



SPECIAL REPORT

Renewable Energy Certificates

April 2012



This paper discusses renewable energy certificates (RECs). RECs have emerged as an essential tool for tracking and selling “environmental attributes” associated with renewable energy.

The REC market is of significant importance to a range of parties facing mandatory and voluntary renewable energy requirements, including project developers, utilities, investors, regulators, government agencies and environment-minded companies.

This paper is intended to provide an overview of how REC markets operate. *Part one* places RECs in the broader context of renewable policy. It contains a definition of RECs and explains why RECs are needed in the first place. *Part two* discusses the different REC products, lists the main buyers and sellers, and describes how trading occurs. *Part three* delves into market dynamics. It explains the forces behind supply and demand and the attendant impact on prices. *Part four* connects theory with real-life, using case studies to show the link between the concepts outlined earlier in the paper with actual REC markets.

I. BACKGROUND

A general consensus exists in the United States that the mix of electricity sourced from renewable resources should increase. Accomplishing this objective, supporters say, reduces greenhouse gas emissions, creates green jobs and leads to greater energy independence.

But turning this ambition into reality has been difficult. Arguably, the biggest challenge is economics. Even though the cost to build

some renewable technologies, especially solar photovoltaic, has fallen significantly over the last few years, lifetime costs are still greater than fossil fuel-fired power plants.

Further, the intermittent nature of wind and solar means renewable sources are less efficient compared with the near-constant stream of electricity from thermal power plants.

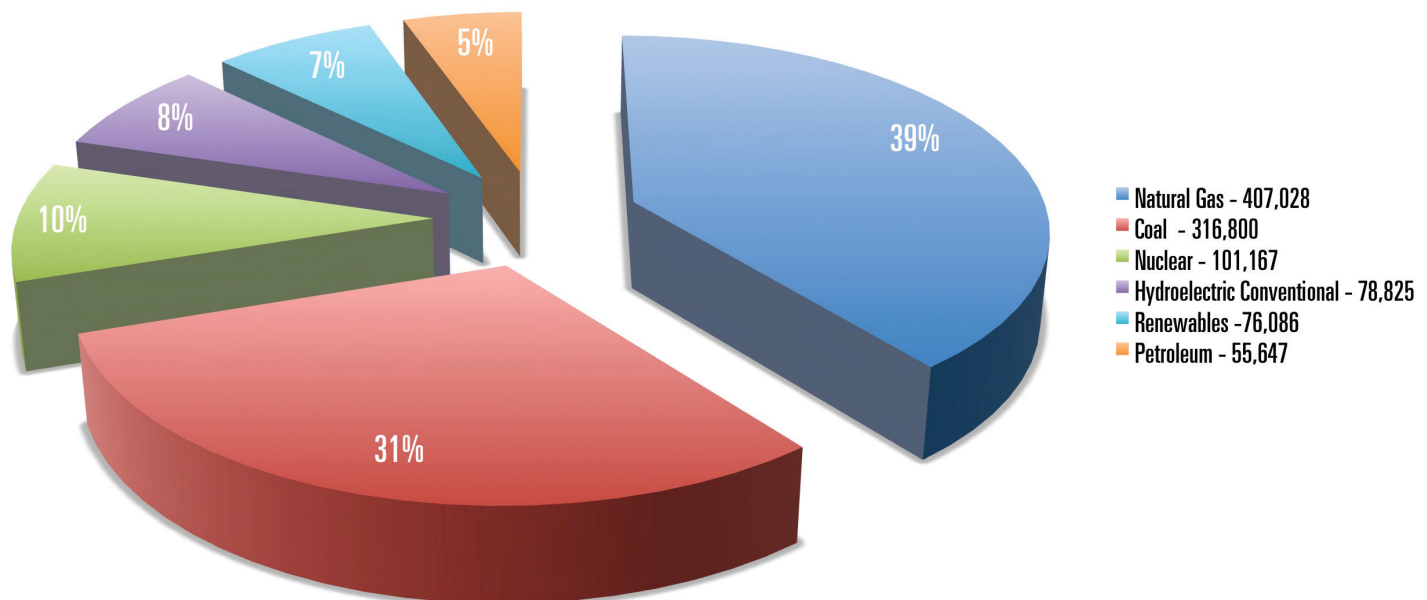
An essential ingredient to overcoming these shortcomings is public policy. Production tax credits, rebates and loan programs are some of the initiatives helping to spur investment in the renewable field.¹

One policy missing from this list, at least on a federal level, has been a renewable energy standard. Congress, so far, has balked at passing a law requiring that a minimum percentage of electricity be sourced from green technologies.

Instead, individual states have forged ahead, implementing renewable portfolio standards in increasing numbers. RPS policies are credited with boosting renewable energy capacity across many states.

The main impetus behind this growth has been the financial penalty load-serving entities must pay for failure to comply with a state’s renewable requirement. Load-serving entities are therefore willing to pay a premium for renewable energy, and that extra money goes to developers who are then incentivized to build more projects.

US Electricity Capacity by Energy Type (Net Summer Capacity)



NOTE: FIGURES ARE EXPRESSED AS MEGAWATTS

SOURCE: US ENERGY INFORMATION ADMINISTRATION'S ELECTRIC POWER ANNUAL 2010, RELEASED NOVEMBER 2011

Outside of RPS mandates, support for renewable energy projects comes from entities with internal environmental goals, such as eco-conscious companies, federal government agencies and utilities with renewable retail programs.

