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REDEFINING RECS: ADDITIONALITY IN THE VOLUNTARY RENEWABLE ENERGY CERTIFICATE MARKET

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REDEFINING RECS: ADDITIONALITY IN THE VOLUNTARY RENEWABLE ENERGY CERTIFICATE MARKET

Michael Wayne Gillenwater

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ABSTRACT

In the United States, electricity consumers are told that they can "buy" electricity from renewable energy projects, versus fossil fuel-fired facilities, through participation in a voluntary green power program. The marketing messages communicate to consumers that their participation and premium payments for a green label will cause additional renewable energy generation and thereby allow them to claim they consume electricity that is absent pollution as well as reduce pollutant emissions. Renewable Energy Certificates (RECs) and wind energy are the basis for the majority of the voluntary green power market in the United States. This dissertation addresses the question: Do project developers respond to the voluntary REC market in the United States by altering their decisions to invest in wind turbines? This question is investigated by modeling and probabilistically quantifying the effect of the voluntary REC market on a representative wind power investor in the United States using data from formal expert elicitations of active participants in the industry. It is further explored by comparing the distribution of a sample of wind power projects supplying the voluntary green power market in the United States against an economic viability model that incorporates geographic factors. This dissertation contributes the first quantitative analysis of the effect of the voluntary REC market on project investment. It is found that 1) RECs should be not treated as equivalent to emission offset credits, 2) there is no clearly credible role for voluntary market RECs in emissions trading markets without dramatic restructuring of one or both markets and the environmental commodities they trade, and 3) the use of RECs in entity-level GHG emissions accounting (i.e., "carbon footprinting") leads to double counting of emissions and therefore is not justified. The impotence of the voluntary REC market was, at least in part, due to the small magnitude of the REC price signal and lack of long-term contracts that would reduce the risk of relying on

revenue the voluntary green power market. Although no simple solutions are identified, a proposal for integrating RECs into a load based cap-and-trade system is presented.

Keywords: Renewable Energy Certificate (REC); Renewable Portfolio Standard (RPS); emission offset; additionality; attributes

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This research effort originated with a nagging sense that something was wrong with voluntary green power markets without a clear sense of what it was. At that time, which was almost a decade ago, I was employed with one of the leading nonprofit organizations promoting environmental markets, including the certification and trading of Renewable Energy Certificates (RECs). Even then, a few gadflies were beginning to question the role of RECs in environmental markets, but without a rigorous analysis or argument, and so they were largely ignored.

Almost 20 years after the birth of the voluntary REC market, we are still dealing with the legacy of a poorly defined and constructed tradable environmental commodity. I hope that this research will not only lead to much-needed reform in voluntary green power markets, but also serve as an instructive case study to help future policy makers avoid the mistakes made in the voluntary REC market. Over this decade, I am enormously grateful to the dozens of colleagues from around the world who discussed and debated this issue with me. This process has been instrumental in advancing my understanding of environmental markets.

Without question, the one person deserving the most appreciation at the completion of this dissertation journey, though, is my wife, Bindiya. At 42 years old, I am not exactly a young student. During this journey we have had two children (Keya and Cimeren), faced a personal year and a half long health crisis, changed jobs, moved several times, closed one organization, founded another, and went for long periods with only one full income. Though at multiple times I was ready to give up in frustration, Bindiya not only gave essential encouragement and substantive support by allowing me to take time from her and our family, but actively became

my work planning guidance counselor at critical points. Without a doubt, absent her, this dissertation would not exist (i.e., she was additional!).

My parents will be happy to hear that this the last degree program they will have to watch me struggle through. I want to thank them for a lifetime of support and love.

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ABBREVIATIONS AND ACRONYMS

ACORE	American Council on Renewable Energy
BAU	Business As Usual
CDM	Clean Development Mechanism
CDP	Carbon Disclosure Project
CER	Certified Emission Reduction
CO_2	Carbon Dioxide
C-REC	Compliance Renewable Energy Certificate
CRS	Center for Resource Solutions
EMA	Environmental Markets Association
EU-ETS	European Union Emissions Trading System
FTC	Federal Trade Commission
GE	General Electric
GEAC	Generation Emission Attribute Certificate
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
IRR	Internal Rate of Return
LB	Load Based
LSE	Load Serving Entity
NERC	National Electric Reliability Council
NGO	Non-governmental Organization
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxides
NPV	Net Present Value
NR	No Response
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PDF	Probability Distribution Function
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
REC	Renewable Energy Certificate
RE-OC	Renewable Energy Offset Credit
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SB	Source Based
SO_2	Sulfur Dioxide
SREC	Solar Renewable Energy Certificate
UNFCCC	United Nations Framework Convention on Climate Change
USEPA	United States Environmental Protection Agency
VER	Voluntary Emission Reduction
V-REC	Voluntary Renewable Energy Certificate

WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Chapter 1. Introduction

With the rise of the environmental degradation, and specifically climate change, as an issue of concern, over the last two decades, proponents of renewable energy have sought ways of allowing and encouraging consumers—both residential and commercial—to "purchase" their electricity from renewable energy sources rather than from sources using fossil fuel combustion. This desire grew along with the rise of corporate "carbon footprinting"[1] and sustainability reporting, which produced a consensus that consumers should take some responsibility for the indirect emissions associated with their electricity purchases (WRI/WBCSD 2004). The challenge has been that electricity is not like most other goods or services, in that it is delivered to a collective transmission and distribution grid from which all consumers draw from and is produced and consumed simultaneously (i.e., it is not stored in any significant quantity). In an attempt to overcome these challenges, new tradable environmental commodity markets have developed over the last twenty years that have advertised a range of environmental benefit claims to customers.

In the United States, electricity consumers are told by actors in the voluntary green power market that they can "buy" electricity from renewable energy projects, versus fossil fuel-fired facilities, through participation in a voluntary green power program.[2] The marketing messages communicate to consumers that their participation and premium payments for a green label will cause additional renewable energy generation and thereby reduce pollutant emissions to the atmosphere and allow them to claim they consume electricity that is absent pollution. The retailers that operate in this voluntary green power market typically purchase Renewable Energy

[1] A carbon footprint is the colloquial term for an accounting of greenhouse gas emissions and removals for an entity (e.g., person or corporation), event, or product. The focus for this dissertation is on entity-level GHG accounting.
[2] For example, see the U.S. Environmental Protection Agency's Green Power Partnership at http://www.epa.gov/greenpower/index.htm.

Certificates (RECs) from renewable energy project developers to resell to their customers. Despite the marketing promises and claims, it has not been well established what impact this voluntary environmental market has on emissions or renewable energy generation.

While environmental markets were originally conceived as being a government regulatory tool (Montgomery 1972), voluntary environmental markets have also developed. These markets are driven by the aggregate preferences of many consumers to take actions and engage in transactions that produce public goods (Andreoni 1990). The green power market is one of these voluntary environmental markets that developed in the 1990s during a period of growing acceptance of tradable environmental commodities. RECs were specifically conceptualized as a tool for government-imposed Renewable Portfolio Standards (RPSs),[3] yet were quickly adopted by environmental non-profit organizations and environmentally conscious corporations as the financial instrument upon which regional, and then national, voluntary green power market was largely developed.

A REC is created when one (net) megawatt hour of electricity is generated from an eligible renewable energy resource. RECs are intended to provide an economic incentive to investors to increase the amount of electricity generated from renewable energy sources. RECs were unbundled from commodity electricity, thereby allowing them to be sold separately from the underlying electricity generated. The result was that a REC can be purchased and "used" by a consumer who may or may not have any physical connection, via the electrical grid, to the renewable energy generator that initially issued the REC.

The voluntary green power market in the United States, like most voluntary environmental markets, has gone largely unregulated. It has instead been shaped by the interests of various

[3] A RPS is a regulation that requires utilities that supply customers with electricity to procure a minimum amount of that electricity from qualified renewable energy sources. These types of regulations are also referred to as Renewable Electricity Standard (RES) or Renewables Obligation.

stakeholder organizations, most of which have been focused on promoting market growth. However, a debate has slowly emerged within the broader environmental markets and renewable energy communities regarding:

1. the proper definition of a REC when used in voluntary green power markets,
2. whether RECs should be treated as equivalent to emission offset credits,
3. the broader role of RECs in emissions trading markets, and
4. the role of RECs in entity-level greenhouse gas (GHG) emissions accounting (i.e., "carbon footprinting").

To answer these questions, it is essential to establish the voluntary REC market's ability to increase the amount of electricity generated from renewable energy sources. In other words, does the U.S. voluntary green power market make a difference, environmentally speaking? This dissertation focuses primarily on this more fundamental question: Do project developers respond to the voluntary REC market in the United States by altering their decisions to invest in wind turbines? This dissertation narrowly focuses wind power projects because wind energy supplies the vast majority of RECs to the voluntary green power market in the United States (Bird and Sumner 2010).

The hypothesis investigated is that the voluntary REC market in the United States has, at most, a small marginal effect on the generation of electricity from renewable energy sources. The hypothesis is tested by modeling and probabilistically quantifying the effect of the voluntary REC market on a representative wind power investor in the United States using data from formal expert elicitations of active participants in the industry. It is further explored by comparing the distribution of a sample of wind power projects supplying the voluntary green power market in the United States against an economic viability model that incorporates geographic factors such

as the location of physical wind resources and transmission lines. Overall, this dissertation contributes the first quantitative analysis of the effect of the voluntary REC market on project investment. Further, the resulting research findings have decisive implications for each of the four debated issues above.

My central finding is that the voluntary REC market in the United States does not increase the quantity of investment in or generation from grid-connected wind projects, except in a few special cases. This is likely due to the small magnitude of the REC price signal and lack of long-term contracts for unbundled RECs. The implication of this finding is that RECs are defined in a way that is not substantiated by the actual environmental benefits associated with them as an environmental commodity. And therefore, the claims made by those selling and procuring RECs are in need of significant revision. I speculate that the historical root of this problem is that RECs have been defined ambiguously while being used for multiple applications in multiple markets. Each of these applications entails specific environmental benefit claims and conflicting requirements for a single environmental commodity. Carefully addressing these conflicts is essential given the interactions between renewable and emission markets, as well as GHG emissions accounting frameworks.

An alternative hypothesis is offered and promoted by some leading green power market advocacy organizations (CRS 2007; Harmon 2009) and numerous green power marketing firms.[4] They have argued that by purchasing and retiring RECs, consumers are effectively buying "green power" and are reducing their emissions due to the avoidance of fossil fuel generation. Their position, along with their prominent role in the industry, has resulted in the common practice for REC consumers to make emission reduction claims on the basis that one REC has avoided the emissions from the generation of one MWh of electricity from the average mix of generators on

[4] For a detailed list of firms, see http://apps3.eere.energy.gov/greenpower/markets/marketing.shtml?page=2

the grid, which is dominated by fossil fuel sources in most regions. Further, it has led to the practice by some green power market firms and other organizations to resell RECs as GHG emissions offset credits in the voluntary carbon market.

A more recent and nuanced argument is that if RECs are not equivalent to emission offset credits then they should, nonetheless, be used as the basis for calculating an entity's Scope 2 emissions within their GHG emissions inventory (Trexler 2009; USDOE 2010; Bird and Sumner 2011).[5] The foundation of this argument is the assumption that purchasing a REC is equivalent to purchasing 1 MWh of electricity from a renewable source and that the accounting framework for Scope 2 emissions is sensitive to these individual "purchases."

After investigating the research question above, presenting results, offering conclusions, and discussing the implications for the four issues above, I then offer specific proposals for how RECs can be re-defined and integrated into an emissions cap-and-trade system so as to serve as a more useful policy tool for both voluntary and compliance environmental markets.

1.1 Summary of Chapters

This dissertation examines the voluntary REC market in the United States with the purpose of understanding how its actual environmental impacts correspond to the benefit claims made by those actively promoting and participating in the green power market. At the core of these claims is an assumption among its participants that the voluntary green power market leads to more renewable energy investment and generation than would exist in the absence of this market activity. In environmental markets, the assumption that an intervention of some type, such as a program or policy that offers an incremental source of revenue in the form of an environmental commodity, will “cause” a public good to be produced is referred to as "additionality."

[5] Scope 2 emissions are a "reporting organization’s emissions associated with the generation of electricity, heating/ cooling, or steam purchased for own consumption." See the GHG Protocol for a more thorough discussion of accounting scopes (WRI/WBCSD 2004).

Why should we care about additionality with respect to the voluntary REC market (or more precisely, activities that RECs are sold from)? An environmental market that ignores additionality at both a single activity level as well as a system-wide level will be flooded by a supply of tradable instruments associated with no public good benefits, thereby overwhelming demand and pushing prices down to zero. The feedback effect is then to reduce or eliminate the incentive the environmental market was originally intended to create.

I examine the research question using two quantitative modeling approaches, presented in two chapters. These chapters are preceded by a presentation of historical background and literature review (Chapter 2), followed by an investigation of relevant concepts and terms associated with tradable environmental commodities in general and REC markets specifically (Chapters 3 and 4).

The first modeling chapter uses data from formally elicited expert judgments and a set of hypothetical project investment scenarios (Chapter 5). It concludes that it is highly improbable that the voluntary REC market has led to additional investment in wind turbines in the United States, thereby confirming my hypothesis. The second approach uses a large sample of actual voluntary green power projects in the United States and models the influence of the voluntary REC market on their financial viability (Chapter 6). Similarly, it concludes that the voluntary REC market had little influence on the viability of these projects.

The two modeling chapters are followed by a discussion of broader policy implications (Chapter 7), focusing first on a claim related to emission offsetting: that purchasing a REC is equivalent to consuming electricity without causing any emissions. I then look at proposals by REC market advocates to integrate RECs into emissions cap and trade markets and follows this with an examination of an alternative approach to structuring the voluntary REC market and

defining RECs to address the problems identified in earlier chapters. Chapter 8 then elaborates on a specific policy proposal formulated by this author and a colleague for how the voluntary REC market could be restructured and integrated with a load-based emissions cap and trade system for the electric power sector that would avoid these problems with additionality and allocation of indirect emissions from purchased electricity.

In sum, I find no clear environmental benefit resulting from the voluntary REC market for wind power in the United States, which is the basis for the bulk of the U.S. voluntary green power market. RECs are found to not be equivalent to an offset credit. They instead function as a simple production subsidy for renewable energy generators, but one that is insufficient to even have a marginal impact on wind power investment. I speculate that the long-standing confusion within voluntary green power market with respect to additionality and what can be legitimately claimed by those purchasing RECS has been enabled by imprecise definitions both within green power and emissions markets concerning RECs, attributes, and additionality. Unfortunately, upon investigation there does not appear to be any simple change to the design of the voluntary REC market that would effectively solve these problems absent the imposition of government regulations (see Chapter 8 for such an example). Alternatives to achieve additional renewable energy investment and avoid the problems of the voluntary green power market include the voluntary carbon offset market, the imposition of a national RPS, and/or the proposal offered in Chapter 8, which integrates RECs into an emissions cap-and-trade system.

My conclusions are qualified because this analysis looked only at wind power in the United States. These conclusions may not fully apply to RECs associated with solar energy, although solar energy accounts for an extremely small portion of the voluntary green power market.

The following sections concise summaries of each chapter of this dissertation.

1.1.1 Chapter 2 Summary: Background and literature review

This chapter first summarizes the history of the voluntary REC market, explaining how it emerged from the debates over renewable energy policy at the state and Federal level in the United States. It is important to note that only about 1.25 percent of U.S. electricity customers participate in voluntary green power markets. Many of these participants are large commercial consumers of electricity, and while growing rapidly, their participation is associated with only about 1 percent of electricity sales. Importantly, participants view their purchases of RECs as a part of their contribution to mitigating GHG emissions. Therefore, voluntary REC markets are likely function as a substitute for other potentially environmentally beneficial activity such as onsite energy conservation.

Chapter 2 demonstrates the policy relevance of the research question as one that is actively of concern by the Federal Trade Commission; the leading corporate GHG emissions accounting standard setting organizations (e.g., the GHG Protocol Initiative and The Climate Registry); the U.S. Environmental Protection Agency; the government of the United Kingdom; as well as individuals, companies, and other organizations around the world interested in accounting for their entity-level GHG emissions.

Following the presentation of historical context, I present a framework for understanding different types of tradable environmental commodities. Proponents of RECs make claims that RECs function in a way that mimics quota, offset credit, and tracking/allocation tradable environmental commodity instruments. I then survey the existing definitions of RECs found in standards and legislation and show that definitions of RECs across markets are currently ambiguous and argue that this condition prevents them from functioning as homogeneous environmental commodity.

Lastly, a literature review is presented that first notes the series of publications from this author that this dissertation is built upon and then surveys other publications on the topic of voluntary REC markets. There have been a number of publications that offer a variety of positions and arguments with respect to the influence and voluntary REC markets as well as the definition of what a REC represents, yet, to date, none have provided a thorough or quantitative analysis of the question.

1.1.2 Chapter 3 Summary: What is additionality?

This chapter looks in detail at what we mean by "additionality" in the context of environmental markets. Precisely defining additionality is a key first step to analyzing the research question posed by this dissertation, as it is the concept embedded in emission markets as the central criterion to defining and emission offset. Therefore, claims made within the voluntary REC market that their environmental commodity is equivalent to an emission reduction offset credit are necessarily made with respect to a claim of additionality.

This chapter first discusses the purpose of additionality and the challenges in its application. It then provides brief historical and literature reviews of the concept, focusing on the problems with the existing definitions and language. It shows that many current emission offset standards and programs are based upon definitions of additionality and baseline that are circular and that the existing literature and standards for additionality and baselines commonly fails to clearly and consistently define the policy intervention created and recognized by offset programs. I later speculate that this confusion has facilitated the ability of those in voluntary green power markets to make claims with respect to emission reductions and thereby establish in the minds of REC buyers their equivalence to offset credits.

I propose definitions of additionality and baseline that are intended to be generally applicable to environmental commodity markets and that avoid the problems with existing definitions.

1.1.3 Chapter 4 Summary: Additionality and RECs

This chapter examines how the concept of additionality is currently applied in voluntary REC markets. I discuss the economics of renewable energy investment and generation and situate the voluntary REC market in this context, showing that additionality is solely determined by how decisions by investors are altered.

Within voluntary markets, additionality is a mechanism of constraining supply of environmental commodities so that they can credibility represent a unit amount of environmental public good benefits. If renewable energy projects that sell RECs into voluntary markets are not additional, then they can, at best, be expected to have a marginal effect that is less than the total number of RECs sold. Therefore, unless the process for assessing additionality in voluntary REC markets adequately screens out most free-rider projects, it is inaccurate to assume that all RECs sold in the voluntary market represent additional megawatt-hours of renewable energy generation simply because there appears to be a market demand effect on the margin.

This chapter then briefly introduces issues with how voluntary and compliance REC markets interact, which will be relevant for the discussion in Chapter 7.

1.1.4 Chapter 5 Summary: Probabilistic decision model of wind power investment

This chapter is the first of two that presents the results of quantitative modeling studies. It focuses on wind power, which represents the majority of the voluntary green power market in the United States (over 80%). The study quantifies the value of and uncertainty in key parameters affecting investment decisions in the wind power industry when those investments are made to

supply the voluntary green power market in the United States. It uses a formal expert elicitation protocol to collect input data in the form of probability distribution functions, for use in a financial-based Monte Carlo model of a typical U.S. wind power project investment. A key objective of this chapter is to understand investor expectations, especially for price variables, and the threshold for project investment. Data of this type were not available from other sources. The results presented are the first quantitative estimates of the effect of the U.S. voluntary REC market on wind power investment.

The results of this chapter indicate that the investment decisions of wind power project developers in the United States are unlikely to have been influenced by the voluntary REC market. The problem with the current voluntary REC market is that it does not offer developers a significant risk-adjusted revenue stream. Consequently, direct or indirect claims that voluntary market RECs are issued from wind power projects that are additional lack credibility.

For the voluntary REC markets to drive investment in wind power generation and produce additional emission reductions, the market will need to foster both higher prices and a standard of long-term purchase contracts. Yet, absent a dramatic change in consumers' willingness to pay, it is not clear this is feasible. Assuming it is allowed in RPS legislation and the compliance REC market that is not long (i.e., RPS quota is binding), then allowing consumers to purchase and retire compliance RECs, thereby forcing utilities to find additional supply of RECs, could replace the existing voluntary REC market and be a credible solution.

Although customers are told by green power marketing firms that they are buying a product (i.e., "green electricity" or "green power"), RECs were not found to actually convey a tangible private service or good to the customer. So even in situations where RECs remain bundled with the sale of electricity, there is no tangible differentiation in product quality relative to electricity

unbundled with RECs. Like many other voluntary environmental markets, there are challenges in converting what is inherently a public good into a private good. As currently structured, the voluntary REC market in the United States may be better described as an effort to commoditize charity than a market for the sale of a green product.

1.1.5 Chapter 6 Summary: Additionality of wind energy investments in the U.S. voluntary green power market

The vast majority of the U.S. voluntary green power market is based upon wind power projects. Once built, wind energy facilities can be operated with very low variable costs, and so any influence the voluntary green power market has on the amount of electricity produced from wind (as well as other most other renewable energy technologies) must be in the form of additional generation capacity from either new construction or repowering of existing facilities. If voluntary green power markets do not lead to additional investment then consumers who pay a premium to participate in these markets and retailers who promote the purchase of RECs are being mislead and misleading, respectively.

This chapter explores the influence of the voluntary REC market on wind energy project finance using a dataset of projects registered with the Green-e program. In 2010, Green-e certified generation accounted for 65 percent of the U.S. voluntary green power market, and the vast majority of Green-e registered generation capacity is wind power. More specifically, this chapter examines the economic feasibility of these Green-e registered wind power projects under scenarios that include and exclude the economic incentive provided by the voluntary green power market. It uses a spatial financial model that incorporates geographic factors such as wind resource availability and the costs of grid connection at each project site. It explores three key regional factors not addressed in Chapter 5: local variation in the wind resource (i.e., capacity

factor), local variation in wholesale electricity prices, and the influence of REC demand from state-level RPS compliance markets.

The analysis in this chapter showed that the voluntary REC market has a negligible influence on the economic feasibility or wind power projects. Nevertheless, voluntary green power marketers at least implicitly claim that buying their products creates additional renewable energy. This study seems to indicate the contrary. Therefore, in the United States consumers appear to be receiving misleading marketing messages regarding the effect of their participation in voluntary green power markets that rely on RECs as a tradable environmental commodity.

Another key finding of this chapter is the overlap between voluntary REC markets and compliance REC markets that supply utilities to meet their RPS obligations. The majority of state RPS rules in the United States allow for regional or even national sourcing of RECs. The broad eligibility of wind power projects across several states allow them to sell into multiple compliance markets. As a result, wind power project investors appear to be using the voluntary REC market as a backstop for RECs in excess of demand associated with RPS compliance.

1.1.6 Chapter 7 Summary: Policy implications

This chapter examines whether the claim made by organizations and individuals with respect to their participation in voluntary green markets are justified. Previous chapters focused on the relationship between RECs and GHG emission offset credits and concluded that voluntary REC programs in the United States are unlikely to lead to additional renewable energy investments or generation relative to a baseline condition where these voluntary programs did not exist. Therefore, claims that RECs can be treated as equivalent to emission offset credits are not supported by evidence.

This chapter extends the previous analysis by looking at select policy implications for other related claims made by voluntary green power program participants related to entity-level GHG emissions inventories (i.e., "carbon footprints") and for the integration of RECs with regulatory emissions trading markets. Specifically, this chapter examines the following issues:

- the relationship between REC markets and emissions trading markets, and
- the role of RECs in entity-level greenhouse gas (GHG) emissions accounting (i.e., "carbon footprinting").

This chapter expands on the issues of "attribute" ownership introduced in Chapter 4 and explains why even if additionality issues with RECs are addressed, that there is still a problem with the double counting of emissions embedded in the internationally accepted entity-level accounting framework for indirect GHG emissions from electricity purchases. It then discusses the current problems with integrating RECs into emission trading markets and presents an option for redefining what a REC is in an attempt to solve some of these problems. It finally argues that even new REC definitions do not result in environmental commodities that are superior to existing alternatives, such as GHG emission offset credits from renewable energy projects.

1.1.7 Chapter 8 Summary: Integrating certificates with emissions cap-and-trade

This chapter elaborates in detail an approach for a comprehensive overhaul of REC markets (compliance and voluntary) that does address the problems identified in earlier chapters. This approach involves the use of unbundled Generation Emission Attribute Certificates (GEACs), of which RECs would be one type, that are used in the implementation of an emissions cap and trade system for the electric power sector. The caveat with this approach is that it increases the complexity of emissions trading systems by adding a new tradable commodity and therefore involves some added uncertainty in the broader price dynamics of competitive wholesale

electricity markets. The proposed approach is built upon a load-based emissions cap and trade system for the electric power sector that provides a mechanism to internalize an emissions price signal at the generator dispatch level and addresses some limitations in alternative source-based cap and trade and contract path load-based systems.

1.1.8 Chapter 9: Conclusions

This chapter final chapter summarizes conclusions and discusses potential topics for further research.

Chapter 2. Background and literature review

Both compliance and voluntary green power markets use RECs. In the United States, these compliance markets have been established to support state Renewable Portfolio Standard (RPS) policies and would likely be the basis for a future federal RPS (referred to as a Renewable Energy Standard, or RES, in some Congressional bills). Several states allow or require load-serving entities (LSEs)[6] to use tradable RECs to meet a quota for the amount of their delivered electrical load (or capacity as in the case of Texas) that must be met by electricity generated from qualifying renewable energy sources. Both voluntary "green power" markets—which provide retail customers the choice to pay a premium to LSEs or electricity generators using renewable resources—and voluntary GHG offset markets also trade in RECs.[7]

In 2010, 1.8 million residential and non-residential customers in the United States participated in some form of voluntary green power market (approximately 1.25 percent of all U.S. electricity customers). This participation was associated with more than 35 million MWh (almost 1% of total U.S. retail electricity sales), and has grown at a compound annual growth rate of 31% since 2006. The majority participants purchased RECs that were unbundled from contracts for the supply of electricity, with the remainder consisting of utility green pricing programs and competitive (restructured) electricity markets where consumers can directly contract with generators.[8] Wind energy supplied that vast majority of green power markets in 2010 (83.1%) (Heeter and Bird 2011).

