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# Do Renewable Portfolio Standards Deliver?

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## Abstract

Renewable Portfolio Standards (RPS) are the largest and perhaps most popular climate policy in the US, having been enacted by 29 states and the District of Columbia. Using the most comprehensive panel data set ever compiled on program characteristics and key outcomes, we compare states that did and did not adopt RPS policies, exploiting the substantial differences in timing of adoption. The estimates indicate that 7 years after passage of an RPS program, the required renewable share of generation is 1.8 percentage points higher and average retail electricity prices are 1.3 cents per kWh, or 11% higher; the comparable figures for 12 years after adoption are a 4.2 percentage point increase in renewables' share and a price increase of 2.0 cents per kWh or 17%. These cost estimates significantly exceed the marginal operational costs of renewables and likely reflect costs that renewables impose on the generation system, including those associated with their intermittency, higher transmission costs, and any stranded asset costs assigned to ratepayers. The estimated reduction in carbon emissions is imprecise, but, together with the price results, indicates that the cost per metric ton of CO<sub>2</sub> abated exceeds \$115 in all specifications and ranges up to \$530, making it least several times larger than conventional estimates of the social cost of carbon. These results do not rule out the possibility that RPS policies could dynamically reduce the cost of abatement in the future by causing improvements in renewable technology.<sup>1</sup>

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\*Working paper. Comments welcome.

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# 1 Introduction

Even as evidence mounts on the costs of climate change, the United States has had great difficulty developing significant and enduring policy responses, particularly in the power sector which is a primary source of greenhouse gas emissions. One major exception has been renewable portfolio standards (RPS) that require that a certain percentage of electricity supply in a state is met by generation from sources that are designated as renewable. The first RPS was passed in Iowa in 1991 and since then others have followed suit. As of 2015, RPS policies have been enacted in 29 states and the District of Columbia, which together account for 62% of electricity generation.<sup>2</sup> Further, the ambition of these policies has grown dramatically. In the early years of implementation, RPS policies typically required increases in the renewables share of electricity of a couple of percentage points, but states have greatly ramped up their ambitions, with, for example, 2030 targets of 41% (Massachusetts), 44% (Connecticut), 50% (New York), and 60% (California). Indeed, RPS have been credited with greatly expanding the penetration of renewable technologies, most frequently wind and solar, which rose from 0.1% of all generation in the United States in 1990 to 5.3% in 2015. Further, their penetration rate has increased greatly in recent years and indeed they accounted for approximately half of the new installed capacity since 2010.<sup>3</sup>

Despite the popularity of these policies, there is little if any systematic evidence on RPS' impacts on electricity prices or carbon emissions. A common approach to estimating their costs is to calculate the difference in costs associated with a RPS— that is, compare the costs of a renewable plant with the costs of a fossil fuel plant that it replaces. This type of calculation entails comparing the levelized cost of energy (LCOE), calculated by dividing the total direct costs associated with investment in new capacity by expected total lifetime energy production. The latest data from the Energy Information Administration's Annual Energy Outlook (EIA, 2019) suggests that solar and wind plants can produce electricity at about 6 cents per kWh, while a natural gas combined cycle plant produces at roughly 4 cents per kWh. Since to date RPS policies have only increased renewable penetration by a few percentage points, it is this type of comparison of LCOEs that lead observers to suggest that RPS policies have had only a minimal impact on electricity prices; one recent study found that they increase retail electricity bills by about 2% (see, e.g., Barbose (2018)).

However, this comparison of LCOEs misses three key ways in which renewables impose costs on the electricity generation system that need to be covered and are reflected in *retail* prices but can be difficult to observe directly or measure systematically. First, and most obviously, renewables by their very nature are intermittent sources of electricity. Solar plants cannot provide power when the sun doesn't shine and wind plants cannot provide it when the wind isn't blowing. On average, utility scale solar plants have a capacity factor (i.e., average power generated divided by its peak potential supply over the course of a year) of about 25% and wind plants are not much higher at

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<sup>2</sup>An additional seven states enacted non-binding targets under similar programs.

<sup>3</sup>This fact comes from Bushnell et al. (2017).

34% according to the EIA. This means that a comparison of LCOEs between these intermittent sources and “baseload” technologies that “always” operate (e.g., natural gas combined cycle plants have capacity factors of 85%) is very misleading with respect to total system costs, because they do not account for the additional costs necessary to supply electricity when they are not operating. For example, given current cost structures, the installation of renewables are frequently paired with the construction of natural gas “peaker” plants that can quickly and relatively inexpensively cycle up and down, depending on the the availability of the intermittent resource.

Second, renewable power plants require ample physical space, are often geographically dispersed, and are frequently located away from population centers, all of which raises transmission costs above those of fossil fuel plants. A literature review of transmission cost estimates for wind power by the Lawrence Berkeley National Laboratory (LBNL) finds a median estimate of about \$300 per kW, or about 15% of overall wind capital costs (Mills et al., 2009). This is approximately equivalent to adding 1.5 cents per kWh to the levelized cost of generation for wind. More generally, a separate analysis by the Edison Electric Institute in 2011 found that 65% of a representative sample of all planned transmission investments in the US over a ten-year period, totaling almost \$40 billion for 11,400 miles of new transmission lines, were primarily directed toward integrating renewable generation.<sup>4</sup> The highly disproportionate share of transmission requirements for renewables relative to their share of generation highlights the importance of accounting for the associated costs as part of the total cost of renewable energy.

Third, RPS driven increases in renewable energy penetration can also raise total energy system costs by prematurely displacing existing productive capacity, especially in a period of flat or declining electricity consumption. Adding new renewable installations, along with associated flexibly dispatchable capacity, to a mature grid infrastructure may create a glut of installed capacity that renders some existing baseload generation unnecessary. The costs of these “stranded assets” do not disappear and are borne by some combination of distribution companies, generators, and ratepayers. Thus, the early retirement or decreased utilization of such plants can cause retail electricity rates to rise even while near zero marginal cost renewables are pushing down prices in the wholesale market. The incidence of excess capacity costs on ratepayers is likely greater in regulated markets with vertical integration, although even in deregulated markets there are various mechanisms for direct payments to producers unconnected to actual generation that can contribute to the rates consumers face.<sup>5</sup> Overall, there exists no comprehensive source of data on payments to displaced electricity producers, and even the availability of such information would not provide an obvious path to attributing these costs to the integration of renewables. Like many of the other ancillary

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<sup>4</sup>The Edison Electric Institute collected a representative sample of transmission projects totaling over \$61 billion from their members, who cover about 70% of the total US electricity market. See EEI (2011) and Mills et al. (2009).

<sup>5</sup>For instance, ISO New England made over \$1 billion of capacity market payments unconnected to actual generation in 2013, comprising 12% of their total wholesale market expenditures. Over 95% of these payments supported existing, rather than new, capacity. The Independent System Operator for New England covers production in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. They publish capacity market information in their annual market report: <https://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf>.

costs of renewable energy integration, directly observing the total costs associated with stranded capacity is unlikely to be feasible.

As an alternative to what we believe is the nearly impossible task of directly measuring each of the mechanisms by which RPS policies influence costs, this paper compares states that did and did not adopt RPS policies, using the most comprehensive panel data set ever compiled on program characteristics and key outcomes from 1990-2015. Importantly, there is variation in the timing of the adoption of RPS programs across states, which lends itself to powerful event-study style figures that reveal no meaningful evidence of pre-existing different trends in outcomes between adopting and non-adopting states. Further, we are able to control for a series of potentially confounding electricity policies.

There are three key findings. First, RPS policies' statutory requirements for renewable generation frequently overstate their *net* impact on generation, because they often include generation that existed at the time of the policy's passage. For example, six years after Minnesota adopted its RPS policy, its statutory or total requirement was that renewables account for 14.2% of generation. Yet at the time of adoption, renewables already accounted for 5.3% of generation. So, its net requirement in this year was 8.9%. Due to the substantial heterogeneity in the form and structure of RPS policies, it is challenging to estimate the net requirements and there is no common source for this information. For a handful of states in our sample, even the gross requirement differs across data sources. Nevertheless, our best estimates are that 7 years after adoption the average adopting states' net requirement was 1.8% of generation and 12 years after it was 4.2%.

Second, electricity prices increase substantially after RPS adoption. The estimates indicate that in the 7th year after passage average retail electricity prices are 1.3 cents per kWh or 11% higher, totaling about \$30 billion in the RPS states. And, 12 years later they are 2.0 cents, or 17%, higher. The estimated increases are largest in the residential sector, but there are economically significant price increases in the commercial and industrial sectors too. These estimates are robust to controlling for local shocks to electricity costs in a variety of ways. Given the price increases, we also test for impacts on economic activity and fail to find any impact on electricity consumption or state level employment. There is some evidence of a decline in manufacturing employment, but it would not be judged statistically significant by conventional criteria.

Third, the estimates indicate that passage of RPS programs leads to reductions in the generating mix's carbon intensity, although these estimates can be noisier and more sensitive to specification than is ideal. The estimated decline in emissions intensity implies a reduction of 71-250 million metric tons of CO<sub>2</sub> across the 29 RPS states 7 years after passage. When the CO<sub>2</sub> emissions estimates are combined with the estimated impact on average retail electricity prices, the cost per metric ton of CO<sub>2</sub> abated exceeds \$115 in all specifications and can range up to \$530, making it at least several times larger than conventional estimates of the social cost of carbon ([Greenstone et al., 2013](#); [EPA, 2016](#)).

Our paper builds on previous work in the economics and engineering literatures that considers the costs and benefits of renewable electricity generation and the impact of RPS programs in particular. One significant line of existing research investigates how baseload, dispatchable, and intermittent resources interact on the grid and how this affects the value of generation from the respective sources and renewables in particular (Denholm and Margolis, 2007; Borenstein, 2008; Lamont, 2008; Joskow, 2011; Cullen, 2013). Recent work by Gowrisankaran et al. (2016) has made particular progress in quantifying the costs of intermittency, and their model resembles the one we present in Section 3. This line of research in economics runs parallel to an engineering literature that uses an energy systems modeling approach to evaluate similar questions (Milligan et al., 2011; Jacobson et al., 2015).

The literature on RPS program impact in particular has thus far largely consisted of ex-ante impact estimation. Fischer (2010) and Schmalensee (2012) document the conceptual issues underlying the costs of these programs and Chen et al. (2007) survey pre-program prospective assessments, often commissioned by states considering adoption. The median estimate projected that RPS standards would raise retail prices by 0.7%, though the range of projections included significant heterogeneity. The authors also note the importance of underlying assumptions, which focus on capital infrastructure and fuel input costs. A limited body of post-implementation evaluations of certain RPS programs has found slightly larger costs of approximately 2-4% (Heeter et al., 2014; Tuerck et al., 2013), although this literature has largely taken place outside peer-reviewed journals and generally does not account for all the ways these programs can affect system costs. An important exception to this is Upton and Snyder (2017), who use a difference-in-difference synthetic controls framework to show that RPS programs substantially raise electricity prices and modestly reduce emissions at the state-level.<sup>6</sup>

The paper proceeds as follows. Section 2 provides background on RPS policies and their typical implementation. Section 3 constructs a model to explicate the channels through which integrating renewable generation could raise costs. Section 4 outlines our data sources and presents summary statistics on the electricity sector prior to RPS passage. Section 5 describes our empirical strategy, and Section 6 presents and discusses the results. The paper then finishes with Interpretation and Conclusion sections.

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<sup>6</sup>Tuerck et al. (2013) and associated work by those authors also constitute exceptions to this pattern. They account for intermittency and other associated costs using techniques such as engineering estimates, and produce somewhat higher cost estimates of close to 5% of retail prices, though these are still smaller than the effects implied by our estimates.

## 2 Renewable Portfolio Standards

By 2009, 29 states and the District of Columbia had adopted mandatory portfolio standards, while an additional seven states had passed optional standards.<sup>7</sup> These programs currently cover 62% of electricity generation in the US. Figure 1 is a map of the United States that indicates which states have enacted RPS programs, with the colors indicating the years of enactment. Most RPS programs require that retail electricity suppliers meet a percentage of demand with energy from renewable sources.<sup>8</sup> Once in place, the standard typically increases along a predefined schedule until a specified fraction of generation is achieved. For example, California’s policy specifies a goal of 33% retail sales from renewables by 2020, with interim targets of 20% by 2013 and 25% by 2016. While the standards sometimes exempt certain providers, most often smaller municipal or cooperative suppliers, they cover 82% of electric load in a state on average.<sup>9</sup>

The key feature of RPS programs is that compliance requires production from a set of designated technologies with the frequent motivation of aiming to help spur innovation that lowers those technologies’ costs over time. In practice, the list always includes wind and solar, but whether other technologies are included differs from state to state. Nuclear power is excluded from the policy in all but two states (Massachusetts and Ohio), although it is also a zero carbon energy source.

Electricity providers must demonstrate compliance with the program through Renewable Energy Credits, or RECs, which certify that a given unit of electricity production qualifies to meet the standard. Most RECs are awarded by various regional authorities encompassing several states, which issue unique serial numbers for every megawatt hour of generation produced by registered generators. The approximate coverage of these systems is shown in Appendix Figure A.1. This independent tracking seeks to prevent double counting of generation used for RPS compliance. While there is some scope for transferring RECs between regional systems, in practice most RPS compliance occurs within tracking regions, a fact we will return to later on when considering the impact of RPS on generation outcomes.

Once awarded, credits can be sold separately from the underlying electricity, enabling flexible transfer of the rights to environmental benefits and providing additional revenue to renewable suppliers.<sup>10</sup> In most cases, individual generators must be further approved by the state office

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<sup>7</sup>West Virginia also passed an *Alternative and Renewable Energy Portfolio Standard* in 2009 with characteristics similar to an RPS but which we do not consider. While renewables received some preference in this program, a much broader set of generation sources qualified, including “Advanced Coal Technology,” and there was no guaranteed compliance from renewable sources. This program was also repealed before its first binding requirement came into effect.

