

Evaluating Policies to Increase Electricity Generation from Renewable Energy

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Building on a review of experience in the United States and the European Union, this article advances four main propositions concerning policies aimed at increasing electricity generation from renewable energy. First, who bears the short-run costs of programs to subsidize the generation of electricity from renewable sources varies with the organization of the electric power industry, and this variation may be a significant contributor to such programs’ political attractiveness in U.S. states. Second, despite the greater popularity of feed-in-tariff (FIT) schemes worldwide, renewable portfolio standard (RPS) programs may involve less long-run social risk. Third, in contrast to the E.U.’s approach to reducing carbon dioxide emissions, its renewables program is almost certain not to minimize the cost of achieving its goals. Fourth, state RPS programs in the U.S. are also almost certain to cost more than necessary, even though most employ market mechanisms. To support this last proposition I provide a fairly detailed description of actual markets for renewable energy credits (RECs) and their shortcomings.

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Introduction

At the start of 2010, eighty-three nations and all U.S. states had policies to promote the generation of electricity from renewable energy, typically defined to exclude large-scale hydroelectric facilities (REN21 2010, National Research Council 2010 (Appendix D)). As of May 2011, twenty-nine U.S. states¹ and the District of Columbia (for simplicity, hereafter considered to be a state) had enacted renewable portfolio standard (RPS) programs (generally

¹ These states are Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Washington, and Wisconsin.

along with other policies) to help achieve this purpose.² RPS programs are quantity-based policies and generally require that a minimum fraction of electricity demand be met by renewable energy. These policies typically require load-serving entities to obtain renewable energy credits (RECs), produced by state-certified renewable generators in proportion to their output, equal to at least a minimum fraction of their retail sales. Since 2007, the U.S. House of Representatives has twice passed bills that would impose a nationwide RPS.

Outside the U.S., feed-in tariff (FIT) policies have been much more popular. FIT policies are price-based and generally require that electricity generated from renewable energy be purchased at a fixed, premium price. At the start of 2010, FIT policies were employed by fifty nations while RPS policies were used by only ten. In contrast, FITs have been used very little by U.S. states and have received essentially no recent attention at the federal level (Couture et al 2010). Since 1992, federal support of renewable generation in the United States has mainly involved tax credits that provide per-kWh subsidies of generation or fractional subsidies of up-front capital cost (Schmalensee 2010). While the adverse incentive effects of subsidizing capital costs are clear, the shortcomings of providing subsidies in the form of tax credits are also serious. Tax credits generally require renewable generation developers, who rarely have enough taxable income to make use of tax credits, to partner with one of a few large tax-paying financial institutions who are willing to serve as “tax equity” providers (Bipartisan Policy Center 2011). The need to form such partnerships raises costs significantly, with no social benefit.

This article evaluates policies aimed at increasing the generation of electricity from renewable energy. Building on a review of experience in the United States and the European

² Unless otherwise noted, all statements in this article about U.S. federal and state policies in support of renewables are based on the online DSIRE database (<http://www.dsireusa.org/>) and its links to state and federal online resources.

Union (EU), I advance four main propositions. First, who bears the short-run costs of subsidies to electricity generation from renewable sources depends on the organization of the electric power industry and this variation in incidence may be a significant contributor to the political attractiveness of such subsidies. Second, despite the greater popularity of FIT schemes worldwide, under plausible conditions RPS programs may involve less long-run social risk. Third, in contrast to the E.U.'s approach to reducing carbon dioxide (CO₂) emissions, its approach to renewables is almost certain not to minimize the cost of achieving the program's goals. Fourth, state RPS programs in the U.S. are also almost certain to cost more than necessary, even though most employ "market mechanisms." To support this last proposition I provide a fairly detailed description of actual markets for renewable energy credits (RECs) and their shortcomings. The final section summarizes this article's findings and discusses the implications of this analysis for the design of a possible nationwide RPS program in the U.S.

Why Subsidize Renewable Electricity Generation?

Many economists have argued that subsidizing renewable electricity generation is not an economically attractive approach to achieving most of the policy goals that have been used to justify such subsidies.³ In this section I briefly summarize the main economic arguments that have been made for and against these subsidies. I then discuss a possible reason why such subsidies seem to be more politically attractive in regions served by competitive wholesale electricity markets.

³ Fischer and Preonas (2010) develop many of the points made in the next several paragraphs.

Energy Security

Subsidies for renewable electricity generation have sometimes been justified on the basis of energy security. However, subsidizing renewables does not promote energy security in the U.S., since North America is essentially self-sufficient in coal and natural gas, and only about two percent of U.S. petroleum consumption is used to generate electricity. The issue is more complex in Europe, which depends heavily on imported natural gas. But because the output from the most rapidly growing renewable generation types, wind and solar, is both variable over time and imperfectly predictable, these generators are referred to as variable energy resources or VERs. The greater the fraction of generation that comes from VERs as opposed to conventional fossil-fueled or nuclear plants, the greater the need for gas-fired reserve capacity.⁴ Thus subsidizing renewables may not be a sound response to energy security concerns (Moselle 2010), even in Europe.

Green Growth

Some advocates of subsidies claim that they will create “green jobs.” But the notion that this sort of program can affect the aggregate level of employment makes sense only under conditions of substantial unemployment. Even then, however, it seems a priori unlikely that the most efficient way to create jobs in a deep recession would be to subsidize switching from one capital-intensive method of generating electricity to another.

Subsidies for renewable electricity generation will, of course, change the composition of domestic employment. Some argue that there will be rapid growth in the global market for renewable generation equipment, and that subsidizing domestic demand for renewables will

⁴ Accommodating high levels of VER generation also requires significant changes in system planning and operations (NERC 2009).

create a strong domestic industry able to compete in that market. At its base, this is an argument that the government has been able to find an economically attractive investment opportunity that private capital markets will not exploit without a subsidy. However, despite repeated attempts, governments have rarely been able to outsmart[?] the private sector in this fashion. Moreover, while growth prospects for renewables may indeed be bright, particularly in the long term, as demonstrated by the U.S. auto industry, a large domestic market does not guarantee a healthy domestic industry (though, to be fair, it surely never hurts). In a more relevant example, although at the end of 2008 the U.S. led the world in installed wind generation capacity, half of the new capacity installed in the U.S. in that year was imported.