[6] A load-serving entity provides the electrical demand and energy requirements of its customers (e.g., an electrical distribution utility).
[7] RECs may also be used by LSEs to track their generation mix for public disclosure purposes on retail electricity bills (Holt and Bird 2005).
[8] Even under these other types of sales, RECs are often involved for tracking purposes while being sold as bundled with the electricity.

The National Renewable Energy Laboratory (NREL) estimated the 2010 value of these markets (i.e., the incremental cost of green power products like RECs beyond the value of the electric power) in the United States was between $168 million and $285 million (0.05 to 0.08 percent of total U.S. electricity market). Roughly three-quarters of these sales were to non-residential customers (e.g., industrial and commercial) (Heeter and Bird 2011). Dozens of companies market unbundled RECs directly to residential, commercial, and industrial customers in the United States.[9]

The voluntary greenhouse gas (GHG) emission offset market was estimated to be valued at $424 million in 2010 (Peters-Stanley, Hamilton et al. 2011). More than twenty-five companies offer GHG emission offset products in the United States, some of which are derived from RECs and/or renewable energy generation projects (Heeter and Bird 2011).

Like any market, the voluntary REC market includes a number of actors along a value chain. The primary actors include:

- renewable energy project developers and investors who sell RECs for an extra revenue stream ,
- voluntary REC project certification organizations that set standards for projects to be eligible to sell RECs into the voluntary green power market and give guidance on what claims can be associated with them,
- REC brokers who connect buyers and sellers and facilitate transactions and contracts,
- REC retailers who purchase RECs directly from project developers or brokers and then resell them at a markup to individual customers, and

[9] See U.S. DOE's Green Power Network at website: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=2

- individual and corporate buyers of RECs who voluntarily purchase RECs with the expectation of making some form of "green" claim.

The relationship between RECs and GHG emissions is also relevant to companies that estimate and report their Scope 2 GHG emissions. In 2011, over 3,000 companies—accounting for 81% of the Global 500 and 68% of the S&P 500—responded to the Carbon Disclosure Project's (CDP's) annual climate change questionnaire, which include as its core a GHG emission inventory for their organization.[10] Many of these companies participate in green power markets and make emission reduction or avoidance claims in their CDP and pubic reporting of corporate GHG emissions based on their belief that RECs cause emission reductions and/or transfer the right to claim the consumption of zero emission electricity. More detailed reports are made by many companies to The Climate Registry[11] in North America and similar organizations in other countries.

The four issues listed in chapter 1 have been and continue to be debated by government agencies, non-profits organizations, and the media. In October 2010, the Federal Trade Commission (FTC) proposed revisions to its Green Guides, which provide guidance to marketers to help them avoid making misleading environmental claims. An issue of explicit focus for these new Guides is the question of what claims are appropriate with respect to RECs (FTC 2010; Heeter and Bird 2011). This issue has also been recently taken up by the GHG Protocol Initiative, led by the World Resources Institute and World Business Council for Sustainable Development (Blyth 2012).[12] The Climate Registry, the leading voluntary corporate GHG emissions registry in North America, as well as the now terminated U.S. EPA Climate Leaders have both struggled with the relationship between RECs and GHG accounting (USEPA 2007b;

[10] See https://www.cdproject.net/en-US/Programmes/Pages/samples.aspx
[11] See http://theclimateregistry.org
[12] See http://www.ghgprotocol.org/feature/ghg-protocol-power-accounting-guidelines

TCR 2009). In addition to the earlier work of this and other authors (see Literature review below), this attention has been spurred by a series of critical articles by journalists on these issues (Gewin 2005; Elgin 2007; Hickman 2007; CCN 2008; Elgin and Holdren 2008; Rose 2008; Galbraith 2009).

This chapter will first present a review of the historical origins of RECs, followed by a framework for understanding different types of environmental commodities. Based on this framework, the various existing definitions and standards for RECs are summarized and critiqued. And lastly, a literature review related to the relationship between RECs and renewable energy investment is provided.

2.1 Historical background

REC markets have historically developed in two ways that are relevant to this dissertation. First, as will be shown in later chapters, REC products have been ambiguously and inconsistently defined by multiple stakeholders, including state and local governments, public utility commissions, private sector companies, and non-profit organizations that promote voluntary green power markets. These definitions often refer to "attributes" or "benefits", ownership to which is stated to be included in and transferred with a REC. These definitions claim that these attributes or benefits include factors indirectly associated with renewable energy generation. A typical definition of a REC includes language such as “RECs represent all environmental attributes or benefits from electricity generated by renewable sources,” although there is wide variation in the language and specificity of definitions used in both the compliance and voluntary markets (Holt and Wiser 2007; Gillenwater 2008a).[13] Second, RECs have been used for multiple applications, each of which, in theory, should require an environmental commodity with different characteristics.

[13] Also see Appendix A.

RECs were originally proposed during the U.S. electricity restructuring debates of the mid-1990s as a tradable environmental commodity that would be used as a compliance accounting instrument for renewable energy quotas. The concern at the time was that newly competitive electricity markets would drive renewable energy generation out of the market, and so government mandates were needed to create demand for renewable energy due to its higher costs (Rader and Norgaard 1996; UER 1996b; Wingate and Holt 2004; Wood 2007).

Some of the earliest discussion of RECs was in 1995 during the California Public Utilities Commission's debates regarding the adoption of a RPS (Holt and Bird 2005). News articles at the time described RECs as "credits [that] would be tradable like emission allowances under the federal Clean Air Act" (UER 1996c; UER 1996a).

RPS legislation failed to pass in California at that time, but the concept of tradable RECs entered the debates in Congress over the repeal of the Public Utility Holding Company Act (PUHCA) and amendments to the Public Utility Regulatory Policies Act (PURPA). In order to promote renewable energy in a competitive generation market, several bills called for a national RPS that included the use of tradable RECs for determining compliance.[14] Here too, the model for a REC was an emission allowance under the recently implemented sulfur dioxide (SO_2) trading program under Title IV of the 1990 amendments to the Clean Air Act.

Despite the failure of a bill including a national RPS to become law, several states and localities proposed their own RPS legislation that included tradable RECs.[15] In 2001, Texas became the first state to implement an RPS after passing the enabling legislation in 1999 (Sloan

[14] For example, see H.R. 3790 "Electric Consumer's Power to Choose Act of 1996" (Schaefer, CO) in July 1996; as well as S.237 "Electric Consumers' Protection Act of 1997" (Bumpers, AR) and H.R.1960 "To modernize the Public Utility Holding Company Act of 1935, the Federal Power Act, the Fair Packaging and Labeling Act, and the Public Utility Regulatory Policies Act of 1978 to promote competition in the electric power industry, and for other purposes" (Markey, MA) during the 105th Congress.
[15] For example, see (UER 1997)

2001; Holt and Bird 2005).[16] The Texas RPS required LSEs to use tradable RECs purchased from renewable energy generators to track compliance. LSEs submit RECs to regulators in an analogous fashion to how emission allowances were submitted under the Acid Rain Program for determining compliance with a regulatory quota.

Around the same time, RECs were also adopted by some non-governmental organizations (NGOs) in the United States and Europe as the basis for a broader and more liquid voluntary market in green power that would allow generators to engage end-use customers through a tradable instrument (Morthorst 2000; Voogt, Boots et al. 2000; Martinot, Wiser et al. 2005).[17] Voluntary programs and markets emerged to allow electricity consumers enroll in green power pricing programs with their local utility, select a renewable power provider if they were in competitive electricity markets, or directly purchase RECs (Bird and Swezey 2006; Pino 2006).[18] RECs, specifically, became popular with marketers, brokers, corporations and individuals due to their low cost and fungibility.

Although they have been smaller than RPS compliance markets, these voluntary REC markets grew rapidly in the United States and in Europe.[19] By 2005 voluntary purchase of RECs accounted for 46 percent of U.S. consumer green power market participation, which was

[16] Texas was the 6th state to pass RPS legislation, but it was the first state to promulgate and implement rules.
[17] In January 1998 a voluntary renewable energy certificate system called "Green Label" was introduced in the Netherlands. In 2002, the Center for Resource Solutions in San Francisco launched the Green-e certification label for retail renewable energy sales, including RECs.
[18] RECs are often re-bundled by utilities and marketers with wholesale electricity and sold to retail customers as a green power product. When retail consumers purchase RECs directly and then retire them, these customers are effectively re-bundling RECs with their electricity. For a list of green power marketers see http://www.eere.energy.gov/greenpower/markets/marketing.shtml?page=2
[19] In September 2001, the European Commission passed Directive 2001/77/EC, which calls for member states to set quantitative targets for electricity consumed in the country produced from renewable energy sources. A European Energy Certificate System (EECS) is being developed to register and track an environmental commodity called Guarantees of Origin (GoOs), which are replacing RECs in the voluntary green power market in Europe. The voluntary market for green electricity in Europe varies greatly among countries. It is significant in the Netherlands, Germany, and Sweden. /http://europa.eu.int/eur-lex/pri/en/oj/dat/2001/l_283/l_28320011027en00330040.pdf/

dominated by commercial and industrial customers, versus residential customers who are more likely to utilize utility green pricing programs (Bird and Swezey 2006).

With the support of green power market advocates, many of these marketers and consumers immediately began making claims that these REC purchases were offsetting their GHG emissions (Bird, Holt et al. 2007) and that they were "purchasing" electricity from renewable sources rather than a generic mix of generation associated with the consumers' distribution utility. In marketing and promotional materials by stakeholders throughout the green power industry—including government research labs (Bird, Holt et al. 2010), government agencies[20], and environmental organizations—consumers have been told they are reducing GHG emissions because of their REC purchases. Carbon offset retailers have also sold RECs as GHG emission offset credits (i.e., "carbon offsets), arbitraging against the lower prices of the RECs relative to registered carbon offsets in voluntary markets.[21] Their underlying rationale for these claims has been that the generation of electricity by a renewable facility, such as a wind turbine, displaces generation, and therefore emissions, from fossil fuel-fired power plants. And therefore, this displacement could be claimed as an emission reduction. Further, that the purchase of a REC transferred ownership rights to these emission reductions because these rights fell within the scope of a REC's "all environmental attributes" definition.

In sum, RECs were originally conceived as a tracking instrument to be used to meet a regulatory quota, in the form of an RPS.[22] However, RECs are now also traded in multiple voluntary environmental commodity markets, including green power and GHG emission offset markets, as well as being linked with some compliance emissions markets. This change is

[20] See the U.S. EPA's Green Power Partnership: http://www.epa.gov/greenpower/
[21] For example, see Carbon Fund (www.carbonfund.org) and the Bonneville Environmental Foundation (http://www.b-e-f.org).
[22] Unfortunately, the original terminology for a REC in Congressional legislation was “renewable energy credit," which probably fostered confusion with emission offset credits.

important when we consider the definition of RECs in relationship to the claims associated with them in voluntary green power and GHG emission markets.

2.2 Environmental market instruments

Before presenting the analysis of the research question (i.e., do project developers respond to the voluntary REC market in the United States by altering their decisions to invest in wind turbines?), it is valuable to establish a framework of tradable environmental commodity types that are relevant to the electric power industry. Three fundamental types of tradable commodity instruments can operate in compliance and voluntary markets: quota instruments, offset credit instruments, and tracking/allocation instruments. The difference between these types of instruments can most simply be explained in terms of the boundaries of a trading scheme and the environmental accounting framework used.[23]

Table 1. Environmental Commodity instrument types

Instrument type	**Boundaries**	**Environmental accounting framework**
Quota instruments	Mandatory participation by a set number of entities and emission sources	Typically facility level, with absolute changes measured relative to a system-wide quota.
Offset credit instruments	Boundary set around each individual activity or project	Typically project or activity level with changes measured relative to a projected baseline for each activity (i.e., consequential accounting)
Tracking/allocation instruments	Boundary set around all producers and consumers of an environmental public good.	Typically entity-level with no changes measured (i.e., attributional accounting).

[23] Environmental commodities are intangible instruments. In most cases, they are only a record in a registry database. Therefore, transacting an allowance, REC, or offset credit is simply an act of information management. Anyone can potentially buy an environmental commodity from anywhere. Trading in environmental commodities makes most sense where the geographical and temporal extent of environmental good or harm represented by the environmental commodity is not localized. For example, greenhouse gases have long atmospheric lifetimes and mix well in the atmosphere.

2.2.1 Quota instruments

The demand for or supply of quota instruments is defined by the quota and the boundary that establishes which entities are subject to the quota. The quota instrument serves as to measure compliance with the quota; the regulation setting the quota then, if binding with respect to the intervention-free baseline, creates a market scarcity. Specifically, entities within the boundaries of a scheme are required to submit a certain number of tradable instruments to comply with the scheme while a quota (e.g., cap) mandates the aggregate supply or demand for these instruments. Allowances under an emissions cap-and-trade scheme and RECs under an RPS are examples of quota instruments. An allowance is a transferable commodity that confers the legal authorization to an entity to take some action (e.g., to emit a unit amount of a pollutant) without facing a penalty. Similarly, a REC is proof that an entity has taken a required action (i.e., purchased a unit of electricity from a renewable generator) or has the right to sell a commodity representing that action.[24]

As of February 2012, twenty-nine states and the District of Columbia had mandated RPSs in the United States.[25] And twenty-seven of these states allowed or required the use of tradable RECs for determining compliance.[26] Yet, neither REC definitions nor nomenclature is consistent across states (Gillenwater 2008b) (see Appendix A). REC definitions vary in the restrictions placed upon trading and what a REC fundamentally represents. In practice, these inconsistent

[24] It would be feasible to design an RPS scheme in a way that is more analogous to a cap and trade system. Under such an approach, a cap would be set on the amount of non-renewable electricity that LSEs are permitted to utilize to meet their load instead of the amount of renewable electricity they must utilize. The effect on the generation mix should be equivalent to a traditional RPS design. However, an absolute cap on non-renewable generation could provide incentives for LSEs to invest in electricity demand reduction, unlike an RPS. See Chapter 7 for further discussion of a similar option.

[25] Several utilities have also adopted RPS policies. See the Database of State Incentives for Renewables & Efficiency (DSIRE) at http://www.dsireusa.org/

[26] If tradable RECs are not allowed under a state's RPS, then LSEs must either own and operate their own renewable generation or contract for electricity wholesale from renewable generators, which is then tracked for compliance with the RPS.

definitions and restrictions can create separate local compliance markets for RECs (Holt and Wiser 2007).

2.2.2 Offset credit instruments

GHG emission offsets credits are examples of offset credit instruments. The accounting for offset credit instruments is done relative to a reference baseline against which performance is measured and credit is awarded based on the measured quantity that the baseline has been exceeded. In contrast, the accounting-basis for quota instruments is typically an absolute level of activity (e.g., total emissions) instead of a change in the activity relative to a baseline level.

The demand for offset credits can come from two sources: (1) entities under a quota that purchase credits from project activities implemented by entities not subject to the quota (i.e., outside the regulatory boundaries of the quota); and (2) entities and individuals that voluntarily purchase and retire offset credits for the purpose of making environmental claims regarding their support of some public good. If sold into a compliance market with a quota (i.e., #1 above), offset credits have the effect of reducing the scarcity of tradable quota instruments in the market. An example of an offset credit instrument sold into a compliance market is a Certified Emission Reduction (CER) under the Kyoto Protocol's Clean Development Mechanism (CDM). RPS schemes typically have not allowed the use of offset credit instruments for compliance, although there would be nothing to prevent such a provision in RPS legislation.[27]

Because they lack a regulatory mechanism to define compliance boundaries and enforce quotas on market participants, voluntary environmental commodity markets are typically

[27] For example, the recent debates over a federal RPS in the U.S. Congress included options for including energy efficiency credits in the overall target/quota and making these credits fungible with RECs.

expected to trade offset credit instruments.[28] Voluntary emission offset markets are focused almost exclusively on GHG emissions.[29] These voluntary GHG offset markets are generally unregulated and lack standard protocols and nomenclature (Gillenwater, Broekhoff et al. 2007); some refer to GHG offset credit instruments as voluntary emission reductions (VERs).[30] Consumers in these markets include both organizations and individuals who voluntarily commit to offset some portion of their GHG emissions from their operations, events, travel, products, concerts, or other activities. Although small, GHG offset markets are growing rapidly in several regions, including North America and Europe (WB 2011).

2.2.3 Tracking/allocation instruments

Some environmental accounting frameworks attempt to measure indirect factors, such as indirect emissions associated with a consumers purchases of electricity. For example, under the WRI/WBCSD GHG Protocol, indirect emissions associated with the purchase of electricity from a public grid are referred to as Scope 2 emissions (WRI/WBCSD 2004). For an undifferentiated product or service that is consumed by a group of consumers, indirect emissions are often accounted for by assuming an average emissions rate per unit consumed. Another option is to account for indirect emissions based on the actual emissions associated with each purchase; however, this requires the ability to attribute specific environmental attributes to each purchase by tracking information on producers along the supply chain. For some products, this option is uncomplicated; but for products or services distributed through networks, such as electricity, this option can be difficult or impossible.

[28] The Chicago Climate Exchange (CCX) was an example of a voluntary emissions market where participants voluntarily accepted a quota (i.e., cap). Such markets will tend to attract more sellers than buyers. Therefore, the market will tend to be oversupplied and fail to create an economic incentive to reduce emissions.
[29] Voluntary markets exist for purchasing and retiring SO_2 or NO_x allowances from compliance markets in the United States. The volumes purchased by voluntary participants and retired in these markets are extremely small.
[30] Also referred to as verified emission reductions. For an example see the Gold Standard Foundation's Gold Standard VER at: /www.cdmgoldstandard.org/

A potential solution is to create a tradable environmental instrument that includes information on the profile of environmental attributes for each unit measure of the product or service and issue them to producers. These instruments can be bundled with or unbundled from transactions along the supply chain of the underlying product or service. They can then be used as a tool for allocating environmental attributes and/or costs to consumers, who purchase or receive them, within a closed system under the condition that they are used by all consumers within the product supply network.

For example, instead of consumers using a utility grid average emissions rate to calculate Scope 2 emissions, they could acquire certificates that indicate a specific emissions rate that they would pair with each MWh of electricity they actually purchase. This type of tracking/allocation instruments works if all parties within the network participate, or provisions are made to rebalance the overall allocation of attributes and costs if some do not participate.

2.3 Existing definitions and standards

There is little agreement regarding the question of what a REC is or represents. Existing definitions largely rely on ambiguous concepts that themselves are rarely defined. This lack of precision and consensus regarding the definition of a REC creates confusion on the part of consumers as to whether and what kind of benefits result from their participation in voluntary green power markets. And it seems likely that it has facilitated a tendency for marketers and proponents of RECs to stretch their environmental benefit claims.

Appendix A presents a close to comprehensive selection of REC definitions used in both RPS compliance and voluntary REC markets (Gillenwater 2008b). Holt and Wiser (2007) also discuss the variation and inconsistency in REC definitions among state RPS mandates.

Given the lack of consensus on what a REC represents, there is little consistency across REC definitions. Again, definitions often use of the term “attribute” or “benefit” to describe what

a REC is. Specifically, RECs are commonly purported to "include all" attributes or benefits associated with renewable energy. Yet, there is rarely an attempt to address what these attributes or benefits are, how they should be quantified, or how ownership can be assigned to the holder of the REC. Do these attributes or benefits include both pollutants directly released by the renewable energy generator and impacts of renewable generation on the broader electricity grid? Is there a distinction between an "attribute" and a "benefit?" If a REC includes emission attributes or benefits, then why denote it in MWh instead of tons of specific pollutants? Additionality is rarely explicitly mentioned in REC definitions, but it is typically implied by the language used in definitions or other language used to promote RECs. Box 1 provides an example for why additionality is relevant to voluntary market RECs.

Box 1. Example of showing the relevance of additionality to voluntary green power markets

Below is an example to illustrate why additionality is a relevant to voluntary REC markets.

Accountants, Incorporated begins purchasing 1,000 RECs in keeping with their annual purchases of 1,000 MWh per year of electricity in 2010. Previously, the company estimated its Scope 2 (indirect) emissions from electricity purchases to be 1,000 metric tons of CO_2 based on a grid average emission factor of 1 metric ton per MWh. Beginning in 2010, Accountants reported its Scope 2 emission as now being zero. Being an office-based company with limited travel needs and located in a warm climate, the majority of Accountants' organizational emissions are associated with electricity consumption. Because of its REC purchases, Accountants now reports on its website and corporate socially responsible reporting that it has reduced its emissions to almost zero from what they were the previous year, in keeping with existing GHG accounting and reporting standards. If the renewable energy projects supplying RECs to Accountants are additional, then this claim would be justified.

However, if they are not additional but instead those projects would have been developed and would have supplied electricity even in the absence of the voluntary REC market, then there is no actual increase in the total amount of renewable electricity generated. And therefore, there is no change in total GHGs emitted to the atmosphere in 2010 versus 2009, despite the claims made by the company.

Accountants' management and customers look at the company’s GHG emissions reporting over time, which shows that their emissions have been dramatically reduced. The management and customers believe that emissions to the atmosphere have reduced, whereas actual emissions to the atmosphere are the same. If aware of this fact, most stakeholders would likely feel that the information in the company's GHG report is misleading and inaccurate. Further, Accountants management now sees no need to invest or change behaviors that would actually reduce emissions, such as my making onsite energy efficiency improvements. Because of existing accounting practices, even if the firm did reduce is electricity consumption, these improvements would now not be reflected in its GHG emissions inventory, which already shows indirect emissions from electricity consumption to be zero.

The language used by participants in the voluntary REC market is quite diverse. Some REC marketers make specific claims that RECs include rights to emission reductions from displacing

fossil generation (Holt and Bird 2005). Pino (2006) states that RECS “may include” air pollution and greenhouse gas benefits but does not specify under what conditions they would or would not. More recently Holt, Sumner et al. (2011) stated that RECs "track the ownership of the environmental attributes of renewable energy…and are the basis of all renewable energy claims".

Similar language is used in RPS legislation to define RECs for compliance markets (Holt and Bird 2005). A point of particular confusion is the treatment allowances under existing cap-and-trade programs, such as for SO_2 and NO_x in the United States. Despite claims implied in many of these definitions, RECs have failed to show how they convey any legal rights to emission allowances allocated to fossil fuel-fired generators (Gillenwater 2007b).[31]

The dominant advocacy organization for voluntary green power markets, the Center for Resource Solutions, which owns the Green-e brand, has regularly promoted definitions of a REC that state they include a transfer of rights to avoided emissions, and that RECs more broadly include all "environmental attributes" and that these attributes include emissions benefits associated with the "displacement of fossil fuel energy use on the electricity grid" (Lemei 2008).[32] The Green-e program has included language in their definition saying that attributes exclude any pollutant under a regulatory cap. They have conceded that REC marketers who use their certification standard must retire an allowance of any capped pollutant as a prerequisite for an emission reduction claim of a capped pollutant.

RECs have been described as being a “green jewel box” of all good things resulting from renewable energy (Jansen 2003). The problem with the ambiguity and breadth of these definitions is that they are used within the voluntary green power market as a substitute for a

[31] The California REC definition is the most detailed, yet it also fails to address the practical issue of ownership of emission allowances.

[32] See Montoya, Karlstad et al. (2008) for a contrasting opinion and an example of the debate surrounding the definition of a REC.

meaningful substantiation of through evidence of benefit claims. The default assumption is that by purchasing RECs a consumer is causing renewable energy to be generated. There is no mechanism within these markets to substantiate or police claims associated with this assumption (or actor with the incentive to do so).

A minority have argued that RECs simply represent the "unique proof that (i) the underlying specific quantity of renewables-based electricity has been produced under conditions specified by the standard information on the certificate, and (ii) that the certificate has not yet been used for another application" (Jansen 2003; Leahy and Hathaway 2004).

The Renewable Energy Resources Committee of the American Bar Association (ABA), the American Council on Renewable Energy (ACORE), and the Environmental Markets Association (EMA) drafted a Master Renewable Energy Certificate Purchase and Sale Agreement in an attempt to address the confusion with REC and environmental attribute definitions.[33] The model agreement is intended to be applicable to both voluntary and compliance REC markets, with the objective of promoting "the fungibility of RECs across programs."

However, the draft agreement fails to achieve this objective. It provides a detailed framework for sellers and buyers of RECs to define RECs specifically for each transaction and defines three categories of REC types: "standard", "basic" and "specified". Their "standard" REC definition suffers from the same faults as earlier ambiguous definitions. The agreement's "basic" and "specified" REC types do improve transparency, but the agreement does not create a single or even multiple homogeneous commodities for the marketplace that would be fungible across programs. Deciphering what collection of public goods that any given REC might account for requires a careful reading of more than 40 pages of legal contract language plus attestation

[33] See Electronic Annex 1 in the online version of this article and http://www.acore.org/programs/rectrading.php/

statements and verification reports specific to each transaction.[34] The model agreement also does not address the issue of additionality, yet its promoters advertise RECs as a way to reduce GHG emissions.

If claims are made regarding emission reductions within the voluntary REC market, RECs would logically need to satisfy the criteria associated with the definition of an offset project, which most importantly is additionality. While RECs used for RPS compliance would logically be regarded as quota instruments and not need to satisfy the criterion of additionality. Yet, voluntary markets and RPS compliance markets fail to make this distinction in their definition of a REC.

