planning and investment decisions made under previous RPS designs.

# Appendix: New State RPS Policies, Major Revisions to Existing RPS Programs, and New Non-Binding Renewable Electricity Goals Established in 2007

**Table A-1. New State RPS Policies Established in 2007**

| State | Key Elements of Renewables Portfolio Standard Design |
|---|---|
| Illinois | In 2001, Illinois established a non-binding renewable energy goal by legislation, and in 2005 a non-binding goal was established through regulatory action. In August 2007, the RPS was made mandatory and targets were both increased and extended, starting at 2% in 2008 and increasing to 25% by 2025. The targets only apply to electric utilities serving over 100,000 Illinois customers, and further only to customers taking fixed-price service (i.e., the fixed-price offerings of the IOU default service providers), making POUs and competitive energy service providers exempt from mandatory renewable purchases. Seventy-five percent of each year's target is to come from wind power, and in-state resources are strongly encouraged through 2011 (with out-of-state resource eligible during that period only if cost-effective in-state resources are not available). Cost caps change over time. In 2011, the cap will equal the greater of an additional 0.5% of the amount paid per kWh during the year ending May 2010, or 2% of the amount paid per kWh during the year ending May 2007. The newly created Illinois Power Agency is responsible for developing the procurement plans and conducting solicitations to ensure compliance by the state's IOU default service providers, making Illinois the second state (after New York) to use a variant of a central procurement model to pursue its RPS. |
| New Hampshire | New Hampshire's RPS, enacted in May 2007, establishes a renewables target for all of the state's electricity suppliers of 4% in 2008, increasing to 23.8% by 2025. The target is segmented into four classes of eligible resources: Class I is for new renewable facilities beginning operation in 2006 or later (16% by 2025); Class II is for solar electricity from facilities beginning operation in 2006 or later (0.3% by 2014); Class III is for pre-2006 biomass and methane projects (6.5% by 2011); and Class IV is for certain pre-2006 hydroelectric facilities with a nameplate capacity of 5 MW or less (1% by 2009). Alternative compliance payments (ACPs) vary according to the four classes, with starting values that range from $28/MWh for Class III and IV to $57.12/MWh for Class I and $150/MWh for Class II. The PUC is provided limited authority to accelerate or slow scheduled changes to the renewable energy targets, and to alter Class III and IV requirements. |
| North Carolina | North Carolina's RPS, signed into law in August 2007 and the first mandatory RPS in the Southeast, requires IOUs to meet eligible energy targets of 3% in 2012 (solar targets begin in 2010), increasing to 12.5% in 2021 and thereafter. Electric cooperatives and municipal utilities are obligated to the same early-year targets but are not required to achieve more than 10% in 2018 and thereafter. Utility-implemented energy efficiency (including waste heat from fossil CHP) qualifies as an eligible resource for IOUs, up to a limit of 25% of each yearly target through 2020 and 40% in years thereafter; renewable CHP, both electricity and heat, qualifies for the renewables portion of the RPS. POUs may include load management as a substitute for energy efficiency, have no limits on the use of these sources, may use hydropower to qualify for up to 30% of their standard, and are provided additional leniency on the vintage of projects with which they contract. Unbundled RECs may be used for compliance, but unbundled RECs from out-of-state facilities may not meet more than 25% of annual requirements (except that one supplier – Dominion – is allowed unlimited use of such RECs). The RPS includes set-asides for swine waste, poultry waste, and new solar electric or solar thermal facilities (the solar set-aside begins in 2010). Cost caps vary by customer type. |
| Oregon | Oregon's RPS was signed into law in June 2007, requiring utilities serving greater than 3% of statewide load (and any utility making a new investment in a coal plant) to meet a renewable energy purchase target of 5% in 2011, increasing to 25% by 2025. Smaller utilities have 2025 targets of 10% or 5%, depending on utility size, and no targets in intervening years. Competitive ESPs must meet targets that are dependent on the RPS obligations of the utility that would otherwise have served their customers. Unbundled RECs may be used for RPS compliance, but IOUs are capped at 20% unbundled RECs; large POUs may use up to 50% unbundled RECs until 2020; other suppliers have no restrictions. The PUC and consumer-owned utility governing boards are required to determine ACP rates for each utility. Suppliers are not required to comply if incremental compliance costs exceed 4% of annual revenue requirements. Suppliers are also not required to comply with the RPS in individual years if doing so would require them to acquire renewable energy in excess of load growth, displace non-fossil energy with eligible renewable power, or displace low-cost power from the Bonneville Power Administration. The legislation also contains a non-binding goal that community-based and small-scale renewable energy projects of 20 MW or less provide at least 8% of 2025 retail load. |