Climate Change

Perhaps the strongest argument for subsidizing renewables in the U.S. is that shifting away from fossil fuels will reduce emissions of CO₂, which are generally believed to contribute to global climate change. However, no such case can be made to support the E.U.'s ambitious renewables program (discussed below), since the EU's aggregate CO₂ emissions are already capped under the E.U. Emissions Trading System (EU ETS) (Ellerman et al 2010). Aggregate CO₂ emissions from electricity generation are likewise capped, in principle, in the ten U.S. states participating in the Regional Greenhouse Gas Initiative (RGGI),⁵ although the RGGI cap may not be binding in practice. Even where such caps do not exist, the key to reducing CO₂ emissions from electricity generation is to reduce the use of coal. However, adding renewable generation to a power system does not result in a reduction in generation from coal-fired power plants, which generally have low marginal costs, but rather in a reduction in plants with high marginal costs – typically gas-fired plants.

⁵ Nine of these ten states have RPS programs, with Vermont being the exception.

A related argument is that subsidies that increase the output of renewables reduce the costs of renewable technologies via learning-by-doing and thereby encourage their widespread adoption. But learning exists in many industries. It only provides an economic justification for subsidies if there are knowledge spillovers from one producer to others. To my knowledge, such spillovers have not been demonstrated in this context, nor has it been demonstrated that costs are more effectively reduced by subsidizing deployment of today's expensive technologies than by directly supporting research and development aimed at finding lower-cost alternatives or offering prizes tied to generation cost.⁶ Moreover, in the U.S. context, I don't believe it has ever seriously been argued that any single U.S. state's subsidies for renewables will reduce their costs enough to have a discernable effect on their global penetration.

Sources of Political Support for RPS and Other Renewables Policies

Although the strongest arguments for subsidizing renewable electricity generation are probably those related to climate change, the first nine U.S. RPS programs were adopted before 1999 along with electric utility restructuring, and their political support had nothing to do with climate change or any other environmental issue (Hogan 2008).⁷

While climate change and other environmental concerns did play a role in the adoption of the second wave of RPS programs that began in 2004, support for the four most recently adopted U.S. RPS programs seems at best loosely connected to concerns about climate change. In June 2009, the U.S. House of Representatives passed the Waxman-Markey bill (H.R. 2454), which would have reduced U.S. CO₂ emissions, despite opposition from majorities of the delegations

⁶ For example, such a prize might be a commitment to purchase a very large quantity of solar electricity at a relatively *low* FIT from the first firm willing to supply at that price.

⁷ These early RPS programs include California's RPS, which was adopted in 2002 to replace an ineffective renewables subsidy that had been adopted in 1996 in connection with utility restructuring.

from Ohio, Missouri, and Kansas. Nonetheless, Ohio and Missouri had adopted RPS programs in 2008, and Kansas, from which three of the four Representatives opposed Waxman-Markey, had followed suit in the month before the Waxman-Markey vote. The 2008 statute establishing the Michigan RPS lists “improved air quality” as the law’s fourth purpose, after diversifying energy resources, providing greater energy security by using in-state resources, and promotion of private investment in renewable energy. Climate change is not even mentioned.

Impact of Renewable Resources

The fact that state RPS policies have been adopted for a variety of reasons is consistent with studies finding that multiple factors influence their political appeal (Chandler 2009, Lyons and Yin 2010). It is interesting to note, however, that states’ renewable resources, which vary enormously, do not seem to be a major factor. Wind power has accounted for most of the growth in U.S. renewable generation in recent decades (Schmalensee 2010). Of the seventeen states that the National Renewable Energy Laboratory (U.S. Department of Energy, no date) estimates to have annual wind generation potential that is more than four times their 2009 retail sales, ten have RPS programs. At the other extreme, eighteen states (including the District of Columbia) have estimated wind potential of less than ten percent of 2009 retail sales, yet nine of these have RPS programs.

Impact of Governance of Electricity Supply

To my knowledge, the governance of electricity supply has not been formally considered to be a determinant of the decision to subsidize renewables, but theory and a bit of evidence suggest that it may, in fact, be an important factor. In states with rate-of-return regulation, utilities are entitled to earn a fair rate of return on their sunk investment in fossil-fueled generating plants, even if those plants are run less to make room for renewable generation. This

means that ratepayers must bear all of the incremental costs of shifting to renewables that are not borne by taxpayers. In contrast, in the twenty-nine states where all or most electricity is traded in organized wholesale markets managed by Independent System Operators (ISOs) or Regional Transmission Authorities (RTOs), as well as in the E.U., the returns earned by independent power producers (IPPs, generators that do not serve retail customers) are *not* guaranteed. These profits (or, more properly, quasi-rents) can be expected to fall in the short run as excess capacity reduces the IPPs' output and drives down wholesale electricity prices. In this way, some of the short-run costs of RPS programs are shifted from ratepayers to generators.

Such a shift in costs to electricity generators seems to have been important under the FIT program in Germany (Frondel et al 2010). In addition, the drop in generators' returns because of Spain's FIT program may have actually been sufficient to lower retail rates (Sáenz de Miera et al 2008). Appendix A illustrates how the addition of high-cost renewables under an RPS program can cause a short-run rate decline when fossil supply is inelastic. In the long run, of course, ratepayers necessarily bear all the costs of RPS or FIT programs, but the long run does not arrive soon in the electric power sector.

In the U.S., the 2011 reference case projection of the U.S. Energy Information Administration (EIA) (U.S. Energy Information Administration 2011a) implies that under current policy, between 2008 and 2015, U.S. electricity generation will increase only 3.1 percent. Renewable capacity is expected to increase by 23.5 percent and renewable generation to increase by 44.4 percent.⁸ Fossil-fueled capacity is projected to rise by only 2.1 percent. Not surprisingly, U.S. generation from fossil-fueled plants is projected to *decline* by 2.3 percent, with greater

⁸ The EIA projects a dramatic slowdown in renewable capacity growth after 2015 because the main federal subsidy programs expire in that year, and "current policy" requires EIA projections to assume that these popular programs will not be extended.

declines to be expected in states with RPS programs. It is unclear whether these declines will be sufficient to lower wholesale prices, but IPP quasi-rents will surely be reduced.