2.4 Literature review

A number of studies and publications have touched the topic of the voluntary green power market, its influence on electricity generation, and the relationship between REC markets and other emission trading markets. However, no systematic and quantitative analysis has been presented previously in the literature.

This dissertation builds upon previously published work by the author (Gillenwater, Broekhoff et al. 2007; Gillenwater 2008a; Gillenwater 2008b; Gillenwater 2008c; Gillenwater and Breidenich 2009; OQI 2009b; Gillenwater 2012a; Gillenwater 2012b; Gillenwater 2012c).

Gillenwater (2008a) examined the relationship between RECs and emission offset credits, and argued, based on a qualitative analysis, that because renewable energy generation has minimal operating costs, historically the revenue from voluntary market REC sales has not affected decisions to operate or dispatch renewable generation. Further, that voluntary REC markets lack a credible additionality assessment process, and therefore the sale of RECs in voluntary markets can at best be expected to have a marginal effect that will be less than the

[34] See flowchart on Exhibit A/Part B, page 31 of the ABA/ACORE/EMA draft master agreement.

supply of RECs on the market. In sum, it was argued that voluntary market RECs are not equivalent to emission offsets and the retiring of a REC may have no impact on emissions from electric power generation.[35] Instead, consumers that purchase RECs in voluntary markets are providing financial assistance to renewable generators in the form of a production subsidy. Generators that sell RECs are, also, not transferring property rights to emission reductions, since they are unlikely to have ownership. Gillenwater (2008a), however, did not support this conclusion with a quantitative analysis.

Gillenwater (2008b) offered a proposal for redefining renewable energy commodities so that compliance and voluntary renewable energy and emission markets can all function without confusion or conflicts. Gillenwater and Breidenich (2009) extended this proposal by providing a specific design for a load-based cap-and-trade system for emissions from electricity generation that integrates environmental commodity markets for renewable energy and emissions without conflicts while addressing tracking and leakage problems. Gillenwater (2008c) examined the use of RECs in entity-level GHG accounting for indirect emissions from electricity purchases by customers. It discussed the ownership problems with incorporating RECs into this emissions accounting framework and proposed solutions.

Previously, others addressed the issue of defining RECs, but none provided systematic or quantitative analyses or proposed comprehensive solutions (Jansen 2003; Leahy and Hathaway 2004; Holt and Bird 2005; Bird, Holt et al. 2007; PointCarbon 2008).

Bird, Wüstenhagen et al. (Bird, Wüstenhagen et al. 2002) conducted an early review of voluntary green power marketing activity internationally, including the United States. They found that the impact of this activity on the investment in new renewable generation capacity was limited and that the voluntary green power certificate markets, especially in Europe, were

[35] A conclusion supported by OQI (2009b).

heavily dependent on existing (e.g., large hydroelectric) facilities. However, they qualified their finding by saying that these markets were nascent in most countries.

In the United States, Bird, Holt et al. (2007) and (2010) argued that being able to claim GHG reductions is an important motivation for large non-residential consumers of green power products. Based on a survey by the Center for Resource Solutions, two-thirds of the fifteen largest corporate REC purchasers in the U.S. EPA's Green Power Partnership claimed that their participation in a voluntary green power market program, primarily through the purchase of voluntary market RECs, had reduced their GHG emissions or carbon footprint (Bird, Holt et al. 2010).

Bird and Wright (2009) summarized the debate over the relationship between RECs and GHG emission offsets and acknowledge that the key to the debate is the question of additionality (see Chapter 3 below). They cited a new program by the largest certifier of voluntary market RECs, the Center for Resource Solutions, called Green-e Climate[36] as providing a solution to the debate. Trexler (2009), though, argued that the Green-e Climate program largely re-labels the same projects that previously sold RECs as now being eligible to sell GHG emission offsets without new criteria that would properly address the issue of additionality. Harmon (2009) argued in defense of treating RECs as offsets and in support of the Green-e Climate program, stating that "the sale of the REC provides the *profitability* that allows the wind plant to be financed"[37] but did not offer evidence in support of his position.

Moore, Lewis et al. (2010) discussed the relationship between REC markets and emissions cap-and-trade programs, noting that allowances must be retired for the emission reduction claims

[36] See http://www.green-e.org/getcert_ghg.shtml
[37] Emphasis is original author's.

of green power participants to be justified. They noted that "to date, the environmental impacts of many green [power] products have been known only qualitatively or imprecisely."

Bird and Lokey (2008) argued that the voluntary green power market has another type of indirect impact: that it may have facilitated the passage of RPS policies in Wisconsin and Colorado, although they offer no evidence to support this claim. They did provide evidence showing that voluntary green power markets were not negatively affected by the adoption of state RPS legislation in those states, thereby contradicting arguments of Bird and Holt et al. (2010) and (2007).

More recently, Holt, Sumner et al. (2011) at NREL asked the question "do RECs play a direct role in new project development?" Their report, the most extensive to date on this question, addressed both the compliance and voluntary REC markets and was written in response to Gillenwater (2008a; 2008b; 2008c), Trexler (2009), and other critics of the claims made within the green power marketing industry. They acknowledge that the "major challenges with respect to RECs to develop new projects are risks related to demand uncertainty, low or uncertain prices, and the difficulty, in some cases, of securing long-term contracts."[38] They conducted sixteen anonymous interviews of participants in wind power project development "to gain their perspective on the use of RECs in renewable energy project development." Their analysis was qualitative, anecdotal, and at times mixed results for the compliance and voluntary REC markets. The authors accepted that "voluntary RECs generally do not by themselves [drive project development]; however, it depends on the nature of the market." The authors stressed the importance of long-term REC contracts for influencing project developers and investors.

Also recently, Bird and Sumner (2011) reviewed the issues and practices of corporations and GHG programs regarding RECs and entity-level GHG accounting. However, they approached

[38] See page 9 (Holt, Sumner et al. 2011).

the issue with a bias towards supporting the claims made by green power marketing stakeholders over the last dozen plus years, repeatedly using ambiguous language such as RECs "represent the emissions attributes of renewable electricity" (Bird and Sumner 2011). These biases are common in the green power market advocacy community, which are grounded in the assumptions that: i) purchasing a REC is equivalent to purchasing electricity generated with renewable sources, and ii) that a REC represents and transfers ownership to environmental/emissions/renewable attributes/benefits directly and indirectly associated with renewable power.

As major companies have begun to express doubts and confusion as to whether RECs are a legitimate instrument to reduce their carbon footprint and achieve carbon neutrality,[39] Bird and Sumner (2011) represent the beginning of a reluctant acceptance by the green power market advocacy community that, because renewable projects that sell RECs are not subject to rigorous additionality assessments, it is difficult to justify RECs being treated as equivalent or similar to emission offset credits.

An acknowledgment of growing doubts in the proper relationship between RECs and emissions accounting is illustrated by the recent guidance from a coalition of governmental and non-governmental green power market advocacy organizations:

> Despite the estimates [of reduced emissions] provided by these calculation tools, organizations should be careful about claiming avoided emissions because the ability to make emission reduction claims vary according to the regulatory policies affecting the emissions in question. Under voluntary programs, such as EPA's Climate Leaders program, it has become common practice to use the zero emissions attributes of green power purchases to reduce indirect or "Scope 2" emissions (from purchased electricity) as permitted by the program's reporting guidelines. Under a mandatory cap and

[39] For example, see the case of Dell computer (Wheeland 2011).

trade program, these accounting practices may change, so buyers of green power should check with EPA or other authorities about any updated greenhouse gas accounting rules prior to making new environmental claims (USDOE 2010).

Similar issues have been debated in Europe. Markard and Truffer (2006) examined voluntary green power products and programs in five European countries and concluded that the impacts of these products and programs was "rather limited." However, they went on to state that they still held some promise in terms of their potential to produce learning among stakeholders engaging in competitive markets and potentially lead to a broader array of "eco-oriented" behaviors. More recently, Raadal, Dotzauer et al. (2012) concluded that the Guarantees of Origin (GO) certificates[40] market, which serve the role of RECs in Europe, "currently has very low, or no, impact on investor calculations" and therefore has done little to supplement the renewable energy compliance quotas in Nordic countries. Like previous studies focused on the United States they did not support their conclusion with a quantitative analysis.

[40] A GO certificate is defined under the European Union's renewable energy directive as documentation on the characteristics of how a unit quantity (usually 1 MWh) of electricity was produced, and can be issued to both renewable and nonrenewable generators.

Chapter 3. What is additionality?

Unfortunately, and despite years of debate within the environmental policy community, there is no commonly held precise understanding of what additionality means or how to best implement it in the context of environmental commodity markets. This lack of progress has surely inhibited consensus on environmental policy design issues as well as the development of environmental markets by reducing stakeholder confidence in the claims that tradable environmental commodities are intended to represent. A key reason for taking this seemingly conceptual issue seriously is this: if the additionality concept is perceived by policy makers and the public as inherently dubious and/or problematic, then political support for emission offset policies, and potentially environmental markets more generally, could further erode.[41]

Several authors have examined problems with offset programs—often focusing on the Clean Development Mechanism (CDM), the world's largest GHG emissions offset scheme—and have cited the "additionality" of offset projects as a leading source of concern (Gillenwater, Broekhoff et al. 2007; Schneider 2007; Wara 2007; OQI 2008; Wara and Victor 2008; Haya 2009; OQI 2009a; Hayashi, Müller et al. 2010; Bushnell 2011). For example, the most common reason for the rejection of proposed CDM emission reduction projects has been the inability of project proponents to demonstrate additionality using the CDM process for doing so (WB 2009; Gillenwater and Seres 2011).

But before exploring this topic, it is important to first discuss a prerequisite: what is an offset? The relevant dictionary definition of "offset" refers to something that counterbalances or compensates for something else with some measure of equivalence (Webster 1986). It is a

[41] An added challenge is that some policy makers may resist more precise definitions of additionality and baseline for strategic reasons (e.g., to maintain regulatory discretion).

concept that is not unique to environmental markets. However, it is within GHG emission markets that the issues related to offsets and additionality have received the most attention.

How do we offset the harm caused by someone or something else? In the simple terms, one does something that results in extra good that is equivalent—in magnitude, approximate timing, and recipient population—to the original harm done. The key questions are: how do we define what is "extra" and to what is this "extra" measured against? These are just another way of asking about additionality and the baseline against which additionality is assessed.[42] One cannot examine the topic of offsets without understanding additionality.

Conceptually, additionality is a determination of whether a proposed activity will produce some "extra good" in the future relative to a reference scenario, which we refer to as a baseline. In other words, additionality is the process of determining whether a proposed activity is better than a specified baseline.

In the context of offsets, a baseline is a quantified amount of good or harm produced by the behavior of the actors proposing and affected by the proposed activity in the absence of one or more interventions, holding all other factors constant (*ceteris paribus*). In other words, the concept of a baseline is defined by the absence of the specified intervention that is created by the offset policy or program. Explicit and careful identification of interventions has been a key missing element in reaching consensus on more precise definitions of additionality and baseline.

Overall, additionality is about assessing causation. It is about deciding if a proposed activity is being caused to happen by an intervention. This assessment is performed by deciding if a proposal is different from its baseline, which is defined as the scenario in the absence of the

[42] Additionality has at times also been referred to as "surplus," meaning public good benefits that are surplus to what would have been provided under baseline conditions (ELI 2002).

same intervention. The concept of additionality is further grounded in an assumption that interventions can cause behavior change.

Although techniques for assessing additionality and baselines have been developed, implemented, and debated for years, especially within the climate change policy community, insufficient attention has been given to defining and specifying interventions as well as cause and effect relationships.

This issue is relevant to voluntary green power markets because many of the claims made by participants in these markets are explicitly or implicitly grounding in an assumption that voluntary green power purchases result in additional renewable energy generation and therefore additional emission reductions. In order to analyze the research question regarding the additionality of voluntary green power markets, it is first necessary to clearly specify what we mean by "additionality," which is then a basis for expressing additionality in terms of causal and dependent variables useful for modeling purposes.

3.1 What is the role of additionality?

Typically, an offset program is thought of as issuing tradable credits that can be used in lieu of some other mandatory (or voluntarily imposed) compliance obligation, such as substitution for an emission allowance under an emissions cap-and-trade system. Offset credits are generally issued by a governing offset program, either governmental or non-governmental, and are targeted to activities not easily identified or incorporated into other policy mechanisms (Bushnell 2010; Gillenwater and Seres 2011).

Although, the demand for offset credits is typically thought of as coming from a quota-based market (e.g., cap-and-trade), demand for offset credits can derive from a variety of

sources.[43] For the purposes of this dissertation, though, the concept of additionality can be considered independent of the source of demand for credits.

Additionality is not only an essential quality criterion for offset credits (Trexler, Broekhoff et al. 2006; OQI 2008; OQI 2009a); it is fundamental to the very definition of an offset. Additionality and baselines are also used to constrain the supply of credits in a market. In an environmental commodity market, a mechanism is needed to create a scarcity, since the underlying commodity is typically a public good. In the case of offset programs, scarcity is created by separating the activities eligible to receive credits from those that are not, and then only issuing credits for demonstrated performance improvements to the former group (OECD/IEA 2000).

Additionality also distinguishes offsets from another policy mechanism: economic subsidies.[44] Subsidies can be used to influence behavior and produce extra public goods. But unlike offset credits, subsidy programs rarely involve rigorous procedures to determine whether a recipient of a subsidy would have engaged in the desired behavior even in the absence of the subsidy. If true, then the purpose of assessing additionality is to exclude that receipt[45] from the program (Bernow, Kartha et al. 2001; OQI 2008).[46]

The lack of a reliable process for determining additionality and baselines within a mechanism that issues a environmental commodity that purports to represent a unit improvement

[43] Offset programs require some source of demand for their credits. Examples of such a mechanism include, but are not limited to: direct government purchases, government mandated purchases and retirements, voluntary purchases, or linkage to quota-based trading systems. For example, voluntary offset markets can be thought of as individual parties imposing compliance quotas on themselves, which they then satisfy in part or in whole with offset credits. The origins of demand in a voluntary market are the psychological and/or marketing (e.g., public relations) value to buyers (unless driven by pre-compliance interests).

[44] Similarly, additionality differentiates offsets from certificate-based schemes such as Renewable Energy Certificates (RECs) (Gillenwater 2008a; Gillenwater 2008b; OQI 2009b).

[45] Also referred to as a "free rider" (Chandra, Gulati et al. 2010).

[46] Additionality can also be thought of as a type of inverse price discrimination that intends to screen out inframarginal suppliers under the pre-subsidy demand curve.

in some public good not only subverts potential public benefits from the mechanism, it can also harm those who might appear to benefit from laxness (i.e., those supplying the credits instruments). Asuka and Takeuchi (2004) showed that a lax additionality process under the CDM could actually cost recipient countries (in the form of a lower market price for credits) more than the lax process would benefit them (in the form of greater credit sales volume). Ultimately, errors in additionality and baseline determinations will reduce both the environmental and economic gains of the mechanism, for example, though increased pollution and a less efficient allocation of investment resources relative to an error-free offset program (Fischer 2005).

In this dissertation, the following definitions of additionality and baseline are used.

Additionality is the property of an activity being *additional*. A proposed activity is *additional* if the recognized policy interventions are deemed to be causing the activity to take place. The occurrence of additionality is determined by assessing whether a proposed activity is distinct from its baseline (see below).

A **baseline** is a prediction of the quantified amount of an input to or output from an activity resulting from the expected future behavior of the actors proposing, and affected by, the proposed activity in the absence of one or more policy interventions, holding all other factors constant (*ceteris paribus*). The conditions of a baseline are described in a baseline scenario.

In the context of climate change policy the question of additionality is whether GHG emissions from a proposed activity will be different than baseline emissions.[47] To further elaborate and apply the above definitions of additionality and baseline, several underlying questions must be asked and answered:

- What is the recognized intervention (i.e., treatment or causal factor) created by the policy, which is intended to change behavior?
- What specific treatment variables represent that intervention?
- What theory of behavior is assumed for modeling the effect of the intervention on actors?

These questions outline a theoretical framework for additionality that can provide a generalized foundation for realistic offset policy implementation. Collectively, these questions have neither been systematically asked nor thoroughly analyzed in previous work within the literature on offsets policy.[48]

3.2 What is the intervention?

Additionality is about whether and in which cases an intervention is causing behavior change. The assessment of additionality, then, must take into account the possibility that behavior may remain unchanged even when the policy intervention is present. By intervention, we mean any type of incentive (i.e., "carrots"), assistance, mandate, or threat (i.e., "sticks"). Interventions can vary in magnitude, timing, and form. The issuance of credits is not necessarily the only form of intervention created by an offset program. Programs can take actions that directly or indirectly have the potential to lead to behavior change.

[47] An activity's emissions could be less than or greater than the baseline, but if they are greater than the baseline then no offset credits will be awarded. So, the question of additionality can be more simply formulated as a difference question rather than a less than question.

[48] Individual questions have been partially discussed by Chomitz (1998), Greiner and Michaelowa (2003), Trexler, Broekhoff et al. (2006), and Bennett (2010).

A key step in developing an offset program or defining an offset credit instrument is recognizing a type of intervention for the assessment of additionality and baselines. Policy makers and program administrators have a variety of direct interventions they can make (see Table 2).

Table 2. Relevance of categories of environmental policy interventions to emissions offset policy

Categories of interventions	**Relevance to emissions offset policy and intervention types from Table 3**
1. Economic subsidies for an activity;	Relevant under Types *A*, *B*, and *C*. Expected revenue from sale of issued offset credits. Unlike a fixed publicly funded subsidy, value is a function of market forces (i.e., supply of and demand for credits).
2. Measures to reduce transaction costs, which can reduce the cost of a known activity for an actor and/or add to the list of known options for a given decision or behavioral choice;	
a. Information or educational campaigns;	Relevant under Types *B* and *C*. An offset program could directly deploy informational campaigns that influence behavior or cause other institutional actors to deploy such programs.
b. Changes to existing rules (e.g., remove regulations that discourage or increase the costs of certain activities);	Relevant to Types *B* and *C*. Legislation that creates offset program could also include or lead to other policy or legal changes that directly or indirectly influence behavior.
c. Providing new infrastructure (e.g., telecommunication infrastructure)	Relevant to Types *C* and potentially *B*. The offset program could directly provide new infrastructure that influences behavior (e.g., build new electrical transmission lines), which would be relevant to Type *B*. More likely, it could indirectly influence the path of infrastructure development, which would be relevant to Type *C*.

d. Research and development (R&D) funding;	Relevant to Type *C* and potentially *B*. The offset program could directly provide new funding for R&D that changes technology options in the future, which would be relevant to Type *B*. More likely, it could indirectly influence the path of R&D investment, which would be relevant to Type *C*.
e. Development of voluntary technical standards	Relevant to Type *B* and *C*. Standards could result in lower transaction costs as well as influence the path of technology development.
3. Enforced government mandates or internal organizational policies;	Offset policies are typically designed as a market-based policy instrument, not a mandate.*
4. Reputation-based programs;	Relevant under Type *B* and *C*. An offset program could directly recognize the superior or inferior environmental performance of actors or cause other institutional actors to deploy such programs.
a. Recognition programs for superior performing actors; and	
b. Shaming programs for poorly performing actors.	

* Theoretically, an offset policy could mandate behaviors and still issue credits for only those activities that are deemed to have occurred because of the presence of the mandate (i.e., some activities may take place even in the absence of the mandate). The effect would be to subsidize those activities that were caused by the mandate and not subsidize those that were not while still ensuring the activity was universally implemented.

References to an intervention, where present in the literature, fall into one of the four types presented in Table 3.[49] The type of intervention that an offset program recognizes has major implications for how additionality and baseline are assessed.[50] Specifically, each type leads to a different set of factors that are acknowledged as influencing the behavior of target actors.

[49] Schneider (2009) identifies the act of an offset program registering a project as the recognized policy intervention., Registration is, however, a proximate, not ultimate policy intervention. The policy intervention would be what registration of a project makes possible (e.g., the opportunity to earn revenue from credits).

[50] A policy intervention, here, includes the direct and indirect effects of an offset program efforts, and is defined with respect to the perspective of the targeted actors' considerations. For example, I would define an intervention to be the offset credit price signal rather than the steps taken to create that price signal, because the former is more proximate to the targeted actors.

Table 3. Policy intervention types for additionality and baseline scenario assessments in the GHG emission offset literature

Type	Description of policy intervention type	Typical language in literature	Example References
A	Expected economic value of offset credits	Income from offset credits or carbon funding	(Chomitz 1998; Sutter and Parreño 2007; Au Yong 2009; Bennett 2010)
B	*A* + Measures directly taken by offset program or policy	Offset program	(Asuka and Takeuchi 2004; Fischer 2005; Kartha, Lazarus et al. 2005; Au Yong 2009; CBO 2009; Müller 2009; Bennett 2010)
C	*A* + *B* + Indirect market spillover effects	Offset credit market	
D	Emergence or presence of climate change as an issue for policy or decision making consideration	Issue of climate change	(Sugiyama and Michaelowa 2001; Asuka and Takeuchi 2004; WRI/WBCSD 2005; Trexler, Broekhoff et al. 2006)

Type *A* from Table 3 recognizes an intervention that is narrowly interpreted. With this type, factors other than the expected economic value of offset credits are considered to have an insignificant influence on behavioral change; offset policy is effectively viewed as a specific type of economic subsidy. The resulting treatment variable (i.e., causal variable) under Type *A* would be related to the expected value of the subsidy. For example, the treatment variable could be defined as the Net Present Value (NPV) (i.e., discounting for time as well as uncertainty/risk) of the offset credits expected to be earned by the proposed activity. An intervention of this type would probably be used within a model that focuses on: i) the effects of an offset credit price signal on the behavior of investors or other relevant actors and ii) factors, in the form of variable thresholds, that identify the actors and contexts where changes in behavior due to this price signal are likely to occur (e.g., producers on the margin).[51]

[51] The magnitude of this price signal is typically thought of as a function of market forces (assuming some source of demand for credits), but it could also be a price bound (e.g., through price floors and/or ceilings) or directly set by a program administrating agency.

An intervention of Type *B* would include a broader set of treatment variables than a Type *A*. Type *B* recognizes that an offset program may include a mixture of interventions intended to influence behavior and that interventions are more than simply a price signal. They potentially include other measures directly taken by the offset program. For example, a program could provide new market infrastructure that lowers the transaction costs of implementing activities (e.g., through education or capacity building) or offer other technical, legal, and/or financial support.

An intervention of Type *C* includes yet a broader set of treatment variables than Type *B*. Type *C* recognizes the actual policy intervention to be the creation of a broader offset credit market, and therefore assumes the policy intervention includes broader market effects[52] as well as the offset credit price signal (Type *A*) and other direct measures taken by the offset program (Type *B*).[53] These market effects could include a host of network, positive, and negative externalities. For example, the offset credit price signal could lead to the invention of a new emission reduction technology that would not have developed had the offset market not existed.[54] If such a new technology turns out to be the lowest cost option for a given activity then it may not be assessed as additional under Type *A* or *B*, where its use would be seen as the likely baseline scenario. But if the new technology was created in response to the offset market then it would not been available in the baseline scenario, assuming Type *C*.

If one recognizes an intervention of Type *C*, then a baseline scenario would be modeled as an alternative world that does not (or never did) include an offset credit market and offset

[52] Also referred to as secondary, indirect, spillover, or market transformation effects (Vine and Sathaye 2000; Bernow, Kartha et al. 2001; Nadel, Thorne et al. 2003).
[53] Project leakage (or affected GHGs under ISO 14064-2) is also fundamentally an indirect effect. See Millard-Ball and Ortolano (2010) for a useful discussion of indirect effects and leakage issues related to transport projects.
[54] The presence of an offset market, by offering an alternative compliance option to regulated entities under an emissions cap-and-trade program, could also be argued to reduce the incentive for those capped entities (versus those supplying offset credits) to innovate relative to a scenario in which this alternative compliance option did not exist.

program. Clearly, such an assumption increases the number of relevant treatment variables and the complexity of any model used to predict baselines.

Type *D* dramatically broadens the view of an intervention. It recognizes the intervention to be the emergence or presence of humanity's knowledge of anthropogenic climate change. Under Type *D*, any change in human behavior resulting from this knowledge would be additional. A baseline scenario would then be assessed using a model of the world in which: i) the problem of climate change did not exist, ii) society was unaware of the existence of anthropogenic climate change, or iii) society showed no interest in the issue and so this knowledge had no effect on human behavior. Clearly, modeling an alternative past and future under the assumption of this type implies an unrealistically complex model as well as a host of subjective assumptions. Yet, authors who define additionality in terms of what would have happened in the absence of climate change as a policy issue are implying just this sort of approach (see Table 3).

Returning to the types of interventions in Table 3, Type *A*—related to the economic subsidy effect resulting from the expected value of offset credits (i.e., price signal)—is the most reduced form of a policy intervention. Offset policy is typically thought of and designed as a mechanism that issues credits that have some market value. The treatment variable would be the expected revenue to an activity from the sale of offset credits. The variable is an "expected" value because the actual number of credits issued, as well as their future selling price, will be uncertain.

If an offset program actively provides other types of direct support to activities that is intended to influence behavior (e.g., in-kind project development assistance), then it may be appropriate to include other treatment variables in the model, in keeping with Type *B*. Taking

from the literature on transaction costs, these other treatment variables may be coded in terms of their economic value (Williamson 2005). Analogously, non-financial barriers to a class of activities can also be represented in models as transaction costs using control variables, thereby building relationships in the model with treatment variables (Schneider 2007).