In either scenario, the desire to purchase “green” electricity runs headlong into the physical reality of a grid. Due to the laws of science, it is impossible to know the source of a particular electron and whether it was generated by a wind farm or a coal-fired power plant.

RECs offer a solution to this dilemma. Conceptualized in the 1990s, RECs separate the environmental attributes of renewable energy from the actual electricity. With an infrastructure system in place, generation data could flow into an online system used to record and track RECs, essentially creating a new commodity.

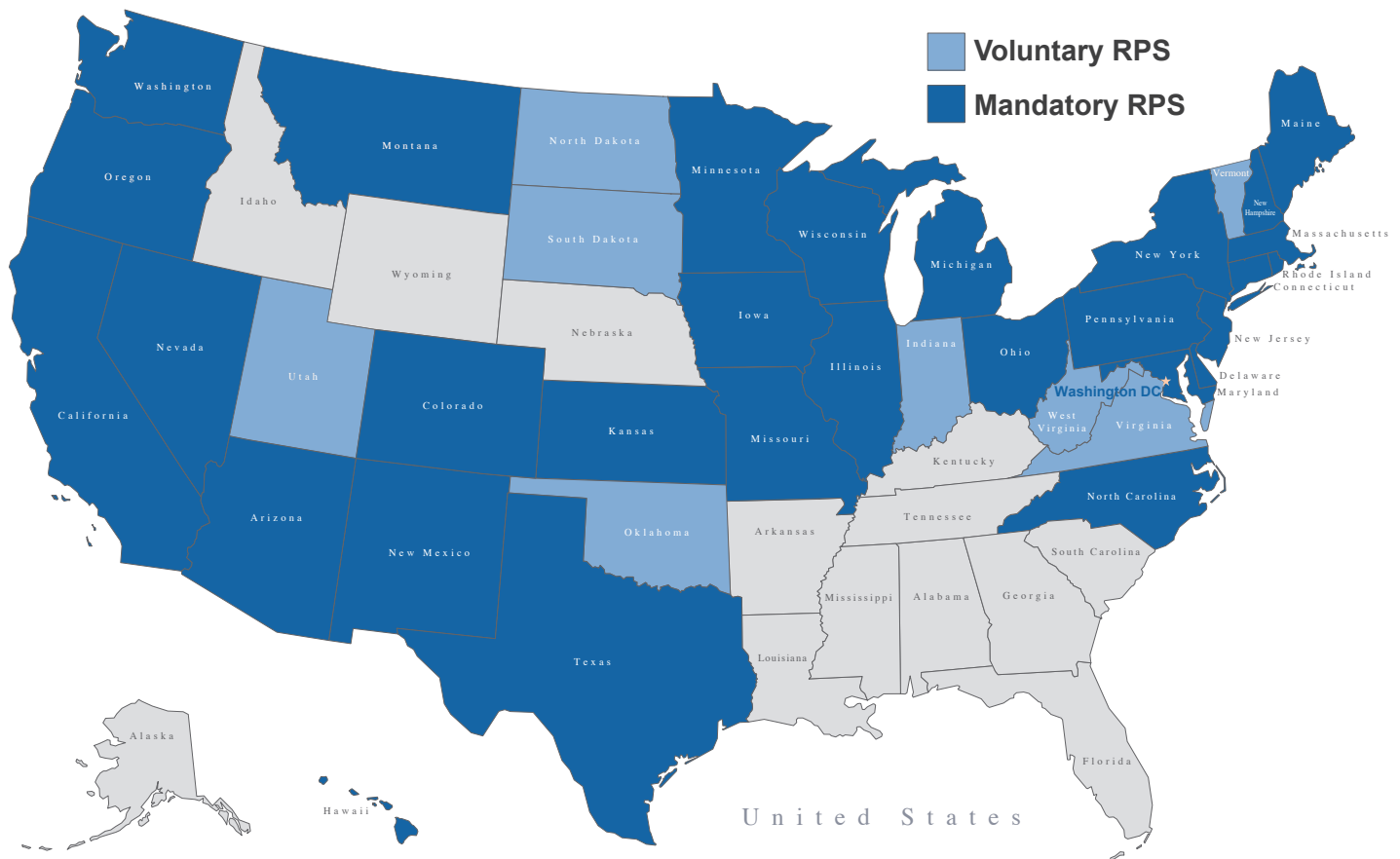
Parties would be able to negotiate a sale, and upon completion, transfer the RECs sold from one account to another. The owner gets to claim the environmental attributes related to the underlying electricity.