**Table A-2. Major Revisions to Existing State RPS Policies in 2007**

| State | Key Elements of Renewables Portfolio Standard Revisions |
|---|---|
| California | California's RPS first took effect in 2003, and was designed such that certain above-market renewable energy contract costs would be paid through a separate fund administered by the California Energy Commission (the payments were called supplemental energy payments, or SEPs). This structure created administrative complexity and imposed financing difficulties on renewable energy projects. As a result, legislation was passed in October 2007 that repeals the SEP process and returns the funds to the state's LSEs. To continue to ensure that the cost of the RPS is capped, above-market contract costs for the state's IOUs and ESPs will be limited to the funds transferred to them by the California Energy Commission. Separate legislation, also enacted in October 2007, expanded the resource eligibility rules to include certain hydropower facilities. |
| Colorado | Colorado was the first state to enact an RPS via the ballot box. In March 2007, follow-up legislation doubled the ultimate RPS target for IOUs (now 20% in 2020, up from 10% in 2015), thereby also doubling the effective size of the solar set-aside. The 2007 legislation also obligates all of the state's electric cooperatives (previously limited to coops serving over 40,000 customers) and municipal utilities serving more than 40,000 customers to meet a target of 10% by 2020, and eliminates any ability to opt-out of these requirements. POUs are now excluded from the solar set-aside; instead, solar projects that come online prior to July 2015 will receive a 3x multiplier. "Recycled" energy was added to the list of eligible technologies, while community-owned renewable projects of under 30 MW and located in Colorado will receive a 1.5x multiplier. The revisions also increase the retail-rate-cap for the RPS to 2% (up from 1%, except that electric cooperatives are still subject to the 1% cap), and provide some encouragement for utility-owned renewable energy projects. |
| Connecticut | In June 2007, new legislation increased Connecticut's RPS to 23% by 2020, with at least 20% from Class I resources. The new legislation also requires the Connecticut Municipal Electric Energy Cooperative to develop renewable energy standards for the state's municipal electric utilities and report progress on those standards annually. |
| Delaware | In July 2007, Delaware increased its RPS, previously at 10% by 2019, to 20% by the same year, and created a solar PV set-aside that reaches 2.005% by 2019. The legislation also increases the level of ACP payments that may be made in lieu of purchasing RECs, and establishes an ACP schedule for the solar set-aside. |
| Maine | Maine's original RPS did little to support new renewable projects. In June 2007, the legislature made mandatory a new and additional target (stated as a non-binding goal in 2006 legislation) of 10% of supply from new renewable capacity by 2017, starting at 1% in 2008. ACP levels for the new requirement are determined by the PUC, and the PUC subsequently established an ACP for the 10% requirement starting at $57.12/MWh in 2007 dollars, matching the ACP levels in MA, NH, and RI. The PUC is also given the discretion to suspend annual increases in the new standard under certain conditions. |
| Maryland | Legislation enacted in April 2007 raises Maryland's existing RPS targets by adding a requirement for solar that increases to 2% by 2022, thereby increasing the overall renewable energy target from 7.5% to 9.5%. In exchange for the new solar set-aside, the revised legislation deletes the earlier 2x multiplier for solar. The legislation establishes solar contracting requirements, revises solar REC ownership rules, and creates a higher ACP for the solar set-aside. Delays in achieving the solar set-aside may be allowed if certain cost limits are reached. |
| Minnesota | February 2007 legislation alters the RPS in Minnesota in several respects. Most importantly, it raises Xcel's RPS obligations to 30% by 2020 (of which at least 25% must come from wind; the remaining 5% may come from other sources), and creates somewhat lower but mandatory targets for the state's other electric utilities (including POUs) increasing to 25% by 2025 (previous targets were 10% by 2015). A separate "good faith" objective of 7% by 2010 exists for all electric utilities in the state. Unbundled RECs may now be used for compliance. |
| New Jersey | In 2007, New Jersey's BPU began to significantly change the implementation of that state's solar set-aside. In particular, the importance of up-front rebates for PV is to decline, with the goal of transitioning towards a system that relies more-heavily on the purchase and sale of solar RECs. As part of that process, among other proposed changes, solar ACP levels are to increase and become more predictable, with a rolling 8-year price schedule set in advance. The trading life of solar RECs is to be extended to two years, and PV systems will only be allowed to create solar RECs for 15 years. The BPU staff was also directed to develop an overall cost cap for solar incentive payments, at a level of roughly 2% of retail rates. Additionally, the BPU staff was directed to cap solar capacity requirements at a level that accounts for the state's aggressive energy efficiency goals. New Jersey also extended the timeframe for 2007 RPS compliance, given the run-up in Class I REC prices. |
| New Mexico | In March 2007, New Mexico's RPS for IOUs was increased to 20% by 2020 (up from 10% by 2011 previously), and for rural cooperatives an RPS of 10% by 2020 was established. Rules adopted by the New Mexico PRC encourage resource diversity for IOUs through set-asides for solar and wind (each required to meet at least 20% of 2011 targets, and thereafter) and biomass or geothermal (a combined minimum of 10% of 2011 targets, and |

| State | Key Elements of Renewables Portfolio Standard Revisions |
|---|---|
| | thereafter); distributed generation is required to serve 3% of the RPS by 2015. These set-asides replace earlier-developed credit multipliers. The PRC has also established caps on energy costs by resource type, and has developed an overall cost cap of 2% for IOUs, and 1% for coops. |
| Pennsylvania | In July 2007, legislation was passed that clarifies the force majeure clause in Pennsylvania's RPS, creates a more-detailed schedule for the solar set-aside, adds solar thermal to the list of eligible Tier I technologies, confirms REC property rights for generators and customer-generators, and somewhat limits the geographic scope of projects that may be eligible. |
| Texas | Legislation in 2007 clarifies that RECs retired for other purposes (e.g., sold through a voluntary green power program) can not be counted toward the RPS. The legislation also permits certain large customers to opt out of the RPS requirements, and empowers the PUC to establish alternative compliance payments for the RPS. |