A practical way forward is for offset policy makers and program administrators to limit what type of intervention and treatment variables they recognize to be Type *A* (i.e., expected economic value of offset credit revenue) except where significant program resources are dedicated to other categories of interventions that would fall under Type *B* (i.e., other measures directly taken by offset program or policy). This approach recognizes that there may be some equilibrium (i.e., spillover) effects (i.e., Type *C*) that are omitted; however, specifying these effects with treatment variables and incorporating them into models would be challenging and highly uncertain. Limiting the number of treatment variables both simplifies the modeling and results in more conservative additionality assessments. The implications of Type *D* (i.e., emergence of climate change as an issue for policy or decision making consideration) make modeling, and the entire concept of offsets, impractical and should not be given serious consideration.

3.3 Assumptions for voluntary REC markets

For the voluntary REC market, the initial intervention was the creation of the voluntary green power market by organizations that promoted it to buyers and provided other market making and governance functions. However, this initial intervention functionally led to a proximate intervention, from the perspective of renewable energy project developers, which takes the form of the expected value of the voluntary REC market price signal. It is assumed in this dissertation that no other activities taken by green power market organizations have effects that should be considered as additional intervention causal variables.

In the case of voluntary market RECs, the relevant target actors for the intervention are the investors (and their analysts) that are the decision makers for whether and where a wind turbine project is invested in. For this dissertation, it is assumed (and supported below with data in Chapter 5) that wind power project developers are rational economic actors and make investments decisions accordingly.

Chapter 4. Additionality and RECs

In environmental markets, additionality is has been assessed using some combination of assessment "tests". The underlying concern is the overall stringency of the additionality tests, which regulate the supply of credits on the market. Overly stringent tests may unnecessarily increase offset credit prices by rejecting many truly additional projects (i.e., higher false negative error rate). While overly lenient tests may submerge the market with non-additional credits and depress prices (i.e., higher false positive error rate), thereby driving out activities with real public good benefits. The overall goal of additionality determinations is to assure that the commodity sold in the market actually represents a change in behavior.

As discussed in Chapter 2, it is unnecessary for quota instruments to demonstrate additionality relative to a baseline if they are used to meet a quota requirement.[55] Quota instruments are denoted in terms of an absolute level of an activity because the system-wide scarcity created by the overall quota ensures that the policy creates behavior change. However, voluntary markets that trade instruments claiming to produce quantified behavior changes are implicitly claiming to be trading in offset credit instruments. In these markets, it is necessary to have some procedure to determine the additionality of projects that are awarded offset credits. If the argument made by REC marketers is that the revenue from the sale of RECs “caused” a public good to be produced, then additionality assessments determine the credibility of this causation claim. So, do RECs sales in U.S. voluntary green power markets lead to additional electricity generation from renewable sources? It should not be taken as a given that voluntarily

[55] The eligibility requirements for RECs under a few state RPS requirements do include weak additionality tests. However, there is no need to burden a quota-based trading system with the transaction costs associated with additionality tests. It is only under an open, or uncapped, system that a determination of additionality is necessary.

buying green power or RECs will increase the amount of renewable electricity generated or, more importantly, decrease the amount of non-renewable energy generated.

Why should we care about the additionality of RECs? The concern is that in a system that ignores additionality, non-additional projects will dominate the market. Truly additional projects that result in environmental improvements will not be able to compete in the marketplace because they face additional costs or barriers. In such a market, there are two losers: the public good and well-intentioned project developers. Eventually, these environmental markets would be expected to collapse due to lack of credibility with the public.

A variety of different types of additionality tests have been used in offset crediting schemes (Table 3) Trexler and Kosloff (2006) state that RECs are not subject to any additionality tests. However, voluntary market RECs certified under the major governing organization standards do pass some additionality tests (Table 3). Yet, these tests, compared to those established for GHG emission offset projects, are the weakest of those available.

Table 4. Types of additionality tests and their application to GHG offset credits and U.S. voluntary REC markets[56]

Type*	Description*	Stringency[57]	Applied to GHG offsets[58]	Applied to RECs [59]
Regulatory	The project activity is not required by government regulations or commonly accepted industry standards. Behavior change from the project activity must exceed that required or implied by regulations or standards.	Typically weak. Also depends on level of regulatory enforcement.	✓	✓ Cannot be counted toward RPS compliance (weak)
Technology	Specific technologies are predetermined to be additional or eligible.	Can be weak or strong depending on technology and support mechanisms	(varies)	✓ Eligible renewable technologies (weak)
Financial	The project activity would have a lower than acceptable financial return without the revenue from the sale of offset credits.	Typically strong.	✓	
Barriers	A project activity must face significant implementation barriers (e.g., lack of local infrastructure) that the revenue or other assistance provided through the sale of offset credits allows the project to overcome.	Can be weak or strong. Difficult to objectively assess.	✓	
Common practice	The project activity must utilize technologies or practices that are not in common use within a particular jurisdiction or industry.	Can be weak or strong. Easier to analyze where data on industry practices available.	✓	

[56] Whether a project is determined additional is also a function of time. For example, an activity that is not common practice today may be next year. Additionality standards are typically updated in conjunction with a crediting period. Project developers need warning about updates to additionality standards to avoid stranded investments.
[57] Subjective judgments of author, but based on perceived likelihood that test, in isolation, will screen out free riders.
[58] Primarily based on Clean Development Mechanism (CDM) (UNFCCC 2006).
[59] Based on U.S. NGO certification standards (CRS 2006; ERT 2006). Again, not all voluntary market RECs are certified.

Initiation date	The project activity must be initiated by a certain date. Projects started earlier than this date are deemed non-additional.	Weak	✓	✓ Began operation after 1996 or in the last 15 years
Performance benchmark	The project activity must perform at a rate (e.g., per MWh of electricity generated) that is lower than some industry or technology benchmark.	Can be weak or strong. Requires extensive methodological development.	(varies)[60]	

* Types and descriptions modified from (Trexler, Broekhoff et al. 2006).

The two major REC certification schemes cover a large portion of the market, and both apply nearly identical additionality tests.[61] The *regulatory test* applied to certified voluntary market RECs requires that the same MWh of renewable generation must not be counted toward RPS compliance. The *technology test* is simply that electricity is generated from an eligible renewable energy technology (e.g., wind, solar, or geothermal). The *initiation date test* is formulated such that all generation capacity installed since the early days of the voluntary green power market is eligible.

The U.S. Environmental Protection Agency's (EPA's) Green Power Partnership has recently increased their threshold for what is considered "new" renewable energy. Previously, "new" was defined as facilities put into service on or after January 1, 1997, which is generally considered to be the inception of the voluntary green power market. As of July 15, 2011, USEPA and the Green-e Energy National Standard moved to a 15-year rolling "new date," meaning that projects must have come online within 15 years prior to the sale of the green power in order to be

[60] The Australian National Emissions Trading Scheme is developing performance benchmarks and model projects to determine additionality for sub-sectors (Fowler 2007).

[61] Not all RECs sold into voluntary green power markets are certified under these standards. It is likely that these uncertified RECs are not subject to any additionality tests. For a list of REC products and marketers see http://www.eere.energy.gov/greenpower/markets/certificates.shtml

classified as new. As of January 1, 2012, the EPA's Green Power Partnership defined the "new date" as January 1, 1998, and advance one year each year thereafter (EPA 2010).

In an attempt to respond to the criticism directed at it for advocating that RECs could be used as emission offset credits, as discussed above in the literature review chapter, CRS created its Green-e Climate program, which certifies renewable energy projects in the United States to sell carbon offset credits.[62] Green-e applies essentially the same additionality tests to renewable energy projects for its Climate program as it does for RECs under its green power program. The only difference is that the age restriction on renewable energy projects is set to reject projects built prior to 2005 under the Climate program; and thereby automatically accepting any project built thereafter (CRS 2010).

In combination, CRS has assumed that all renewable energy generation capacity built after 1996 or anytime in the last 15 years (and not counted towards an RPS quota) would not have been constructed without revenue from voluntary market REC sales. To determine whether this assumption is adequate for screening out free-riders, we must consider the economics of renewable energy generation, investments, and REC markets.

4.1 Economics of renewable investment and additionality

Wind turbines operate with near zero variable operating costs, as well as being zero emitting. Once constructed, wind turbines always run, assuming availability (e.g., wind is blowing and unit is operational) because revenue can be earned from generating electricity without incurring variable costs.[63] For this reason, the additional revenue supplied to a renewable generator from REC sales is unlikely to affect the dispatch or quantity of electricity produced by an existing renewable generation facility. Therefore, the additionality of RECs can be

[62] For a list of projects and offset retailers see http://www.green-e.org/getcert_ghg_products.shtml

[63] In rare exceptions the output of wind turbines is curtailed if the overall output of turbines actually exceeds the demand for electricity within the relevant distribution network or the capacity of transmission lines.

exclusively assessed in relation to the decision whether to invest in renewable generation capacity.[64] Projects shown to have been started with the expectation and need for REC revenues are likely to be additional.[65]

Renewable energy investment decisions are affected by a variety of financial considerations. Overall, investors need a minimum amount of revenue per MWh to recover their initial capital investment. In the United States wind generators need a fairly predictable revenue stream. In addition to revenue from wholesale electricity sales, renewable generators may also receive government support. Many countries, as well as some states and localities, provide incentives for renewable energy investments such as guaranteed feed-in-tariffs, exemption from property taxes, an accelerated depreciation option, and tax credits. In the United States, the Production Tax Credit for new wind generation capacity currently provides $21/MWh for 10 years (Wiser and Bolinger 2011).[66] In some cases, subsidies and other incentives make renewable generation investments economical.

Renewable generators may also sell RECs into RPS compliance or voluntary green power market as an additional source of income. REC prices in RPS compliance markets vary widely and are primarily a function of the stringency of the quota mandated by the RPS. REC prices in voluntary markets vary by resource type (e.g., biomass, wind, and solar) (Holt and Bird 2005) and region (Hathaway 2007).

The wholesale price of RECs represents the gross income from certificate sales. There may be certification and/or broker fees involved in a voluntary market REC transaction. Typically,

[64] Repowering of existing generations capacity is assumed to be a special case of the investment of new capacity. For wind energy, repowering generally involves the complete replacement of turbines.
[65] Although common in voluntary REC markets, insisting on the purchase of current vintage year RECs does nothing to address the issue of additionality. Additionality is independent of when electricity is generated. Prohibiting banking of RECs or offset credits from renewable energy projects is unlikely to increase the probability of projects being additional.
[66] The Production Tax Credit covers the entire output of a wind generator and is adjusted for inflation. However, it regularly expires and must be renewed by Congress.

certification and brokerage costs separately range from 3 to 5 percent (e.g., $0.05 to 0.15/MWh) (Hathaway 2007). The retail prices for voluntary market RECs are often significantly higher than wholesale prices, reflecting retailer marketing costs and profit margins. Retail REC prices for residential and small commercial customers can range from $15 to $30/MWh, (Bird and Swezey 2006; Hathaway 2007). Large commercial and industrial customers, which make up the majority of the voluntary REC market, are often able to negotiate prices near wholesale price (e.g., $1 to $10/MWh).

The net income from voluntary market REC sales for wind generator can account for roughly 1 to 10 percent of total project revenue (Holt, Sumner et al. 2011). This amount is compared to approximately 59%, 21%, and 19% of total project revenues that is supplied by wholesale electricity sales, advantageous accelerated depreciation polices, and the Production Tax Credit, respectively (Holt, Sumner et al. 2011).

Further, most purchasers of voluntary market RECs in the United States do so through short-term contracts. "In voluntary markets, long-term contracts for retail purchases are rare. End-use companies that drive the voluntary market are uncertain about their future business strategies more than 5 years into the future, and they do not want to risk locking in a long-term price only to see general market prices fall" (Holt, Sumner et al. 2011). The forward market for RECs trades at a maximum of only three years ahead, and in some cases contracts are only available for one or two years ahead. A survey conducted by U.S. EPA's Green Power Partnership, which included 60% of voluntary market REC sales in 2009, confirmed that long-term contracts for RECs were rare, showing that about 92% of partners contracted for RECs only 1 or 2 years ahead (Holt, Sumner et al. 2011).

This situation is in contrast to what is widely recognized by wind power investment researchers: that it is essential for project developers to procure long-term purchase contracts to make the financing of renewable generation capacity economical (Holt and Bird 2005; Agnolucci 2007; Baratoff, Black et al. 2007; Cory, Coughlin et al. 2008). The additionality of renewable energy projects is therefore likely to be dependent on the ability of investors to secure long-term contracts for REC sales. Holt and Bird (2005) note that a problem with the voluntary REC markets is that they often do not provide sufficient income certainty to alter investment decisions. As a result, the revenue obtained from voluntary market RECs is likely to be discounted by investors, unless a long-term contract for REC sales can be obtained (Baratoff, Black et al. 2007). Such long-term contracts can be obtained in some RPS compliance markets, but are much less common in voluntary REC markets.

4.2 The importance of scarcity

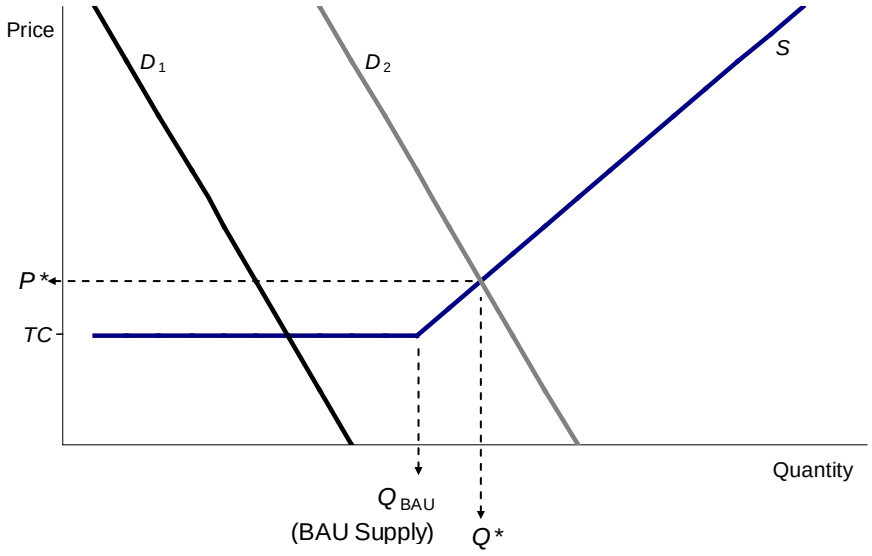
In determining the additionality of renewable energy projects supplying RECs to the voluntary market it is helpful to consider the market as a whole. If the process for determining the additionality of wind power projects supplying RECs to the voluntary REC market is grossly insufficient to screen out free-riders, then there will be a large supply of non-additional RECs in the market, referred to here as the BAU supply (i.e., false positives). A large BAU supply is likely to cause the overall market to be long, and thereby depress prices. A market is long when the supply of RECs is greater than the demand.

Both RPS compliance and voluntary REC markets can be long. However, it is more likely that a RPS compliance market, with its defined participation boundaries, will exhibit a market scarcity due to the ability of government to set a mandatory quota that establishes the demand for compliance RECs.

How does one determine whether a REC market is long? One approach is to look at prices. If wholesale REC prices are not significantly above the level of transaction costs in the market, then it implies that the market is long and non-additional projects have not been adequately screened out.[67]

Figure 1 presents an idealized supply-demand curve for a voluntary REC market. The supply line (*S*) is discontinuous because RECs are not the only source of revenue for renewable energy generators. There is a supply of RECs on the market that result from projects that are not implemented with consideration of the revenue from REC sales.

Figure 1. Idealized supply-demand curves for a voluntary REC market



Two demand scenarios are presented in Figure 1. Demand scenario 1 (D_1) illustrates a case where the voluntary market demand for RECs is less than the amount supplied by nonadditional

[67] Another approach would be to investigate whether there is a significant number of renewable energy generators that are eligible, but do not sell RECs into the market. Some small renewable generators in the United States do not sell RECs into the voluntary market (Hathaway 2007).

projects and the REC market is long. The wholesale price of these RECs is equivalent to transaction costs (*TC*) in the market. Renewable generators face transaction costs, including certification and brokerage fees (Table 5) and a minimum payment simply provide an incentive to engage in the transaction. A wholesale REC price of at least $0.5/MWh is likely necessary to cover these transaction costs. Therefore, a long REC market will not present a price of zero for RECs. Under demand scenario 1, the voluntary REC market has no effect on the supply of renewable energy generation or capacity and no additional environmental benefits are created. The second demand scenario (D_2) does create a scarcity and the market does have a marginal effect on renewable energy investments. Under this second scenario, wholesale REC prices trade at a price of P^*, which is above the level of transaction costs.

Table 5. Generic supply and demand characteristics of REC markets

Demand scenario	Marginal cost of REC supply	Generator response	REC price determinant
D_1 (Long market)	0	The demand for RECs is less than the BAU supply that would be produced anyway.	Prices are roughly equal to transaction costs. Prices are mostly unaffected by changes in demand below the BAU supply.
D_2 (Market scarcity)	Positive	Additional generation capacity with lowest marginal cost will be brought online to meet demand above BAU.	Marginal cost of generating additional MWhs of renewable electricity above BAU demand plus transaction costs.

It is important to recognize that even if a voluntary REC market exhibits a scarcity for RECs, not all of the RECs sold in that market are necessarily from additional renewable energy projects. There can still be an excessive number of free-riders that have not been screened out of the market. It may simply be that consumer demand exceeds the BAU supply (i.e., the supply by

free-riders) of RECs in the market. In this case, the incremental effect on renewable energy investments caused by the voluntary REC market is not equivalent to the total number of RECs sold in the market. The incremental effect is instead equal to the total demand for RECs minus the BAU supply ($Q^* - Q_{BAU}$). If renewable energy projects that sell RECs into voluntary markets are not additional, then they can at best be expected to have a marginal effect that is less than the total number of RECs sold.

Therefore, unless the process for assessing additionality adequately screens out most free-rider projects, it is inaccurate to assume that all RECs sold in the voluntary market represent additional megawatt-hours of renewable energy generation simply because there appears to be a market demand effect on the margin (i.e., voluntary market demand is greater than the BAU supply).

So, is the demand for RECs in voluntary markets greater than the BAU supply? An examination of actual prices in the U.S. voluntary REC market suggests that these markets, are in most cases, long. National wind REC prices in the U.S. voluntary market have, in general, been quite low and do not appear to be significantly above the level of estimated transaction costs.

4.3 Voluntary and RPS compliance market interactions

There are a number of ways voluntary and RPS compliance REC markets can influence each other. Voluntary green power markets can provide an alternative market for RECs if RPS compliance markets become oversupplied (Bird and Lokey 2008). Using this argument, voluntary REC markets influence RPS markets by establishing a price floor function, albeit an uncertain floor, for wind power developers. Compliance RPS markets also have the potential to influence voluntary REC markets by siphoning RECs away from the voluntary market, although this has not appeared to happen yet based on observed prices. An aggressive national RPS, though, could change this, resulting in higher voluntary market REC prices.

In some states, consumers have the option of purchasing and retiring RECs that are eligible to be submitted for RPS compliance. Doing so reduces the supply of RECs available to LSEs to meet their quotas. However, if an RPS target does not produce a real scarcity (i.e., the compliance REC market is long) then voluntarily removing a REC from the market will have no effect on renewable energy investments or generation. Voluntarily removing RECs from a RPS compliance market with a binding quota, though, is an effective tactic to ensure the additionality of RECs. The act of retiring and removing RECs from the compliance market, in this case, establishes additionality. When an RPS creates a REC market scarcity and a REC is retired so that it cannot be used for compliance by LSEs, then a renewable generator will have to produce an additional REC to supply the fixed market demand. Retiring RECs and other environmental commodities from a compliance market that exhibits a market scarcity, avoids the need to conduct project-by-project additionality determinations.

Like voluntary REC markets, whether a RPS compliance market is long can be evaluated based on REC wholesale prices. REC prices in these markets vary with the stringency of the RPS target and by technology type. A relatively clear indication that an RPS market is not long is when REC prices are at or near the penalty fee for non-compliance (Agnolucci 2007).

Chapter 5. Probabilistic decision model of wind power investment

To test the hypothesis that the voluntary REC market in the United States has, at most, a small marginal effect on the generation of electricity from renewable energy sources, this chapter presents results from an individual project investor model. This model is designed to simulate the decision making process of a representative wind power project investor and uses a Monte Carlo simulation of a project financial analysis. Data, in the form of probability distribution functions (PDFs) for key input variables were collected from interviews with investors and other professionals active in the U.S. wind power industry using a formal expert elicitation protocol.

The ideal approach to test the hypothesis would be to analyze a rich data set of implemented and proposed (but rejected) wind power projects. Unfortunately, the firms engaged in this industry treat specific information on individual projects and proposed projects as business confidential, especially with respect to the details affecting their selection of projects and decisions whether or not to invest. NREL maintains a database of existing wind power projects in the United States (Wiser and Bolinger 2011); however, this database lacks information on rejected project proposals, is not specific to the voluntary green power market, and is protected by confidentially agreements that prevent the release of data that would allow specific projects or developers to be identified. Further, a key component of this study is to understand investor expectations, especially for price variables, and the threshold for project investments to occur. Data of this type is not available from the NREL database. Instead, NREL data were compared with the results from the expert elicitation performed done for this study. These elicitation results for common parameters were found to be consistent with distribution of values found in NREL project database.

To overcome the research barrier of confidentiality, experienced experts in wind power industry firms were asked to describe their decision-making process and PDFs for key variables under a set of hypothetical cases intended to represent typical investment scenarios were elicited from each expert. As stated by Morgan and Henrion (1990), expert elicitation is a recognized technique in such situations: "When the value of an uncertain quantity is needed in policy analysis, and limits in data…preclude the use of conventional statistical techniques to produce probabilistic estimates, about the only remaining option is to ask experts for their best professional judgment." Similarly, the U.S. EPA defines expert elicitation as "a multi-disciplinary process that can inform decision making by characterizing uncertainty and filling data gaps where…data are not yet available" (USEPA 2009).

Model output is in the form of quantitative estimates of the effect that the voluntary REC market has on the probability that a hypothetical wind power project will be invested in. The expert elicitation process also produced valuable qualitative information through the exploring the rationale behind their each expert's judgments as well as a questions regarding the relationship between the voluntary REC market and their decision making.

Expert elicitation has been used previously to study carbon capture and storage costs (Chan, Anadon et al. 2011), renewable energy technologies (Curtright, Morgan et al. 2008), aerosol emissions (Morgan, Adams et al. 2006), and climate change (Morgan and Keith 1995). The influence of REC markets (both RPS compliance as well as voluntary) on renewable project investment has been discussed by Holt, Sumner et al. (2011), but their study lacked a quantitative analysis or effort to model the effect of REC markets. Bode and Michaelowa (2003) used an approach similar to this study when they investigated the additionality of renewable energy projects under the CDM. They constructed a single investor model, similar to the one used here,

and based their analysis on the expectations of various types of projects, including wind power, to exceed investment rate of return thresholds. They examined various CER price and average wind speed (a proxy for capacity factor) scenarios and concluded that wind power projects were, as a project type category, less likely to be additional under the CDM, relative to other project type categories.

Analogous to the claims made by wind power projects under the CDM, green power market proponents have claimed and argued that voluntary market RECs convey emission reductions, and therefore are generated by projects that are additional due to the intervention from the voluntary REC market. The results from this study represent the first quantitative estimates of the effect of the U.S. voluntary REC market, and therefore this study fills a gap in the literature that has important implications for the voluntary green power industry and policy makers.

5.1 Assumptions and scenarios

In providing their judgments, all experts interviewed were instructed to only consider U.S. wind power projects that would sell RECs into the voluntary green power market and to exclude projects from their consideration that do not (e.g., provide RECs to utilities solely for RPS compliance). These projects could be based in States without an RPS (or ineligible to sell into a State with an RPS) or in States where there is or expected to be eligible wind power generation in excess of RPS market demand (e.g., Texas).

For the purpose of the elicitation process and subsequent modeling, detailed assumptions on a limited number of specific hypothetical scenarios were defined. Each scenario differs in terms of the size of the wind power project and the buyer of the project's electricity. Table 6 summarizes the three project size scenarios.[68]

[68] The large project scenario represents a larger generation capacity than has historically supplied the voluntary REC market. However, there has been a trend of increasing project size along with increasing turbine size over time

Table 6. Project size scenarios

Scenario	Project generation capacity	
Small project size	33 MW	(22 x 1.5 MW turbines)
Medium project size	120 MW	(80 x 1.5 MW turbines)
Large project size	297 MW	(108 x 2.75 MW turbines)

To situate the experts, they were instructed to assume that all each project scenario was scheduled to begin operation on 1 January 2011, and therefore the project investment decisions would have been made during 2009 and 2010. Both the small and medium size projects were assumed to use General Electric (GE) 1.5 MW turbines, while the large project was assumed to use GE 2.75 MW turbines. The financial analysis considered a fixed 25 year project lifetime.

The 1.5 MW GE turbine model was selected because it accounted for the largest fraction of wind turbines supplied to the U.S. wind power market from 2006 to 2010, making up for 50% and 40% in 2010 and 2009 of wind power capacity installed in those years, respectively (Wiser and Bolinger 2011). Larger projects tend to select larger turbine sizes, therefore a larger turbine was assumed for the large scenario. The average nameplate capacity of wind turbines installed in 2010 in the United States was 1.79MW.(Wiser and Bolinger 2011).

All scenarios assumed that the project would be owned by an independent power producer (IPP) rather than an electric utility. IPPs have historically been responsible for the vast majority of wind power capacity investments (Wiser and Bolinger 2011). Although, more recently, some utilities have begun investing in their own wind capacity (Barradale 2010).