Such a system has proved successful. A RPS, including the use of RECs, has become the most wide-spread policy for encouraging the growth of renewables. As of early 2012, 29 states and the District of Columbia had implemented a mandatory RPS.² An additional eight states have voluntary goals.³

Moreover, the size of the REC market is expected to continue growing. In 2011, RPS rules required 133 million MWh of electricity from renewable facilities, a 22-fold increase over a decade earlier. (That figure is slightly more than 3% of total US electricity production in 2011 of about 4,000 million MWh.) RPS requirements are forecast to grow to 210 million MWh by 2015.⁴

Projections regarding future demand in the voluntary market are harder to gauge. Without binding targets, demand in the voluntary market depends upon levels of consumer interest and the willingness of utilities to offer green energy programs, among a host of other variables. While expectations are the voluntary market will expand, the amount of likely growth is more difficult to project. One estimate, for example, estimated the voluntary demand reaching between 63 million and 157 million MWh by 2015, up from 35 million MWh in 2010.⁵

States with Renewable Portfolio Standards



SOURCE: DATABASE OF STATE INCENTIVES FOR RENEWABLES AND EFFICIENCY

II. INTRODUCTION TO THE REC MARKET

A good starting point for an analysis of the REC market is the source of demand. As noted above, RECs have no inherent value, unlike physical energy commodities, such as coal, electricity, natural gas and oil.

RECs share more similarities with other environmental products (e.g. carbon dioxide allowances, carbon offsets and sulfur dioxide/nitrogen oxide permits), in which demand stems mostly from the need to comply with state or federal environmental regulations. Understanding this regulatory-driven market requires examining the underlying statute, in this case a state RPS.

The basic design of a RPS is the same across all states. There are annual renewable targets that load-serving entities must meet. The benchmarks are usually quantified as a percentage of retail electricity sales and increase over time. The RPS specifies a penalty fee that load-serving entities must pay for failing to fully comply.

On the supply side, a RPS defines the conditions that renewable facilities must meet to become certified as eligible facilities. The main criteria are geography, technology and start-up date.

The actual terms and conditions, however, differ from state to state. That is because states have designed RPS rules without any coordination. The outcome has been a patchwork of conflicting rules, reflecting each state's unique set of resources and goals. In fact, no two states have identical RPS rules.⁶

The marketplace has grown up around this balkanized approach. RECs are labeled in terms of RPS eligibility, meaning a new REC product is created for every new RPS. That often amounts to several REC products per state when renewable mandates are divided into multiple tiers.

Such a tier system has become commonplace. Tiers are defined on the basis of technology, start-up date and/or geography. Newer projects generally qualify as top tier, while older projects get relegated to a lower tier. Otherwise, some RPS requirements could be met with RECs from existing projects, defeating the purpose of the renewable mandate. Over time, the percentage requirements attached to upper tiers is greater than lower tiers.

The picture gets muddier in terms of *which* technologies may count for a top tier, and *where* facilities can be located. Wind farms qualify for top tier status in all states, but consensus falls apart with respect to biomass, landfill gas, waste-to-energy and hydroelectric, reflecting the wide range of views that states hold about the merits and drawbacks these technologies represent.

Geography is another criterion with inconsistent rules across states. States must decide whether to cast a wide net or to draw tight boundaries. Thus, a renewable facility may end up qualifying for one RPS or multiple RPSs if states have overlapping eligibility terms.

For example, a wind farm in Maine might qualify as Connecticut Class I, Maine New and Massachusetts Class I. In this case, the wind farm would create one REC for every MWh of electricity, but that REC would be stamped as eligible in Connecticut, Maine and Massachusetts.

This is an example of how a single REC can be counted more than once in terms of eligible supply. But only one party can actually own the REC at a given time. A load-serving entity will ultimately retire the REC in Connecticut, Maine or Massachusetts.

How a state decides to write its RPS rules regarding geographic eligibility will depend upon how it views the trade-off between costs and local impact.

By restricting the geographical scope of eligible projects, a state can channel money toward facilities closer to home. But that policy comes at an expense. Narrowing the pool of eligible facilities increases the price of the related REC products, a cost ultimately passed on to ratepayers.

Ohio, for example, requires one-half of its RPS – for both solar and non-solar – to come from facilities located within the state. This mandate gives rise to the creation of “Ohio In-State Solar” and “Ohio In-State Non-Solar” REC products.

The following table lists some of the most actively traded REC products:

NEW ENGLAND		
Massachusetts Class I	Massachusetts Class II	Connecticut Class I
Connecticut Class II	Connecticut Class III	Maine New
Maine Existing	Rhode Island New	Rhode Island Existing
New Hampshire Class I	New Hampshire Class II	New Hampshire Class III
New Hampshire Class IV		
PJM		
New Jersey Class I	New Jersey Class II	DC Tier I
DC Tier II	Pennsylvania Tier I	Pennsylvania Tier II
Maryland Tier I	Maryland Tier II	Ohio, In-State Non-Solar
Ohio, Adjacent Non-Solar	Delaware New	Delaware Existing

In a similar vein, a number of states have implemented technology-specific carve-outs. The most common example would be the solar carve-out. Solar technology holds a strong allure. Manufacturing and installing solar panels represent potential green jobs, advocates say. Residential-scale solar also avoids the tricky permitting and transmission-related difficulties commonplace with other technologies, like wind farms.

Yet, solar panels are still relatively expensive. Investment requires a significant price premium over traditional fossil fuels and even other renewable technologies.

A separate solar requirement is one solution to this problem. Similar to other RPS categories, solar carve-outs require load-serving entities to purchase a number of RECs equal to a percentage of retail sales. But only RECs generated from eligible solar facilities can be used to meet this carve-out. These solar-eligible RECs are therefore known as "SRECs."