<sup>8</sup>Our data classify qualifying generation as one of wind, solar, biomass, geothermal, landfill gas, or ocean power, with some states also allowing small hydroelectric.

<sup>9</sup>The statistic on load covered comes from the North Carolina Clean Energy Center’s Database of State Incentives for Renewables & Efficiency (DSIRE).

<sup>10</sup>A minority of RPS programs have the more stringent requirement that credits be “bundled” with electricity delivered into the state, as demonstrated by transmission to a state balancing authority.

administering the RPS to assure that they comply with the specific requirements for generators set forth by that state. In restructured markets, retail providers then purchase RECs generated by these approved facilities, either via brokers or directly through individual contracts. In non-restructured markets, retail providers may also use RECs generated by their own renewable facilities. The serial numbers of the RECs obtained are filed for compliance and their retirement verified with the relevant tracking system. Depending on program rules, excess RECs may also be “banked” for use in later years, though there are typically vintage restrictions requiring relatively recent credits be used. Therefore, REC prices reflect the marginal costs of *producing* electricity from one of the designated technologies, relative to the least expensive alternative, but they do not capture the systemwide costs of *supplying* that electricity, which additionally reflect the costs associated with intermittency, transmission, and compensating owners of stranded assets.

Most RPS programs enforce compliance using a system of Alternative Compliance Payments (ACPs), which effectively fine retail providers for failing to acquire sufficient RECs to cover their sales. These payments are large, averaging about \$50 per MWh.<sup>11</sup> Such penalties are substantial, representing about half of the average revenue per MWh observed in 2011. In addition to a penalty, ACPs also provide an effective cost-ceiling for the REC market, as they provide an outside option for compliance. While in practice few retail suppliers fulfill their requirements through ACP payments, REC markets in some states have periodically traded at the ACP level, suggesting that marginal sources of compliance can be relatively high cost.

While statutory requirements like Maine’s 40% target appear quite large, they often ramp up gradually from lower levels and may not reflect the amount of marginal generation actually mandated by RPS policies. Intuitively, if an RPS requirement were entirely covered by existing sources at its inception, in a competitive market we would expect producers to bid down the price of RECs to zero. Distinguishing the amount of new renewable generation required to comply with RPS policy is quite difficult in practice, since covered sources of generation vary from state to state even within narrowly defined categories. For instance, some states allow small-scale hydropower but not large-scale hydropower to qualify for their RPS. Further, six states, including Maine, explicitly mandate that part of their RPS be met using newly constructed renewable capacity. Our best estimate of the “net” requirement imposed by RPS policies takes the gross amount of MWh required for RPS compliance, as reported by LBNL, and subtracts existing generation from the broad categories of covered sources in the year prior to RPS passage.

Figure 3 reports each states’s total and net requirements as of seven years after the state passed RPS legislation, ordering states by the calendar year in which they first adopted an RPS. While these numbers do not fully account for the complications described above, they do show a clear pattern of statutory requirements overstating the amount actually necessary to achieve compliance. For instance, seven event years after passage, the gross requirement in Michigan is 6.2%, but the

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<sup>11</sup>In the case of mandates for generation specifically from solar energy, they can climb even higher, sometimes exceeding \$400 per MWh.



net requirement after subtracting existing generation in the year of passage is only 2.6%. On average, seven event years after RPS passage, RPS states have a total requirement of 5.1%, but a substantially lower net requirement of 1.8%. In the remainder of the paper, we primarily focus on estimates of net requirements, described in greater detail in Section 4.1.

Figure 2 plots the number of RPS programs passed into law in each year.<sup>12</sup> The majority of programs were not passed until after 2000. While a number of states adopted RPS policies during, or subsequent to, broader electricity market restructuring, RPS programs have also been adopted in a number of traditionally regulated markets. Figure 2 also plots real national average retail electricity prices (right y-axis) which declined from about 12 cents per kWh to 10 cents per kWh from 1990 through 2002 but by the end of the sample in 2015 returned to 12 cents per kWh.<sup>13</sup> This break in the decline in prices and subsequent upwards turn loosely corresponds with the number of states that passed RPS programs in those years. Whether this relationship is causal will be examined in much greater detail below.

### 3 Conceptual Framework

As discussed above, standard LCOE estimates measuring the direct capital and maintenance costs of various generation sources provide an incomplete summary of the impact of transitioning electricity production to renewable sources on consumer prices. We set out a simplified model of the decision-making process of a retail electricity provider to illustrate the mechanisms through which renewable integration can raise costs, and consequently retail prices. The model demonstrates how intermittency, transmission, and the displacement of existing capacity infrastructure interact to raise the total costs incurred by a utility. Notably, the model highlights the wide range of parameters and nontransparent data inputs that would be required to calculate these costs directly. The paper’s empirical procedure sidesteps this difficulty by summarizing the aggregate effect of these mechanisms through the reduced-form impact of RPS standards on retail electricity prices.

For simplicity, the model assumes a vertically integrated setting with a single utility responsible for both power capacity and retail provision. The intuition from this framework translates straightforwardly to a deregulated setting with a retail provider purchasing electricity from competing generators, except for the assumption that ratepayers always pay the full cost of installed capacity. As discussed below, the extent to which owners of capital bear the losses from excess capacity stranded by integrating renewable sources will be one factor that contributes to the overall effect on retail prices.

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<sup>12</sup>Iowa was the first state to establish a binding standard in 1991, requiring the states’s two investor-owned utilities to build or contract for 105 MW of renewable capacity. Although Iowa originally enacted an *Alternative Energy Law* in 1983, the program wasn’t given a concrete goal or made compulsory until a revision in 1991, so we consider that the first year of passage.

<sup>13</sup>All monetary figures are reported in January 2019 dollars.

### 3.1 Representative Utility Model

A representative utility chooses capacity investments and daily generation sources to fulfill two requirements: ensuring that they meet the full electricity demand of their customers every day and that their annual electricity production meets the RPS requirement.<sup>14</sup> Utilities have three types of production capacity available with which to meet daily electricity demand: renewables,  $R$ , baseload power,  $B$ , and dispatchable “peaker” plants,  $D$ , the latter two of which we assume come from non-renewable sources. Baseload generation produces a constant daily amount governed by annual capacity,  $B_t$ , and cannot be adjusted in response to daily demand. Renewable generation is stochastic and drawn from a distribution  $F(R)$ , with mean,  $\tilde{R}$ , standard deviation,  $\sigma_R$ , and support  $[\underline{R}, \overline{R}]$ .  $F(R)$  is a function of installed renewable capacity,  $R_t$ . The daily demand for electricity is also drawn from a distribution,  $G(E)$ , with mean  $\tilde{E}$ , standard deviation  $\sigma_E$ , and support  $[\underline{E}, \overline{E}]$ . So given the available capacity of  $B_t$ ,  $R_t$ , and  $D_t$  in year  $t$ , the utility observes the daily draws of  $E_s$  and  $R_s$  and chooses the level of dispatchable power,  $D_s$ , to satisfy customer demand.

$$\begin{aligned} E_s &= B_t + R_s + D_s, \\ E_s &\sim G(E_t), \quad R_s \sim F(R_t). \end{aligned} \tag{1}$$

With knowledge of this daily optimization problem, the utility chooses investment in new capacity at the beginning of each year. Total capacity in period  $t$  consists of the depreciated capital from last period plus new investments in each of the three categories of electricity sources:

$$C_t = B_{t-1}(1 - \delta_B) + R_{t-1}(1 - \delta_R) + D_{t-1}(1 - \delta_D) + I_B + I_R + I_P. \tag{2}$$

The utility chooses annual investments in new capacity to fulfill its two primary requirements. First, the RPS requirement dictates the proportion of annual electricity production that must come from renewables. For mandated renewable percentage,  $M$ , the utility must satisfy the following:

$$\frac{\sum_{s=1}^{365} R_s}{\sum_{s=1}^{365} E_s} \geq M. \tag{3}$$

Under RPS requirements, failure to meet this condition will cost the utility a per-unit fine,  $f$ , for the amount by which renewable generation falls below the threshold. To avoid paying the fine, utilities must have enough installed renewable capacity,  $R_t$ , to produce enough electricity to meet this requirement. Determining what constitutes enough renewable capacity also may not be straightforward. If draws from the  $F(R)$  distribution are correlated across days, simply ensuring that  $\frac{E[R_s]}{E[E_s]} = M$  might not be sufficient to ensure compliance with the RPS mandate in a year with systematically low realizations for renewable generation. The utility will trade off the cost of

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<sup>14</sup>The period in which instantaneous demand must be met can equivalently be thought of as an hour rather than a day.

increasing renewable capacity,  $R_t$ , with investments,  $I_R$ , against the fine for noncompliance when making their choice over optimal  $R_t$ .

Second, the utility must ensure it can supply enough energy every day of the year. We assume there is an infinite penalty for failing to meet demand. Since both energy demand and renewable production are stochastic, the utility must have enough dispatchable generation available to fill the largest possible daily need. In particular, the utility chooses  $D_t$  such that it can meet total electricity needs on a hypothetical day with the highest possible demand draw,  $\bar{E}$ , and the lowest possible renewable generation draw,  $\underline{R}$ .

$$D_t = \bar{E} - B_t - \underline{R}. \quad (4)$$

In addition to choosing investment, the utility also has the option to prematurely retire capacity at the beginning of each period. The carrying costs of retired capacity are lower and for simplicity we assume that capacity that has not been retired will be run. Under certain conditions, they may choose to retire baseload capacity because too much baseload generation could prevent the utility from meeting the RPS requirement. If  $\frac{B_t}{E[E_s]} > 1 - M$ , for instance, then renewable production would be expected not to meet its mandate even without any dispatchable production. To ensure compliance with the RPS mandate, the utility must estimate the amount of dispatchable production necessary during the year and then scale back  $B_t$  such that the expected sum of baseload and dispatchable generation does not exceed  $1 - M$  as a proportion of all production.

Total costs for the utility include the fixed costs of installed capacity, associated transmission and distribution requirements, and the variable costs associated with each type of power. The utility finances new investments such that they make a constant annual payment over a horizon of  $T$  years. The annualized prices of installed capacity,  $p_B$ ,  $p_R$ , and  $p_D$ , incorporate differences in the cost per MWh for baseload, dispatchable, and renewable sources, as well as any differences in financing costs or investment tax incentives. New transmission investments in each period, which are also financed over a  $T$ -year horizon with annualized payment  $p_T$ , are a function of new installations across the three categories and depreciation of the existing transmission capital stock, with geographically dispersed renewable installations such as wind and solar likely having greater associated requirements. Since renewables require no fuel inputs, they incur no variable costs whereas baseload and dispatchable power have average costs  $ac_B$  and  $ac_P$  for each unit generated. For the purposes of this model, these average costs capture not only the cost of fuel inputs, but also any startup and shutdown costs associated with the operation of these generating sources. Thus, the utility's total costs in period  $t$  are as follows:

$$\begin{aligned}
TC_t = & \sum_{k=t-T}^t p_{Bk} I_{Bk} + \sum_{k=t-T}^t p_{Dk} I_{Dk} + \sum_{k=t-T}^t p_{Rk} I_{Rk} \\
& + \sum_{k=t-T}^t p_{Tk} Tr(I_{Rk}, I_{Bk}, I_{Dk}) + 365 B_t ac_B + \sum_{s=1}^{365} D_s ac_D.
\end{aligned} \tag{5}$$

The retail rate is given by total costs in period  $t$  divided by total kilowatt-hours of energy produced plus a markup,  $\mu$ , assigned by the regulator. Thus:

$$\text{Retail Rate in Year } t = (1 + \mu) \frac{TC_t}{\sum_{s=1}^{365} E_{st}}. \tag{6}$$

### 3.2 Empirical Requirements for Estimating the Full Costs of a RPS

This framework illustrates the major practical difficulties involved in developing the costs of RPS programs piece-by-piece. This simplified model reveals that even if renewable and non-renewable production have the same LCOE, defined by the prices of installed capacity and fuel inputs, transitioning a mature grid infrastructure could increase costs through a wide variety of channels. The list of excess costs includes:

- investments in new dispatchable capacity to protect against shortfalls of intermittent renewable generation,
- investments in new transmission infrastructure to accommodate the geographic locations of new renewable capacity,
- premature retirements of baseload capacity and/or transmission infrastructure that serves nonrenewables to reduce nonrenewable production enough to meet RPS mandates.

Further, the incidence of this last category between ratepayers and owners of capital is unclear ex ante, although ratepayers seem more likely to bear the costs in traditional regulated “cost-plus” markets, compared to restructured ones. Regardless of the ultimate incidence, these costs are part of the full costs of the introduction of a RPS program. However, it is worth noting that this last category is “transitional” in nature, while the first two are permanent features of increasing renewables’ share of production.

It is instructive to consider the challenges with constructing a bottom-up or structural estimate of the costs of an RPS policy. First, it would require data or estimates of several moments from the distributions of daily energy demand,  $G(E_t)$ , and daily renewable generation,  $F(R_t)$ , the pre-existing level of installed capacity by generation type,  $B_t, D_t, R_t$ , the respective depreciation rates,

investment prices, and fuel input prices for each of these three energy categories, and the transmission investments necessary to incorporate renewable capacity. Second, the estimates would need to make a series of assumptions for how utilities project electricity demand, renewable intermittency, the need for dispatchable generation to protect against insufficient or excess supply, as well as the decision criteria for retiring baseload generation. Third, estimating the model would require going beyond the representative utility setup and incorporating interactions between heterogeneous generators and retail providers in restructured and non-restructured markets; these interactions have proven to be quite complex to model as they involve questions of market power and doing so in this context would undoubtedly be both a great research topic and a difficult problem to solve. Fourth, the incidence of these costs between ratepayers and owners of capital is also a complicated question and, as we noted above, is likely affected by the regulatory environment.