IPPs can sell the electricity they generate from wind under a Purchase Power Agreement (PPA), as a merchant plant (i.e., to a wholesale electricity spot market), or some combination of

(Wiser and Bolinger 2010). This scenario was included to investigate the effect of such a large project with larger turbines on the results.

the two. Most purchasers of PPAs are utilities. PPA terms range from 10 to 20 years. In 2009, 58% of wind capacity installed was under long-term PPA (Wiser and Bolinger 2010). In 2010, projects with some portion of their output intended for sale to the spot market accounted for 23% of added capacity (Wiser and Bolinger 2011). Most of this merchant activity occurred in Texas, New York and Illinois (Wiser and Bolinger 2010). For this study, two power sales scenarios were defined and are shown in Table 7.

Table 7. Electricity sales scenarios

Scenario	Output under PPA	Merchant output
PPA	100%	0%
Merchant	0%	100%

The scenarios assume electricity is either sold 100 percent under a PPA or 100 percent as a merchant plant, so as to isolate the effect of this variable.[69] To summarize, the four scenarios listed in Table 8 are analyzed in this study.

Table 8. Modeling scenarios

Scenario	Project Size	Electricity Sold
1 (Small)	Small	PPA
2 (Medium)	Medium	PPA
3 (Large)	Large	PPA
4 (Merchant)	Medium	Merchant

The U.S. Production Tax Credit (PTC) is an income tax credit for electricity produced by qualified wind turbines and other renewable energy facilities. It has been adjusted upwards annually for inflation, reaching $0.021/kWh ($21/MWh) in 2010. Renewable energy facilities

[69] Although not utilized for this study, the model is designed to be run with any combination of merchant and PPA pricing.

receive the PTC for their first 10 years of operation. The PTC was created under the Energy Policy Act of 1992 and expires frequently, requiring renewal by the U.S. Congress. Between 1992 and 2011 it has been renewed seven times, usually for one or two year at a time (Wiser, Bolinger et al. 2007; Barradale 2010; Lu, Tchou et al. 2011). Most recently, it was extended by Congress through 2012.[70] All scenarios in this study utilize the PTC; the annual inflator for the PTC is assumed to be 2 percent.[71]

It is common for the structure of wind power project finance to be designed around a need to accommodate the PTC (i.e., finding investors with appetite for the tax credit). A simple summary of typical financing structures is as follows:

1) Equity financing structures
    a) Single developer corporate equity (i.e., corporate balance-sheet finance). A single developer funds all of the project costs and has sufficient tax appetite to use all of the government tax benefits (no other investors or debt financing is initially involved) (Bolinger, Harper et al. 2009).
    b) Investor flip structures (structure that involves institutional tax-equity investors such as major banks and insurance companies)
2) Project-level debt financing structures (debt taken on by project developer against future cash flows and PTC benefits)

For the purpose of the elicitation and modeling, it is assumed that a single developer corporate equity structure (i.e., #1a above) was used in all scenarios. This form has historically been the most common financing structure in the U.S. wind power industry (Wiser and Bolinger

[70] Extension beyond 2012 is currently being debated in Congress as of this writing (May 2012).
[71] Congress has also permitted some projects to substitute the PTC for a cash grant or investment tax credit, the latter being a temporary option. To simplify this analysis, we will only consider the PTC.

2008). Few projects have been reported to utilize significant project debt (Harper, Karcher et al. 2007); however, more recently debt has been increasingly relied upon for project finance.[72]

In 2010, the annual U.S. inflation rate was reported to be 1.64% (www.inflationdata.com); a rate of 2% is assumed in the model over the project lifetime as well as a combined 39 percent federal and state income tax rate. Wind power projects are allowed, under Section 168 of the Internal Revenue Code, use an accelerated depreciation schedule (Schutzer 2010); the schedule assumed for this study is provided in Table 9.

Table 9. Assumed accelerated depreciation schedule

Years	Rate (%)
1	9.8
2	35.4
3	21.3
4	12.8
5	7.8
7	6.2
8	5.4
9-17	0.1

Table 10 summarizes the assumptions provided to experts as part of the elicitation protocol and used as inputs to the Monte Carlo model.

[72] A detailed discussion of wind power financing structures and trends is available in Schutzer (2010), Barradale (2010), Bolinger, Harper et al. (2009), Bolinger and Wiser (2009), and Cory and Schwabe (2009).

Table 10. Summary of elicitation and modeling assumptions

Parameter	Assumption
Project size scenarios	Small: 33 MW (22 x 1.5 MW turbines) Medium: 120 MW (80 x 1.5 MW turbines) Large: 297 MW (108 x 2.75 MW turbines)
Turbine model and size	General Electric (GE) 1.5 MW Except for large project size: GE 2.75 MW
PPA vs. merchant scenarios	100% PPA 100% Merchant (wholesale)
Use of PTC	Yes
Federal and State tax rates	35% and 4%, respectively
Financing Structure	Single developer corporate equity structure
Inflation rate	2%
Accelerated depreciation schedule	(see table above)
First year break in output	95% of capacity factor
Landowner royalties	3% of electricity revenues for first 10 years 4% of electricity revenues starting in year 11
Warranty fees	$45,000 per turbine per year for first 2 yrs $50,000/year per turbine for years 3 thru 5
Operations & Maintenance costs	$6-14/MWh, uniformly distributed[73] Following end of 5 year warranty period
Project energy usage costs*	$1,800/MW each year
Site administration costs	$7,000/MW each year
Insurance costs	$5,000/MW each year
Other hard capital costs Development costs Balance of plant Interconnection	 4% of turbine costs 20% of turbine costs 8% of turbine costs
Other soft capital related costs (i.e., equity closing costs, developer fees, working capital, and contingency costs)	10% of turbine costs

* Associated with onsite building(s) to store spare parts, staff offices and meeting space, lighting, HVAC, computer systems, etc.

[73] Based on data from Wiser and Bolinger (2011)

5.2 Data collection

5.2.1 Expert selection

Experts were selected for interviewing based on the extent of their direct experience in wind power project development and their specific experience with projects supplying the U.S. voluntary REC market. Also included in the sample were experts with experience in the wholesale buyer and marketing side of the voluntary REC market. All experts have experience with multiple projects over multiple years.

A total of seven (7) experts were interviewed using a formal elicitation protocol. Prior to these interviews, the elicitation protocol was piloted with a renewable energy project finance researcher at NREL, and revised based on expert feedback.[74] The names, titles, affiliations, and background of each expert are provided in Table 11.

Although this sample size would be considered small for a statistical survey, because expert elicitations produce data in the form of parameter PDFs, small sample sizes are considered accepted research practice. In their study of acid rain pollution, Morgan, Morris et al. (1984) elicited PDFs for two parameters using nine experts for the first and seven for the second. Similarly, Wallsten and Whitfield (1986) used five experts in their study of lead pollution effects. A series of studies have repeatedly confirmed that there are rapidly diminishing marginal returns associated with increasing numbers of experts in elicitation studies (Makridakis and Winkler 1983; Clemen and Winkler 1985; Ferrell 1985; Clemen and Winkler 1999; USEPA 2009). Ferrell (1985) suggested three to five experts was appropriate for most studies, while

[74] An eighth expert was interviewed but elected to not to have his quantitative judgments coded in this study. However, he did provide insightful qualitative input on the research question, which conformed to the majority opinion of other experts interviewed. The protocol was also piloted with a single expert from the National Renewable Energy Laboratory. Feedback from this expert directly lead to improvements that were implemented prior to its use for data collection.

USEPA (2009) reported that based on a survey of 38 expert elicitation studies, 90 percent employed eleven or fewer experts, and 60 percent relied on six to eight experts (USEPA 2009).

The total population of experts with extensive direct experience in wind power project investment analysis in the United States is likely to be in the range of only 50 individuals.[75] The companies represented by the experts listed below include the second largest wind developer in the United States and accounted for more than 25 percent of the U.S. wind capacity additions in 2010. Further, the parameters on which quantitative elicitation was performed are subject to market discipline as well as economic and technological constraints. The author is aware of no reason to expect selection bias has influenced the results presented below.

Table 11: Experts interviewed

Expert Name **Title** **Organization**	**Years of relevant experience**	**Role in industry**	**Number of projects**	**Typical project size**
Vikram Bakshi VP of Strategic Transactions Iberdorola	>8	Project developer	>15	60.1-140 MW
Brent Beerly Executive VP of Business Development Community Energy, Inc.	>8	Project developer REC marketer Public policy	11-15	20.1-60MW
Cameron Brooks VP of Policy Tendril	>8	REC marketer Advisor to developers	>15	10-25 MW
Alden Hathaway Senior VP Business Development Sterling Planet	>8	REC marketer	0-5	20.1-60 MW
Manuel Ramos VP - Renewable Power (employer confidential)	6-8	Project developer Investor	>15	60.1-140 MW

[75] Ten wind power project developers have accounted for roughly 95% of the total MW of installed capacity in the United States. The experts interviewed for this study commented that each company typically has a team of 4 or 5 staff members responsible for financial analysis, giving population of roughly 50, of which only a subset will have more than 8 years of direct experience.

Peter Toomey Originator, Energy & Environmental Products Iberdrola Renewables, Inc.	6-8	Project developer	>15	60.1-140 MW
Matt Williamson Managing Director Sparq Energy Advisors	>8	Broker Investor Advisor to investors	>15	20.1-60 MW
DRAFT PROTOCOL PILOT SUBJECT Paul Schwabe Energy Analyst National Renewable Energy Laboratory	3-5	Researcher	0-5	No response

5.2.2 Elicitation protocol

The formal expert elicitation protocol use was developed specifically for this study and used for all encoding of probabilistic judgment data as well as other interview questions. The protocol is in keeping with good practice as outlined in the literature on this method (Merkhofer 1987; Morgan and Henrion 1990; Keeney and von Winterfeldt 1991; Hora 1992; Otway and Von Winterfeldt 1992; Hora and Jensen 2002; Boring, Gertman et al. 2005; IPCC 2006; Slottje, Sluijs et al. 2008; USEPA 2009) and included content serving as a briefing book. The complete expert elicitation protocol is provided in Appendix B.

All experts voluntarily agreed to be interviewed, have their judgments encoded and have their identity published, except where noted. Each expert was assigned a letter code to maintain the confidentiality of his or her individual responses.[76] Individual interviews with each expert were scheduled more than one week in advance and conducted by phone.[77] The elicitation

[76] Letter codes do not correspond to alphabetical order.
[77] Individual, rather than group, elicitation approaches are recommended by NRC (1994) due to problems associated with biases that arise from group dynamics.

process included steps addressing each of the five components of the Stanford/SRI expert elicitation protocol process (Spetzler and Staehl von Holstein 1975; Morgan and Henrion 1990).

Motivating. At the beginning of each interview, the general purpose of the study was reviewed with the expert and time was first dedicated to engage in a conversational discussion to facilitate rapport development. Prior to the start of the encoding portion interview, a discussion was held regarding the documented tendency of experts to be over confident in the bounds of their quantitative estimates (Morgan and Henrion 1990). Specifically, each expert was informed of specific cognitive biases that they should be aware of as they consider their judgments during the elicitation process (Kahneman, Slovic et al. 1982; Morgan and Henrion 1990; IPCC 2006).

Structuring. Prior to the interview, each expert was required to read a background document on the study as part of a structuring phase of the elicitation. Experts were also required to review, also in advance of the interview, the full elicitation protocol to familiarize themselves with the format of the questions; establish unambiguous and precise definitions of the scenarios, assumptions, and parameters being elicited; and calibrate judgments with published background information relevant to each question. At the beginning of each interview, the fulfillment of this requirement was confirmed before the interview was continued.[78]

Conditioning. At the close of the parameter encoding step in the overall process, each expert was asked to consider and discuss specific reasons why the judgments they just provided may be biased and to consider other scenarios in which the actual values could be significantly higher or lower than the range they provided. Experts were also asked to identify any previously unstated assumptions their judgments could be conditional upon.

[78] Interviews were rescheduled if the expert had not yet fully met this requirement.

Encoding. The formal interview process included two major steps: (i) encoding PDFs for key model parameters, and (ii) discussion around six qualitative questions. At every point during both steps in the interview process, experts were encouraged to provide their own commentary and rationales.

Verifying. All quantitative and qualitative responses from each expert were documented and returned to them to verify that their judgments had been accurately recorded.

The encoding of a parameter (X) was in the form of a cumulative probability distribution function F, where $F(X) \equiv P[X \leq x]$ using fixed probability encoding methods. To specify F for each parameter, three data points on the distribution were collected from each expert: $P[X \leq X_p] \equiv p$, where p is equal to 0.05, 0.50, and 0.95, respectively. This format of data collection allowed for the presence of skewness in the specification of F (i.e., for non-Gaussian distribution functions to be used). To reduce the influence of an anchoring or overconfidence bias, experts were asked to provide judgments for upper and lower p values before being asked their judgment on the median value ($X_{0.5}$) (Kahneman and Tversky 1979; USEPA 2009).

PDFs were elicited for five model input parameters, which were selected based on a model sensitivity analysis using a range of values reported in the literature (Cory and Schwabe 2009; Wiser and Bolinger 2011). Although the value of several of these parameters varies significantly by region, experts were instructed to consider the full range of values across the United States. The five parameters are:

- Annual average electricity prices over a 25 year forward curve
- Voluntary Market REC Prices (for wind) over a 25 year forward curve
- Turbine cost
- Capacity factor
- Target rate of return

Following verification, elicited values from individual experts were combined as an un-weighted arithmetic mean (Equation 1),where *E* is the expected value for the parameter *x* at the *p* probability and *N* is the total number of experts. This method of combination has been repeatedly found to produce as good or better results than more sophisticated analytical (e.g., Bayesian) or behavioral methods of aggregation (Winkler 1971; Seaver 1978; Ferrell 1985; Gigone and Hastie 1997; Clemen and Winkler 1999; IPCC 2006).[79]

$$E_p = \frac{\sum_{i=1}^{N} x_{p,i}}{N} \quad \text{[Equation 1]}$$

5.2.3 Elicitation results

The results for the elicitation process are presented in three parts. The first part addresses the experts' responses regarding the appropriateness and representativeness of the assumptions and scenarios used in this study as well as the overarching assumption that investment decision making within the wind power industry can be represented by a financial analysis model. The second part provides detailed encoding results for each parameter's PDFs. Lastly, the third part summarizes results from a series of qualitative interview questions. Where available, elicitation results are also compared with published statistics. Based on these comparisons, no obvious selection bias was identified.

5.2.3.1 Confirmation of assumptions

All experts confirmed that the assumptions and scenarios presented to them in the elicitation protocol were appropriate for projects supplying the U.S. voluntary REC market (Table 12), given two primary caveats. The first was that the large project size scenario was acknowledged to be historically atypical. Second, that a 100 percent merchant plant project was seen as

[79] For a dissenting opinion on combining judgments see Keith (1996).

unlikely. As explained to the experts, this scenario was designed to explore the effect of this factor and that it was acknowledged that the pure merchant scenario was an idealized hypothetical; all experts expressed comfort with this approach and their ability to provide representative judgments for it. The experts also unanimously, and without caveats, confirmed that financial analysis was the basis for decision making within the industry with respect to project investments, thereby supporting the theoretical basis of the model used in this study. As stated by another researcher of voluntary green power markets: "Fundamentally, a project has to be financially viable to be built, and RECs should be viewed in the context of revenues and costs driving that build versus no-build decision" (Holt, Sumner et al. 2011).

Table 12. Elicitation results confirming appropriateness of model assumptions and scenarios

Expert	***Do these assumptions seem appropriate to you?***	***Overall, do you believe that a financial analysis model is a reasonable approach for predicting decision making by wind energy project developers and investors?***
A	Yes	Yes
B	Overall, yes	Yes
C	Appear fine	Yes, definitely
D	All seems fine, given comments	Yes, financial analysis is the basis for decision making.
E	Appear fine	Yes, I think so.
F	Looks good	Yes.
G	Looks good	Absolutely! We model everything multiple times

5.2.3.1 Quantitative parameter PDF encoding

Elicitation results were successfully obtained from quantitative encoding of all five key model parameters for all scenarios. For the two price variables, experts were allowed to select whether they were more comfortable providing responses on a nominal or real basis. Real prices were converted to nominal values using the assumed inflation rate in Table 10. Price data for

these two parameters were collected at intervals over the assumed 25-year project investment lifetime, allowing for a forward price curve to be interpolated for each expert and *p* value. These forward curves were then combined as described above.

5.2.3.1.1 Power prices

Figure 2 summarizes the combined electricity sales price elicitation results for the medium project size scenario under a PPA. The values for each year of this graph partially define a PDF for the parameter in that year, with each line functioning as the forward price curve at the given *p* value. Unsurprisingly, on a nominal basis prices were expected to increase over time and the spread (i.e., uncertainty) in the parameter's distribution also increases over time. Figure 3 then focuses on the responses from the experts for a single year, 2015, to illustrate the degree to which the judgments across experts varied. There was good agreement across experts and, as can be seen in the figure, the composite distribution captures most of the range reported by experts. One expert chose to not respond (NR) to questions on this parameter. For all parameters, a non-response from an expert was due to that expert voluntarily deciding that they lacked sufficient experience to make precise judgments on that particular variable. Power price elicitation results for the small, large, and merchant project scenarios are presented in Figure 4, Figure 5, and Figure 6, respectively. Smaller size projects were generally viewed as requiring higher power prices to be viable. And merchant projects, because of the increase risks associated with the lack of a contractual PPA, were reported to also require higher power prices to be viable. This increased risk is clearly visible in the greater range in future prices in Figure 6.

Figure 2. Elicitation results for power prices, medium project size scenario

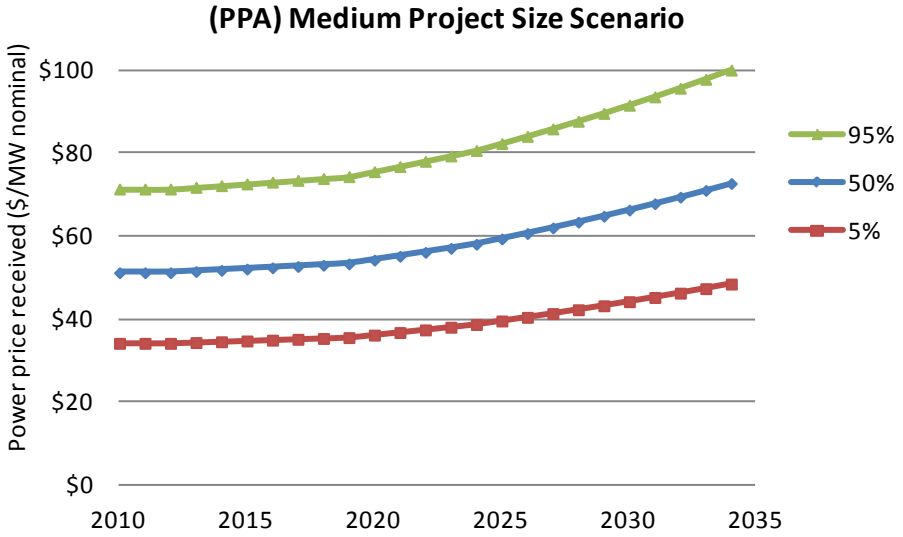
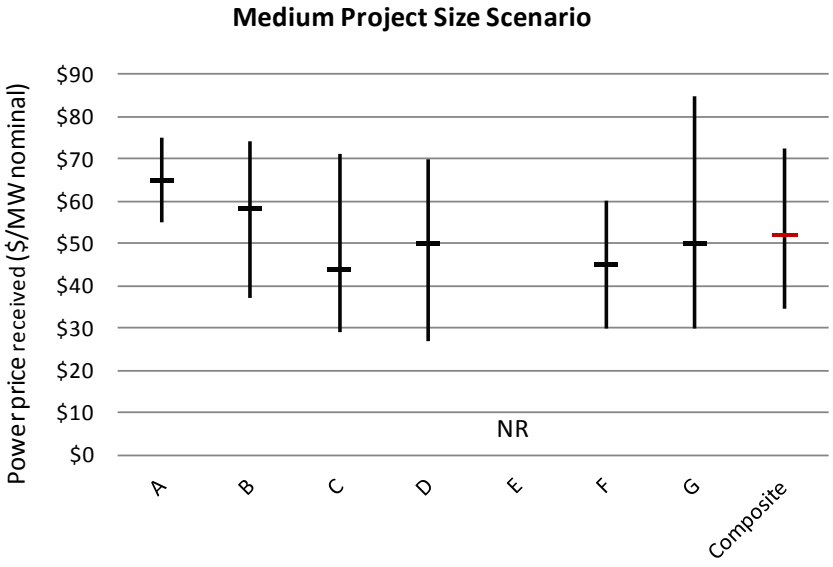


Figure 3. Sample of elicitation results for power prices for 2015, medium project size scenario



Note: Lower and upper ends of each line indicate the P(0.95) and P(0.05) values, respectively, while the hash mark indicates the median P(0.50) value.

Figure 4. Elicitation results for power prices, small project size scenario

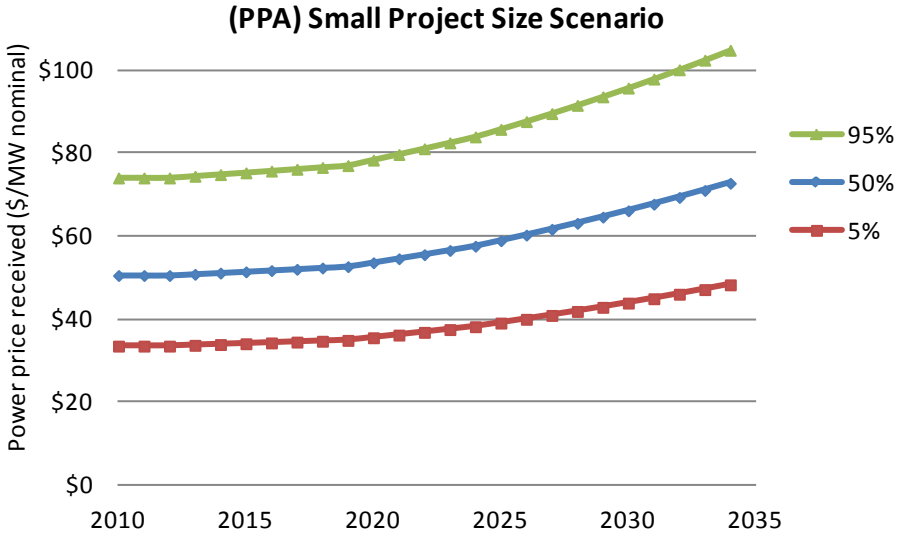


Figure 5. Elicitation results for power prices, large project size scenario

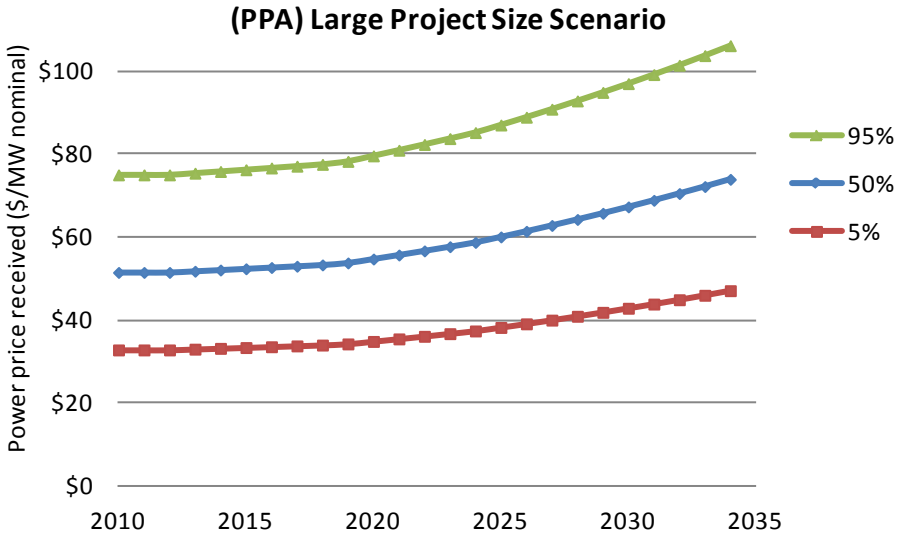
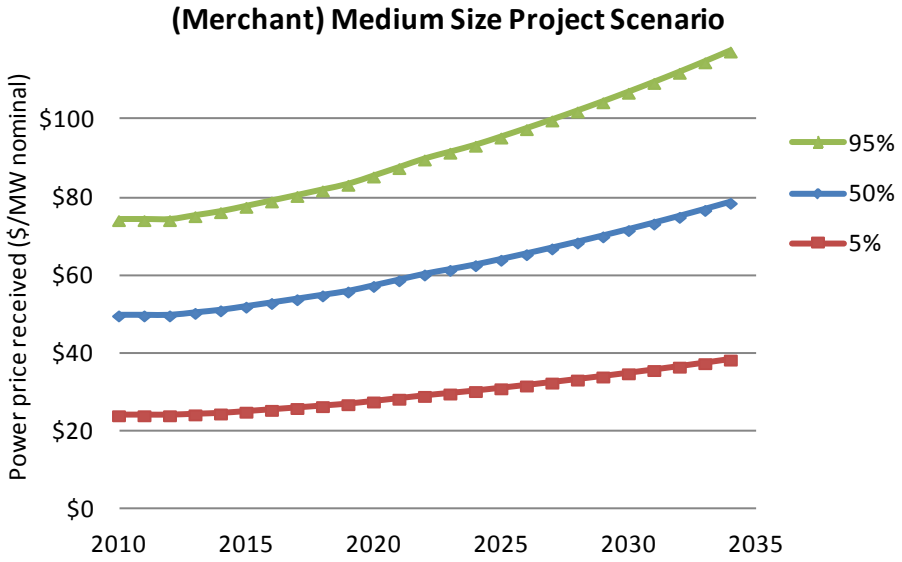


Figure 6. Elicitation results for power prices, merchant project scenario

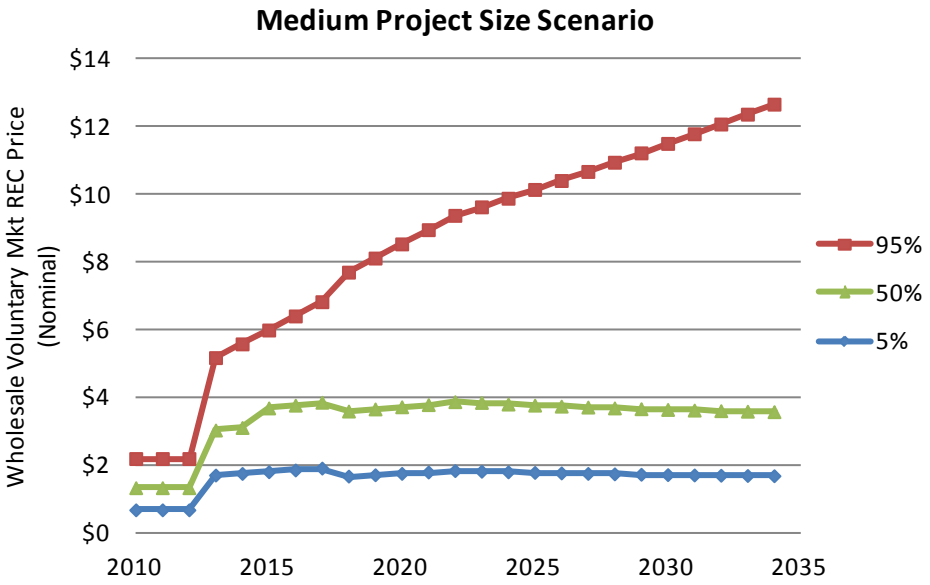


5.2.3.1.1 Voluntary market REC prices

Similarly, Figure 7 summarizes the combined elicitation results for the forward curve of U.S. voluntary market REC prices for wind power. The temporal pattern illustrated in these data was reported by the experts as being a function of the liquidity of the market. Firm forward contracts for wind power voluntary RECs are generally available for no more than three years in advance.