Sixteen states plus the District of Columbia have passed separate solar carve-outs. The major SREC products traded are the following:

Massachusetts SREC	New Jersey SREC
Ohio, In-State SREC	Ohio, Adjacent-State SREC
Pennsylvania SREC	Delaware SREC
District of Columbia SREC	Maryland SREC

All REC products are also quoted in terms of the year in which the REC was generated. This date, called a "vintage," corresponds with a state's compliance year. States have defined their compliance schedules on either a calendar year basis or on a June to May basis.

For example, a REC generated in April 2012 would be stamped as "vintage 2012" with respect to the former, and as a "vintage 2011-12" with respect to the latter.

The vintage is relevant because RPS rules specify the window period in which a vintage can be used for compliance purposes. All states allow for a REC generated to be used during the contemporaneous compliance period. And some states will count older vintages as well.

The voluntary market is more straight-forward and less bifurcated in terms of REC products. The five main voluntary products are called National Solar, West Solar, West Wind, National Wind and National Any Technology. Most voluntary products are marketed under the "Green-e" logo, a standard established and administered by the San Francisco-based Center for Resource Solutions.

TRADING CHANNELS

Like other commodities, RECs can be bought and sold through formal exchanges or "over-the-counter." So far, OTC transactions represent the vast majority of deals. The IntercontinentalExchange is the only major energy exchange listing RECs to date.⁷

There are a few factors favoring OTC transactions over exchanges:

- A range of legal terms must be negotiated as part of a transaction, which parties have preferred handling bilaterally rather than through the use of a standardized exchange contract. One of the more contentious issues centers on liability. A contract must specify who bears financial responsibility in the event a state changes its RPS rules, invalidating a REC in the process. A successful, standardized contract would have to craft language acceptable to buyers and sellers, a difficult task.
- Because load-serving entities must purchase RECs to meet annual RPS requirements, buyers do not need to buy RECs on a daily or even weekly basis. Most will choose to procure RECs periodically during the course of a year, and therefore, have the time to negotiate individual deals to get the best terms possible.

Without much exchange-based trading, publicly-available information is scarce regarding prices. The main source of pricing information is brokers. A handful of brokers distribute daily bulletins with bids and offers for REC products with the most liquidity.⁸

Many buyers and sellers will contact brokers when they would like to trade RECs. However, large players, like wind farm owners, may bypass brokers to negotiate deals directly. These sellers can offer enough RECs to interest potential buyers with relatively large needs for RECs.

That is not the case for owners of small-sized renewable facilities. An extreme example would be the owners of residential solar panels. It would not make any sense for utilities to deal with any one of these sellers, and there is the additional issue of creditworthiness.

Stepping into this void between the buyer and seller are solar aggregators. As the name suggests, an aggregator buys up SRECs from many solar owners at a fixed price, and then negotiates the sale of that portfolio with a load-serving entity. The aggregator, in exchange for potential profit, assumes downside risk.

Another venue for the procurement of RECs is a request-for-proposal. The frequency with which utilities issue REC RFPs can vary from anywhere between once a year to every few months.

The process basically works the same as other RFPs that utilities issue. Either the utility or an outside consulting firm serves as the RFP manager. Some utilities end up releasing the results, pursuant to state law, but most of the time such information is kept proprietary.

Auctions are also a REC trading channel. A few companies run online auctions on a regular basis.⁹ This business model has had the most success with respect to the SREC market. An auction format serves a similar function as an aggregator, in the sense of providing the owners of residential-scale solar facilities with an outlet for finding buyers and monetizing SRECs, while buyers benefit from being able to purchase a large number of solar RECs in a single transaction.

LIQUIDITY

Volume is the lifeblood of the trading industry. The ability of any one player to succeed depends upon gaining market share. Brokers, aggregators and exchanges must each command a big enough slice of the pie to sustain a business. Naturally, a larger and growing pie would mean more potential business for market participants.

Trading volume is a function of the number of RECs in circulation and how often RECs change hands. On an annual basis, the number of RECs in circulation equals the total megawatt-hours of electricity generated by renewable facilities that meet the standards of the compliance or voluntary markets.

As total generation from renewable facilities increases, the volume of RECs in circulation also rises, with one key caveat. Some RECs may never enter the marketplace under the following circumstances:

- A utility signs a long-term agreement with renewable generators to purchase electricity and RECs. Such an arrangement would provide the utility with a steady supply of RECs at a fixed price and a generator with a guaranteed income stream, but reduce the number of RECs in circulation by an equal amount.
- A vertically-integrated utility builds a renewable facility and uses the RECs to meet RPS obligations, meaning any RECs created would be consumed internally.

The amount of RECs in circulation forms the basis of a spot market. But volume is also a function of how many times RECs are traded back and forth. If a market is “churning,” then trading volume is greater than the number of RECs in circulation.

Which parties are more inclined to churn? Load-serving entities usually buy a REC once and hold it until retirement. But speculators have a profit motive, rather than a natural position, and would be willing to trade regardless of the time of year. They can inject daily trading volume into periods that otherwise would be quiet, as long as one condition is met.

Speculators will only participate in liquid markets. Any market in which finding buyers or sellers is difficult entails too much risk for a speculator to get involved.

In the case of the REC market, speculators have not been active for this very reason. There has not been enough liquidity to instill confidence in the minds of speculators. That illiquidity is a testament to the fact that load-serving entities must retire RECs *only once a year*. Natural buyers can sit on the sidelines until the end of a compliance year, and then purchase whatever is needed.