Our approach circumvents this complex interplay of underlying mechanisms with a reduced-form approach that captures the costs imposed on ratepayers due to all potential mechanisms through which RPS policies raise costs. If generators or distributors bear part of the costs, our approach will not capture the full social costs of RPS policies.

Finally, we note that coincident to the increase in the number of RPS programs and the scope of their ambitions, there have been important changes in the operation of electricity markets. As one example, several Regional Transmission Organizations began holding centralized auctions for capacity market payments in the mid-2000s as RPS programs began to proliferate.<sup>15</sup> Since their initiation, these payments comprise a substantial fraction of overall market costs - reaching 9-28% of total costs in ISO New England, the New York ISO, and the PJM Interconnection between 2008 and 2016 (GAO, 2017). These three RTOs cover all or part of 15 of the 29 RPS-adopting states in our main sample, and the Mid-continent Independent System Operator (MISO) added a capacity market auction covering 4 more RPS states in 2013. Further, (Bushnell et al., 2017) document that similar payments to maintain “Resource Adequacy” take place in other locations as well and that they likely also preceded the centralized auctions in those four RTOs. We take the significant share of these types of payments for generator availability after RPS implementation, be it through auctions or resource adequacy payments, as suggestive evidence that RPS program’s mandated increase in intermittent renewable generation imposes systemwide costs on electricity markets, very likely due to these technologies’ intermittency.

Thus, it is at least plausible that an important share of RPS programs’ total costs comes from the indirect costs that they impose on the electricity supply system. These costs are not evident from a simple comparison of LCOEs or RECs prices. Of course, the qualitative evidence about the growth of capacity markets or resource adequacy payments is not decisive and could be due to other factors, so the remainder of the paper exploits a differences in differences research design that is generated by the staggered adoption of RPS programs by some states and the non-adoption

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<sup>15</sup>ISO-NY began their current system of auctions in 2003, PJM in 2004, NE-ISO in 2007, and MISO in 2013.

by other states.

## 4 Data Sources and Summary Statistics

In order to assess the retail price and other impacts of RPS programs, we construct a state-level panel from 1990 to 2015 with data on RPS programs, electricity prices, generation capacity and outcomes, and CO<sub>2</sub> emissions. We believe this is the most comprehensive data set ever compiled on RPS program characteristics and potential outcomes. This section describes each data source and presents some summary statistics describing the context of the policy.

### 4.1 RPS Program Data

Since 1990, 29 states and the District of Columbia have adopted RPS programs. We construct indicators for the year in which legislation for a mandatory RPS program first passed in each state, compiled using state legislative documents, state government websites, and summaries from the U.S. Department of Energy. While there is typically a few years' lag between policy enactment and the onset of binding mandates for renewable generation, costs to electricity providers, and consequently customers, are likely to begin accruing when they start planning for and investing in the required future capacity. Data from the Lawrence Berkeley National Laboratory (LBNL) also include information about qualifying renewable sources under each program, including whether there are specific requirements for solar generation.

To better characterize each state's implementation, we also collect more detailed information on year-by-year requirements. Most RPS programs require an increasing percentage of electricity sales to come from renewable sources, leading to increased stringency over time.<sup>16</sup> However, as mentioned earlier, the statutory percentage requirement may overstate the additional generation required if a large number of existing generators are eligible for compliance. To account for this, we construct a measure of RPS net requirements as the difference between statutory requirements and pre-existing renewable generation. We collect data from LBNL on total generation required from renewables in each RPS state in each year of enforcement (Barbose, 2018), and define pre-existing compliance as total generation from qualifying categories of renewables in the year before RPS legislation was passed. The difference is the amount by which each state had to expand renewable generation to comply with the policy - our measure of net requirements.<sup>17</sup> Recall, Figure 3 highlighted the substantial differences between the total and net requirements.

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<sup>16</sup>Iowa and Texas have fixed capacity requirements for new renewable generation, which will tend to decrease stringency over time if demand is increasing.

<sup>17</sup>Some states include waste-to-energy and similar forms of power generation in their RPS, but we do not have data for these sources, so we cannot account for these in our net generation estimates. In addition, there are 3 states - California, Montana, and Minnesota - for which the gross MWh requirements reported by LBNL differ by more than 3 percentage points from the statutory percentages reported by DSIRE.

In addition to data on RPS programs, we also collect information from the North Carolina Clean Energy Center’s Database of State Incentives for Renewables & Efficiency (DSIRE) on the presence of other state programs that may influence the amount of renewable generation and the retail price of electricity (Barnes, 2014). We have information on the implementation dates of three types of programs: net metering, which pays consumers for electricity they add to the grid with distributed generation such as solar PV, green power purchasing, which gives consumers the option of paying to have renewable energy account for a certain percentage of their consumption, and public benefits funds, which place a surcharge on retail electricity prices to fund programs such as research and development, energy efficiency investments, and low-income energy assistance. This information is used to account for the presence of potentially confounding programs.

## 4.2 Electricity Sector

Information on electricity sector variables is drawn from Energy Information Administration (EIA) survey forms. Electricity prices are computed from EIA Form 861, a mandatory census of retail sales by electric power industry participants.<sup>18</sup> Respondents report sales and revenues separately for commercial, industrial, and residential sectors. Average price is then computed based on average revenue per megawatt-hour sold for each sector and for total retail sales.

Electricity generation by state and fuel source is compiled from EIA forms 906, 920, and 923, which concern power plant operations. This data is broken down by fuel type, ensuring plants with multiple fuel sources are accurately reflected in aggregate numbers. Generating capacity by state and fuel source is compiled from EIA Forms 860 and 867, along with starting year and month and location. These surveys cover all grid-connected generators larger than 1 MW in capacity currently able to deliver power. For simplicity, we aggregate the EIA’s fuel type categories, measuring generation by hydroelectric, solar, wind, coal, natural gas, nuclear, other renewables, and other fuels.<sup>19</sup>

To measure CO<sub>2</sub> emissions, we use estimates derived by the EIA from power plant operations data taken from forms 767, 906, and 923. Their estimation process involves converting fuel use to BTUs to provide a common comparison measure. Next, fuel uses that do not generate emissions are subtracted out. Finally, source-specific carbon emission coefficients are used to convert to metric tons of carbon.<sup>20</sup> The result is a yearly panel of state emissions from electricity generation.

As part of our analysis, we also attempt to look at the difference between RPS impacts in

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<sup>18</sup>The 3,300 respondents cover essentially the universe of retail suppliers, including electric utilities, energy service providers, power marketers, and other electric power suppliers.

<sup>19</sup>“Other Renewables” includes biomass, geothermal, and wood-based fuels, while “Other” covers remaining sources, including pumped storage, blast furnace gas, and other marginal fuels. See the Electric Power Monthly published by the EIA for a full accounting of possible disaggregated fuel sources.

<sup>20</sup>More details on this process, including the conversion factors used, can be found in “Methodology and Sources” section of the *Monthly Electric Review* published by the EIA.

regulated versus deregulated markets. Using data compiled for an earlier paper by [Fabrizio et al. \(2007\)](#), we code an indicator for whether or not a state ever deregulates their electricity market, defined by retail market access for non-utility-owned generation plants.<sup>21</sup>

### 4.3 Manufacturing Employment

If RPS programs do in fact raise electricity prices, there may be downstream impacts on industries for which energy is a large input to production. To assess this, we construct a panel of employment in each state by industry code using data from the County Business Patterns (CBP). One issue with these data is that employment statistics are often suppressed when the industry code and establishment size potentially disclose information about a specific business. Following previous papers, we apply an imputation procedure to estimate employment for these cells, using the national average for the industry in that cell size. To allow comparisons across years, we recode NAICS industry codes used in later years to SIC industry codes, redistributing employment proportionally based on concordances provided by the census.<sup>22</sup> We then calculate total and manufacturing employment for each state in each year.

### 4.4 Summary Statistics

Before describing our empirical approach in detail, we briefly present some summary statistics from the data and report on some comparisons of treatment and control states in the year prior to RPS passage. Table 1 presents summary statistics for treatment states, defined as those in which legislation passes in the following year, and control states, which consist of states that did not pass RPS by 2015. The summary statistics for control states are averaged across the set of control states that correspond to each RPS state’s year of passage.

The statistics in Table 1 show some level differences between RPS states and control states in the year prior to legislation. RPS states tend to have somewhat more expensive electricity — 11.4 cents per kWh versus 9.4 in control states — larger populations, and better resources for producing solar and wind energy. Such level differences do not threaten the identification of our difference-in-differences design, but may be informative about the degree to which our results would be representative of the impact of a national RPS policy. The RPS states in our analysis are also more likely to have other simultaneous programs affecting renewable energy, including public benefit funds, net metering, and green power purchasing programs. We control for the time-varying passage of these programs at the state by year level in our analysis. Finally, we note that the pre-existing trends of electricity prices in treatment and control states are similar, with an average six-year

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<sup>21</sup>We thank Fabrizio, Rose, and Wolfram for generously sharing this data.

<sup>22</sup>For further details, and code used, see [Autor et al. \(2013\)](#) and the accompanying data files. For 2012 and 2013, where official concordances are unavailable, we allocate employment proportionally based on 2011 employment using the official code mapping 2012 to 2007 NAICS.



decrease in electricity prices of 0.6 cents per kWh in both RPS states and control states prior to the year of passage. Our analysis in the next section will control for differences in pre-trends, but the similarity of these trends lends validity to the key identification assumption of equal trends in electricity prices in RPS and non-RPS states in the years before RPS passage.

## 5 Empirical Strategy

Our empirical approach begins with an event study-style equation:

$$y_{st} = \alpha + \sum_{\tau=-19}^{18} \sigma_{\tau} D_{\tau,st} + X_{st} + \gamma_s + \mu_t + \epsilon_{st}, \quad (7)$$

where  $y_{st}$  is an outcome of interest in state  $s$  in year  $t$ . We include state fixed effects  $\gamma_s$  to control for any permanent, unobserved differences across states. Year fixed effects,  $\mu_t$ , non-parametrically control for national trends in retail prices. The variables  $D_{\tau,st}$  are separate indicators for each year  $\tau$  relative to the passage of a RPS law, where  $\tau$  is normalized to equal zero in the year that the program passed; they range from -19 through 18, which covers the full range of values of the  $\tau$ 's.<sup>23</sup> For states that never adopt an RPS program, all  $D_{\tau,st}$  are set equal to zero. As non-adopters, they do not play a role in the estimation of the  $\tau$ 's but they aid in the estimation of the year effects,  $\mu_t$ , as well as the constant,  $\alpha$ .

The  $\sigma_{\tau}$ 's are the parameters of interest as they report the annual mean of the outcome variable in event time, after adjustment for state and year fixed effects. An appealing feature of this design is that because states passed RPS programs into law in different calendar years, it is possible to separately identify the  $\sigma_{\tau}$ 's and the year fixed effects  $\mu_t$ . In the remainder of the analysis, we will particularly focus on the  $\sigma_{\tau}$ 's that range from -7 through 6. This is the maximum range for which the  $\sigma_{\tau}$ 's can all be estimated from a fixed set of states. Restricting the treatment period in this way holds the advantage of eliminating questions about the role that differences in the composition of states identifying the various  $\sigma_{\tau}$ 's plays. This range is determined by Nevada, which passed its law in 1997 on one side of the range, and Kansas, which passed its law in 2009 on the other side of the range. We will present event-study figures that plot the estimated  $\sigma_{\tau}$ 's against  $\tau$ . These figures provide an opportunity to visually assess whether there are differential trends in the outcome variables prior to RPS passage, which help to assess the validity of the difference in differences identification strategy. The event-study figures also demonstrate whether any impacts on outcomes emerge immediately or over time, which will inform the choice of specification to summarize the average effect of RPS policies.

To summarize the information contained in the event-study plots and formally assess the pro-

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<sup>23</sup>Iowa adopted a RPS in 1991, which means that only one pre-RPS year is available. Consequently, we drop Iowa from the primary sample although its inclusion does not alter the qualitative findings.

gram impact, we estimate two equations. In the first, we assume that the difference in differences' identification assumption of parallel trends holds and allow for RPS programs to have only a mean-shift effect on retail electricity price:

$$y_{st} = \delta_0 + \delta_1 \mathbb{1}(-19 \leq \tau \leq -8)_{st} * \mathbb{1}(\text{RPS} = 1)_s + \delta_2 \mathbb{1}(7 \leq \tau \leq 18)_{st} * \mathbb{1}(\text{RPS} = 1)_s \\ + \delta_3 \mathbb{1}(0 \leq \tau \leq 6)_{st} * \mathbb{1}(\text{RPS} = 1)_s + X_{st} + \gamma_s + \mu_t + \epsilon_{st}. \quad (8)$$

Here, the parameter of interest is  $\delta_3$ , which measures the mean of the outcome variable in the first 7 years after the passage of RPS policies, in RPS states, relative to the preceding 7 years, after adjustment for state and year fixed effects. The coefficients  $\delta_1$  and  $\delta_2$  measure the mean of the outcome in the unbalanced samples in the years before and after the 14 year period where the sample is balanced, in RPS states. These are nuisance parameters.