Whether the ability to shift some of the short-run costs of an RPS from ratepayers to IPPs makes it more or less likely that a state will adopt an RPS depends, all else equal, on the IPPs' political influence. Since these entities lack retail customers and have relatively few employees, one might expect them to have less political influence than, say, comparably-sized electricity distribution companies. In fact, this is what the evidence suggests. Of the sixteen states with organized wholesale markets in which IPPs accounted for more than thirty percent of electricity generation in August, 2010 (according to EIA's *Electric Power Monthly*), fifteen have RPS programs. The exception is Vermont, an active supplier of renewable generation and RECs in the New England market. At the other extreme, of the eleven states not in ISO/RTO regions in which IPPs account for less than twenty percent of generation, only three have RPS programs. Here the exceptions are New Mexico, North Carolina, and Washington.

It is important to note that particularly in multi-state organized markets, the in-state importance of IPPs is clearly an imperfect measure of the ability to shift costs to IPPs, and decisions regarding RPS programs, ISO/RTO status, and the role of IPPs are all endogenous to the political system. Thus, this evidence is only suggestive of a causal relationship between the ability to shift short-run costs to IPPs and the political attractiveness of subsidies to renewable generation.

RPS or FIT?

Most analysts seem to believe that price-based FIT policies are superior to quantity-based RPS approaches. This general view is neatly summarized by the European Commission (2008, p. 3;

italics in original): “*well-adapted* feed in tariff regimes are generally the most efficient and effective support schemes for promoting renewable energy.”

This conclusion is based in part on experience in the E.U., where FIT regimes in, for example, Spain and Germany outperformed the RPS regime in the U.K., although siting problems in the U.K. and the success of the RPS policy in Texas suggest that in practice the relationship between FIT and RPS policies is more complex.

The clearest theoretical argument for FIT’s superiority over RPS is that guaranteeing the price at which a renewable generator can sell removes electricity market risk from investors in renewable generation, so that more capital can be raised per dollar of subsidy expense. But this “bang for the buck” measure neglects the impacts on actors other than investors in renewables and those who pay subsidies. Measures that remove market risk from one set of players may simply shift it to others and thus not reduce the risk to society as a whole. There is accordingly no obvious reason why overall social risk could not be higher under an RPS than under FIT. However, overall social risk seems to have received little attention from analysts.

A Simple Model of Social Risk

A simple model presented in Appendix B shows that total social risk may actually be higher under a FIT than under a comparable RPS, even though individual investors bear no risk under an RPS. More specifically, using a very stylized, long-run model of a large electric power system with fixed total load, I compare an RPS and a FIT that would have the same cost and deliver the same generation mix under certainty. Fossil generation at the system level is assumed to operate under constant returns to scale with known costs, while the supply curve of renewable energy is assumed to be rising (because potential sites vary in quality), and the quantity supplied at any price is assumed to be ex ante uncertain. The model shows that as long as the unit cost of

renewables is always higher than the unit cost of fossil electricity, the variance of the total cost of serving the fixed load, a natural measure of total social risk, is always higher under FIT than RPS. The difference in total social risk is greater the more elastic is the renewables supply curve, since what drives the result is uncertainty regarding the quantity supplied (and subsidized) under a FIT policy.

There are, of course, obvious design features that can reduce the riskiness of both types of policy. FIT regimes could have a fixed maximum quantity of generation that can be sold at the guaranteed price, for instance, and RPS regimes could have a cap on total costs. It is interesting that FIT regimes in the E.U. have generally not had such quantity limits (Couture et al 2010), and some have experienced significant positive quantity surprises, while nine of the 30 U.S. RPS programs have explicit cost caps. These caps limit RPS-induced retail rate increases to between one and four percent.⁹

The U.S. Preference for RPS

I doubt that considerations of social risk explain why, despite the EU experience and the weight of expert opinion, U.S. states have overwhelmingly chosen RPS over FIT to subsidize renewable electricity generation. It is possible that states had bad memories of their experience under the Public Utilities Regulatory Policies Act (PURPA) of 1978, which required them to purchase renewable generation at utilities' "avoided cost," thereby establishing a FIT-like regime. Or they may have been reluctant to attempt to set wholesale rates for renewable power, given the jurisdiction of the Federal Energy Regulatory Commission (FERC) over wholesale power rates. But FERC first opined on a (very limited) state FIT in October, 2010 (133 FERC ¶

⁹ One of the nine cost-cap states, Montana, also sets the penalty for non-compliance at \$10 per MWh, effectively ruling out the purchase of expensive renewable power.

61,059 2010). In any case, neither of these factors explains the complete lack of interest in FIT approaches at the federal level.

It is thus something of a puzzle why U.S. politicians so strongly prefer RPS to FIT. Perhaps quantity goals are generally more attractive than price goals, as might be suggested by the universal use of the former rather than the latter in international climate change negotiations. Or perhaps, more cynically, it may be easier to get RPS programs adopted where environmental groups are only moderately strong because the costs of RPS programs are less visible than the costs of FIT programs. It is not hard to find Americans who think wind and solar power must be cheap because their “fuel” is free; I expect it would now be more difficult to find Spaniards or Germans who share this mistaken belief.

Is the E.U. Renewables Program Ex-Post Efficient?

The notion of ex-post efficiency, explored in this section and the next, involves taking detailed policy goals as given and asking whether they are likely to be attained at minimum cost or anything close to it. In the case of renewable energy, ex-post efficiency mainly requires production at the best sites, given the technologies required or allowed to be employed.

The goals of the E.U.’s renewable energy program are simply stated: twenty percent of overall energy and ten percent of energy used in transportation must come from renewable sources by 2020 (European Union 2009). The relevant directive defines “renewable” fairly broadly and argues, plausibly, that because transportation fuels are freely traded, there is no reason why the same ten percent requirement should not apply to all member states.