Consequently, trading tends to be lumpy, with long periods of inactivity punctuated by bursts of activity around the end of a compliance period, or during the grace period, or “true-up” window during which a load-serving entity can purchase any additional RECs it needs. (This true-up phase continues until the deadline for submitting compliance reports, often lasting several months.) This pattern is accentuated in markets where only a few utilities represent the bulk of retail sales and the demand for RECs.

III. MARKET DYNAMICS

First and foremost, supply and demand are functions of RPS rules. Load-serving entities demand RECs in order to comply with a state’s RPS. Supply comes from renewable facilities meeting the eligibility requirements of a particular RPS.

The supply-demand balance can be measured to get a sense for whether the market is tight or not. But first, the appropriate time period must be considered. In wholesale electricity markets, for example, supply and demand must be balanced in real time, and the real-time markets operate based on time intervals as short as every 5 minutes.

The REC market involves a much longer time period. Demand is based upon state RPS requirements, which require a load-serving entity to retire RECs *once a year*. Therefore, supply needs to be calculated on the same annual basis.

Demand is typically expressed as a percentage of annual retail sales, though a few states set a fixed number. Supply equals the number of megawatt-hours generated over a 12-month period from eligible renewable facilities.

We can use a hypothetical example to illustrate this idea. Imagine a state with a 10% RPS requirement in 2010. Annual

retail sales are 50 million MWh, so demand equals 5 million RECs. If the number of eligible RECs is 5.5 million, then the market will have a surplus of half a million RECs. The oversupply should keep REC prices low.

RATIONAL VERSUS IRRATIONAL MARKETS

A helpful framework for analyzing a commodity's price behavior is asking whether a market can be described as *rational* or *irrational*.

In a *rational market*, price equals marginal cost. A shift in the supply or demand curve may push price above or below marginal cost, but that imbalance is only temporary. Supply adjusts to take advantage of profits or avoid losses until once again the market is in a state of equilibrium.

An *irrational market* dissolves that identity between price and marginal cost. In essence, the market exists in a continuous state of disequilibrium because price does not equal marginal cost. The outcome is suboptimal in economic terms because of the loss in benefits to producers and consumers compared to a rational, optimized market.

So which category does the REC market fall under? In a rational market, we would expect to observe REC prices converge around a dollar amount such that the revenue from selling the actual electricity as well as the REC equals the cost of generating a megawatt-hour of electricity from a renewable facility.

However, that is generally not the case. REC prices vary so widely, from about one dollar to several hundred dollars, that it would be difficult to draw any connection between price and marginal cost.

The root cause of the REC market's "irrationality" stems from the unresponsiveness of supply and demand to price. In economic terms, changes in quantity are "inelastic" to changes in price. Graphically, supply and demand curves are each drawn as steep curves showing a unit change in price has little impact on quantity.

Why is the market inelastic in both the short-term and long-term? The element of time is important because of how long it may take consumers and producers to modify their behavior in response to price.

SHORT-TERM PRICES

The short-term is the time period in which buyers and sellers face constraints in terms of their ability to change. Sellers can adjust only the variable factors of production, while buyers may consider substitutes.

In the context of the REC market, we assume capacity is fixed because it typically takes years to build a new project. Operators can ramp existing facilities up or down. But that capability is limited due to the intermittent nature of renewables. It is Mother Nature who dictates output from wind farms and solar arrays.

Short-term demand is also unresponsive to price. The only motivation load-serving entities have for buying RECs is to fulfill a state's RPS requirement. And there are no substitute products, so to speak, to choose from. As a result, REC demand is the same regardless of price.

With supply and demand inelastic to price, the market will find itself in a state of imbalance. The sharply vertical supply and demand curves do not intersect. Theoretically, REC prices would be expected to either fall close to zero or rise to infinity.

In practice, caveats make this analysis more complex. In the event a market is under-supplied, the willingness to pay is capped by the alternative compliance payment (ACP). The ACP is the penalty fee that a load-serving entity must pay for failing to purchase enough RECs during a year. RPS rules state the actual dollar amount

The ACP works as follows. Let's say a load-serving entity has an RPS obligation of 200,000 RECs, but only manages to buy 150,000 RECs. If the ACP is \$40, then the firm would face a penalty of \$2 million (150,000 * \$40). In this example, a load-serving entity would pay as much as \$40 in the open market.

On the other side of the spectrum, prices drop close to zero when RECs outnumber demand. But prices find support around the cost of the transaction fees, which is about one dollar. Sellers would not be willing to sell a REC for a price below the costs of the transaction.

Another wrinkle further confounds price behavior. Some states extend the life of a REC, meaning compliance entities can use that REC in the same year it was generated, as well as future compliance periods – typically the next two years. This concept is known as "banking."

Banking changes the calculation of supply and demand. Supply includes any surplus RECs carried forward from the last two years. Demand becomes a projection of the number of RECs needed for the present year, as well as the next two years.

Even though a market might be over-supplied, if a load-serving entity projects a shortage in the next year or two, then it would make sense to purchase additional RECs, which can be banked for future compliance periods.