Most RPS programs have requirements that increase gradually over time after legislation is passed, so it is likely that the impact on electricity prices will increase correspondingly. Therefore, a specification like a trend break model seems better equipped to summarize the effect of RPS programs on outcomes because it allows the programs' effect to grow over time. Further, specifications that allow for the possibility of differences in pre-adoption trends require weaker assumptions to produce valid estimates of the impact of RPS programs. For these reasons, we also fit an equation that allows for differential trends before and after RPS programs are passed into law:

$$y_{st} = \delta_0 + \delta_1 \mathbb{1}(-19 \leq \tau \leq -8)_{st} * \mathbb{1}(\text{RPS} = 1)_s + \delta_2 \mathbb{1}(7 \leq \tau \leq 18)_{st} * \mathbb{1}(\text{RPS} = 1)_s \\ + \delta_3 \mathbb{1}(0 \leq \tau \leq 6)_{st} * \mathbb{1}(\text{RPS} = 1)_s + \beta_0 \tau_{st} + \beta_1 \mathbb{1}(-19 \leq \tau \leq -8)_{st} * \mathbb{1}(\text{RPS} = 1)_s * \tau_{st} \\ + \beta_2 \mathbb{1}(7 \leq \tau \leq 18)_{st} * \mathbb{1}(\text{RPS} = 1)_s * \tau_{st} + \beta_3 \mathbb{1}(0 \leq \tau \leq 6)_{st} * \mathbb{1}(\text{RPS} = 1)_s * \tau_{st} \\ + X_{st} + \gamma_s + \mu_t + \epsilon_{st}. \quad (9)$$

To summarize the cumulative effects, we calculate and report the impact seven years after RPS passage, which is given by  $\delta_3 + 6\beta_3$ . Finally, we report standard errors that are clustered by state from the estimation of Equations (8) and (9) to allow for correlation in the errors within state over time.

## 6 Results

### 6.1 Net RPS Requirements and Retail Electricity Prices

We begin with an examination of the net RPS requirements. Figure 4a plots the event-year means of net RPS requirements against  $\tau$ . Recall that event time is normalized so that the program passage year occurs at  $\tau = 0$  and the vertical line at  $\tau = -1$  indicates the last year before program passage. It is apparent that the RPS programs' passage into law leads to increases in the required

use of the RPS technologies that begin almost immediately and increase every year. Seven years after passage, the average RPS state’s net requirement is 1.8 percentage points of generation. It is noteworthy that this is substantially smaller than the increase in total or gross requirement which is 5.1%. through the end of the balanced sample which is 7 years later.

Figure 4b reports on the estimation of equation (7) for the average retail price. where prices are normalized so that they equal zero at  $\tau = -1$ . Recall, the estimated  $\sigma_\tau$ ’s are adjusted for state and year fixed effects. There are two primary points that emerge. First, there is no evidence of a meaningful difference in the trends of prices, either upwards or downwards, among adopting states in the six years preceding RPS programs becoming law, from  $\tau = -7$  to  $\tau = -1$ . Thus, for example, there doesn’t appear to be any evidence that prior to RPS passage, adopting states were differentially passing other policies that influence electricity prices positively or negatively or facing differential cost shocks. More broadly, this figure supports the validity of the difference in differences research design. Second, it is apparent that retail prices increased after program passage, but not all at once; the figure suggests that a model that allows for a trend break describes the data well. It is striking that the trend in prices appears to very closely shadow the trend in net RPS requirements.

Columns (1a) and (1b) in Panel A of Table 2 present results from the estimation of equations (8) and (9) that confirm the visual impression that retail electricity prices increase after RPS programs become law. The mean-shift specification suggests that RPS programs raised prices by 0.5 cents on average in their first 7 years. In the mean shift and trend-break model, the estimates indicate that retail prices in RPS states rise by roughly 0.16 cents each year post-passage, with statistically insignificant pre-trends and post-passage mean-shift.

Given these results and the visual event-study evidence suggesting that RPS programs affect the trend in prices, we treat Equation (9) as our primary specification. We focus on the effect 7 years after RPS passage, which is calculated as  $\delta_3 + 6\beta_3$ . Overall, the estimates from this regression suggest that RPS policies have increased retail electricity prices by about 1.3 cents per kWh seven years after passage. This increase is statistically significant and economically substantial, representing an increase of about 11.1% over the mean retail price at  $\tau = -1$ . Such a large increase in the retail price of electricity is striking, given the modest net requirements 7 years after passage. Further, these estimates are much larger than LCOE differences alone would suggest, indicating that the indirect costs of RPS mandates are an important component of their total costs.

We next consider whether RPS policies exhibit heterogeneous effects by the category of customer. The EIA divides retail sales among three sectors, residential, commercial, and industrial, that together account for total retail sales.<sup>24</sup> Residential is the largest sector for most years in our data,

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<sup>24</sup>According the EIA, the sectors are composed of:

- Residential: “living quarters for private households,”
- Commercial: “service-providing facilities and equipment of: businesses; Federal, State, and local governments; and other private and public organizations,”

comprising about 37% of sales in 2015.<sup>25</sup> On a per-customer basis, though, the commercial and industrial consume significantly more. A typical commercial customer uses nearly seven times the typical residential consumption, while the typical industrial customer uses more than 120 times the typical residential consumption. As noted in Table 1, retail rates also vary among these groups, with residential customers paying the highest rates while industrial customers pay the lowest. This differentiated pricing may reflect demand elasticities that are correlated with usage, leading utilities to price discriminate by charging lower prices to their most intensive, and therefore price sensitive, customers (Bjørner et al., 2001).

The event-study figures derived from the fitting of Equation (7) for these outcomes are presented in Appendix Figure A.4. There is little evidence of difference in trends between adopting and non-adopting states prior to RPS passage. Industrial prices appear to shift upwards substantially in the first year after passage, while the commercial and residential sectors adjust more gradually. Overall, changes by sector track closely with net requirement changes, though perhaps with a slight lag.

The statistical sectoral price analyses for the balanced sample are reported in columns (2) - (4) of Panel A in Table 2. As in our analysis of total prices, sectoral prices appear best captured by the mean-shift and trend-break model, so we focus on estimates from Equation (9) in the (2b), (3b), and (4b) columns. In all three sectors, the point estimates represent substantial price increases in the first 7 years after RPS passage; they are 12.8% for residential, 7.7% for commercial, and 9.2% for industrial, although only the residential one would be judged statistically significant by conventional criteria.

The appeal of the Panel A results is that there is a balanced sample for all event years, but this sample restriction limits the number of post-years. In Panel B, we extend the post-period through  $\tau = 11$  which allows us to estimate the effect of the RPS programs through 12 years after passage. However, the number of RPS states that reach  $\tau = 11$  in the sample declines from 29 in the balanced sample to 16, so the cost is that there is not a constant sample of states for all event years.

The Panel B results tell much the same story of higher prices. As RPS programs are in force longer here, their net requirements increase and their impact on electricity prices also increases. The column (1b) estimates indicate that at twelve years after passage, the average retail price has increased by 2.0 cents per kWh or 17% and at the same point net RPS requirements have risen to 4.2 percentage points of generation (although gross or total RPS requirements are higher at 11.1 percentage points).<sup>26</sup> The remaining columns reveal that over this longer time horizon the higher electricity costs remain evident in all three sectors, with the residential sector experiencing the

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- Industrial: “all facilities and equipment used for producing, processing, or assembling goods.”

For complete definitions, see the EIA’s [Electric Power Monthly](#).

<sup>25</sup> Authors’ calculation, from the [EIA Electricity Data Browser](#).

<sup>26</sup> Appendix Figures A.2a and A.2b present the accompanying extended period figures for net requirements and average retail prices. See Appendix Figure A.3 for a plot of gross, i.e. total, RPS requirements.

largest increase.

Table 3 explores the robustness of the Table 2 Panel A results to a variety of changes in Equation (9). In column (1), we drop the two states with nuclear in their original RPS (i.e., Massachusetts and Ohio) as these states’ policies are closer to a zero carbon energy standard and in column (2) we drop Hawaii due to its unique geography. Neither of these sample restrictions meaningful change the qualitative findings. The remaining columns aim to adjust for the possibility of local shocks to electricity prices that might confound the adoption of RPS programs; specifically, columns (3) and (4) include year by census region and year by census division fixed effects, respectively. There are 4 Census regions and 9 Census divisions. The estimated increases in electricity prices are modestly smaller here than in Table 2, however the differences are small compared to the standard errors. Our conclusion is that these models that handle local shocks more flexibly leave the qualitative findings unchanged.

## 6.2 Heterogeneity in RPS Price Effects

To this point, we have assumed that the effect of RPS programs on average retail prices are constant across states. However, there are several important characteristics that might differ across states and could affect the magnitude of the impact of RPS programs or their incidence on ratepayers versus owners of capital. This subsection explores this possibility by taking the trend and mean shift model (i.e., Equation (9)) and fully interacting it with an indicator for membership in a subsample of interest. Table 4 presents the results from this exercise for average retail prices and residential retail prices by reporting the effect of RPS programs among states *not* in the subsample and the marginal effect for the subsample. The latter estimate tests whether the seven year effect differs in the subgroup of interest and the full effect for this group is the sum of the two reported estimates.

Panel A examines whether RPS program effects differ for late adopters, defined as those with laws that were passed after 2004, the median year of passage in the data. This specification tests the hypothesis that the costs of RPS programs might be lower in the later years of the sample, perhaps due to decreasing costs for renewable energy or learning about how to more efficiently integrate renewables into the grid. Panel B explores differential impacts among states that have restructured electricity markets. Panel C examines the effect of setting specific requirements that can only be fulfilled by solar energy, which restricts flexibility to use the cheapest available renewable resource. Panel D estimates effects for “heavy coal” states, defined as those above median percentage coal generation in 1990, to test whether these states encounter higher costs to incorporating renewables.

This type of subgroup analysis is very demanding of the data, but some intriguing, albeit suggestive, patterns emerge. There is little evidence to support the hypothesis that the costs for ratepayers were lower in late (i.e., post-2004) adopting states. The point estimates in Panel B indicate that the impact on prices is smaller in states where electricity markets have been restructured, which is

consistent with the possibility that it is easier to pass on the costs of stranded assets to ratepayers in vertically integrated non-restructured settings. However, the magnitude of the standard errors warrants caution in drawing strong conclusions. The point estimates suggest that solar set asides substantially increase prices, which is consistent with the fact that solar REC prices can be several times larger than general REC prices, but here too the imprecision of the estimates tempers the strength of any conclusions. Finally, the costs appear to be higher in heavy coal states, but the same problem of noisy estimates is evident.

### 6.3 Economic Activity

Since the estimates suggest that RPS programs lead to substantial increases in electricity prices, it is natural to examine whether there are impacts on the real economy. We begin by testing whether electricity consumption responds to these increases. Some previous studies suggest that consumers typically appear to be responsive to the average prices, which is our variable of interest, rather than marginal prices, potentially due to inadequate real-time information about current consumption (Borenstein, 2009; Ito, 2014). In columns (1a) and (1b), there is little evidence of a change in electricity consumption.

The remaining columns of Table 5 report on the estimation of the same equations for total employment and manufacturing employment. Energy costs are a relatively high share of total costs in manufacturing. There is little evidence of an impact on overall employment as would be expected. The estimates suggest roughly 2% to 4% declines in manufacturing employment but neither would be judged statistically significant by standard criteria.

### 6.4 Generation

A number of previous papers have examined the impact of RPS programs on state renewable generation (see Shrimali et al. (2012) for an excellent overview of the varied findings). In general, they find that program heterogeneity appears to have some impact, while requirement stringency generally does not. Considering individual state responses, however, is likely confounded by spillovers, as most RPS programs allow out-of-state resources within the REC region to comply.<sup>27</sup> To allow for these spillovers, we aggregate our state-level data to the REC region by taking state-level measures of technology-specific generation shares, taking CO<sub>2</sub> emissions intensity (in metric tons per MWh) and whether an RPS program was law, and calculating a weighted average at the REC region level where the weight is the MWh of generation in the relevant state by year observation. REC permits can be traded within a REC region and the ten REC regions are shown in Appendix Figure A.1. We then estimate versions of Equation (9), except now an observation is at the region by year level, rather than state by year level.

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<sup>27</sup>Johnson (2014) find that future RPS levels are associated with current regional capacity additions.

Table 6 presents estimates for generation sources observed in the EIA data. There is a case for estimating unweighted (Panel A) and weighted (Panel B) versions of Equation (9) here. The case for the unweighted regression is that the data generating process takes place at the REC region level, with substantial cross-state spillovers due to the tradable REC permits. The case for weighting by the number of states in a REC region depends on whether one wants to count more heavily regions that are comprised of more states. Since the analysis of RPS on retail prices takes place at the state level, weighting REC regions by the number of states to recover the effect on the average state provides the most directly comparable results for the impact of RPS on prices, generation, and carbon intensity.

The table reports separate estimates both 7 and 12 years after RPS passage for generation shares of hydro, solar, wind, other renewables, coal, natural gas, petroleum, and nuclear, as well as CO<sub>2</sub> intensity. Although these technology share regressions are noisy, a few interesting findings emerge. First, RPS passage is associated with substantial increases in the wind and hydro shares of generation. The increase in wind generation is consistent with anecdotal evidence about wind playing an important role in RPS compliance. However, we underscore that the wind estimates are statistically significant in some specifications but certainly not all. Second, the estimates suggest that RPS programs displace petroleum as its share declined meaningfully, although again the standard errors preclude definitive conclusions. Third, although RPS programs likely have countervailing effects on natural gas generation - with renewables likely to displace baseload generation but require an increase in the use of peaker plants as backup for their intermittent production - our estimates are too noisy to provide a test with real empirical content.

Column (9) reports on specifications where CO<sub>2</sub> intensity is the dependent variable. Just as with the generation outcomes, the REC-level value of this variable is calculated as the weighted average of state CO<sub>2</sub> intensity, where the weight is the MWh of generation in the relevant state by year. The mean of this variable in the year prior to program passage is 0.64. The Panel A estimates indicate modest declines in CO<sub>2</sub> intensity that have associated t-statistics below 1. In Panel B, the estimated emissions intensity declines by about 16% ( $=.101/.641$ ) seven years after RPS passage and by 23% twelve years after passage. Both of these estimates are close to being statistically significant at the 10% level.<sup>28</sup>

Overall, the table reveals that RPS programs are associated with changes in the generation mix that are admittedly sensitive to specification and often imprecise. The most consistent evidence appears to be that RPS programs led to reductions in the CO<sub>2</sub> intensity of generation, although the imprecision of these estimates also remains a source of concern. In the next subsection, we combine the emissions intensity results with the price effect results to learn about the costs per metric ton of CO<sub>2</sub> abated.