Options for Achieving Ex-Post Efficiency

Ex-post efficiency that takes the overall twenty percent target as given requires E.U.-wide equalization of the marginal cost of producing electricity from renewable energy. Assuming no within-country inefficiencies, this goal could be attained in at least three ways. First, a uniform E.U.-wide subsidy or FIT regime could be employed, and, to hit the overall renewable-share target, adjusted as information about quantities supplied emerged. Second, almost any set of national goals could be specified, as long as a system was in place for E.U.-wide trading of RECs. Finally, even without international trading, a set of national goals could lead to ex-post efficiency if they were carefully set so as to equalize the marginal cost of compliance across countries. Of course, even if a set of national targets for the share of renewables were met exactly, unless those targets were identical across countries, different patterns of national growth would lead to different shares of renewables for the E.U. as a whole.

An E.U.-wide subsidy scheme does not seem to have received serious attention, perhaps because member states were already attached to their existing array of FIT regimes. But there was a good deal of debate within the E.U. about the establishment of an E.U.-wide REC system (Toke 2008). In the end, however, in part because of protests from Germany and Spain, along with their renewable energy industries, the final directive allowed for only limited government-to-government trading as well as joint projects.

Equity Concerns and National Targets

As noted above, limits on international trading would not lead to appreciable ex-post inefficiency if national targets were carefully chosen to ensure that marginal costs of compliance were roughly equal across countries. But the E.U.'s statement concerning its target-setting procedure suggests at least as much concern with equity as with efficiency:

It is appropriate [to share] the required total increase in the use of energy from renewable sources between Member States on the basis of an equal increase in each Member State's share weighted by their GDP, modulated to reflect their starting points, and by ... [taking account of] Member States' past efforts with regard to the use of energy from renewable sources. (European Union 2009, ¶15)

To get some sense of the importance of national wealth relative to other factors in the E.U.'s target-setting process, I performed the following simple exercise. The E.U.'s renewables directive (European Union 2009, Annex 1) gives each Member State's share of energy from renewables in 2005 (C) and assigns each State its 2020 target (T). For each State (excluding Cyprus, Luxembourg, and Malta for various reasons) I computed two measures of the toughness of its target: an absolute measure, (T-C), and a relative measure, (T-C)/C. According to both measures, four nations (Germany, United Kingdom, Netherlands, and Ireland) were in the top third of Member States and four nations (Romania, Latvia, Lithuania, and Estonia) were in the bottom third. The 2005 per-capita GDP of the poorest country in the top group was more than 3.3 times that of the richest country in the bottom group. Clearly, ability to pay played an important, perhaps the dominant, role in the determination of national targets.

Not surprisingly, two independent studies have concluded that the cost of restricting international trading to meet the specified national targets is substantial: about €17 billion annually in 2020, increasing cost by roughly twenty percent compared to a system with unlimited trading (Eurelectric 2009). The contrast with the pioneering EU ETS for capping E.U.-wide CO₂ emissions efficiently could hardly be stronger (Ellerman et al 2010).

Are U.S. State RPS Programs Ex-Post Efficient?

Since states make independent political decisions regarding RPS programs, and, as noted above, the presence of RPS programs appears to be unrelated to the availability of renewable resources, it is extremely unlikely that state RPS targets equalize the marginal cost of generating electricity from renewables across states. Total national costs of meeting states' aggregate targets could nonetheless be minimized, at least with respect to the twenty-seven states that use RECs, if all RECs were nationally traded in efficient, competitive markets.¹⁰ Unfortunately, as discussed below, there are enormous obstacles to both interstate trade and market efficiency.

Features of State RPS Programs

No two of the thirty state RPS programs are identical, and the differences among programs are often substantial. For example, some programs appear to be highly ambitious, while others have much less aggressive goals. Iowa, for instance, simply requires its utilities to own or contract with 105 MW of renewable generation capacity, even though the state currently has 3,675 MW of wind generation capacity (AWEA n.d.). At the other extreme, New Jersey's solar generation requirement seems very ambitious indeed, as discussed below.

Most states require an alternative compliance payment (ACP), in effect a penalty that must be paid for each MWh by which load-serving entities fall short of meeting their requirements under the RPS, but ten states appear to leave enforcement to the discretion of their public utility commissions. Most ACPs are around \$50/MWh, but some are as low as \$10/MWh. ACPs relating to solar-specific requirements are much higher, with the New Jersey solar ACP, at

¹⁰ The three state RPS programs that do not use RECs are New York (which uses a system of centralized procurement), Iowa (which requires ownership of or contracts with specific facilities), and Hawaii (where the RPS statute simply makes no mention of RECs.)

\$675/MWh, being the highest. If there are not enough RECs available to meet utilities' requirements in a given year, one would expect the corresponding REC price to approximate the ACP. In the case of Missouri, however, the ACP is specified by statute as twice the REC price. So it will be interesting to see what happens if there is ever a shortage of eligible RECs to satisfy the Missouri RPS.

No two states use the same definition of "renewable," and twenty states have laws that set multiple tiers or classes of technology-specific requirements. Generators powered by renewable energy sources such as geothermal or municipal biomass are dispatchable, like fossil or nuclear generators, while substantial penetration of VER sources such as wind and solar that are not dispatchable requires additional reserve capacity and changes in system operations. In addition, in some cases, these sources are sited remotely and require large investments in transmission capacity (NERC 2009; National Research Council 2010, ch. 6). Nonetheless, no state RPS program systematically dis-favors VERs. In fact, twelve programs have specific requirements for the use of solar energy, and, as noted above, wind has accounted for the bulk of increases in renewable generation in recent years. If all technologies designated "renewable" are thought to produce equal benefits, it follows that total social costs would be reduced if policy favored those (non-VER) technologies that imposed fewer external costs on the rest of the electric power system.

Some features of RPS programs are clearly aimed at promoting in-state economic activity. For instance, Texas and some other states give credit only for renewable generation that serves in-state customers, while New Jersey has requirements for in-state solar generation and, effective in 2011, for in-state off-shore wind. North Carolina has minimum requirements for electricity generated using swine waste and poultry waste.

In-state solar requirements, particularly when coupled with requirements for distributed generation, seem to be aimed at creating jobs installing and maintaining solar cells rather than manufacturing them. According to the EIA (U.S. Energy Information Administration 2011b) in 2008, Ohio and Michigan accounted for sixty-one percent of solar cells manufactured in the U.S., while California and Massachusetts accounted for another twenty percent. Of these four states, only Ohio and Massachusetts had solar RPS requirements. No solar cells were produced in five states with solar requirements, and there was some production in six other states without solar requirements.