As more buyers make the same calculation, aggregate demand will rise, causing the range of bids and offers to also rise. Sellers,

responding to greater demand, are no longer willing to sell RECs at the price of the transaction costs, while buyers are willing to pay more than the transaction cost, but not as much as the ACP.

LONG-TERM PRICES

Quantity is inelastic to price in the short run, but what happens over the course of several years? Do buyers and sellers adjust?

With respect to demand, the most important determinant remains the RPS requirement. Load-serving entities must purchase RECs in accordance with annual benchmarks, implying demand is still inelastic to price.

The only variability in demand may be due to a change in retail load. Retail load is strongly correlated with GDP. So a significant discrepancy between actual and forecasted economic growth would impact REC demand.

Long-term supply is a different story. Supply reflects the total installed capacity of eligible renewable facilities. Developers will eventually build new facilities, thus boosting the REC supply if the project is economically feasible.

How important REC prices are to that overall decision varies. A REC product trading for a few dollars wouldn't spur development. But if that same figure were several hundred dollars, then new supply would be expected to come online.

The clearest example to illustrate this point would be SRECs, which are the most expensive category of RECs and play a big role in spurring new projects.

Even when REC prices alone are not high enough, other factors may justify the development of new projects. Production tax credits improve the bottom line for capital-intensive projects. And if a developer can sign a PPA with a utility, the long-term stability in revenue from electricity and RECs would certainly help secure financing.

The addition of new renewable facilities closes the gap between supply and demand. Ideally, supply would increase incrementally to match demand. But evidence suggests that is not the case.

In numerous states there is track record of capacity swinging up dramatically and outpacing demand. This famine-to-feast phenomenon, especially if new large-scale wind farms get built, sends REC prices plummeting. Developers eventually respond to that price signal by halting construction, but the market remains over-supplied until demand catches up.

RPS DESIGN

Although long-term supply may change if economic conditions are either favorable to expansion or turn so negative as to force

closures, the most important factor behind supply and demand is the RPS design.

To a large extent, therefore, RPS designers influence how much a REC will be worth. That decision must try to balance the costs and benefits. The costs involve the amount of money load-serving entities spend to purchase RECs, which are ultimately passed on to retail customers.

The benefits accrue to the owners of eligible renewable facilities, who earn a new source of income from selling the "environmental attributes" associated with the underlying electricity. Support for the renewable energy industry, advocates say, also spurs green jobs and reduces greenhouse gases.

A state would need to decide where on this cost-benefit continuum it lies. Some states have little appetite for passing a RPS that would raise electricity rates by much, while others may feel the benefits outweigh the costs.

RPS rules can be adjusted to achieve the desired outcome. For illustrative purposes, the table below identifies the handful of issues with the biggest impact on supply and demand and prescribes the general intuition behind a policy yielding a "low cost" or "high cost" REC product.

ELEMENT	LOW COST	HIGH COST
Annual Requirements (Percentage of retail sales or fixed MWh)	Requirements start small and never ramp up	Requirements scale up to high amounts
Geography	Eligible projects located in many states	Eligible projects located in few states, or in-state only
Technology	Include broad array of renewable technologies	Exclude more controversial technologies
Technology Carve-out	None	Yes
Online Date	Push back online date to include older, existing facilities	Set online date to only a few years ago, excluding many existing projects
ACP	Low penalty fee	High penalty fee

IV. CASE STUDIES

This section examines the performance of different REC markets. We have selected four states and regions: New England, the PJM Interconnection, Texas and California, encompassing almost the entire universe of active REC markets.

A. New England

New England states were among the first in the country to implement mandatory RPS rules, beginning in the late 1990s. That decision coincided with a move toward electricity restructuring. New England became dotted with a large number of independent generators and retail suppliers, which combined with RPS requirements, created a relatively liquid REC market.

Initially, most renewable facilities were small and medium-sized facilities generating power from hydro, biomass and landfill gas. Population density, "not-in-my-backyard" attitudes and generally difficult financing conditions prevented the construction of large wind farms in New England states.

Limited supply and high demand targets led to robust REC prices, especially in Massachusetts and Connecticut, hovering near the ACP.

A turning point came with the buildup of utility-scale wind farms in New York and eastern Canada. The amount of renewable generation on New England's doorstep suddenly skyrocketed, with deep implications for the REC market.

Hundreds of megawatts of new capacity came online. Supply soon outstripped demand, causing REC prices to fall.

The additional wind generation had another effect. It caused top-tier New England REC prices to begin converging. Previously, the market had been fragmented, with Massachusetts Class I and Connecticut Class I trading at a significant premium over other New England RECs.

These new wind projects coming online met the RPS eligibility terms in Connecticut, Massachusetts, Rhode Island, New Hampshire and Maine. Arbitrage opportunities narrowed the spread, and today, New England now resembles one regional market.

Despite the influx of new wind generation, additional capacity is still needed to meet New England's cumulative REC demand going out to 2020. Otherwise, the supply-demand balance will flip back within the next few years. A rebound seen in New England REC prices in mid-2011 reflects the belief that demand will eventually outstrip supply once again, although that outcome is far from certain. The future of supply and demand entails several uncertainties. Onshore and offshore wind projects located in New England are in the pipeline, and would significantly boost renewable capacity, but must overcome permitting and financing hurdles.