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<sup>28</sup>See Appendix Figure A.5 for event-study figures associated with these four estimates of the impact of RPS programs on CO<sub>2</sub> emissions intensity that illustrate the source of the column (9) estimates.



## 7 Interpretation

Our estimates suggest that RPS passage has imposed substantial costs on consumers of electricity to date. To make this concrete, we calculate the higher charges that electricity customers paid during the first 7 years after RPS passage in the 29 adopting states. This is calculated as the product of the estimated increase in prices in each post-passage year (from the fitting of Equation (9)) and total electricity consumption in the 29 RPS states in the analysis. The other side of the ledger is the reduction in CO<sub>2</sub> emissions in the 29 RPS states. This is calculated as the product of the estimated effect of RPS passage on CO<sub>2</sub> intensity and electricity generation separately for each year post-passage. Recall, the estimated reduction in emissions intensity is about 3.5 times larger in Panel B, compared to Panel A, of Table 6, so the results will be sensitive to the decision of whether to weight observations on REC regions.

A natural summary statistic of RPS programs' efficacy is the cost per metric ton of CO<sub>2</sub> abated and Table 7 uses this paper's estimates to develop several of these measures. Specifically, the first row of each panel reports the cumulative effect of RPS programs in their first 7 years after passage, using the estimated impact on electricity prices in Table 2 and the unweighted (Panel A) and weighted (Panel B) regressions for CO<sub>2</sub> intensity from Table 6. Without discounting, the total additional RPS costs over the first 7 years are about \$125 billion in the 29 adopting states. The cumulative reduction in CO<sub>2</sub> emissions over the first 7 years after passage is 240 million metric tons in Panel A and 1,010 million metric tons in Panel B.

Column (3) reports the cumulative estimated costs per ton of CO<sub>2</sub> abated during the first 7 years after passage and they are \$530 and \$124 in the two panels, with the wide range underscoring the sensitivity of the estimate to the estimated impact of RPS programs on CO<sub>2</sub> intensity. The second and third rows of each panel report on the cost per metric ton of CO<sub>2</sub> abated in the 7th and 12th years after passage. The cost per ton abated increases modestly between years 7 and 12 in both panels.

Overall, the estimates of the cost per metric ton of CO<sub>2</sub> abated are high by almost any metric. For example, the Obama Administration pegged the social cost of carbon (i.e., the monetized damages from the release of an additional ton of CO<sub>2</sub> in the year 2019) at roughly \$51 in current dollars (Greenstone et al., 2013; EPA, 2016). Thus, it appears that the costs of RPS programs exceed their carbon reduction benefits (again, these benefits would be larger if these programs reduce the future cost of renewable technologies that end up being deployed). Further, they exceed the price of a permit to emit a ton of CO<sub>2</sub> in all the major cap-and-trade markets globally by more than an order of magnitude. For example, the current prices in the CA, Regional Greenhouse Gas Initiative, European Union ETS, and Quebec markets are currently about \$15, \$6, \$25, and \$15, respectively.<sup>29</sup> Put another way, RPS programs appear to be achieve a small fraction of the CO<sub>2</sub>

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<sup>29</sup>Because there are mandates inside these cap-and-trade programs, the permit price may not be reflective of marginal abatement costs across the entire covered sectors.



reductions per dollar of cost, relative to cap-and-trade markets.

There are several caveats and implications of these results that bear noting. First, the analysis is “reduced form” so we cannot assign precise shares of the RPS programs’ full costs to differences in generation costs, intermittency, transmission, and stranded assets. Further, it seems reasonable to assume that these shares vary over time and in ways that further complicate trying to infer their contributions. For example, it seems plausible that any stranded asset costs are declining at the same time that intermittency costs are increasing, because the net requirements grow over time.

Second, there are two reasons that the cost per metric ton calculations may understate the full social costs of RPS programs. This is because the price effects only reflect the portion borne by ratepayers. However, it seems reasonable to presume that at least some of the costs will be borne by owners of capital (e.g., generators or transmission), particularly in states with restructured electricity markets. Further, it is possible that some of the costs are shared by all the participants in wholesale electricity markets, which in several cases includes states with and without RPS programs. If the costs are partially reflected in retail prices in non-adopting states, then the difference in differences approach would understate the full costs borne by ratepayers because it would miss the portion borne by ratepayers in non-adopting states and understate the effect in adopting states.

Third, more broadly, a randomized control trial is unavailable here, so there will always be a form of unobserved heterogeneity that could explain the results without RPS programs playing a causal role. For example, our measures of other state programs that influence retail electricity prices are limited in their detail, only measuring the years in which states adopted three of these types of programs. So while our estimates are adjusted for the presence of three of these types of programs, this may fail to capture their full impact on electricity prices and that could cause us to understate or overstate the impacts of RPS programs on retail electricity prices, depending on their correlation with RPS programs.

Fourth, it is often claimed that renewable policies provide an external benefit by reducing the costs of future generation that is generic and cannot be fully appropriated by the firm that is expanding its operations. If there are such spillovers or positive externalities, then our estimates of the costs per metric ton of abatement will be systematically too high because they will not account for the benefits received by customers outside of the RPS state’s jurisdiction. In principle, these benefits could be global and thus quite substantial. The coincidence of the proliferation of policies that support renewable energy and the decline in solar prices over the last decade are consistent with the possibility of such spillovers. However, research that isolates the magnitude of any such spillovers from other factors is probably best described as emerging, making this a rich area for future research ([Gillingham and Stock, 2018](#)).

## 8 Conclusion

This paper has provided the first comprehensive evaluation on the impacts of RPS programs, which are perhaps the most popular and prevalent carbon policy in the United States. First, these programs mandated increases in renewable generation that are often smaller than is advertised. Seven years after passage, RPS programs require a 1.8 percentage point increase in renewable’s share of generation, and 12 years after it is 4.2 percentage points. Second, RPS program passage leads to substantial increases in electricity prices that mirror the program’s increasing stringency over time. Seven years after passage, we estimate that average retail prices are 1.3 cents per kWh or 11% higher than they otherwise would be. The corresponding effect twelve years later is 2.0 cents per kWh or 17% higher. Third, the estimates indicate that passage of RPS programs lead to reductions in the generating mix’s carbon intensity, although these estimates can be noisier and more sensitive to specification than is ideal. Putting the results together, the cost per metric ton of CO<sub>2</sub> abated exceeds \$115 in all specifications and ranges up to \$530, making it at least several times bigger than conventional estimates of the social cost of carbon.

A particularly striking finding is that the indirect costs of RPS programs, which have not been possible to comprehensively measure to date, appear to account for the majority of RPS program costs. A recent study suggests that the direct costs of RPS increase retail electricity prices by 2% (Barbose, 2018), which is substantially smaller than our estimates that prices are about 11% higher 7 years after passage. Although there are several differences between these two studies, it seems likely that the indirect costs, including intermittency, transmission, and stranded asset payments, account for a substantial fraction of RPS program costs. This finding suggests caution in extrapolating declines in the direct generation cost of renewable energy to its overall impact on electricity prices, and suggests that reducing indirect costs associated with grid integration could represent the more important barrier to substantially increasing renewable energy’s share of generation and meaningfully decreasing carbon dioxide emissions.

Overall, the paper’s results underscore the importance of research on policy and technology mechanisms to reduce the costs of renewable energy, and imply that mechanisms to facilitate the integration of intermittent sources onto the grid, such as advanced storage technologies or time-of-use pricing, could be especially beneficial. While the potential damages from global climate change have been widely documented, it is almost self-evident that failing to cost-effectively reduce emissions will ultimately limit the magnitude of these cost reductions. Further, policies that substantially increase the price of electricity tend to have a regressive impact that hits low-income consumers hardest, and therefore may be especially unattractive in developing countries that account for a large and growing share of global emissions. The most effective climate policy in technologically advanced and innovative nations such as the United States will reduce emissions domestically, but also involves developing low-carbon energy systems that are cost-effective enough to promote adoption in the rest of the world.

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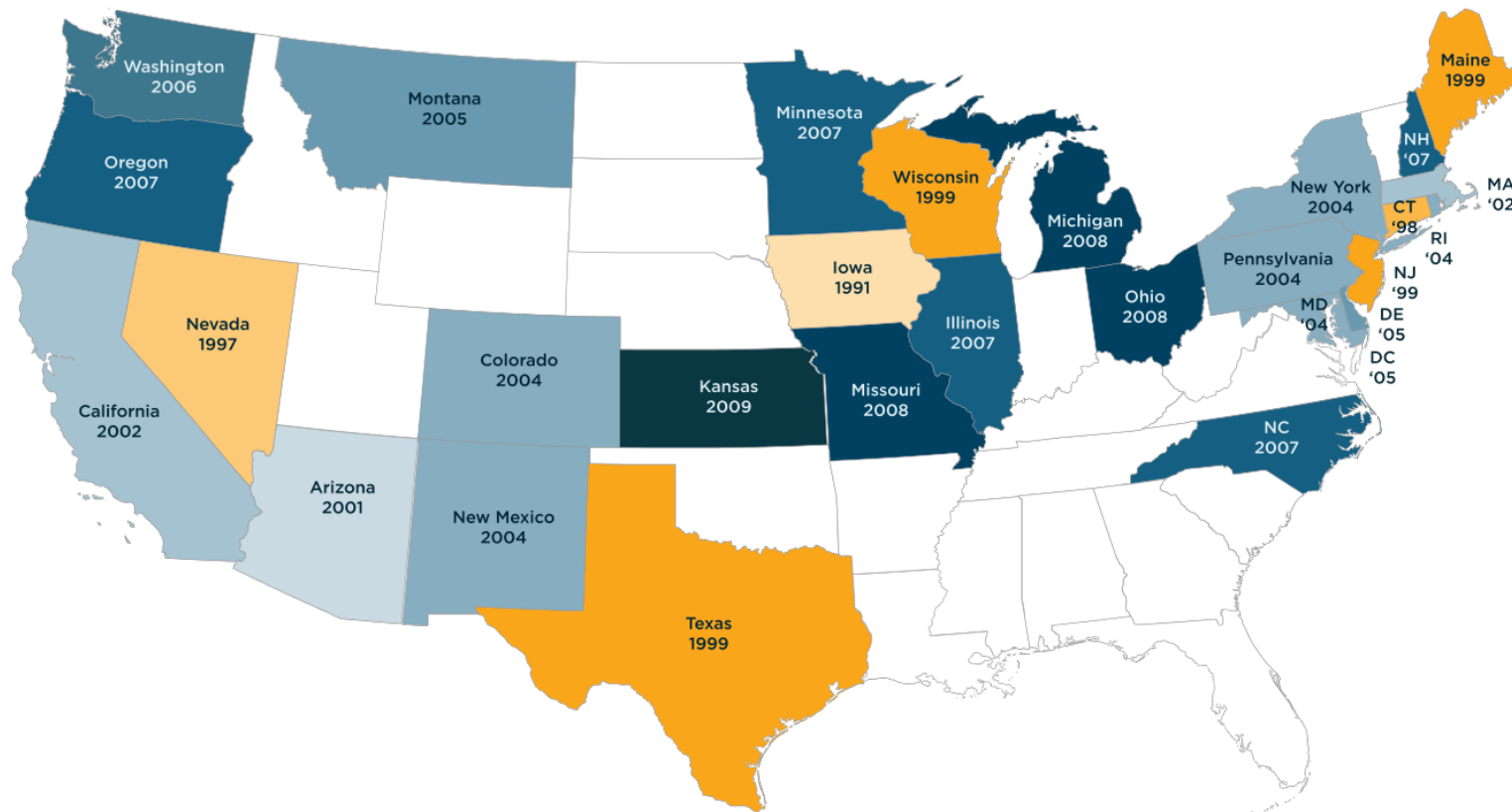
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## 9 Figures

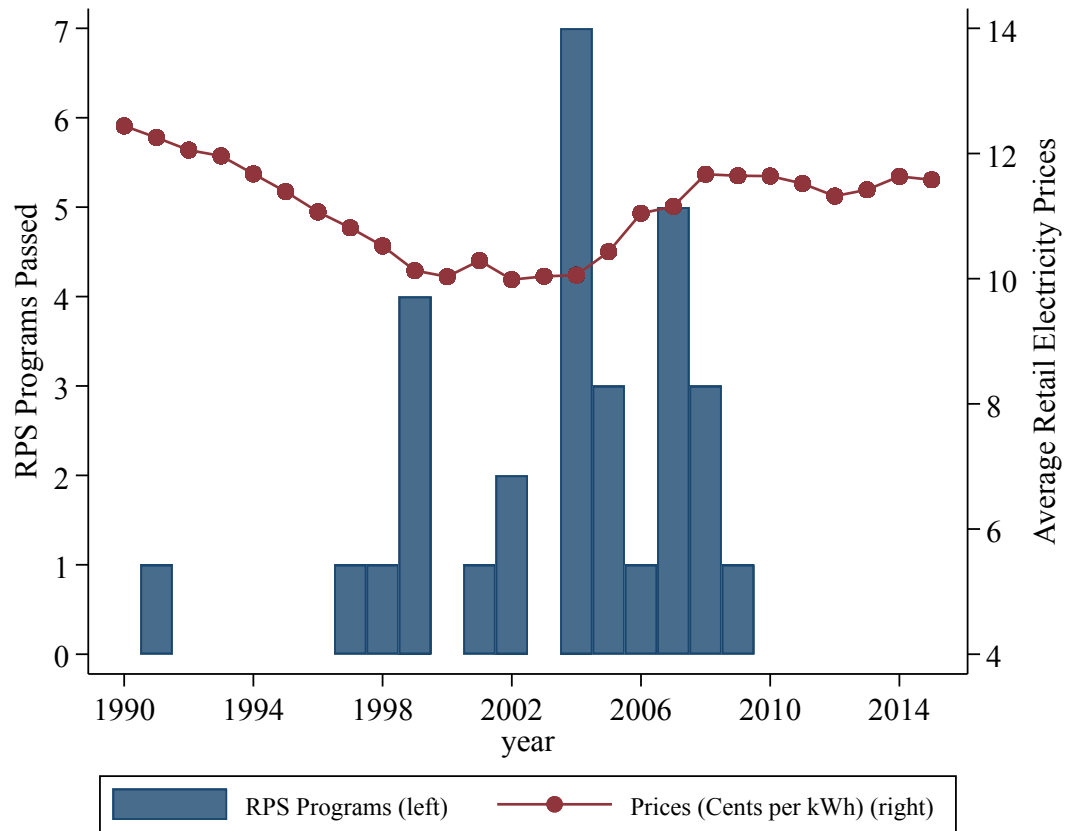
Figure 1: RPS Passage by State



Sources: US Department of Energy and state government websites.