The rationale for other requirements is somewhat harder to understand. For instance, both the District of Columbia and New Hampshire allow the use of RECs from renewable generators over a fairly wide geographic area. Nonetheless, the District of Columbia has three technology-specific requirements within its overall RPS, and New Hampshire has four. These requirements can have very little to do with in-state generation, particularly in the District of Columbia. At most these technology-specific requirements might have some minor impact on the region-wide renewable generation mix. However, it seems implausible that they could have been expected to have a measurable effect on aggregate learning-by-doing in any market area.

Interstate Trade in RECs

To assess whether the states' goals for renewable generation, whatever their merits, are met reasonably efficiently, it is necessary to understand the mechanics of RPS programs, particularly as they relate to interstate trade of RECs. In the twenty-seven states that use RECs, each state must certify that the RECs produced along with the electricity generated by particular facilities can be used for compliance with one or more state-specific requirements. The generation, transfer, and retirement of RECs are generally tracked in online registries

(<http://www.etnna.org/learn.html>). All information in these registries is treated as proprietary and is only available to market participants. This is in stark contrast to the emissions trading systems administered by the U.S. Environmental Protection Agency, in which all such information is public

(http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.progressresults_allowance).

RECs are often bundled with electricity in long-term arrangements between generators and distribution companies. A number of brokers facilitate over-the-counter trades of “unbundled” RECs, and aggregators assemble RECs from multiple sources to meet utilities’ requirements.¹¹ Most (but not all) states use a calendar-year compliance period, allowing a few months after the end of the year for load-serving entities to acquire and turn over the necessary number of RECs.

Colorado and Missouri allow RECs purchased from certified generators anywhere in the US to be used for compliance purposes, but both give twenty-five percent additional credit for in-state generation. Of the remaining twenty-five REC-using programs, fifteen will accept RECs from facilities that do not deliver power in-state, but eligible facilities typically must be located in the same ISO or RTO or in the same geographic region. Washington only accepts RECs from the Pacific Northwest, for instance, and Delaware accepts RECs only from the PJM RTO.

On the other hand, distribution companies in at least some of the fifteen states that allow inter-state trading and generators in these states and elsewhere do engage in substantial interstate (and even international) trade in RECs. Because the information in the various REC registries is treated as proprietary, no systematic data on interstate transfers of RECs are publicly available.

¹¹ A list of brokers and other participants in these markets is maintained by the U.S. Department of Energy at <http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=2>.

However, as shown in Table 1, the few state compliance reports that do provide such data indicate substantial imports. It is worth noting in Table 1 that although Vermont, Virginia, and West Virginia are important sources of out-of-state RECs, they do not have RPS programs, and that Michigan's RPS program was not enacted until 2008.

*** Insert Table 1 Near Here ***

REC Market Fragmentation and Transactions Costs

Some information on REC prices is available, but only in the over-the-counter market. In order to examine pricing in that market, I purchased end-of-month bid-ask data for May 2006 through August 2010 from Spectron, a leading broker. Earlier bid-offer data were made publicly available by Evolution Markets, another leading broker. For May 2006, Spectron provided quotes on RECs from only five states (Connecticut, Maryland, Massachusetts, New Jersey, and Texas), and Evolution Markets covered only one additional state (Maine). As discussed below, over time, coverage has expanded as the number of RPS programs has increased.

Looking at the raw price data, one is struck first by the wide range of REC prices. On August 31, 2010, for instance, all bids for solar RECs for New Jersey, Pennsylvania, Maryland, Delaware, and Ohio were at least \$300/MWh, while other, non-solar bids and offers ranged from \$.05 to \$35.00. This extreme price dispersion is inconsistent with ex post efficiency in meeting states' goals for renewable generation and, as I discuss below, it reflects markets that are fragmented and thin, with high transactions costs. Moreover, price movements in a few relatively thick REC markets for which information on supply and demand conditions is publicly available (with a lag) strongly suggest that traders in these markets do not have good private information.

Of the twenty-seven state RPS programs that use RECs, seven have requirements that begin in 2010 or a later year. As of June 2010, Spectron provided price quotes for RECs in only half of the remaining twenty states. Three more were added by August. Presumably there was insufficient trading volume in the other states' RECs to make it worthwhile even to post bid-ask quotes with wide spreads. Because most states' RPS programs have multiple requirements, at the end of August 2010, Spectron provided quotes for thirty-three different RECs for the thirteen states it covered.

These markets are further fragmented because, with the exception of Arizona and Oregon, RECs can be banked for only a limited time.¹² Colorado allows banking for five years, and Ohio and Wisconsin allow banking for four years. Most of the other REC-using programs allow banking for only two or three years. Of course, limiting banking reduces the incentive for early investment in large-scale generation. It also makes RECs produced in different years imperfect substitutes and thus further fragments markets. In August 2010, Spectron provided bid-offer quotes for an average of two different vintages per REC, for a total of sixty-six different markets. Over the entire May 2006 to August 2010 period, the average of vintages quoted per REC was essentially the same. Of course, this understates the market fragmentation, since interest in other vintages, though they were differentiated by limits on banking, was insufficient to justify issuing quotes.

Fragmented, thin markets lead to high transactions costs, as market-makers need to quote high bid-ask spreads to cover illiquidity risks. Across all the Spectron data, the average bid-ask spread for the current-year vintage was thirty-eight percent. In sharp contrast, spreads for municipal and corporate bonds in 1995-97, a period during which they were also traded in

¹² Neither Evolution Markets nor Spectron provided quotes for RECs from either Arizona or Oregon for any month in my sample.

fragmented, broker-mediated, over the counter markets, averaged 0.23 percent and 0.21 percent, respectively (Chakravarty and Sarkar 2003). Spreads of one hundred percent or more are not uncommon in the Spectron REC data (there were ten in the sixty-six quotes posted on August 31, 2010, for instance), providing further evidence of pervasive illiquidity.