### Table A-3. New Non-Binding State Renewable Energy Goals Established in 2007

| State | Key Elements of Renewable Energy Goal |
|---|---|
| Missouri | Missouri legislatively adopted a non-binding renewable energy and energy efficiency goal for the state's IOUs in June 2007. Utilities are required to demonstrate a "good faith" effort to meet a goal of 4% by 2012, using either renewable energy or energy efficiency, increasing to 11% by 2020. The Missouri PSC is required to adopt criteria and standards for such a demonstration by July 2008. |
| North Dakota | In March 2007, the North Dakota legislature adopted a "renewable and recycled energy objective" of 10% by 2015. All retail suppliers of electricity are covered by the objective. Recycled energy systems are defined as those producing power from previously unused waste heat from combustion or other processes (but not from systems being used primarily to generate electricity). Retail suppliers are required to make an economic assessment of the cost-effectiveness of new renewable and recycled energy purchases. |
| Virginia | In April 2007, Virginia enacted a non-binding renewable energy goal for the state's IOUs of 4% in 2010, increasing to 12% in 2022. The percentages are applied to 2007 retail sales, less the average amount of power supplied from nuclear generators between 2004 and 2006. Utilities that meet the goals are to receive an increased rate of return in addition to cost recovery for their renewable energy purchases. Double credit is to be given for solar and wind power. |

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## Acknowledgments

For their support of this project, the authors thank John Atcheson and Dan Birns of the U.S. DOE's Weatherization and Intergovernmental Program, Larry Mansueti of the U.S. DOE's Office of Electricity Delivery and Energy Reliability, Drew Ronneberg, Steve Lindenberg, Phil Dougherty, and Alejandro Moreno of the U.S. DOE's Wind & Hydropower Technologies Program, and Tom Kimbis and Charles Hemmeline of the U.S. DOE's Solar Energy Technologies Program.

For providing information or reviewing elements of this paper, we thank: Howard Bernstein (Massachusetts Division of Energy Resources), David Bloom (Delaware PSC), James Brack (New Mexico PRC), Joe Bryson (U.S. EPA), Cathie Bussolotta (Connecticut DPUC), Paul Cartwright (Montana Department of Environmental Quality), Roger Clark (The Reinvestment Fund), Craig Cox (Interwest Energy Alliance), Dennis Criswell (Sierra Southwest Cooperative), Jennifer DeCesaro (Clean Energy Group), Bill Drumheller (Oregon Department of Energy), David Goldberg (Connecticut Clean Energy Fund), Kevin Hale (NYSERDA), Paul Helgeson (Wisconsin PSC), Scott Hennessey (Solar Energy Industries Association), Dennis Hughes (Navopache Electric Cooperative), Benjamin Hunter (New Jersey BPU), David Hurlbut (National Renewable Energy Laboratory),Robert Grace (Sustainable Energy Advantage), Gregory Kim (Maryland PSC), Tom Kimbis (U.S. DOE), Jesse Jenkins (Renewable Northwest Project), Barbara Lockwood (APS), Brian Loos (New Jersey BPU), Larry Mansueti (U.S. DOE), Tanya McClosky (Pennsylvania Office of the Consumer Advocate), Richard Mignogna (Colorado PUC), Alan Nogee (Union of Concerned Scientists), Larry Nordell (Montana Consumer Council), John Pearce (Iowa Utilities Board), Susan Peirce (Minnesota Dept. of Commerce), Heather Raitt (California Energy Commission), Shane Rooney (Pennsylvania PUC), Elizabeth Salerno (American Wind Energy Association), Lisa Schwartz (Oregon PUC), Larry Sherwood (Interstate Renewable Energy Council), Linda Silverman (U.S. DOE), Sean Simon (California PUC), Charlie Smisson (Delaware Energy Office), Mitchell Tannenbaum (Maine PUC), Jess Totten (Texas PUC), Sam Watson (North Carolina Utilities Commission), Ray Williamson (Arizona Corporation Commission), Mike Winka (New Jersey BPU). We also thank Anthony Ma for assistance with layout, formatting, and production. Of course, the authors are solely responsible for any remaining omissions or errors.

Berkeley Lab's contributions to this report were funded by the Office of Energy Efficiency and Renewable Energy (Weatherization and Intergovernmental Program, Wind & Hydropower Technologies Program, and Solar Energy Technologies Program) and by the Office of Electricity Delivery and Energy Reliability (Permitting, Siting and Analysis Division) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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