Notes: States that have adopted any RPS policy are colored according to the year in which the RPS legislation was first passed.

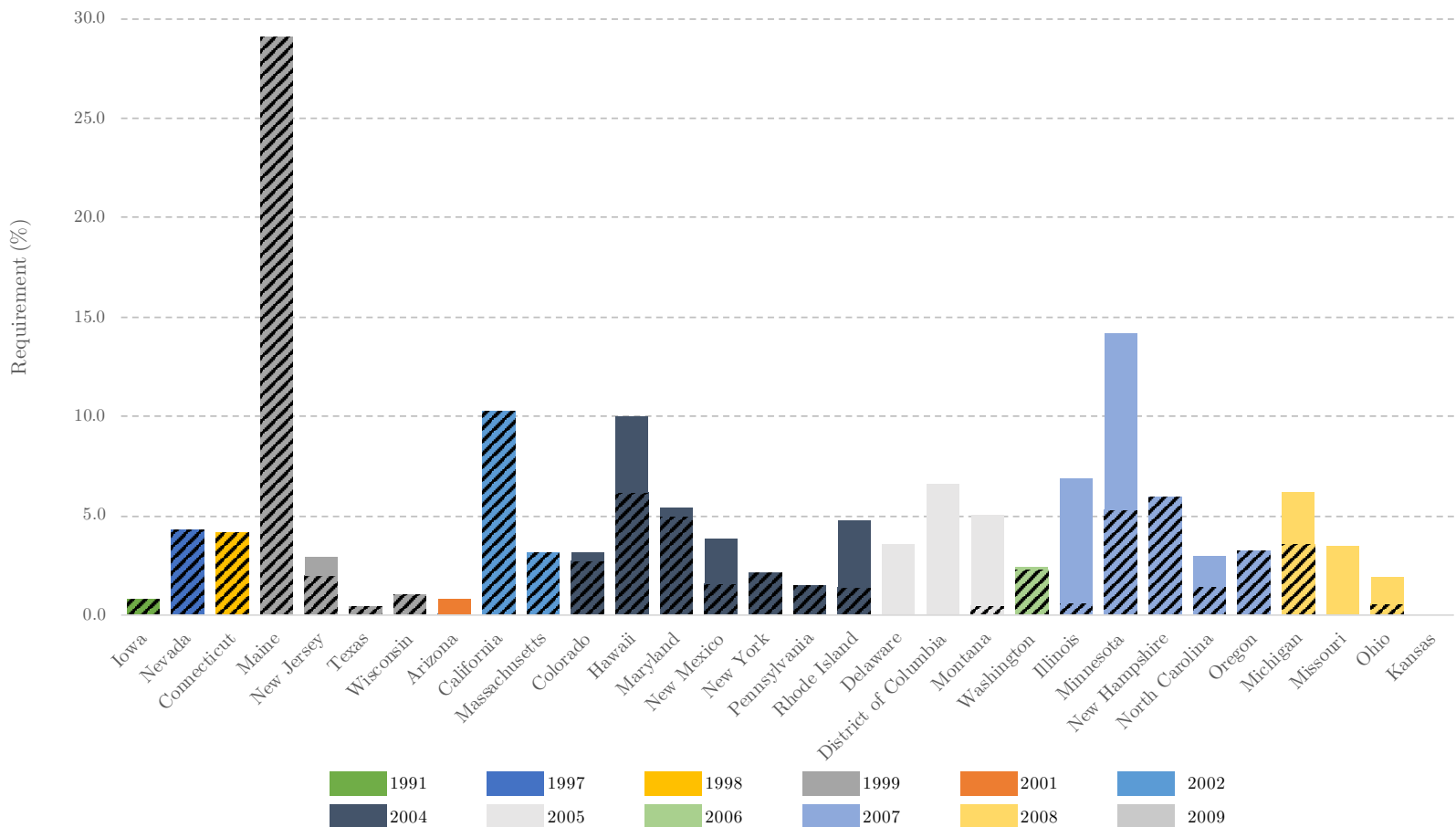
Figure 2: Number of RPS Programs Newly Passed into Law, by Year



Sources: Department of Energy and state government websites (number of policies) and EIA (prices).



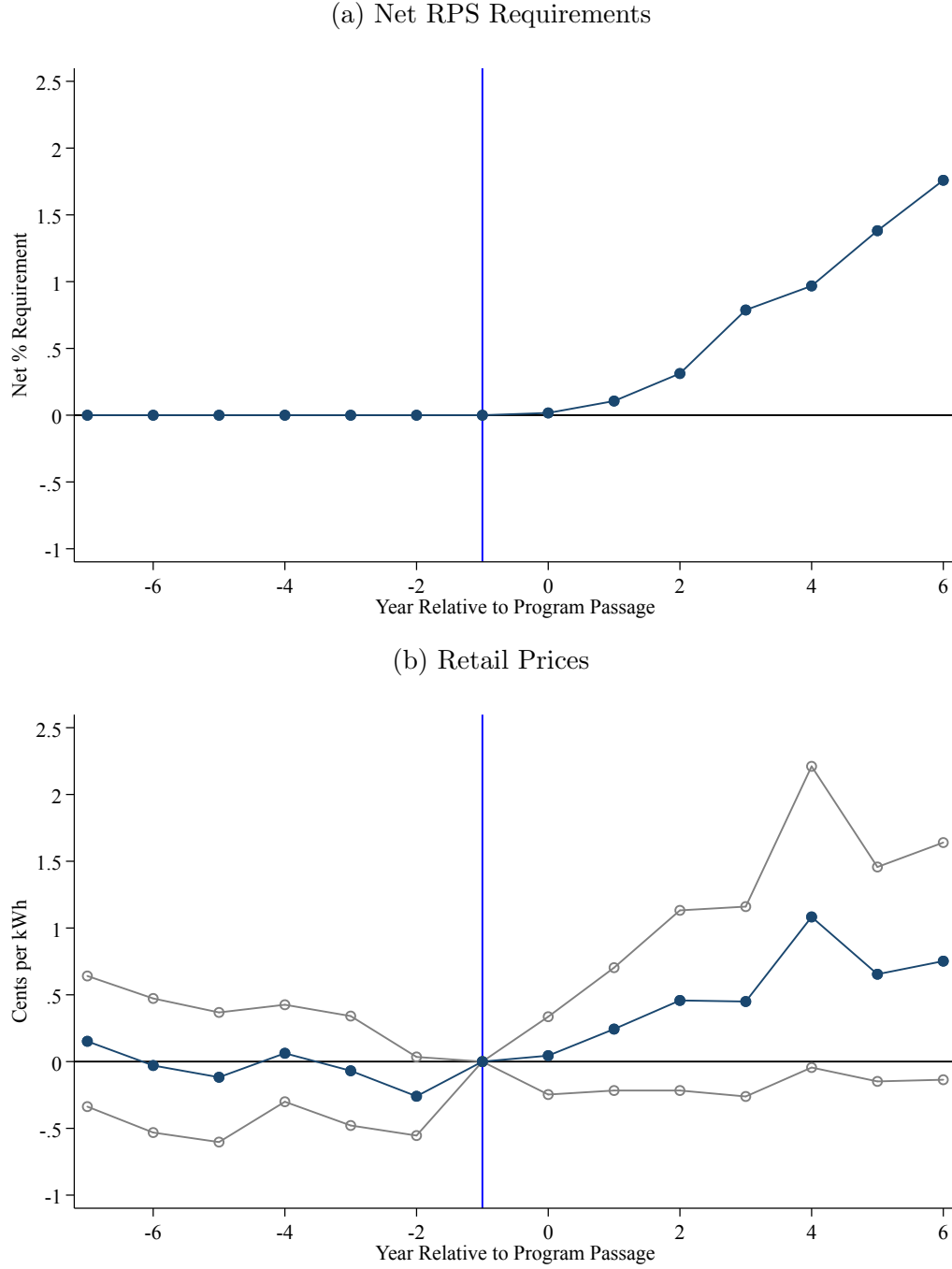
Figure 3: RPS Total and Net Requirements, by State



Sources: Department of Energy and state government websites; Lawrence Berkeley National Lab (LBNL).

Notes: States are sorted by the year in which their RPS policies were first passed. The bars are colored according to RPS passage year. The total height of each bar denotes the gross RPS requirement at  $\tau = 6$ ; the non-patterned portion of each bar denotes net requirement at  $\tau = 6$ . The data for gross RPS requirements are from the LBNL, in MWh, and are converted to percentages by dividing by contemporary generation at  $\tau = 6$ . Note that these percentages do not exactly equal the prescribed statutory percentages in the regulation.

Figure 4: Estimated Effects of RPS Programs on Net Renewable Requirements and Retail Electricity Prices



Source: EIA; LBNL; Department of Energy and state government websites.

Notes: Graph (a) shows the mean net RPS requirement percentage for event years  $\tau = -7$  to  $\tau = 6$ . Graph (b) shows coefficients for  $\sigma_\tau$  for  $\tau = -7$  to  $\tau = 6$  from the event study specification in Equation (7) for retail electricity prices on indicator variables for years relative to program passage, controlling for state, year, and other programs fixed effects. Blue lines show the point estimates and gray lines contain the 95% confidence interval. Gross RPS requirement data are from the LBNL. Electricity price data and electricity generation for calculating net requirement are from the EIA. RPS program passage dates and requirements are from the Department of Energy and state government websites. Standard errors are clustered at the state-level.

## 10 Tables

Table 1: Summary Statistics

	Mean RPS (1)	Mean Control (2)	P-value RPS vs Control (3)
Price (2018 Cents/kWh)			
Total	11.4	9.4	0.01
Residential	13.4	11.3	0.01
Commercial	11.8	9.8	0.01
Industrial	8.5	6.9	0.01
Price Change $\tau = -1$ vs $-7$ (2018 Cents/kWh)	-0.6	-0.6	0.92
Total Sales (TWh)	76.2	64.3	0.38
Population (Millions)	7.0	4.7	0.11
CO <sub>2</sub> Emissions (Million mt)	48.0	49.2	0.90
Renewable Potential (PWh)			
Solar	9.1	6.6	0.34
Wind	1.1	0.9	0.40
Generation			
Total (TWh)	80.5	73.3	0.64
RPS Eligible (TWh)	8.9	5.9	0.36
RPS Eligible (% of Total)	13.5	13.0	0.89
Generating Capacity			
Total (GW)	20.3	18.4	0.60
RPS Eligible (GW)	2.5	1.6	0.36
RPS Eligible (% of Total)	14.2	14.3	0.99
Other Programs (%)			
Public Benefit Funds	0.41	0.11	0.00
Net Metering	0.66	0.45	0.04
Green Power Purchasing	0.07	0.02	0.29

*Notes:* “Mean RPS” is for RPS states in the year prior to RPS passage. A control is defined for each RPS state as the mean across non-RPS states and RPS states that have yet to pass RPS, in the year prior to the reference RPS state’s RPS passage. “Mean Control” is the average across these controls. Column (3) reports p-values from a two-sample t-test between Column (1) and (2) that allows for unequal variances across groups. Iowa is excluded from these summary statistics due to the particularly early passage of its RPS.

Table 2: Estimates of RPS Impact on Retail Electricity Prices

	Average Retail Price		Average Retail Price Residential		Average Retail Price Commercial		Average Retail Price Industrial	
	(1a)	(1b)	(2a)	(2b)	(3a)	(3b)	(4a)	(4b)
<i>Panel A: 7 Post-Passage Years, Balanced Sample</i>								
Mean Shift ( $\delta_3$ )	0.54 (0.35)	0.30 (0.25)	0.48 (0.38)	0.17 (0.24)	0.50 (0.36)	0.30 (0.24)	0.56 (0.37)	0.69 (0.46)
Trend Break ( $\beta_3$ )		0.16* (0.08)		0.26*** (0.09)		0.10 (0.09)		0.01 (0.10)
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )		1.27** (0.61)		1.71** (0.66)		0.91 (0.62)		0.78 (0.48)
<i>Panel B: 12 Post-Passage Years, Unbalanced Sample</i>								
Mean Shift ( $\delta_3$ )	0.66 (0.41)	0.35 (0.31)	0.65 (0.45)	0.26 (0.31)	0.59 (0.42)	0.33 (0.31)	0.62 (0.42)	0.57 (0.40)
Trend Break ( $\beta_3$ )		0.15** (0.07)		0.22*** (0.07)		0.10 (0.08)		0.07 (0.08)
Effect of RPS 12 years after passage ( $11\beta_3 + \delta_3$ )		1.98** (0.81)		2.71*** (0.89)		1.38 (0.88)		1.34 (0.84)
Mean at $\tau = -1$	11.4	11.4	13.4	13.4	11.8	11.8	8.5	8.5
State FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Other Programs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
N	1300	1300	1300	1300	1300	1300	1300	1300

*Notes:* Columns (1a) through (4b) show estimates from Equations (8) and (9), where (a) columns correspond to Equation (8) and (b) columns correspond to Equation (9), with total retail electricity price and sector-specific retail electricity prices as the response variables. In *Panel A*, coefficient estimates are for states with data 7 years before and 7 years after RPS passage. In *Panel B*, coefficient estimates are for states with data 7 years before and 12 years after RPS passage. Using Equation (9) notation, the effect of RPS 7 years after passage is  $6\beta_3 + \delta_3$ , and the effect of RPS 12 years after passage is  $11\beta_3 + \delta_3$ . Standard errors are clustered at the state-level. Asterisks denote p-values: < 0.10 (\*), < 0.05 (\*\*), < 0.01 (\*\*\*).