Information and Market Efficiency: Four Examples

If participants in REC markets had good, current information and if there were no banking, one would expect to see a bimodal distribution of current vintage spot market prices, particularly toward the end of each compliance period, as uncertainties about renewable generation and REC requirements were resolved. On the one hand, if the market were expected to be *long* at the end of the compliance period, with more than enough RECs produced to meet RPS requirements, the price should tend to zero.¹³ On the other hand, if the market were expected to be *short*, with fewer RECs produced than required, one would expect REC prices to tend to near the ACP level. If some banking is allowed, prices should tend to some positive number, well below the ACP, if the market is expected to be long, particularly if it is expected to stay that way for a year or more, but prices should still be near the ACP level if the market is short.

Persistent Shortage: New Jersey

If no interstate trading is allowed, it should be relatively simple for market participants, including brokers, to learn whether the market is likely to be long or short at the end of each compliance period, particularly if the relevant authorities regularly and promptly publish information on market conditions. New Jersey's solar requirement, for instance, can only be met by in-state generation. The state publishes detailed reports on ACP payments, as well as market

¹³ This is basically what happened in the E.U. ETS at the end of the first compliance period (Ellerman et al 2010).

conditions and their determinants, and these reports appear promptly, at least compared to the reports of other states.¹⁴ The New Jersey reports reveal a market that has been consistently and substantially short despite the very high ACP noted above, making clear just how ambitious the corresponding requirement has been. Not surprisingly, New Jersey solar RECs (called SRECs) consistently trade just below the ACP level in a fairly liquid market: spreads in the Spectron data averaged 6.1 percent. Thus, in the case of New Jersey, these prices appear to have tracked the fundamentals in this market well.

Single-State Market: Texas

In contrast, of the eight REC-using states with compliance requirements that began in 2009 or earlier and that only count RECs from facilities that deliver power in-state, seven do not seem to publish *any* information about REC market conditions. Only Texas has such information readily available on line, provided by its grid operator, the Electric Reliability Council of Texas (ERCOT). The Texas reports are detailed and prompt relative to other states: the Texas report for the 2009 calendar year was available online by mid-November 2010. These reports show a market that has been long by a substantial margin since its inception, with planned wind capacity increases likely to prolong this state of affairs.

Figure 1 shows current-vintage REC market prices for Texas, which are not easily reconciled with these market fundamentals: REC prices remained high (though low relative to the \$50 ACP level) until 2006. It has been suggested to me by market participants that these price trends reflect the fact that market participants were building REC banks through 2006 to

¹⁴ For example, a draft of the report for Reporting Year 2009, which ended on May 31, 2009, was produced in February, 2010.

deal with uncertainty, particularly about the future of the federal production tax credit.¹⁵ While the Texas REC market is described by participants as a relatively active REC market, current-vintage bid-ask spreads in the Spectron data averaged 37%, indicating much less liquidity than in markets for most financial assets.

*** Insert Figure 1 Near Here ***

Multi-State Markets: Massachusetts and Connecticut

Decision-making becomes more complicated in principle when interstate trading is allowed. In this case, RECs produced by a wind farm in Vermont, for example, can be used to satisfy RPS requirements in any other New England state. However, for a generation facility or distribution company in, say, Rhode Island to have a well-informed view of the REC prices it is likely to face in the future, it would require a good deal of information on renewable generation in several states and Canadian provinces, along with information on RPS requirements and REC banks throughout New England.

It is possible that sophisticated traders could acquire the necessary information from REC registries and other sources, but the states involved do not provide much help in this regard. For example, of the twelve states that allow RECs produced by facilities that do not deliver power in-state to be used for compliance and that required compliance beginning in 2009 or earlier, four do not seem to post comprehensive RPS program reports. The reports of the other eight states vary considerably in promptness: as of mid-November 2010, only three states had posted reports dealing with all or part of 2009, while the most recent reports from three other states covered 2007. In addition, the amount of information contained in these reports varies greatly, with

¹⁵ In fact, in the 1999-2004 period, the production tax credit lapsed three times (National Research Council 2010, p. 148).

several providing only ACP data, and only a few providing enough information from which one could assess market conditions.

The markets for Massachusetts and Connecticut RECs have been among the more active, and their state reports were among the more informative (though Connecticut's have not been particularly prompt). Thus one can compare current-vintage REC prices in these two states with market fundamentals. Figure 2 shows current vintage prices for Massachusetts Class I RECs.¹⁶ Spreads in this market averaged 8.2 percent in the Spectron data and were generally lower before 2008. This market was short in the 2003-06 period, with twenty-six percent of compliance in 2006 taking the form of ACP payments. In 2007, however, the market was long, with banking amounting to five percent of requirements, and the market remained long in subsequent years. It seems clear from Figure 2 that it took market participants essentially all of 2007 to realize that the market was no longer short.

*** Insert Figure 2 Near Here ***

Figure 3 shows prices for Connecticut Class I RECs¹⁷. Here bid-ask spreads averaged 11.7 percent in the Spectron data. The market was long in 2004 and 2005, twelve percent short in 2006 (the ACP was \$55), and 0.2 percent short in 2007. Prices seem to have been inexplicably high until mid-2005, then so low during 2006 that participants must have been unaware of the impending shortage. After significant ACP payments were required for 2006, prices finally jumped in early 2007 to levels reflecting a short market.

¹⁶ Massachusetts Class I facilities must have been installed after December 31, 1997 and employ any of a fairly long list of technologies. Effective in 2010, a portion of this requirement must be fulfilled using in-state solar facilities. For more information, see http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R&re=1&ee=0.

¹⁷ Connecticut Class I facilities may employ any of a fairly long list of technologies that includes wind and solar power but excludes trash-to-energy (included in the Class II list) and combined heat and power (included in Class III). For more information, see http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CT04R&re=1&ee=0

*** Insert Figure 3 Near Here ***

To summarize these findings concerning the relationship between information and market efficiency, buyers in the market for New Jersey solar RECs clearly knew the market was persistently short because they were unable to avoid making the highest ACP payments in the nation year after year. Moreover, because New Jersey is a relatively small state, new solar installations of any size would be easily observed. In the other three cases, however, market prices seem to have deviated substantially and persistently from those that would have been established by well-informed market participants. As discussed above, this finding is somewhat surprising in the case of Texas but not at all surprising in the cases of Connecticut and Massachusetts, where obtaining all the relevant information promptly would have been quite difficult.