Another factor affecting supply subject to change is RPS eligibility terms. Biomass is one topic drawing much scrutiny. In 2011, Massachusetts proposed tightening its eligibility rules following the release of a state-funded study critical of

greenhouse gas emissions from biomass power plants.¹⁰ Other New England states could follow suit.

The possibility of states loosening RPS eligibility rules with respect to hydroelectric projects also looms over the New England market. Currently, most New England states exclude large-scale hydroelectric from their RPSs on the basis that these projects are self-sufficient without earning REC revenue.

That position is coming under pressure from the owner of a huge source of renewable energy to the north, Canadian hydropower. Hydro-Quebec is urging New England states to adjust their RPS guidelines permitting large-scale hydro. Consenting to that request would significantly help states meet RPS targets, but crush REC prices and hurt the local renewable industry.

B. PJM

About one-half of the members of the PJM Interconnection have active REC markets. These states (Ohio, Pennsylvania, New Jersey, Delaware, Maryland and the District of Columbia) have both RPS requirements and restructured electricity markets.

PJM states adopted RPSs a bit later than New England, beginning in the mid-2000s, but a similar narrative has unfolded there. Lacking indigenous wind resources, PJM states initially relied upon smaller facilities generating electricity from landfill gas and waste-to-energy. But supply was not enough to keep pace with demand, causing a rise in REC prices.

Like New England, supply got a huge boost from new wind farms. In the PJM region, wind farms were built in Illinois, Indiana, Pennsylvania and West Virginia.

Because most top tier RPSs allowed wind projects to count if they were located anywhere within PJM, REC prices collapsed.

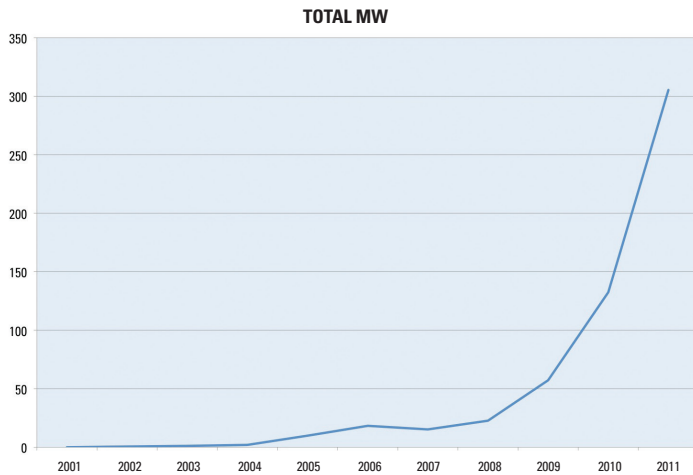
An exception to this rule was in Ohio, where REC prices remained strong because of a stipulation that at least one-half of the RPS must come from in-state facilities. A small pool of Ohio-based renewable generators ensured a strong in-state REC price close to the ACP.

Predictably, a shortage of in-state RECs did not last long. Ohio has seen new renewables come online, mostly wind farms in the northwest corner of the state. There is also a sizeable pipeline of projects under development. The extra supply has pushed down prices for Ohio in-state RECs to a level roughly between zero and the ACP.

The link between geographic eligibility and REC prices is also clearly visible in the track record of PJM SRECs. PJM has been at the forefront of developing SREC markets. In fact, only one state outside of PJM (Massachusetts) has a SREC market.

Solar carve-outs are responsible for capacity growing from practically nothing to hundreds of megawatts in a few years. At the top of this list is New Jersey, which currently ranks second behind California in terms of solar capacity.

New Jersey Solar Installations By Year



The first compliance year of New Jersey’s solar carve-out was 2005. The state used a rebate system before switching to a SREC-based model in 2007.

Source: New Jersey Board of Public Utilities

A major factor explaining the success of New Jersey’s solar carve-out has been the exclusion of out-of-state facilities. Most other PJM states have broader geographic eligibility terms, resulting in lower SREC prices.

For years, New Jersey’s SREC prices remained close to the ACP. It appeared supply could not keep pace with the state’s high targets. But that assumption proved false when in 2011 record-high capacity figures indicated the market would face an oversupply for the first time. New Jersey vintage 2011-12 SREC prices tumbled, causing pressure on state lawmakers to increase solar demand targets.

Indeed, a key question looking ahead will be the degree of backing RPSs receive in statehouses and governor’s mansions, especially in Ohio, Pennsylvania and New Jersey, where the Republican Party support of renewable mandates is lukewarm at best.

C. Texas

Texas, home to enormous wind resources, adopted a mandatory RPS back in 1999. The RPS required 2,000 MW of new renewable capacity by 2009, but that target was subsequently increased several times on account of the huge wind build-out in West Texas and the panhandle.

Texas’ wind capacity surpassed 10,000 MW in 2010, some 15 years earlier than the target date. Each year the number of Texas RECs generated far exceeds the amount required by the RPS. The result has been extremely low REC prices of about a dollar a piece.

The oversupply is so great that more than half of the RECs generated from Texas wind farms are sold into the voluntary market. As a result, there is some price parity between Texas RECs a National Wind voluntary REC.

The example of Texas demonstrates how the *balance* between supply and demand, rather than absolute levels, determines prices. Texas has set high demand targets, but supply has simply been greater.