Table 3: Robustness Checks for RPS Impact

	Retail Electricity Price			
	(1)	(2)	(3)	(4)
<i>Panel A: Total</i>				
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	1.13* (0.63)	1.15* (0.60)	1.08* (0.58)	0.90 (0.56)
<i>Panel B: Residential</i>				
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	1.55** (0.68)	1.59** (0.65)	1.60*** (0.59)	1.40** (0.60)
<i>Panel C: Commercial</i>				
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	0.68 (0.63)	0.77 (0.61)	0.70 (0.58)	0.65 (0.58)
<i>Panel D: Industrial</i>				
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	0.69 (0.51)	0.64 (0.47)	0.32 (0.55)	0.29 (0.58)
Other Programs	X	X	X	X
Excludes States with Nuclear in Original RPS	X			
Excludes Hawaii		X		
State FE	X	X	X	X
Year FE	X	X		
Year-Region FE			X	
Year-Division FE				X
N	1248	1274	1300	1300

*Notes:* The (a) columns report the aggregate effect 7 years after RPS passage from the mean-shift model given by Equation (8). The (b) columns report the same effect from the trend-break model given by Equation (9). Coefficient estimates are for states with data 7 years before and 7 years after RPS passage. Year-Region fixed effects are for all combinations of years and Census regions. Year-Division fixed effects are for all combinations of years and Census divisions. The two states with nuclear in their original RPS are Massachusetts and Ohio. One specification excludes Hawaii due to its geographic isolation and thus its inability to trade electricity across state borders. Standard errors are clustered at the state-level. Asterisks denote p-values: < 0.10 (\*), < 0.05 (\*\*), < 0.01 (\*\*\*).

Table 4: Heterogeneous Effects of RPS Programs on Retail Electricity Prices

	Total	Residential
<i>Panel A: Late Adopters</i>		
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	1.19 (0.82)	1.53 (0.92)
(Effect of RPS)*Late	-0.12 (1.51)	0.27 (1.51)
<i>Panel B: Ever Restructured</i>		
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	1.99* (1.17)	2.35** (1.17)
(Effect of RPS)*Restructured	-0.86 (1.33)	-0.69 (1.38)
<i>Panel C: Has Solar Set-Aside</i>		
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	0.70 (0.75)	1.07 (0.90)
(Effect of RPS)*Solar Set-Aside	1.22 (1.19)	1.36 (1.20)
<i>Panel D: Heavy Coal States</i>		
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	0.78 (0.84)	1.31 (0.96)
(Effect of RPS)*Heavy Coal	0.95 (1.21)	0.82 (1.27)
State FE	Yes	Yes
Year FE	Yes	Yes
Other Programs	Yes	Yes
N	1300	1300

*Notes:* The coefficients give the aggregate effect of RPS programs on total and residential retail prices 7 years after passage estimated from the trend-break model. The top row in each panel shows the coefficient for the subset of states *not* in the given category and the bottom row shows the difference in the coefficient for the given subset. All coefficient estimates are for states with data 7 years before and 7 years after RPS passage. Using Equation (9) notation, the effect of RPS 7 years after passage is  $6\beta_3 + \delta_3$ . Standard errors are clustered at the state-level. Asterisks denote p-values: < 0.10 (\*), < 0.05 (\*\*), < 0.01 (\*\*\*).

Table 5: RPS Effect on Sales and Employment

	Sales		Employment			
	Total		Total	Total	Manufacturing	Manufacturing
	(1a)	(1b)	(2a)	(2b)	(3a)	(3b)
Mean Shift ( $\delta_3$ )	-0.01 (0.02)		0.001 (0.016)		-0.037 (0.028)	
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )		0.01 (0.03)		0.024 (0.022)		-0.022 (0.035)
State FE	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Other Programs	Yes	Yes	Yes	Yes	Yes	Yes
N	1300	1300	1200	1200	1200	1200

*Notes:* The dependent variable in Columns (1a) and (1b) is the log of total sales in MWh. The dependent variable in Columns (2a) and (2b) is the log of total employment in each state; in Column (3a) and (3b) is log manufacturing employment. The (a)-columns show the mean-shift estimates from Equation (8) for sales or employment. The (b)-columns report the aggregate effect 7 years after program passage from the trend-break model given by Equation (9). Coefficient estimates are for states with data 7 years before and 7 years after RPS passage. Using Equation (9) notation, the effect of RPS 7 years after passage is  $6\beta_3 + \delta_3$ . Standard errors are clustered at the state-level. Asterisks denote p-values: < 0.10 (\*), < 0.05 (\*\*), < 0.01 (\*\*\*).

Table 6: Estimates of RPS Impact on Generation and CO<sub>2</sub> Emissions (Trend Break)

	Hydro (1)	Solar (2)	Wind (3)	Other Renewables (4)	Coal (5)	Natural Gas (6)	Petroleum (7)	Nuclear (8)	CO <sub>2</sub> intensity (9)
<i>Panel A: Unweighted</i>									
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	2.87 (2.46)	-0.08 (0.13)	1.22** (0.56)	0.53 (0.48)	-1.27 (3.70)	1.26 (3.80)	-1.68 (1.39)	-2.78 (3.03)	-0.029 (0.034)
Effect of RPS 12 years after passage ( $11\beta_3 + \delta_3$ )	4.87 (3.80)	0.04 (0.18)	2.84*** (1.05)	0.26 (0.87)	3.37 (7.70)	-2.17 (8.32)	-3.83 (3.54)	-5.62 (4.94)	-0.043 (0.057)
<i>Panel B: Weighted</i>									
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	9.97 (6.19)	-0.39 (0.29)	0.98 (1.35)	0.86 (0.77)	-6.28 (4.38)	-4.98 (7.14)	-1.42 (2.63)	0.95 (4.12)	-0.101 (0.062)
Effect of RPS 12 years after passage ( $11\beta_3 + \delta_3$ )	16.33 (9.06)	-0.23 (0.28)	0.93 (1.77)	1.24 (1.35)	-5.90 (6.44)	-9.89 (14.92)	-4.47 (5.75)	1.14 (7.06)	-0.149 (0.089)
Mean at $\tau = -1$	4.53	0.00	0.07	2.42	48.28	14.60	7.56	21.98	0.641
Region FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Other Programs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
N	260	260	260	260	260	260	260	260	260

*Notes:* Columns (1) through (8) show estimates from Equation (9), each with a specific generation source as the dependent variable. Column (9) also shows estimates from Equation (9), but uses the CO<sub>2</sub> emissions intensity as the dependent variable. Coefficient estimates are either for states with data 7 years before and 7 years after RPS passage, or for states with data 7 years before and 12 years after RPS passage. Using Equation (9) notation, the effect of RPS 7 years after passage is  $6\beta_3 + \delta_3$ , and the effect of RPS 12 years after passage is  $11\beta_3 + \delta_3$ . *Panel A* is a region-level generation-weighted average of the states in the region, unweighted by count of states in each REC-region. *Panel B* additionally includes state count as regression weights. Standard errors are clustered at the REC region-level. Asterisks denote p-value < 0.10 (\*), < 0.05 (\*\*), < 0.01 (\*\*\*).



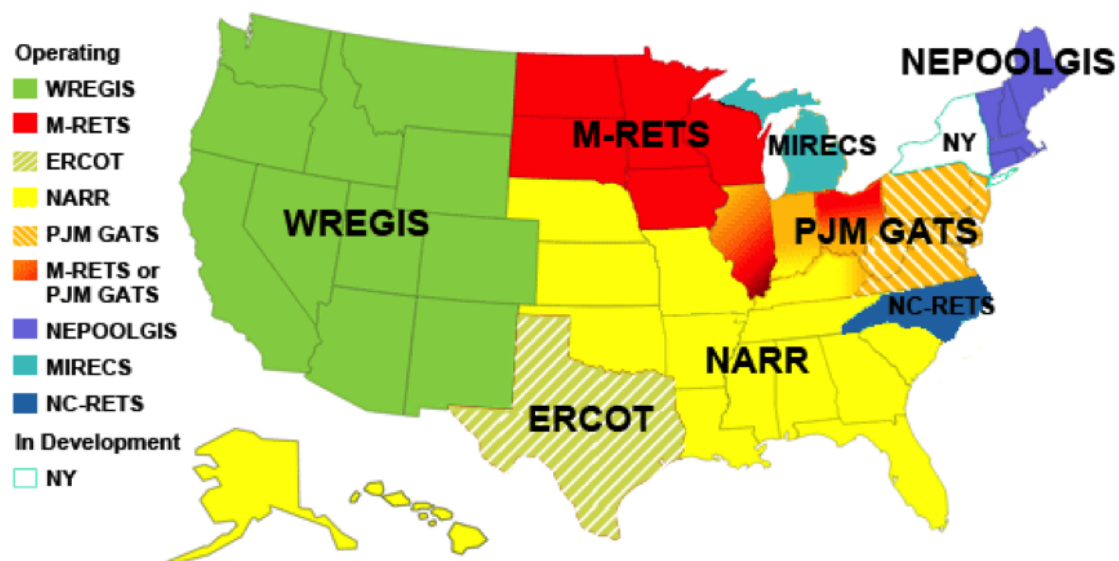
Table 7: Estimated Cost of Abating CO<sub>2</sub> Emissions from RPS

	CO <sub>2</sub> Reduction (mm ton) (1)	Cost to Consumers (bn \$) (2)	Cost per Ton Reduced (\$) (3)
<i>Panel A: Unweighted</i>			
Cumulative Effect of RPS (for first 7 years after passage)	236.1	125.2	530
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	71.5	29.5	412
Effect of RPS 12 years after passage ( $11\beta_3 + \delta_3$ )	62.8	28.2	449
<i>Panel B: Weighted</i>			
Cumulative Effect of RPS (for first 7 years after passage)	1,011.8	125.2	124
Effect of RPS 7 years after passage ( $6\beta_3 + \delta_3$ )	249.8	29.5	118
Effect of RPS 12 years after passage ( $11\beta_3 + \delta_3$ )	217.6	28.2	129
State Count 7 years after passage	29	29	29
State Count 12 years after passage	16	16	16

*Notes:* Column (1) shows estimates from Equation (9) estimated at the REC level, where Panel A excludes and Panel B includes state-count weights. Column (2) shows estimates from Equation (9) estimated at the state level, so no state-count weights are used in either panel. Column (3) is the ratio of column (2) to (1). The cumulative effect of RPS is the sum of the year-by-year effects for  $\tau = 0$  through  $\tau = 6$  inclusive.

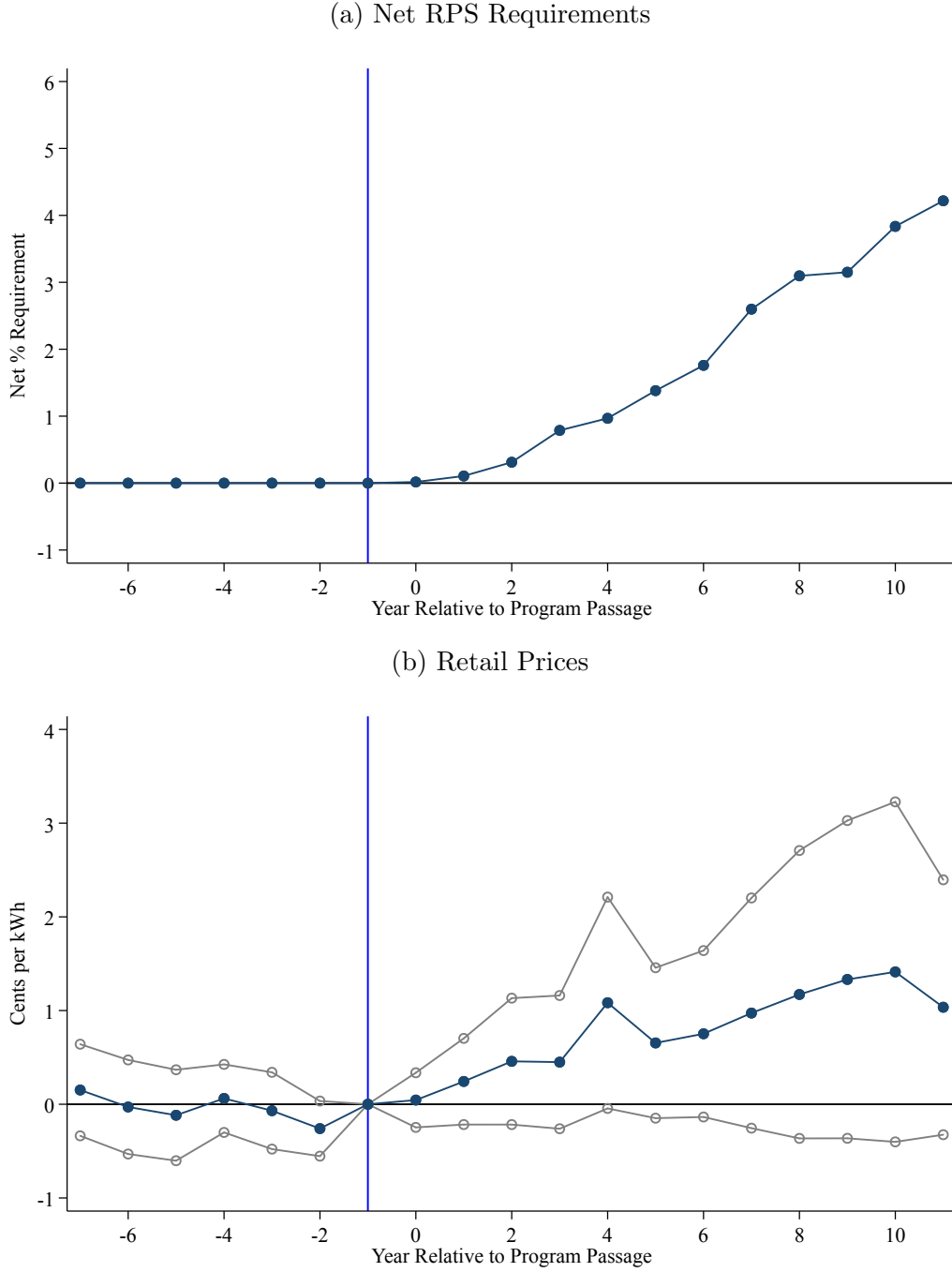
## 11 Appendix

Figure A.1: REC Tracking Markets



Source: EPA.