Summary & Implications for a U.S. RPS Program

This article has examined a number of features of policies that subsidize the generation of electricity from renewable energy. Analysts generally agree that such policies are not an efficient way to reduce CO₂ emissions. The appeal of these policies derives from other sources, one of which (as argued above) is the ability in competitive electricity markets to impose some or all of the attendant costs on generators rather than ratepayers, at least in the short run. The incidence of RPS policies in the U.S. appears to be broadly consistent with this argument.

Globally, the FIT approach is more popular than the RPS approach, importantly, it seems, because the FIT approach removes risk from investors in renewable generation. But removing risk from investors may serve mainly to shift the risk to other actors and hence not reduce the risk to society as a whole. A simple model was presented that showed that the long-run societal

risk may in fact generally be lower under the RPS approach than under a FIT regime. While this possibility is surely not responsible for the RPS approach being so much more popular in the US than the FIT approach, despite the weight of opinion abroad, it remains unclear what is responsible for this phenomenon.

Because CO₂ emissions in the E.U. are capped by the E.U. ETS, the E.U.'s policy to increase its use of renewable energy can have no effect on those emissions. Moreover, national targets under the E.U. renewables policy are systematically more challenging for wealthier countries. This means that the policy's limits on international REC trading are highly likely to inflate the policy's costs – as confirmed in detailed analyses by others.

Finally, in the U.S., some state RPS goals seem to be mainly about local job creation, while for some other states, the environmental or other rationales for their goals are not so obvious. Because most states have multiple technology- or location-specific goals, and all but two states limit banking, REC markets are generally fragmented and thin, and transactions costs are quite high. Most states limit interstate trading and provide little information from which one could infer REC market conditions. Even in relatively active markets, REC prices are sometimes markedly out of line with their fundamental determinants. Thus, because REC markets do not work well, state RPS programs cannot be efficient.

As noted at the beginning of this article, since 2007, the U.S. House of Representatives has twice passed bills that would impose a nationwide RPS. The findings presented above concerning state RPS programs, along with experience with the U.S. acid rain program (Ellerman et al 2000) and the E.U. ETS (Ellerman et al 2010), have clear implications for the design of any U.S. federal program that would impose quantitative requirements for clean and/or renewable electricity generation. First, any such program should pre-empt state RPS regimes

and should allow unlimited nationwide REC trading. A state standard that is tighter than the federal standard would likely have no effect on the national generation mix and would in any case raise in-state and national costs (Goulder and Stavins 2011). Second, to avoid market fragmentation, there should be only one class of REC. Technology-specific multipliers could be used to penalize some VER technologies for the costs they impose on the electric power system or, perhaps, to reward some technologies because of the perceived external effect of induced learning-by-doing if their production is increased. Finally, unlimited banking should be allowed both to reward early large-scale investment and to avoid fragmenting REC markets by vintage, and information on market conditions (including levels of REC banks) should be compiled and provided quickly to market participants. Of course, as with other U.S. emissions trading programs, information on quantities of RECs held and traded should be publicly available.

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Appendix A

To see how electric rates could fall even though ratepayers pay a premium for incremental renewable generation, consider a simple system with fixed load Q . Let R be the quantity of renewable generation added to the system; let r be its per-unit average cost, net of any tax-financed subsidy; let $s(Q-R)$ be the short-run supply curve of fossil generation; and let T be total payments by ratepayers for electricity. If the marginal cost of renewable generation is zero, T must equal the cost of renewables, rR , plus the payments to fossil generators necessary to induce them to supply $(Q-R)$, so

$$T = rR + (Q-R)s(Q-R).$$

Now consider a mandate that increases R slightly. Because $Q-R$ must fall and the fossil supply curve is upward sloping, the wholesale market price must fall and thus the quasi-rents of fossil generators are cut. Moreover, it is immediate that

$$dT/dR = (r - s) - s/\epsilon,$$

where ϵ is the elasticity of supply of electricity from fossil fuels and s is the wholesale price of electricity, equal to the marginal cost of fossil generation. The less elastic is fossil supply, all else equal, the more likely it is that increasing R lowers T , so that fossil generators bear more than the full cost of increasing renewables in the short run. See Fischer (2009) for a much more complete discussion.

Appendix B

In a large electric power system, it seems reasonable to assume that the long-run unit cost of fossil-generated power, c_f , is roughly independent of system scale, but it is likely to be higher the greater the penetration of renewable VERs:

$$c_f = \gamma + \delta(Q_r / Q_f),$$

where Q_r and Q_f are the quantities of renewable and fossil generation, respectively, and δ and γ are positive constants. The supply curve of renewable generation is assumed to rise (because sites vary in quality) and to be uncertain *ex ante*:

$$p_r = \alpha + \beta Q_r + \varepsilon,$$

where α and β are positive constants, and ε is a random variable with mean zero. For simplicity, total load, Q is assumed to be fixed; the argument below holds if Q also has an additive stochastic component.

We want to compare a FIT of T and an RPS of R that are equivalent under certainty (i.e., when $\varepsilon = 0$), so we assume $T = \alpha + \beta R$. Under certainty, the total social cost of electricity under either policy is

$$\bar{C} = p_r Q_r + c_f (Q - Q_r) = (T + \delta)R + \gamma(Q - R).$$

When uncertainty is present, p_r is stochastic under the RPS, and total social cost is simply

$$C_{RPS} = \bar{C} + R\varepsilon.$$

Under the FIT, Q_r is stochastic when uncertainty is present, and a bit of algebra yields