The experts were, on average, optimistic that prices will rise in the future, as indicated by the upward shift in the graph in 2013. This step change in prices was explained as being due to expectations for greater demand in the future from State RPS markets, which will lead to a reduction in supply of RECs for the voluntary market. The increasing skewness in the distribution of this parameter over time was also attributed by the experts as being a function of uncertainty in future government RPS policies, which could further drain supply from the voluntary market.

Figure 7. Elicitation results for voluntary market REC prices, medium project size scenario



Experts varied in their REC price forward curve expectations, which again were explained by differences in their beliefs about the likelihood and timing of expanded State and Federal government RPS policies. For example, experts A, C, and G had low expectations for future price increases. Expert E expected prices to decline. While experts B and D saw some chance of price increases, but with greater uncertainty.

Figure 8. Sample of elicitation results for voluntary market REC prices for 2015, medium project size scenario

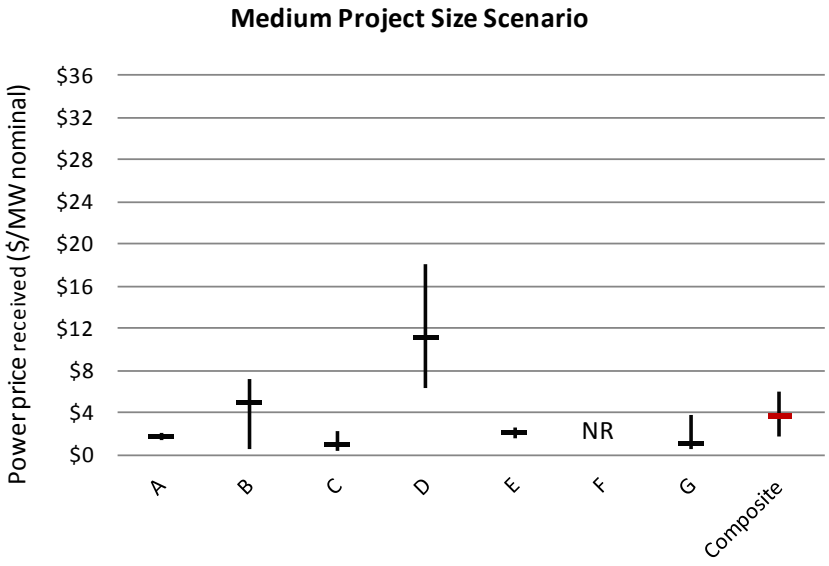


Figure 9. Sample of elicitation results for voluntary market REC prices for 2030, medium project size scenario

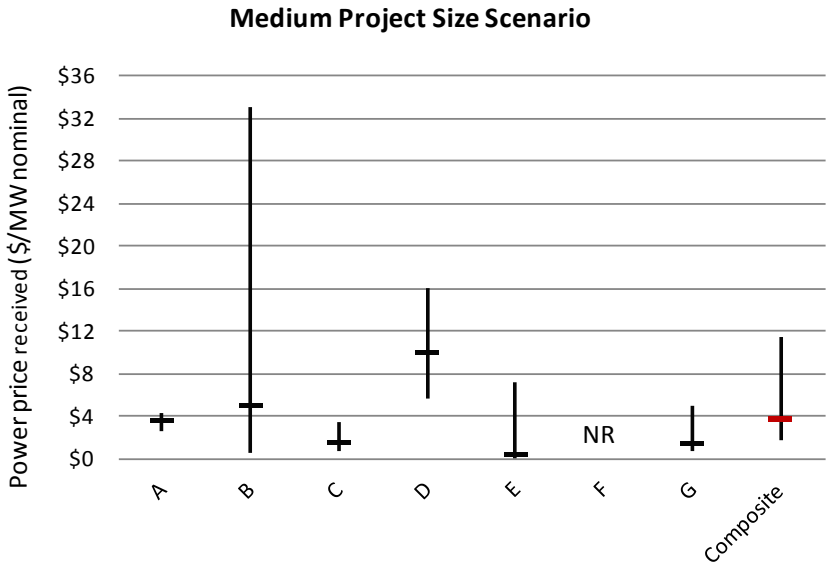


Figure 10 and Figure 11 present REC prices elicitation results for the small and large project scenario, respectively. Both show the same general price pattern, which was explained by the

experts as RECs being a predominantly a commodity product. However, some experts did see the potential for smaller ("boutique") projects to garner slightly higher prices, which is shown through the *p*(0.95) data in Figure 10. Data for this parameter was not collected for the merchant scenario, as there is no reason to believe REC price expectations would differ under this scenario; this was confirmed by the experts.

Figure 10. Elicitation results for voluntary REC prices, small project size scenario

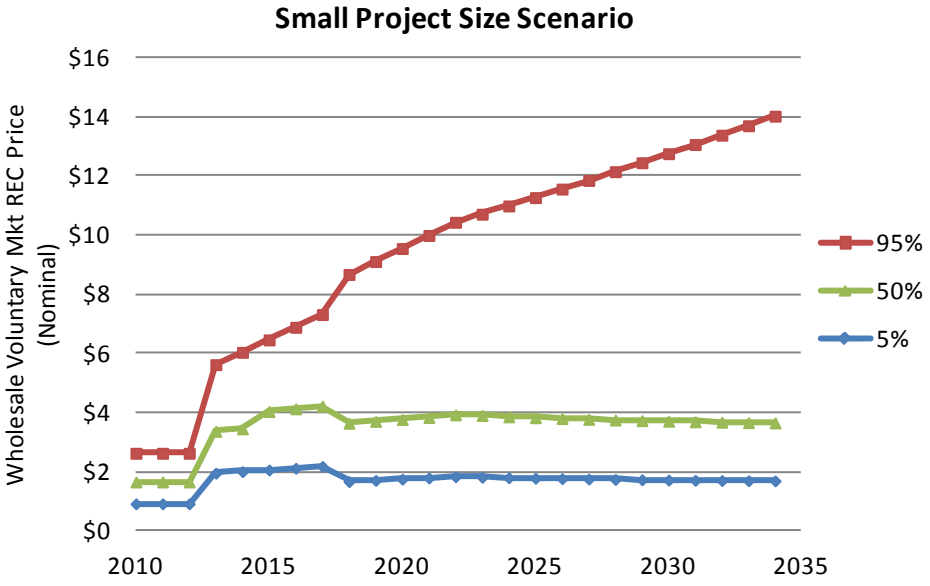
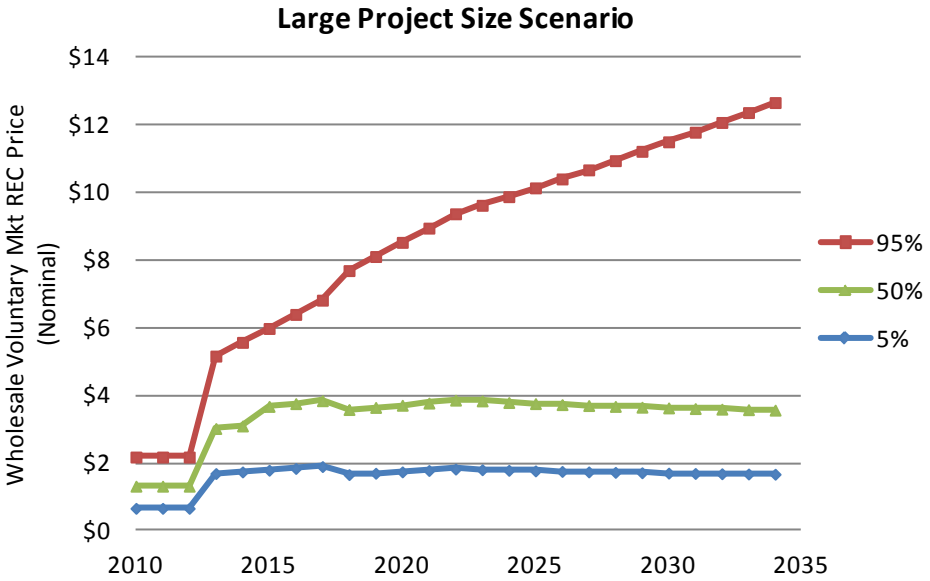


Figure 11. Elicitation results for power prices, large project size scenario



The REC prices discussed in this analysis are wholesale prices. The voluntary market is dominated by large commercial buyers, who are often able to negotiate prices with brokers that are not much above wholesale (Bird and Sumner 2010). However, small commercial and residential buyers will frequently pay a retail price for RECs that can be several times the wholesale price. A study of the green power pricing programs from NREL reported that the marketing and administration expenses of these programs range from $1.26 to 3.04/MWh (Friedman and Miller 2009), which is roughly equivalent to the wholesale prices reported in this study. Added to this cumulative amount is a profit margin, given that many brokers and retail firms in the voluntary REC market are for-profit.

5.2.3.1.1 Turbine prices

There was a good degree of consensus between experts on turbine prices under each scenario, as illustrated in Figure 12, Figure 13, and Figure 14. These results are consistent with data reported by NREL for wind power projects in the United States (includes projects not

engaged in the voluntary REC market), which gave a range a range of $900 to $1400/kW for 2010 and 2011 (Wiser and Bolinger 2011; Bolinger and Wiser 2012).

Figure 12. Elicitation results for wind turbine price, medium project size scenario

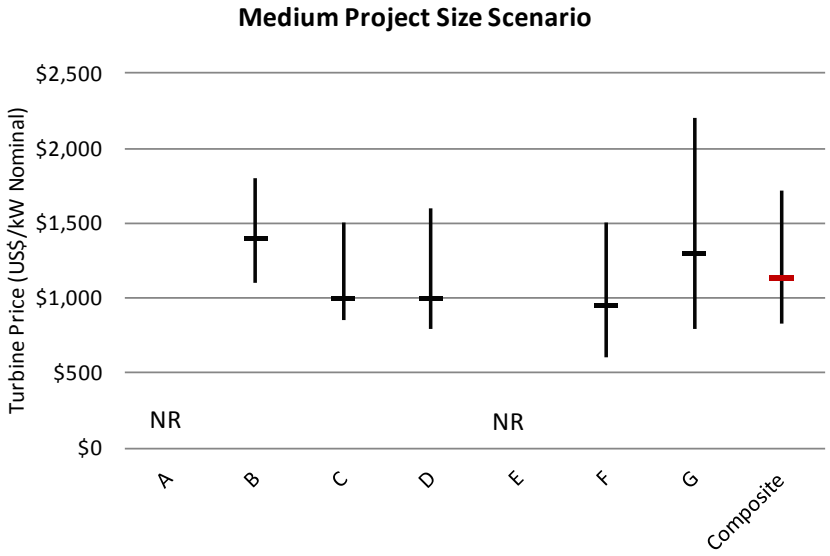


Figure 13. Elicitation results for wind turbine price, small project size scenario

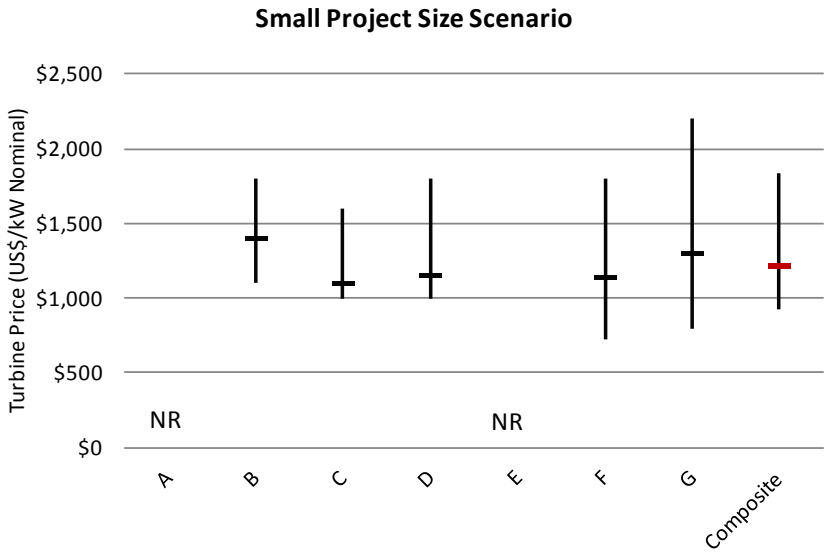
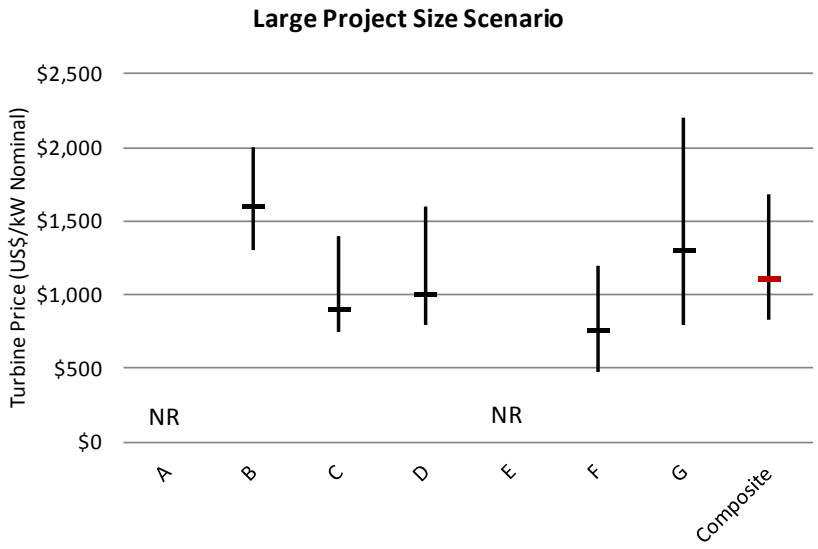


Figure 14. Elicitation results for wind turbine price, large project size scenario



5.2.3.1.2 Capacity factors

A similar degree of agreement was exhibited across expert judgments on the expected capacity factor for a project under each scenario (Figure 15, Figure 16, and Figure 17). These results differ slightly from those reported by NREL, which reported a range from 20 to 46% for projects in 2010 (Wiser and Bolinger 2011). The experts for this study agreed that projects with capacity factors in the low 20s of percent would not be viable for the voluntary REC market. This difference on the low end of the distribution is likely explained by projects being able to sell compliance RECs into states with high prices because of an aggressive RPS, especially in States in the Northeast of the United States.

Figure 15. Elicitation results for wind turbine capacity factor, medium project size scenario

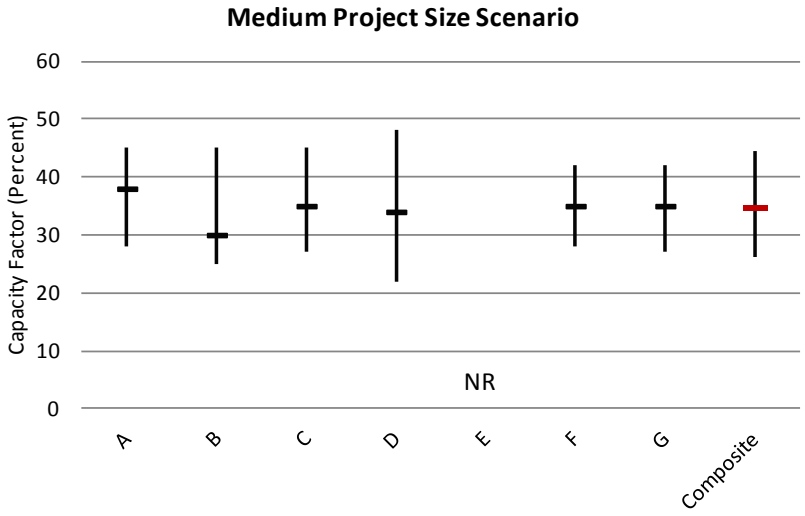


Figure 16. Elicitation results for wind turbine capacity factor, small project size scenario

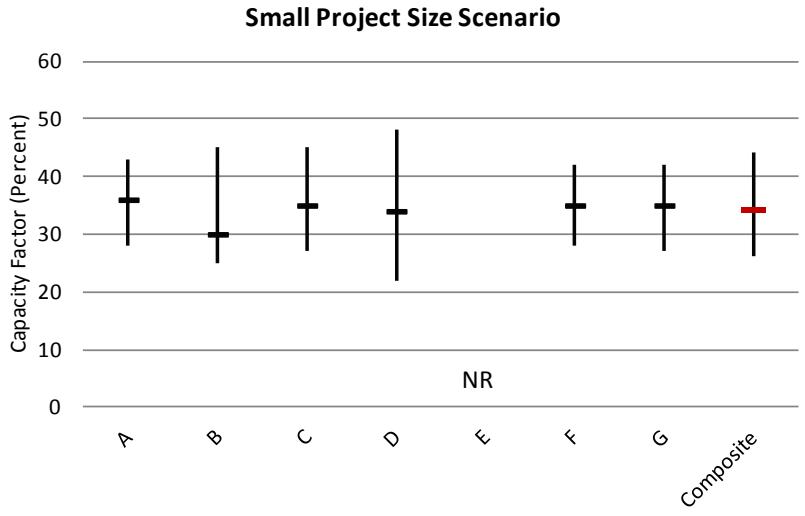
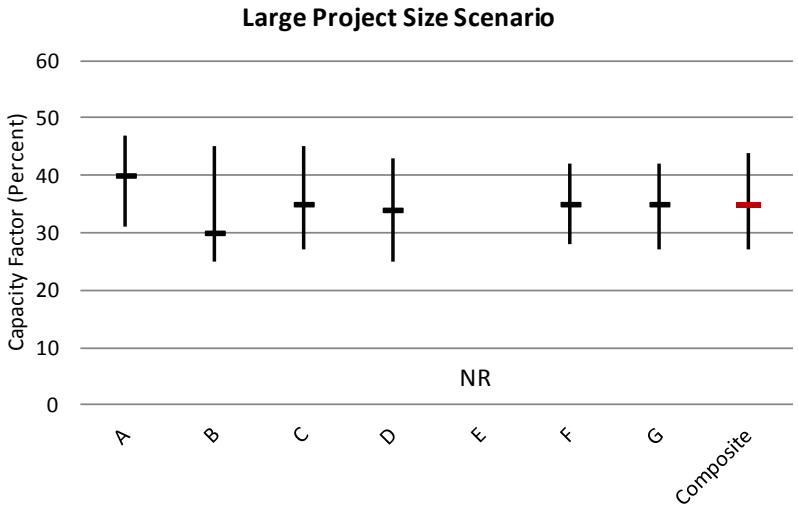


Figure 17. Elicitation results for wind turbine capacity factor, large project size scenario



5.2.3.1.3 Target rate of return

The target, or minimum, rate of financial return on a project is a key parameter in the decision making process of a wind power investor. It is also the parameter that investors treat as most confidential for a given project. However, the experts interviewed expressed comfort in presenting this data probabilistically for a hypothetical scenario (Figure 18, Figure 19, Figure 20, and Figure 21). Unsurprisingly, merchant projects were reported to require a higher return to compensate for the greater risk associated with going forward with a project without a PPA. Smaller projects were also reported to require a slightly higher rate of return.

Figure 18. Elicitation results for target rate of return, medium project size scenario

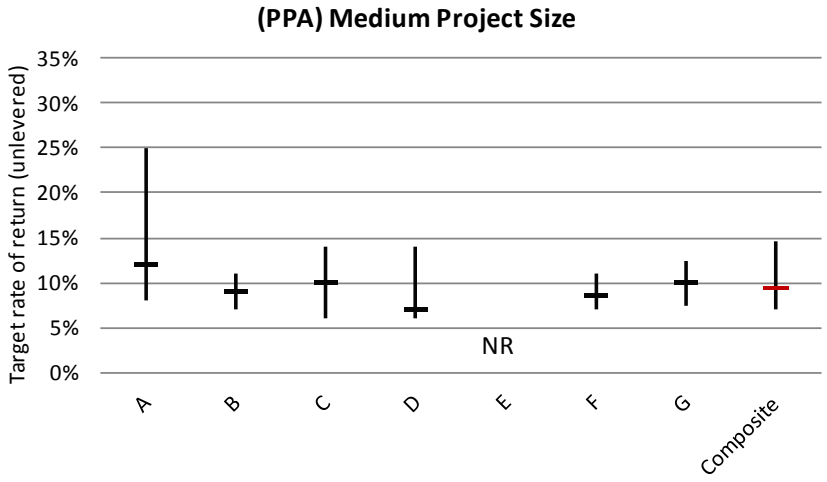


Figure 19. Elicitation results for target rate of return, small project size scenario

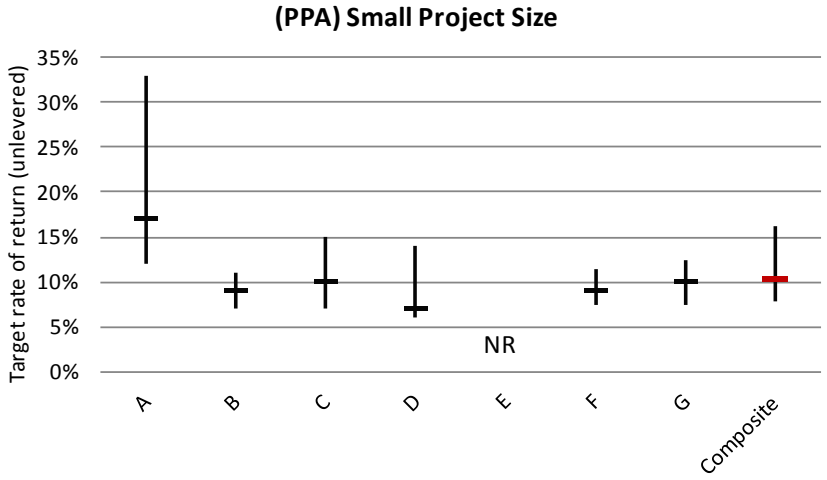


Figure 20. Elicitation results for target rate of return, large project size scenario

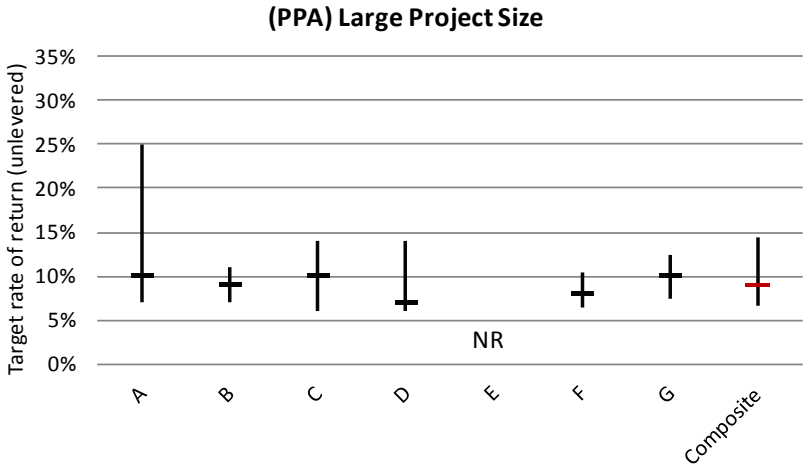
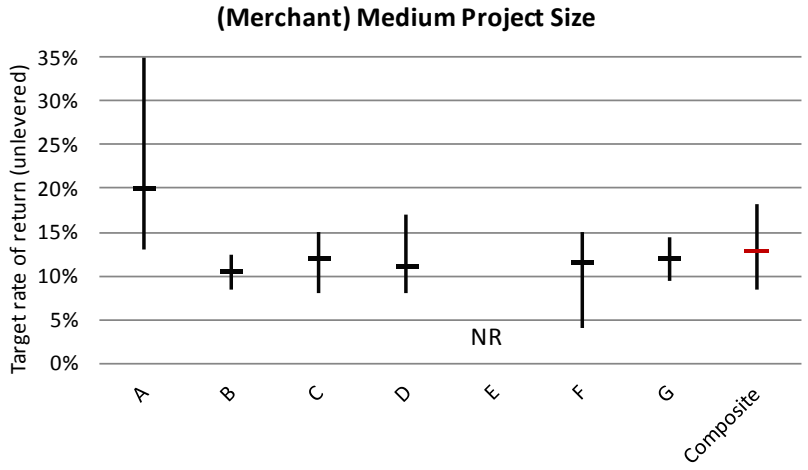


Figure 21. Elicitation results for target rate of return, merchant project scenario



5.2.3.2 Qualitative interview responses

To supplement the modeling results in this study, experts were also asked a series of qualitative questions regarding their experience and opinion of the voluntary REC market. These results are presented in Figure 22, Figure 23, and Figure 24.