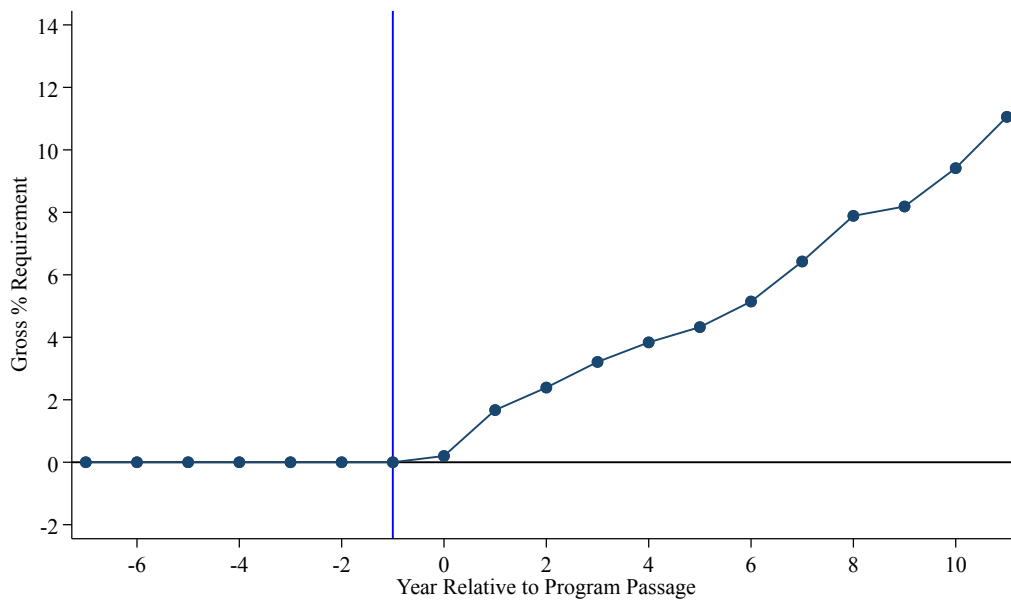
Figure A.2: Estimated Effects of RPS Programs on **Net** Renewable Requirements and Retail Electricity Prices (Extended Post Period)



Source: EIA; LBNL; Department of Energy and state government websites.

Notes: Graph (a) shows the mean net RPS requirement percentage for event years  $\tau = -7$  to  $\tau = 11$ . Graph (b) shows coefficients for  $\sigma_\tau$  for  $\tau = -7$  to  $\tau = 11$  from the event study specification in Equation (7) for retail electricity prices on indicator variables for years relative to program passage, controlling for state, year, and other programs fixed effects. Blue lines show the point estimates and gray lines contain the 95% confidence interval. Gross RPS requirement data are from the LBNL. Electricity price data and electricity generation for calculating net requirement are from the EIA. RPS program passage dates and requirements are from the Department of Energy and state government websites. Standard errors are clustered at the state-level.

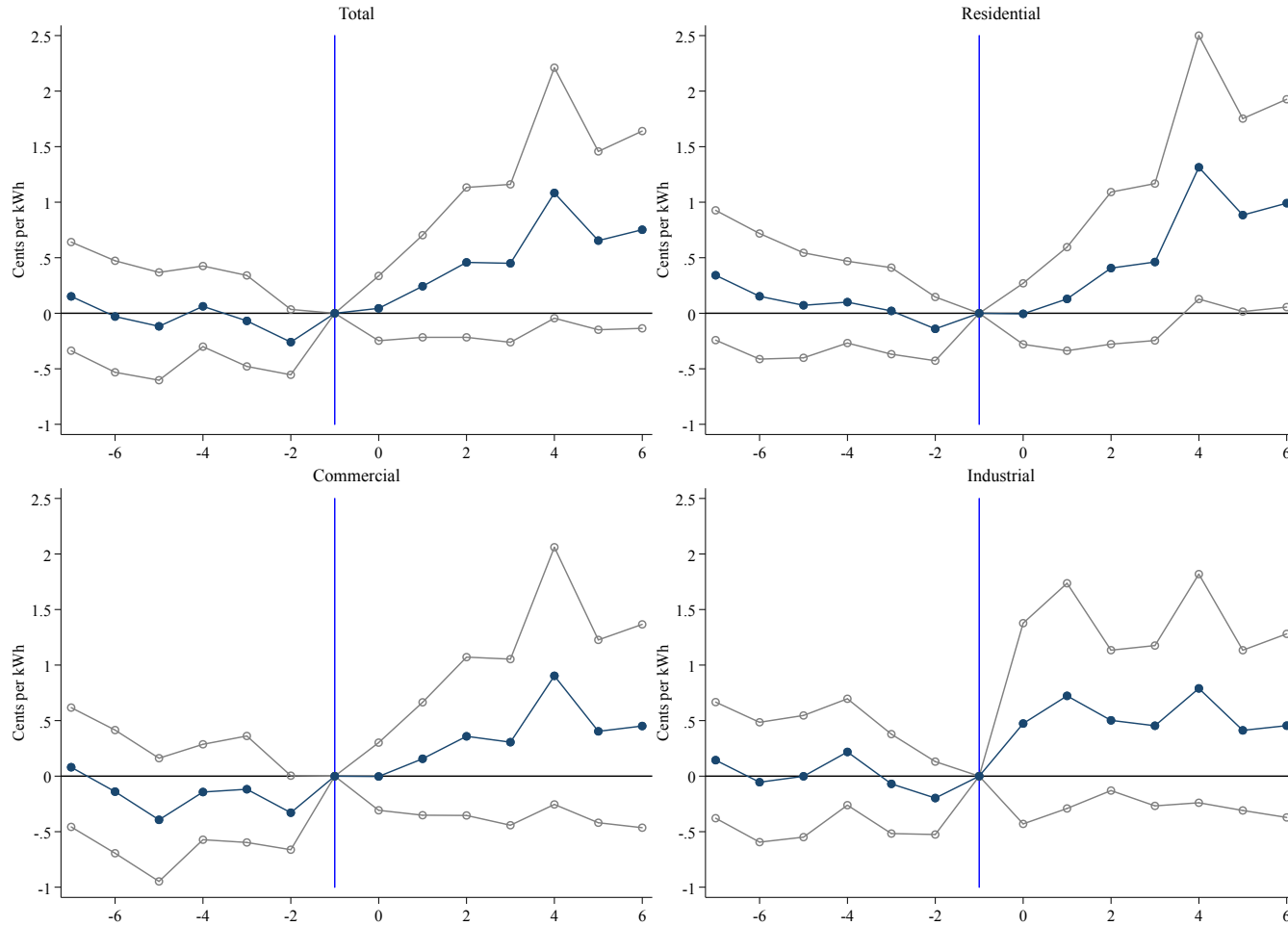
Figure A.3: Estimated Effects of RPS Programs on **Gross** Renewable Requirements (Extended Post Period)



Source: LBNL; Department of Energy and state government websites.

Notes: The graph shows the mean gross RPS requirement percentage for event years  $\tau = -7$  to  $\tau = 11$ .

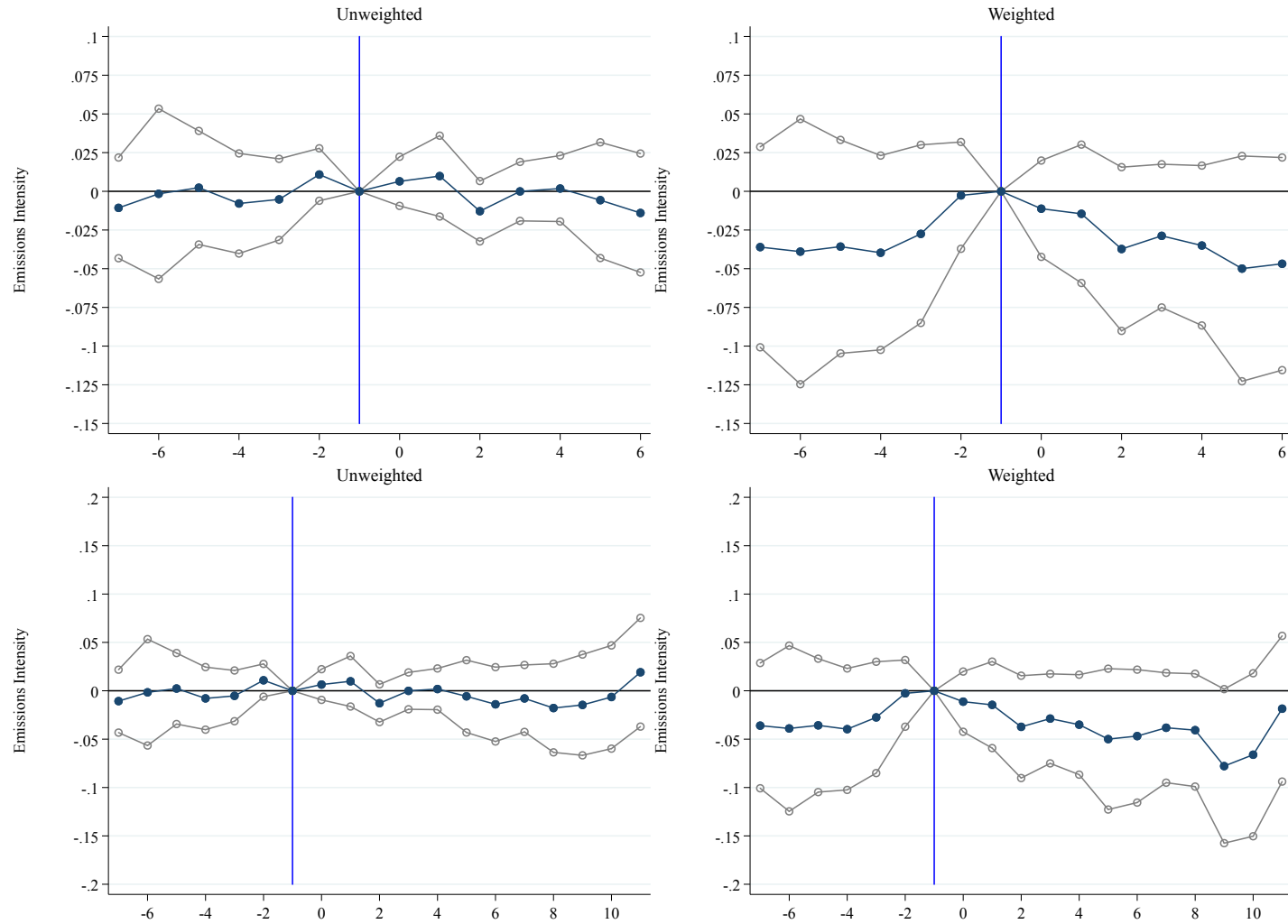
Figure A.4: Electricity Prices Before and After RPS Passage, by Sector



Source: EIA; LBNL; Department of Energy and state government websites.

Notes: Graphs show coefficients for  $\sigma_\tau$  for  $\tau = -7$  to  $\tau = 6$  from the event study specification in Equation (7). This specification regresses the dependent variable - retail electricity prices - on indicator variables for years relative to program passage, controlling for state, year, and other programs fixed effects. Blue lines show the point estimates and gray lines contain the 95% confidence interval. Electricity price data are from the EIA. Standard errors are clustered at the state-level.

Figure A.5: CO2 Emissions Intensity Before and After RPS Passage



Source: EIA; LBNL; Department of Energy and state government websites.

Notes: Graphs show coefficients for  $\sigma_\tau$  from the event study specification in Equation (7). This specification regresses the dependent variable - CO2 emissions intensity - on indicator variables for years relative to program passage, controlling for REC regions and year fixed effects, as well as other programs fixed effects whose values are a generation-weighted average of the states' indicator values within a given REC region. The plots labelled "Weighted" use state-count weights, and the ones labelled "Unweighted" do not. The top two plots show a narrower time frame, from  $\tau = -7$  to  $\tau = 6$ , where we have a balanced panel of 29 states. The bottom two plots show a larger time frame in which we have an unbalanced panel that varies from 29 to 16 states. Blue lines show the point estimates and gray lines contain the 95% confidence interval. Standard errors are clustered at the REC region level.