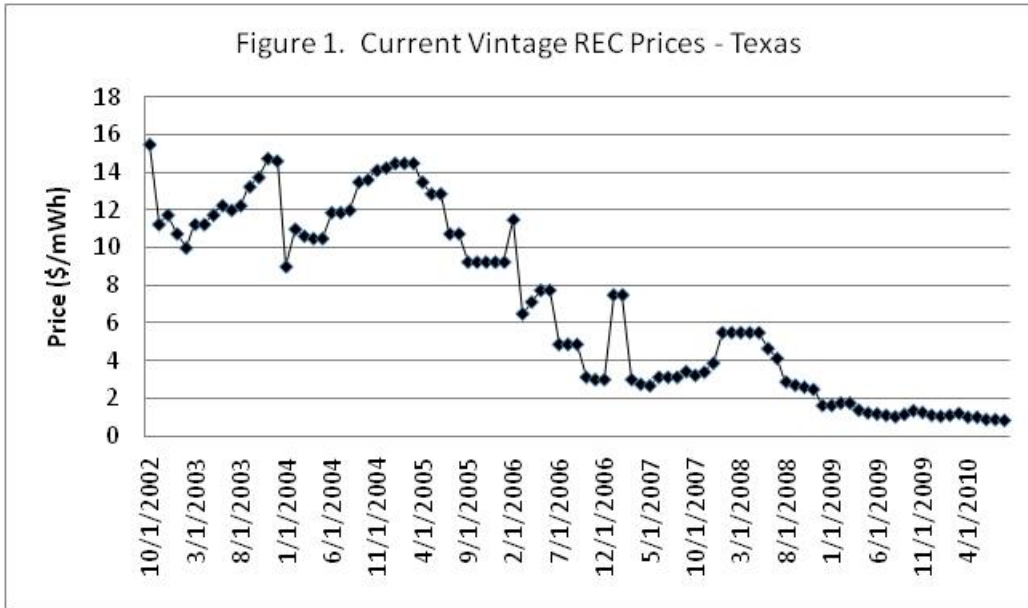
$$C_{FIT} = \bar{C} - \left(R + \frac{(\alpha + \delta) - \gamma}{\beta} \right) \varepsilon.$$

Note that positive values of ε (positive cost shocks to renewables) raise the cost of an RPS, but, by reducing quantity supplied, lower the cost of an FIT. The key point here is that as long as $\beta + \gamma > \alpha$, so that the full incremental cost of renewable electricity always exceeds the incremental cost of fossil electricity, the variance of total social cost is higher under FIT than under RPS. All else equal, the difference is larger the smaller is β , that is, the flatter is the renewable supply curve, and thus the more responsive the quantity of renewables is to cost shocks when price is fixed, as it is under a FIT.

Table 1.
RPS Compliance Using Out-of-State Generation

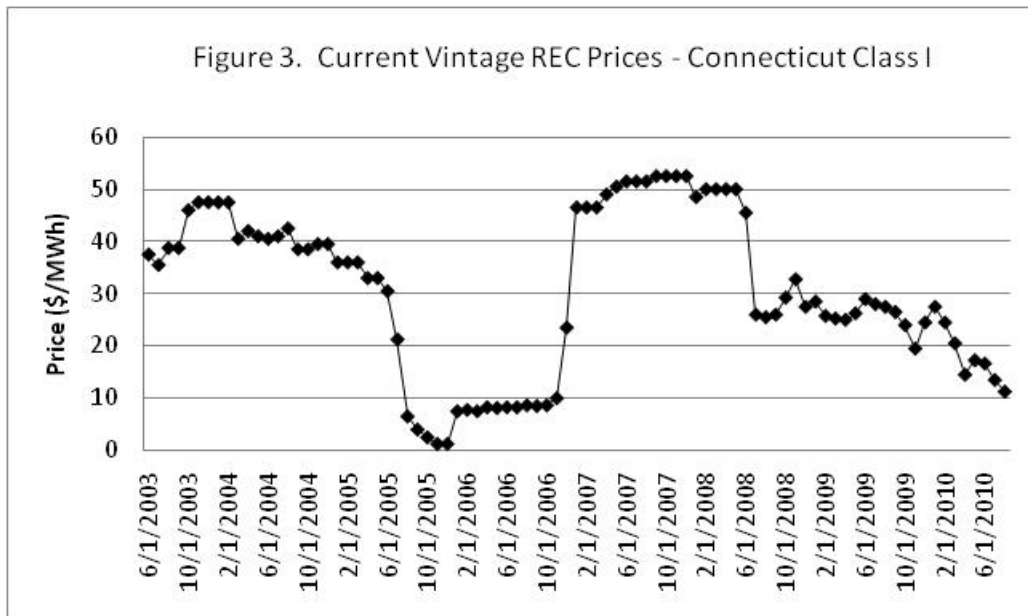
State	REC, Year	Percentage Out of State	Main Sources
Connecticut	Class I, 2007	97.5	Maine, New Hampshire, Rhode Island, New York
Connecticut	Class II, 2007	43.6	Massachusetts, Maine, Vermont
Maryland	Tiers I & II, CY2007	83.7	Pennsylvania, Virginia, Michigan
Massachusetts	2008	90.0	New York, Maine, New Hampshire, Quebec
New Jersey	Class I, RY2009	85.4	Illinois, Pennsylvania, West Virginia, Virginia
New Jersey	Class II, RY2009	54.4	Pennsylvania, Maryland
Rhode Island	New, 2008	91.9	New Hampshire, New York, Vermont
Rhode Island	Existing, 2008	100.0	Massachusetts, Vermont, New Hampshire

Notes : Data from most recent state compliance reports available online in mid-November, 2010. "CY" and "RY" refer to compliance year and reporting year, respectively. Massachusetts had only one RPS requirement in 2008; in 2009 it was renamed Class I and a Class II requirement was added. Definitions of technologies covered by the RECs shown may be found in <http://www.dsireusa.org>.



Sources: Bid-offer data provided by Spectron and Evolution Markets.

Notes: Qualifying renewable energy facilities must have been installed after September 1999; eligible energy sources include solar, wind, geothermal, hydroelectric, wave or tidal energy, biomass, or biomass-based waste products, including landfill gas. Data points indicate arithmetic means of bid and ask prices.



Sources: Bid-offer data provided by Spectron and Evolution Markets.

Notes: Eligible energy sources (regardless of when facilities were built) include solar, wind, fuel cells (any fuel), landfill gas, ocean (thermal, wave, or tidal), certain hydroelectric facilities, low emission advanced renewable facilities, and sustainable biomass facilities. Data points indicate arithmetic means of bid and ask prices.

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