Overall, most experts viewed the voluntary REC market as having little to no effect on project developer and their decision making. Further, they reported that, historically, the

voluntary REC market has had little effect on the expansion of wind power capacity in the United States. Instead, they reported that decisions were driven largely by RPS policies (both directly and indirectly) and the PTC. They not only cited low voluntary REC prices, but also stressed the inability to obtain a long-term sales contract for voluntary RECs as key impediments to the market affecting their decision-making. One expert stated, "without a long-term contract, it is a bit of green-washing." While another explained that voluntary market RECs were, as an instrument "unsuitable" for influencing investment decisions because the contracts for them were so short-term; instead that decisions were driven by utility PPAs. He further offered that, in his experience, project developers do not even discuss the voluntary REC market in their decision making process. Other dominant decision making factors cited by the experts were uncertainty over extensions of the PTC and future expansion of RPS policies. These qualitative results are in keeping with those from Holt, Summer et al. (2011).

Figure 22. Interview responses to the effect of green power market on U.S. wind power investment

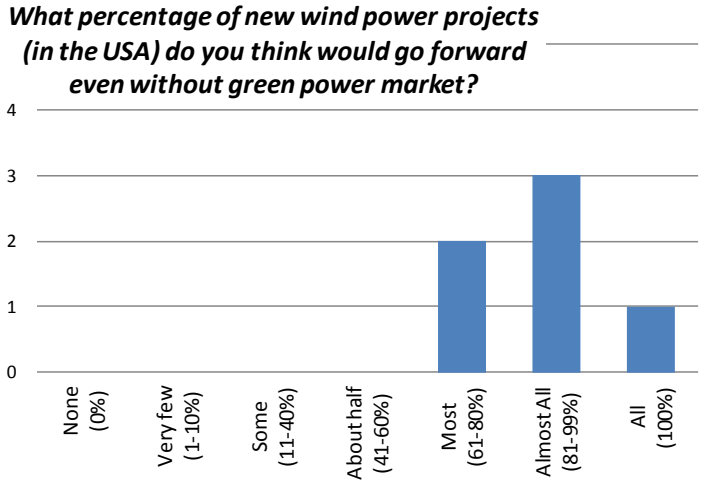


Figure 23. Interview responses to the effect of green power market on experts own wind power projects

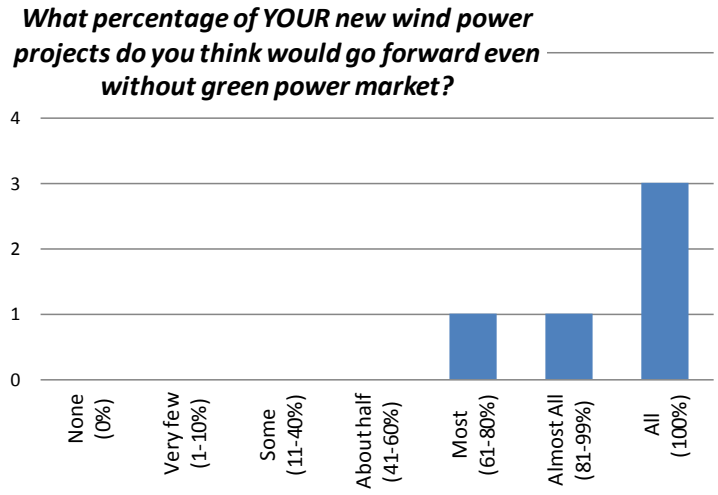
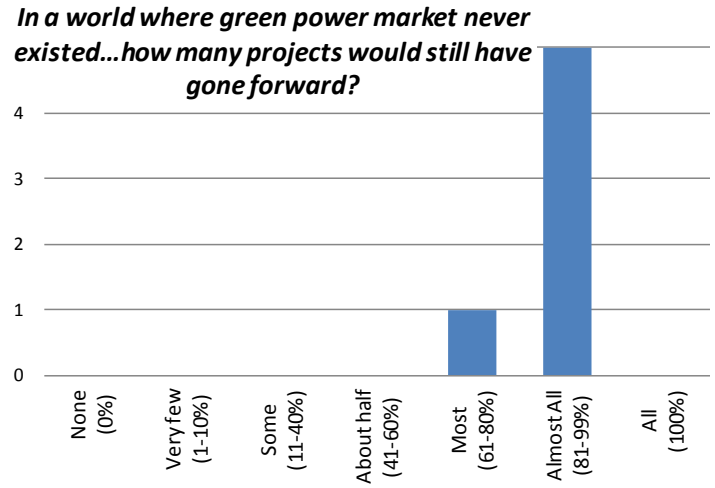


Figure 24. Interview responses to a historical hypothetical question about a world without the green power market



A majority did agree, though, that there have been some exceptional cases, such as a few small community wind projects, where a voluntary initiative that involved a long-term and legally binding financial commitment for a material fraction of project financing or revenue could have altered a decision. Several experts also conjectured that the voluntary green power

market may have had the indirect effect of engaging parts of the public in renewable energy issues and thereby building more political support for state RPS policies and the federal PTC. In discussions, a number of experts volunteered that, again, while revenue from the voluntary REC market was not factored into their investment decisions, it was sometimes modeled and treated as "potential upside" for project developers.

To explore the potential for bias in the expert selected, they were asked for their overall perspective on the future of the wind power industry in the United States. Experts F and G reported being generally pessimistic while all other experts reported being generally optimistic. Quantitative parameter responses exhibited no clear correlation with whether the expert's future expectations were optimistic or pessimistic.

Overall, the quantitative modeling results above are in general agreement with these qualitative results, both indicating a lack of additionality resulting from voluntary REC programs. This concurrence is in keeping with the assumption that project investment decisions are largely determined by a financial analysis. It also indicates that project developers do not appear to share the perspective of retail REC marketers and buyers, who implicitly or explicitly make additionality claims with respect to RECs.

5.3 Modeling methodology

The quantitative results from the expert elicitation, combined across experts, were used to generate aggregate PDFs for the five key parameters and, in combination with the assumptions outlined above, used as inputs to a Monte Carlo financial (i.e., Net Present Value) model of a single representative project investment decision. In this model, it is assumed that decision makers must satisfy a minimum financial return to invest in a project. The model and output variables are described by the Equation 2, Equation 3, and Equation 4.

$$NPV = 0 = \frac{\sum_{n=1}^{N}(-K_n) + \sum_{t=1}^{T}\sum_{j=1}^{J}[Q_{j,t} - C_{j,t}]}{(1+r)^t} \quad \text{[Equation 2]}$$

$$S = r - Z \quad \text{[Equation 3]}$$

$$I = \begin{cases} 1\ , & S \geq 0 \\ 0\ , & S < 0 \end{cases} \quad \text{[Equation 4]}$$

Where,

- K_n is initial capital cost item *n*
- $Q_{j,t}$ is revenue stream item *j* at year *t*
- $C_{j,t}$ is project cost item *j* at year *t*
- T is the life of the project (25 years)
- r is the rate of the return for the project when the Net Present Value is set to zero (i.e., the Internal Rate of Return)
- Z is the target rate of return
- S is the spread (i.e., difference) between the calculated rate of return and the target rate of return and P(*S*) is the probability distribution function of *S*
- I is a binary variable which has the value of 1 if the project is invested in and 0 if not
- E(*I*) is the expected value of *I*; it is the probability of investment when *r* is calculated as a PDF using a Monte Carlo method.
- E(*S*) is the expected value of S; it is the mean difference between P(*Z*) and P(*r*)

The model was run for each of the four scenarios under conditions with and without a voluntary REC price signal. Two key model output variables (i.e., outcome criteria) were defined. The first, ΔE(*S*), is the change in the probability that a project will be invested in for each scenario under conditions with and without the influence of the voluntary REC market (i.e., "spread from target"). The second, ΔE(*I*), is the change in the probability that this spread is greater than or equal to zero (i.e., invest? yes or no?).

Monte Carlo simulations were run using @Risk™ software, 10,000 iterations, and Latin Hypercube sampling across each input parameter PDF.

A standard form distribution was fitted to each input parameter to create a continuous PDF from estimates at the discrete *p* values developed through the expert elicitation phase. As illustrated in the previous section, the PDFs for each of the parameters are skewed, as well as being limited to positive values. Two experts, during the interview process, stated that triangular

distributions were the default assumption in their own project risk modeling. The triangular distribution is often used in cases where there is preference for simplicity and one wishes to indicate that the detailed shape of the distribution is not know (Morgan and Henrion 1990). However, it was not possible to fit a triangular distribution to three of the five parameters. A lognormal distribution is typically employed for parameters that are constrained to being non-negative and positively skewed, and was therefore assumed for all five parameters.[80]

To investigate the assumption of a lognormal distribution shape, unpublished data was provided by NREL from their wind project database on 2010 capacity factors for projects constructed in 2009 and installed project cost for those constructed in 2007 thru 2010 (the latter being a proxy for turbine costs, which is the largest component of total project costs).[81] Using a Kolmogorov-Smirnov statistic to fit various standard distributions to this NREL data confirmed that a lognormal shape provided a relatively good fit for both capacity factor and turbine costs.[82]

Because of the confidential nature of investment decisions within the industry, model validation was limited to testing against a small number of proposed project cases provided by a single project developer under the agreement that no information be published that could identify a specific project or the source of the cases. This small sample included project proposals that were and were not invested in. The model produced results consistent with these decisions, as shown in Table 13. Although this small-sample test is consistent with the ability of the model to

[80] The Gamma distribution is similar to the lognormal distribution. It is less positively skewed and less "tail-heavy." Replacing, where possible, the lognormal distribution assumption with a Gamma or a triangular distribution significantly alter the overall findings of this study. It was not possible to fit a triangular distribution to all parameters nor was it possible to fit a Gamma distribution to the later years of the REC price forward curve due to their degree of positive skewness.

[81] Personal communication with Mark Bolinger at NREL via email (dated 2 March 2012). No confidential was provided by NREL.

[82] The lognormal distribution K-S statistic for capacity factor was 0.0745 (n=103); the K-S statistic for installed cost was 0.0708 for projects <60MW (n=114) and 0.0513 for projects ≥60 to <200MW (n=141).

make gross distinctions with respect to investment decisions, this study's findings must be qualified by the lack of a richer dataset to validate a statistically error rate for the model.

Table 13. Model validation cases (only projects engaged in selling voluntary market RECS were included)

Variable	**Case I**	**Case II**	**Case III**	**Case IV**	**Case V**
Turbine price ($/kW)	$1488	$1459	$1121	$1290	$1149
Levelized PPA price	$80.04	$82.74	$105.40	$73.65	$34.45
Assumed capacity factor	34.5%	33.1%	31.2%	26.8%	39.48%
Project invested in?	*Yes*	*Yes*	*Yes*	*No*	*No*
Model prediction E(*I*)	0.74	0.69	0.99	0.11	<0.01

Another potential source of bias in the model is that the inputs are based upon investor's expressed preferences rather than revealed preferences. However, the experts interviewed are, in general, in the business of making decisions using input parameters identical or similar to those encoded through elicitation. So, although the limited verification of the model does not allow for the presence of this bias to be dismissed, there is reason to expect that there is not a strong divergence between the expressed and revealed preferences of the experts.

To investigate the sensitivity of the model to a single expert, the data from randomly chosen experts were removed from the analysis and the PDF inputs to the model recalculated. Randomly removing a single expert from the study did not substantially alter the quantitative results presented below.

No input parameter correlations were employed in the model. Wiser and Bolinger (2010) did show a correlation between the installed cost of wind projects and power price (i.e., more expensive projects require more revenue) and a small negative correlation between capacity factor and power price (i.e., more productive projects are able to sell power at a lower price). The effect of including these correlations in the model would be to constrain the model from

"considering" the full range of hypothetical projects and would raise the overall probability of investment predicted by the model across all cases but not the relative probabilities between cases.

Although not included in this model, there is a good argument for employing autocorrelation over time in the electricity and REC prices samples. If a project receives a high or low electricity price in year *t* then it is likely to receive a similarly high or low price in year *t*+1, respectively. In this model, the electricity and REC prices in each year were treated as independent from their respective prices for other years. When tested, introducing autocorrelation to the model for the price parameters had no effect on the results, although it did produce results that more sensitive to initial conditions and therefore required a greater number of model iterations.

5.4 Modeling results

Table 14 summarizes the results for all four scenarios studied. Within each scenario, data are provided for four cases: 1) a project without revenue from the voluntary REC market, 2) a project where the entire forward curve of revenue from the voluntary REC market was incorporated into the decision making process, 3) a project where only the first 3 years of revenue from the voluntary REC market was incorporated, and 4) a project occurring in the absence of the PTC.

E(*I*) can be interpreted as an estimate of the probability that a project will be invested in, given the assumptions discussed above. And E(*S*) can be interpreted as an estimate of the mean difference between the representative investor's minimum rate of return and the project's expected rate of return. ΔE(*I*) is then an estimate of how much the specified intervention changes the probability of investment, relative to the baseline case without revenue from the voluntary REC market (but with the PTC), and ΔE(*S*) is how many percentage points an intervention increases or decreases the rate of return.

Table 14. Summary of modeling results

Scenario / Case	**E(*I*)**	**E(*S*)**	**ΔE(*I*)**	**ΔE(*S*)**
Small Project				
No RECs (baseline)	0.27	-3.0	-	-
w/ RECs	0.32	-2.1	**0.06**	0.9
RECs 3 years only	0.28	-2.9	**0.01**	0.1
No PTC	0.01	-8.3	**-0.26**	-5.3
Medium Project				
No RECs (baseline)	0.48	-0.1	-	-
w/ RECs	0.54	0.7	**0.06**	0.8
RECs 3 year only	0.48	-0.03	**0.001**	0.1
No PTC	0.05	-5.9	**-0.43**	-5.8
Large Project				
No RECs (baseline)	0.60	1.4	-	-
w/ RECs	0.65	2.2	**0.05**	0.8
RECs 3 year only	0.60	1.5	**0.003**	0.1
No PTC	0.10	-4.7	**-0.50**	-6.0
Merchant Project				
No RECs (baseline)	0.48	0.0	-	-
w/ RECs	0.55	0.7	**0.06**	0.8
RECs 3 year only	0.49	0.03	**0.01**	0.1
No PTC	0.06	-5.6	**-0.43**	-5.6

Note: E(*I*) is a probability value [0,1]. E(*S*) is in percentage points.

E(*I*) and E(*S*) values generally increasing with project size. The change from a scenario based on revenue from a PPA to a merchant plant scenario, though, had little effect on the results, indicating that the higher risk of a merchant plant is balanced by a requirement by investors for a higher minimum rate of return, as would be expected by economically rational investor behavior.

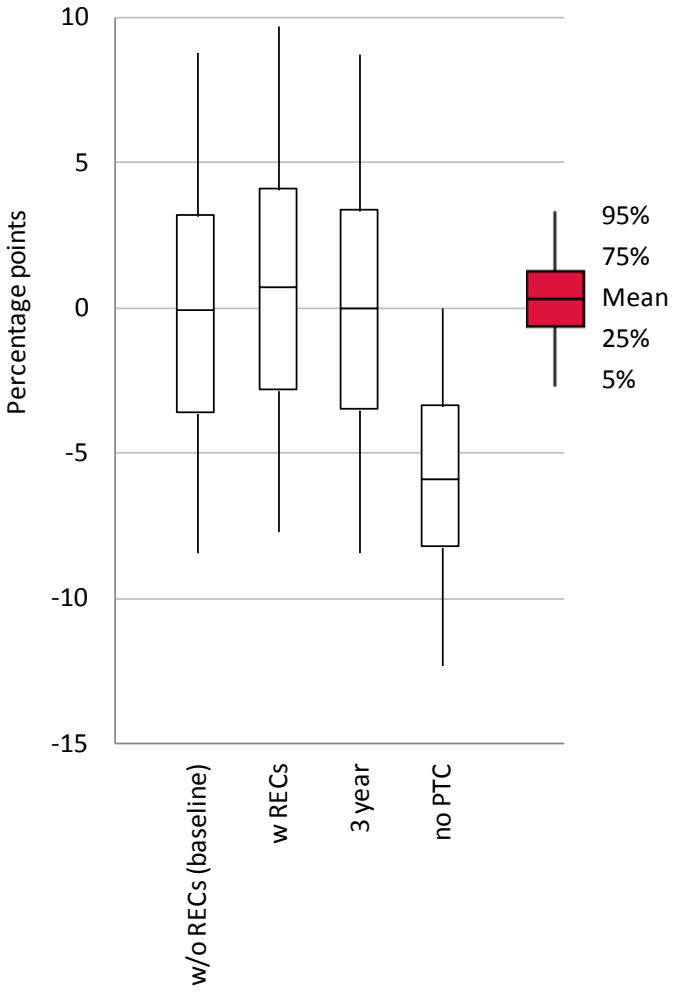
The key statistics for answering this study's research question are ΔE(*I*) and ΔE(*S*) for the two cases that incorporate voluntary market RECs. Across scenarios, it was found that the voluntary REC market, if fully incorporated into decision making, increases the probability of

project investment between 5 and 6 percentage points and increases the expected return to investors between 0.8 and 0.9 percentage points.

Because forward contracts for RECs are generally available for no more than 3 years, a case was also specified assuming REC revenue for only the first three years of a project. For this case, it was found that the voluntary REC market increases the probability of investment by at most 1 percentage point and the rate of return by 0.1 percentage points. Several authors have reported that investors, especially project debt lenders, typically place a zero or near zero value on revenue from RECs unless they are under a firm purchase contract from a utility or other creditworthy buyer (Cory, Coughlin et al. 2008; Holt, Sumner et al. 2011). However, equity investors, as assumed in this study, may be more willing to assign some amount of value to RECs that lack a contract for their sale (Cory, Coughlin et al. 2008). The experts interviewed for this study expressed differing opinions on their willingness to consider voluntary market REC revenue, although most indicated it is either disregarded or heavily discounted. A reasonable interpretation of these results is that the true average behavior for investors falls somewhere in between the "w/ RECs" and "RECs 3 years only" cases, with a bias towards the latter.

For both cases that incorporated RECs, the influence of the voluntary REC market was found to be small compared the influence of the PTC, which increased the estimated probability of investment by 26, 43, and 50 percentage points for the small, medium, and large project scenarios, respectively (and increased the expected rate of return between 5 and 6 percentage points). Figure 25 illustrates these results though the distribution of each case's *S* value for the medium project size scenario.

Figure 25. Box plot of *S* for medium project scenario

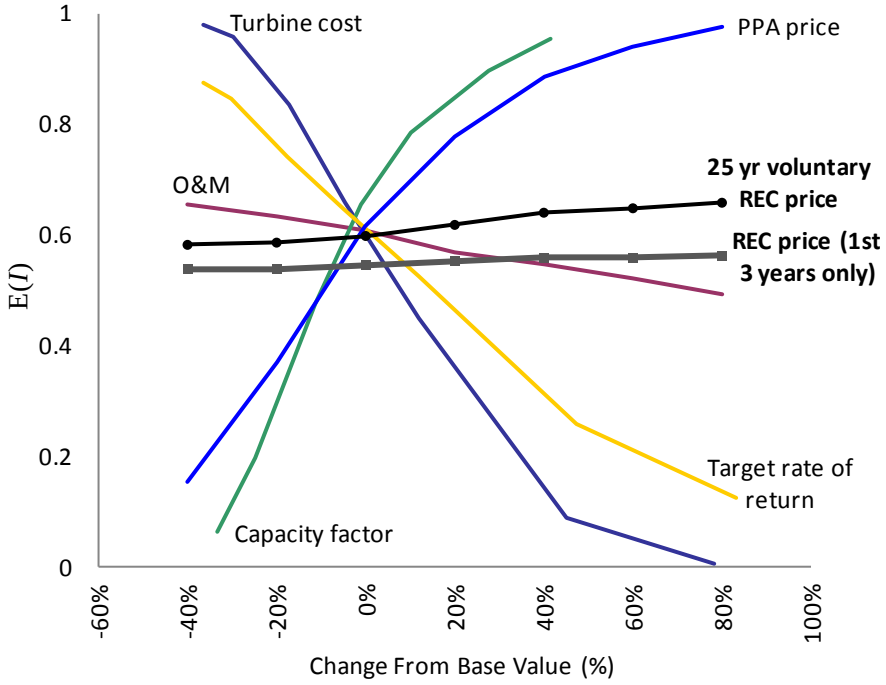


The value of RECs to project investors, as presented in the forward curves in Figure 7, Figure 10, and Figure 11, can be compared to the pre-tax value of the PTC to investors. The pre-tax PTC subsidy rate can be calculated as $21/(1-marginal tax rate). Assuming a marginal federal tax rate of 35 percent, the PTC is then produces a pre-tax revenue stream of $32.31/MWh in 2010 dollars (Wiser, Bolinger et al. 2007). Therefore, not only is the intervention produced by the PTC less risky than that produced by the voluntary REC market, it is also roughly eight times

as large in magnitude.[83] For another comparison, Bolinger and Wiser (2009) estimated that the subsidy value to wind power projects of the accelerated five year depreciation schedule for federal income taxes is roughly equivalent to a pre-tax subsidy of $14/MWh.

The overall sensitivity of the model to the key input parameters is presented in Figure 26. The model is highly sensitive to turbine cost, capacity factor, PPA price, and target rate of return. Consistent with the previously presented results, E(*I*) showed far less sensitivity to REC price.

Figure 26. Model sensitivity to key input parameters

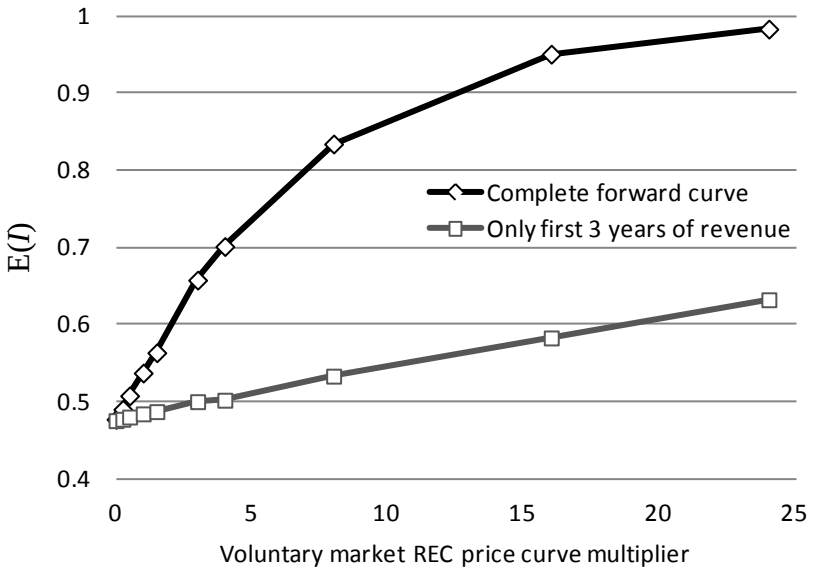


Note: Base value is set at p(.50) for each parameter. Sensitivity results presented for medium size scenario.

[83] Note, that the PTC crediting period is set under existing legislation as the first ten years of operation while the voluntary REC market certification programs recognize a 15 year crediting period.

Figure 27 extends this sensitivity analysis and focuses the influence of REC prices. These results indicate that the expected value of voluntary RECs would need to increase by more than an order of magnitude (i.e., multiplier of ~13) and be able to be sold by developers under a firm long-term contract (e.g., 10 to 25 year) for the voluntary green power market to have an effect on wind power project developer decision making equivalent to that of the PTC. Further, even dramatic increases in voluntary market REC prices, in the absence of long-term contracts, were found to have only a small effect on investor behavior.

Figure 27. Variation of E(*I*) as a function of a multiplier on voluntary REC price curve



5.5 Discussion

Multiple authors have identified investment in additional wind power generation capacity to be largely driven by government incentives (Wiser, Bolinger et al. 2007; Bolinger and Wiser 2009; Barradale 2010; Lu, Tchou et al. 2011; Lüthi and Prässler 2011). Lüthi and Prässler (2011) found, based on a conjoint analysis of survey responses from 102 wind power project developers

around the world, that in addition to providing a minimum risk-adjusted rate of return, projects can be prevented by other barriers such as "ill-structured" permitting procedures, costly interconnection rules, uncertainty in the stability of policies, and social acceptance[84]. They also found that preferences were "quite homogeneous" across developers of different size, role in the industry value chain, and level of experience. This latter conclusion lends support to the assumption that an expert elicitation of a small sample of experts can provide representative results. Alagappan, Orans et al. (2011) summarized these issues and identified the following key features of a successful wind power project:

1) A well-suited site with a good wind resource
2) Easy interconnection to the transmission grid
3) A buyer willing and able to pay a premium price
4) A committed long-term revenue stream
5) A "renewable-friendly" transmission tariff that does not penalize for intermittency or reserve capacity

In the United States, the voluntary REC and broader green power market is intended to address the third factor above by providing a mechanism for customers pay a premium to renewable energy developers that is separate from the sale of electricity.