Developers have been drawn to Texas because of the state’s strong wind resources, its willingness to allow new transmission capacity to be built, and its large open space. Investment has flourished, despite weak REC prices. Unless demand is ratcheted up further, it seems that Texas will remain over-supplied with RECs for years to come.

D. California

California presents a unique case study because it has approached RPS rules in a way that is fundamentally different than other states. The main issue separating California from the rest of the country concerns the deliverability of electricity.

Most states allow RECs to count toward a RPS requirement without any conditions attached to whether the RECs were “bundled” or “unbundled.” After all, the idea behind creating a REC market is having a tradable commodity bought and sold apart from the underlying electricity.

California Renewable Portfolio Standard - Limits By Bucket Type

	Bucket 1	Bucket 2	Bucket 3
Jan 1, 2011- Dec 31, 2013	Min. 50%	Max. 50%	Max. 25%
Jan 1, 2014 - Dec 31, 2016	Min. 65%	Max. 35%	Max. 15%
Jan 1, 2017-	Min. 75%	Max. 25%	Max. 10%

The percentage of RPS-eligible electricity products associated with contracts executed after June 1, 2010 face the above constraints.

California, on the other hand, has been reluctant to allow the unrestricted use of unbundled RECs (“TRECs”). It would appear the desire to demonstrate the tangible procurement of renewable energy has outweighed the benefits of a REC trading system.

California originally passed a RPS in 2002, but debated for years the rules regarding the use of TRECs. It wasn't until January 2011 that the Public Utilities Commission authorized the use of TRECs.

Three months later, Governor Jerry Brown signed into law a bill that raised the RPS from 20% to 33%, extended the compliance requirement to include publicly-owned utilities, and created three categories that renewable transactions can fall under.

One of these categories is for TRECs (known as Bucket 3). However, the 33% RPS statute tightly capped the amount that TRECs can contribute toward a load-serving entity's RPS obligation. Given the limited demand and abundant supply (TRECs can be sourced from an eligible renewable facility located anywhere in the West), most market observers believe TREC values will be low.

The price outlook is more bullish with respect to the other two categories (known as Bucket 1 and Bucket 2) consisting of "bundled" products. The most expensive product is expected to be Bucket 1 since the 33% RPS law assigns the steepest demand and strictest eligibility conditions to that particular bucket.

The latter has been a source of controversy, exposing the long-standing tension at the heart of California's RPS between advocates for in-state versus out-of-state renewables.

Critics contend that the rules are written in such a way to exclude renewable facilities located outside of California from qualifying as Bucket 1. By definition, a renewable facility directly interconnected with a California balancing authority is granted Bucket 1 status. Otherwise, a renewable generator would need

to be able to dynamically transfer electricity to a California balancing authority or demonstrate the electricity was shipped *without* "firming and shaping."

Such deliverability requirements are either technically impossible or uneconomical for out-of-state renewables, critics say. That amounts to a possible violation of the US Constitution's Commerce Clause, some opponents say.

It is too early to know for sure how many, if any, out-of-state renewable facilities end up qualifying as Bucket 1 compared with Bucket 2 (categorized as "firmed and shaped" transactions) or even Bucket 3 ("TRECS").

Interestingly, the drive to qualify out-of-state generators as Bucket 1 resources could have implications for the Western power market. Parties might feel an extra incentive to negotiate dynamic transfer agreements between balancing authorities, a type of arrangement that is currently in its infant stage.

Another possibility is the growth of California balancing authorities. Other balancing authorities could try to link up with the power grid managed by a California balancing authority. This would mean additional renewable facilities meeting the Bucket 1 definition by direct interconnection with a California balancing authority.

Lastly, transmission rights could be a method to demonstrate that electricity from a renewable facility "flows" into California without using substitute energy. Owners of renewable facilities would need to secure transmission paths into California.

¹ A comprehensive source for information on federal, state, local, and utility renewable incentive programs is the Database of State Incentives for Renewables and Efficiency (DSIRE). The DSIRE website is <http://dsireusa.org/>

² States with a mandatory RPS are Arizona, California, Colorado, Connecticut, Delaware, District of Columbia, 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.

³ States with voluntary goals are Indiana, North Carolina, North Dakota, Oklahoma, South Dakota, Utah, Vermont and West Virginia.

⁴ Source: Lawrence Berkeley National Laboratory

⁵ Source: National Renewable Energy Laboratory

⁶ For a spreadsheet showing state-specific RPS guidelines, see <http://dsireusa.org/rpsdata/index.cfm>

⁷ Previously, the Chicago Climate Futures Exchange (CCFE) listed futures contracts for Connecticut Class I, Massachusetts Class I, New Jersey Class I and a Voluntary REC product. In 2010, the IntercontinentalExchange purchased the CCFE, which it closed down in 2012. Existing contracts, including RECs migrated to the ICE OTC platform as physically-delivered, over-the-counter forwards and options.

⁸ Active brokers in this space include BGC Environmental (formerly Cantor CO2e), Clear Energy Brokerage and Consulting, Element Markets, Evolution, ICAP, Karbone, Spectron and TFS.

⁹ Companies providing online auction platforms include the Flett Exchange, Skystream Market and SRECTrade.com.

¹⁰ Massachusetts is expected to finalize its regulations regarding biomass eligibility sometime in 2012.



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