However, the results of this study indicate that the investment decisions of wind power project developers in the United States are unlikely to have been altered by the voluntary REC market. The problem with the current voluntary REC market is that it does not offer developers a significant risk-adjusted revenue stream.[85] Consequently, direct or indirect claims that voluntary

[84] See Agterbosch, Meertens et al. (2009) for a detailed discussion of the importance of social factors on wind power investment.
[85] It has also been noted that revenue from voluntary market RECs is viewed as higher risk because there is little price transparency. Most RECs do not trade on open exchanges (Cory, Coughlin et al. 2008).

market RECs, as an environmental commodity, result from additional wind power projects in the United States lack credibility.

The diversity in judgments expressed by experts elicited for this study was largely due to their future expectations of the voluntary REC market. Yet, even these expectations were found to be a function of government policy. The experts explained that their expectations of future increases in voluntary REC prices were due the competing demand for RECs that the expansion of state, and possibly federal, RPS policies would entail. The central questions regarding future voluntary REC prices then become whether RPS policies will actually expand and the response of green power market participants to that expansion and rising REC prices.

For the voluntary REC market to drive investment in wind power generation and produce additional emission reductions, the market will need to foster both higher prices and a standard of long-term purchase contracts. Yet, absent a dramatic change in consumers' willingness to pay, it is not clear this is a feasible solution. [86] Assuming it is allowed in RPS legislation and the presence of a compliance REC market that is not long (i.e., RPS quota is binding), then allowing consumers to purchase and retire compliance RECs, thereby forcing utilities to find additional supply, could replace the existing voluntary REC market and be a credible solution.

As discussed in Gillenwater (2008c) and Friedman and Miller (Friedman and Miller 2009), it is more accurate to think of participation in the voluntary REC market as a donation to charity (though, the receiving firms, wind power developers, and investors are typically for-profit

[86] A number of willingness-to-pay studies have been conducted on voluntary green power markets around the world. These studies have identified a variety of psychological and other factors that partly explain consumer participation. This dissertation does not explore these demand-side issues, but the reader is referred to the literature on this topic for information (Roe, Teisl et al. 2001; Rose, Clark et al. 2002; Clark, Kotchen et al. 2003; Kotchen and Moore 2007; Diaz-Rainey and Ashton 2008; Hansla, Gamble et al. 2008; Ozaki 2009; Diaz-Rainey and Ashton 2010; Litvine and Wüstenhagen 2011; Mewton and Cacho 2011; Oliver, Volschenk et al. 2011).

entities).[87] Although customers are told by green power marketing firms that they are buying a product (i.e., "green electricity" or "green power"), RECs do not actually convey a tangible private service or good to the customer. First, RECs can be unbundled from sale of electricity. And second, all grid-connected electricity consumers functionally purchase an undifferentiated product from their supplier, which is undifferentiated kWh of energy in the form of electricity. So even in situations where RECs remain bundled with the sale of an electricity product, there is no tangible differentiation in product quality. Like many other voluntary environmental markets, there are challenges in converting what is inherently a public good into a private good. As currently structured, the voluntary REC market in the United States may be better described as an effort to commoditize charity than a market for the sale of a green product, such as organic food.

The approach used in this study could be improved by looking at regional differences in key parameter values. Many of the experts interviewed noted that regional differences are key factors, such as state and utility commission-level regulations and market dynamics that affect decision-making. The primary regional factors cited by experts were quality of wind resource, wholesale electricity prices in a particular market, and renewable energy demand created by state or local RPS legislation. The following chapter explores these three factors. The study could also be expanded to look more deeply at the influence of the PTC and other policy changes. These are potential areas for future research.

[87] As cited in Friedman and Miller (2009), a select few green power marketing programs have actually communicated their activities as being charitable and tax-deductible.

Chapter 6. Additionality of wind energy investments in the U.S. voluntary green power market

6.1 Introduction

In the United States, electricity consumers are told that they can "buy" electricity from renewable energy projects, versus fossil fuel-fired facilities, through participation in voluntary green power markets.[88] The marketing messages communicate to consumers that they are causing additional renewable energy generation and reducing emissions through their participation and premium payments for a green label. The retailers that operate in this voluntary green power market typically purchase Renewable Energy Certificates (RECs) from renewable energy project developers to resell to their customers. The vast majority of the U.S. voluntary green power market is based upon wind power projects to supply these RECs (Bird and Sumner 2010; Heeter and Bird 2011).

The marketing promises and claims are debated, but it has not been well-established through quantitative analysis whether this voluntary environmental market leads to additional investment in renewable energy generation (Gillenwater 2008a; Harmon 2009; Bird and Sumner 2011; Holt, Sumner et al. 2011). Once built, wind energy facilities can be operated with very low variable costs (i.e., once built there is little economic disincentive not to have them operate at their maximum capacity), and so any influence the voluntary green power market has on the amount of electricity produced from wind (as well as solar) must be in the form of additional generation capacity from either new construction or repowering of existing facilities. If voluntary green power markets do not lead to additional investment then consumers who pay a premium to

[88] For example see the U.S. Environmental Protection Agency's Green Power Partnership at http://www.epa.gov/greenpower/index.htm.

participate in these markets and retailers who promote the purchase of RECs are being mislead and misleading, respectively.

The present study explores the influence of the voluntary REC market on wind energy project finance using a dataset of projects registered with the Green-e[89] program in 2011. In 2010, Green-e certified generation accounted for 65% of the U.S. voluntary green power market, and the vast majority of Green-e registered generation capacity is wind power (CRS 2011). Further, the vast majority of the U.S. voluntary green power market is associated with wind power (83%) and some form of REC transaction (56 to 85%)[90] (Heeter and Bird 2011). Therefore, the focus on wind power projects associated with the Green-e program is assumed to be a reasonable proxy for the broader voluntary green power market.

More specifically, this chapter examines the economic feasibility of these Green-e registered wind power projects under scenarios that include and exclude the economic incentive provided by the voluntary green power market. It builds upon the spatial financial model described in (Lu, Tchou et al. 2011), which incorporates geographic factors including wind resource availability and the costs of grid connection at each project site. The wind resources data take advantage of a high-resolution spatial and temporal wind dataset—derived from assimilated meteorological fields compiled by NOAA—to derive project-specific generation capacity factors (Benjamin, Brown et al. 2002).

In the process of completing this analysis, a potentially relevant factor in explaining investor behavior was identified: the potential for the overlap of voluntary REC markets with compliance REC markets that supply utilities need to meet their obligations of Renewable Energy Portfolio

[89] The Green-e Energy program certified retail and wholesale green power products and is administered b the Center for Resource Solutions and is the largest such program in the United States. See http://www.green-e.org/.
[90] The lower estimate includes only unbundled REC market while higher estimate also includes green power transactions in competitive electricity markets in which RECs typically remain bundled with power sales.

Standard (RPS). It was initially assumed that most wind power projects were limited to either supplying RECs to voluntary or compliance-based REC markets, and so the influence of these two market mechanisms on actual investment patterns could be examined independently. However, upon examination of the projects registered with Green-e, the likelihood of this assumption of independence was found to be low. The majority of state RPS rules allow for regional or even national sourcing of RECs, meaning that projects are generally eligible to provide compliance RECs to utilities not only in their home states, but in several other states (Fischlein and Smith 2012).

Section 2 describes in more detail the datasets, assumptions and model used in this study. Results are presented and discussed in Section 3, followed by summary conclusions in Section 4.

6.2 Data and model description

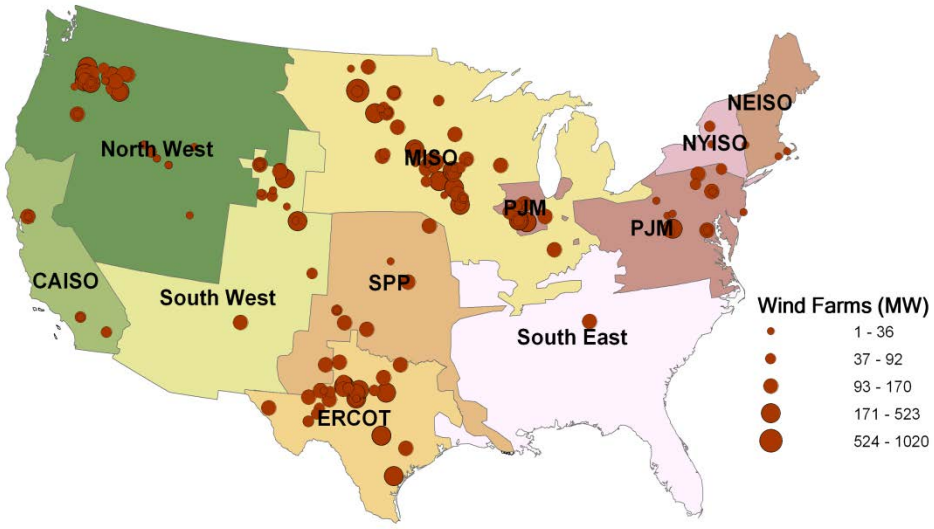
A dataset of 386 renewable electricity generation facilities that have been registered with and approved by Green-e Energy—based on the submission of tracking attestations—was used as representative of the broader voluntary green power market (CRS 2011). Of these facilities, 86% are wind on a nameplate capacity-weighted basis. Only wind facilities were included in this study.

The CRS database includes information on nameplate capacity, state in which the facility is located, and operational date. Importantly, the Green-e program does not publish data on how many Green-e certified RECs each facility sells. Latitude and longitude information on each facility was added to the dataset using information from TWR (2011) and NREL (2011). Location data were not available from these sources for a subset of facilities (4%). For these facilities, press releases and local utility commission permitting documents were used in

combination with satellite imagery from Google and Bing maps to visually locate and geo-code the approximate geographic center of each facility.[91]

Facilities located in Canada, facilities with nameplate capacities less than 10 MW, as well as a small number of facilities (13) for which geo-coded location data could not be found were excluded from the sample. In total, 7% of the U.S. wind generation capacity in the Green-e database was excluded from the present study, resulting in a final sample size of 248 observations. The geographic distribution of facilities and their generation capacities is presented in Figure 28. Table 15 summarizes the geographic distribution of projects according to the regional certificate tracking system to which they reported. The capacity-weighted age of the final sample is 3.0 years (as of January 1, 2011), with a standard deviation of 2.9 years, so the majority of facilities in the sample went online between 2004 and 2010.

Figure 28. Map of regional electric grids in the contiguous United States with illustration of locations and capacities of wind facilities considered in this study



[91] A single wind facility can include numerous turbines spread over a large area (e.g., multiple acres).

Table 15. Geographic distribution of wind project sample by generation capacity

Tracking System	Approximate Geographic Equivalent	Percent of Capacity in Sample
ERCOT	Texas	30%
MRETS	Northern Midwest states	27%
WREGIS	Western states	27%
PJM-GATS	Eastern mid-Atlantic states	14%
NAR	Southeast and Southern Midwest states	2%
NE-GIS	New England states	1%

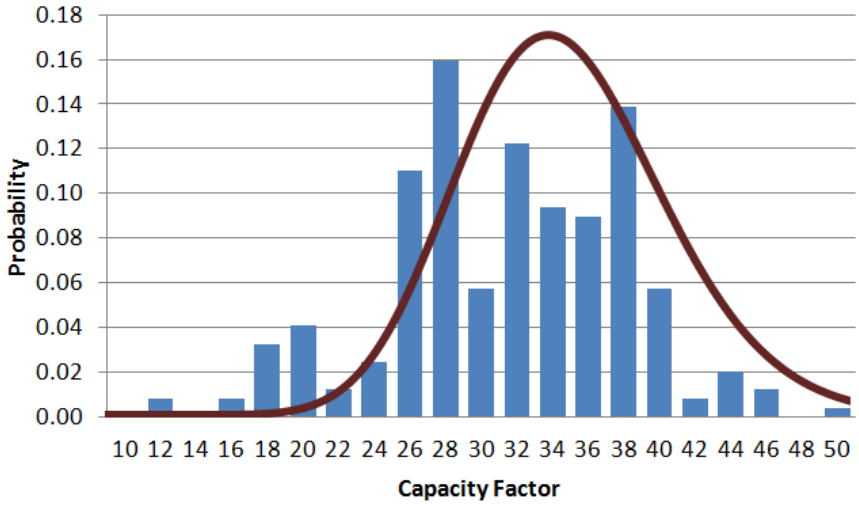
Detailed documentation of the spatial financial model used in this study is provided in Lu, Tchou et al. (2011) and therefore only a summary description is provided here. Wind data were derived using NOAA's assimilated meteorological fields, RUC-20, which provides a spatial resolution of 20 km by 20 km (Benjamin, Brown et al. 2002). Wind speeds at a 100 m elevation were interpolated and used to calculate turbine electricity generation and capacity factors. The output of each turbine in a given grid cell is calculated hourly using a power curve for a GE 2.5 MW turbine (GE 2006) and aggregated over the entire year.

The annual average capacity factors resulting from this approach were then adjusted upwards across the sample based on a statistical comparison with the probability distribution of capacity factors for voluntary market wind projects reported in Chapter 5.[92] Figure 29 shows the distribution of unadjusted capacity factors compared with the distribution developed from an expert elicitation of U.S. wind power industry professionals. Specifically, the capacity factor for each project in the sample was adjusted upwards by 4 percentage points. Projects with capacity factor values that were still less than 26% were then adjusted up to this floor value. The rationale for this adjustment is that project developers choose to site turbines to maximize capacity factors and will not invest in projects with capacity factors below a minimum value. The average wind

[92] Chapter 5 contains the results of a formal expert elicitation of investment decision makers in the wind power industry and includes a probability distribution of capacity factor values for wind energy projects.

speed for a grid cell, therefore, is likely to be an under estimate of actual capacity factors achieved. Ultimately, though, the conclusions presented below were unaffected by this adjustment.

Figure 29. Unadjusted distribution of capacity factors across sample (bars) and expert elicitation distribution (line)



The financial component of the model analyzes the net present value (NPV) over a 25 year capital lifetime to estimate the levelized cost for a project to deliver electricity to the grid with a NPV of zero given an assumed internal rate of return (IRR, r_d) (Equation 1).

$$NPV = \sum_{n=1}^{25} (revenue - \cos t)_n (1 + r_d)^{-n} = 0 \qquad \text{[Equation 1]}$$

Project revenue of a wind facility was estimated as a combination of electricity sales and a 10 year $21/MWh subsidy, in the form of a tax credit, from the U.S. Production Tax Credit (PTC). The financial model was adopted here to estimate the levelized cost of generation of

electricity from wind for each facility. Electricity prices in the local power market were based on the annual average wholesale price in the state in which a project is located. Projects in the United States also benefit from accelerated depreciation rules and obtain revenue from the sale of RECs, the latter of which is discussed in the following section.

Wind power projects entail capital, operations & maintenance (O&M), grid interconnect, and tax costs. For this study, all projects were assumed to face costs in keeping with a typical investment. Specific cost assumptions are summarized in Table 16 and Table 17. A scenario analysis was conducted on the three major project costs.

Table 16. Fixed model cost assumptions

Parameter	**Assumption**
Federal income tax	35%
Financing Structure	Single developer corporate equity structure
Accelerated depreciation schedule	MARCS: 20%, 32%, 19%, 12%, 11%, & 6% applied for the first five years of operation
Minimum IRR	7%

Table 17. Model cost assumptions for Reference, Low and High cost scenarios

Parameter	**Reference cost**	**Low cost**	**High cost**
Capital cost ($/kW)	1,700	1,300	2,100
Transmission connection cost (million $/mile)*	10	6	14
O&M costs ($/MWh)	1.0	0.6	1.4

* Calculated based on shortest distance to existing transmission line.

The Lu, Tchou et al. spatial financial model has been validated on a dataset of wind projects coming online in the United States during 2006 and 2007 to confirm its ability to predict sites where investments in wind projects are economically feasible (Lu, McElroy et al. 2011). However, the conclusions presented here are nonetheless limited by the representativeness of the assumptions on cost parameters, electricity prices, and REC prices.

Data on RPS eligibility was based on primary textual analysis of all relevant state statutes, regulatory codes and administrative rules for the 30 states that had mandatory renewable portfolio standards as of August 2009. A total of 115 documents were coded for policy design aspects using the NVivo 8 qualitative analysis software. State data was then matched to the individual project based on location and age of the facility.

6.3 Results and Discussion

Wind power project investors in the United States are able to earn revenue from the sale of RECs, which they can add to the revenue sources from electricity sales and other subsidies. There is not one REC market in the United States, but instead multiple overlapping markets with which wind power facility managers may engage.

Until recently, there have also been two voluntary markets for wind power RECs in the United States, with one market price existing in the western portion of the country and a lower price for the broader national market (Table 18). In last couple of years, though, the prices for RECs in the Western United States have converged with prices at the historical low end of the national market range, effectively merging these two markets.

States with RPS policies use a variety of rules to determine whether the generation or capacity of a particular wind power facility is eligible to be counted towards compliance of a load serving entity (LSE) (Fischlein and Smith 2012). Of the 30 states (including the District of Columbia) with mandatory RPS regulations, less than half allow LSEs to use RECs to track compliance while also having a sufficiently liquid REC market for spot market prices to be available. These states, and their corresponding range of spot market prices, are presented in Table 18, along with the fraction of generation capacity in the sample that is eligible to participate in the REC market for that state.

Table 18. U.S. REC markets, spot market price ranges, and portion of sample eligible in each category

Category	**REC price range**	**Eligible capacity in sample (MW)[c]**
Voluntary REC market[b]		
National wind	~$1 - 2.50	21,448.7 (100%)
West wind (WECC)	~$3 - 7	14,150.7 (66.0%)
RPS State eligibility[a]		
CT, NH, MA, RI	~$15 - 25	143.6 (0.7%)
DC, IL, NJ, PA, DE, MD, TX, OH (out of state)	~$1 - 5	20,377.4 (95.0%)
ME	~$7	2.8 (<0.1%)
OH (in state)	~$10 - 34	0
Other RPS states	NA	21,448.7 (100%)

[a] Approximate average prices over 2010-2011 (Wiser and Bolinger 2011)
[b] Approximate average prices over 2008-2010 (Bird and Sumner 2010)
[c] Percentages are fraction of total capacity in sample.

One of the key findings of this chapter is the degree of overlap between RPS compliance markets for RECs and voluntary REC markets. This overlap is illustrated in Table 18 by the large fraction of the sample (95.7%) that is eligible to sell RECs into a liquid RPS compliance REC market as well as a voluntary green power market. On average, a facility in the sample was eligible to be counted towards compliance in 7.2 states, while the minimum number of states for which a facility in the sample met eligibility criteria was four.

The eligibility of RECs produced by an individual wind project for RPS compliance is a function of rules around geographic origin and the facility's in-service date. Rules on the geographic origin of compliance RECs fall in three categories: 1) for RECs to be counted towards RPS, the associated energy either has to be physically delivered to the state, 2) delivered to the region, or 3) there are no restrictions on nationwide trade (Table 19). For a small number of states (CO, DE, KS, MN, MO, NC), RECs from anywhere are eligible, but the more common approach is to restrict RECs to regional origin or to project delivering electricity to the state. Twelve RPS states each have such requirements. Eighteen RPS states also restrict the age of

eligible resources by excluding RECs from facilities in service before a certain date. Finally, the liquidity of each state's market for RECs is also influenced by their provisions on how RECs can be used. While all states use RECs in some form for tracking purposes, AZ and WI do not allow RECs to be sold separately from the physical electricity. In addition, states with pure capacity (rather than generation) requirements do not create RECs markets. In practice, wind facilities across the United States are generally eligible to sell into more than one state compliance market.

Table 19. State RPS eligibility rules for the use of RECs from renewable energy facilities

State	Online after[a]	Unbundled RECs[b]	Location eligibility rules
AZ	NA	Not permitted	Delivered to WECC control area
CA	2005	Capped	Generated in state or first point of interconnection to WECC control area
CO	2004	Permitted	NA
CT	NA	Permitted	Delivered to ISO-NE control area
DC	NA	Permitted	Delivered to PJM control area
DE	1997	Permitted	NA
HI	NA	Permitted	Generated in state (island)
IA	NA	NA	Generated in state or utility's service area
IL	NA	NA	Generated in state (through 2011) and adjoining states thereafter)
KS	NA	Capped	NA
MA	1997	Permitted	Delivered to ISO-NE control area
MD	NA	Permitted	Delivered to PJM control area
ME	2005	Permitted	Delivered to ISO-NE or NMISA control areas
MI	NA	Permitted	Generated in state or service territory of provider
MN	NA	Permitted	NA
MO	NA	Permitted	NA
MT	2005	Permitted	Delivered to state
NC	2007	Capped	Unbundled out of state REC capped at 25%, remainder delivered to state
NH	2006	Permitted	Delivered to ISO-NE control area
NJ	2003	Permitted	Delivered to PJM control area (new resources), generated in PJM area (existing resources)
NM	2004	Permitted	Delivered to state
NV	NA	Not permitted	Delivered to state
NY	2003	NA	Delivered to NYISO control area
OH	1998	Permitted	At least 50% generated in state, remainder delivered to state

OR	1995	Capped	Generated in US and WECC control area, delivered to state
PA	NA	Permitted	Generated in control area (PJM,ISO-NE)
RI	1997	Permitted	Delivered to NEPOOL-GIS area
TX	1999	Permitted	Generated in state
UT	1995	Capped	Generated in WECC control area or delivered to utility
VT	2004	Permitted	Generated at facilities owned by or under contract with VT utilities
WA	1999	Permitted	Generated in Pacific NW, or delivered to state
WI	2004	Not permitted	Delivered to state

[a] Facilities that began operation before this data are ineligible.
[b] RECs can be sold separately from wholesale electricity.

The spatial financial model described in the previous section was used to isolate and investigate the influence of voluntary REC market prices on the economic feasibility of the projects in the sample dataset of Green-e registered facilities. National and Western voluntary market REC prices of $2.1/MWh and $6.7/MWh were used based on the approximate average values reported in Wiser and Bolinger (2011). For each facility in the sample the spread between the average price for electricity in the power market and the levelized cost of generation of electricity from wind was calculated. These levelized costs incorporate factors such as the PTC and accelerated depreciation. The resulting difference can be thought of as approximating the profitability of a project above the investor's minimum rate of return.

Figure 30, Figure 31, and Figure 32 present the results from the model for the three cost scenarios. The individual data points in each figure present the cost versus revenue spread excluding any revenue from RECs. The line above the points incorporates revenue from the sale of RECs into a voluntary REC market, assuming ideal market conditions and that all RECs from the facility's generation are sold into the voluntary market. The jagged feature of the "ideal voluntary REC" line is due to the application of the higher REC price for facilities located in the Western Electricity Coordinating Council (WECC) region. The figures show that under ideal conditions, the effect of voluntary REC markets on the economic viability of projects is small but

significant in terms making a few facilities economically that would not have been without the voluntary REC market. For example, in the reference scenario presented in Figure 30, a small number of facilities are "pushed up" over the horizontal zero line due the expectation of REC revenue.

Figure 30. Electricity price and levelized cost spread for reference cost scenario

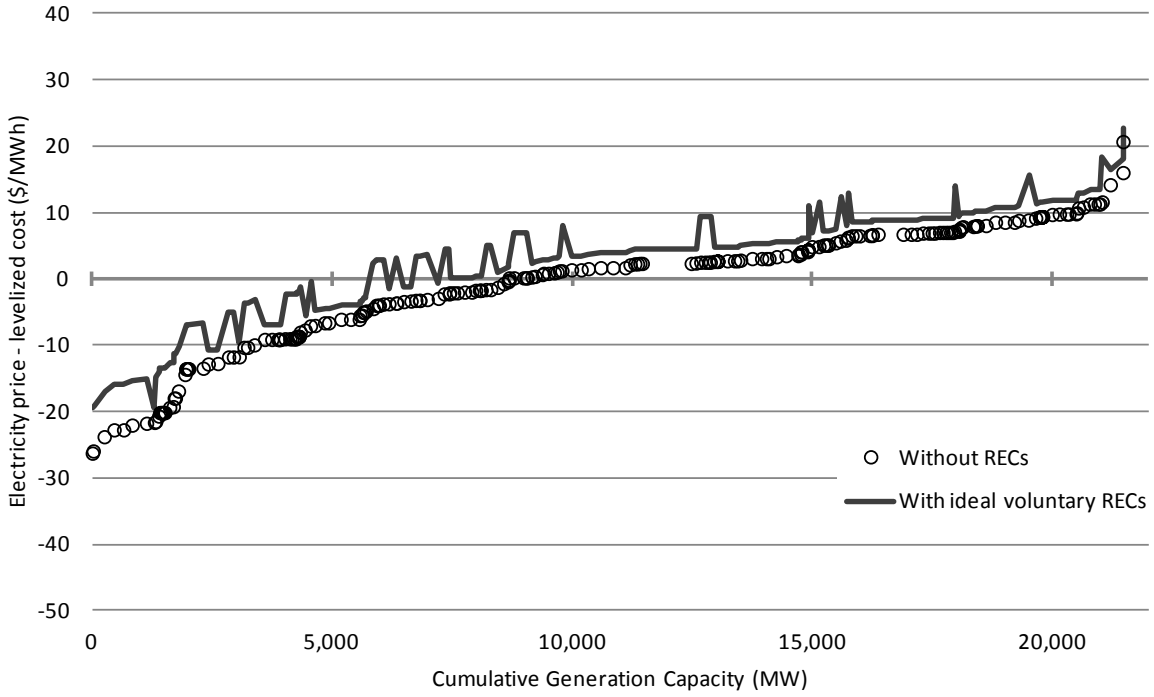


Figure 31. Electricity price and levelized cost spread for low cost scenario

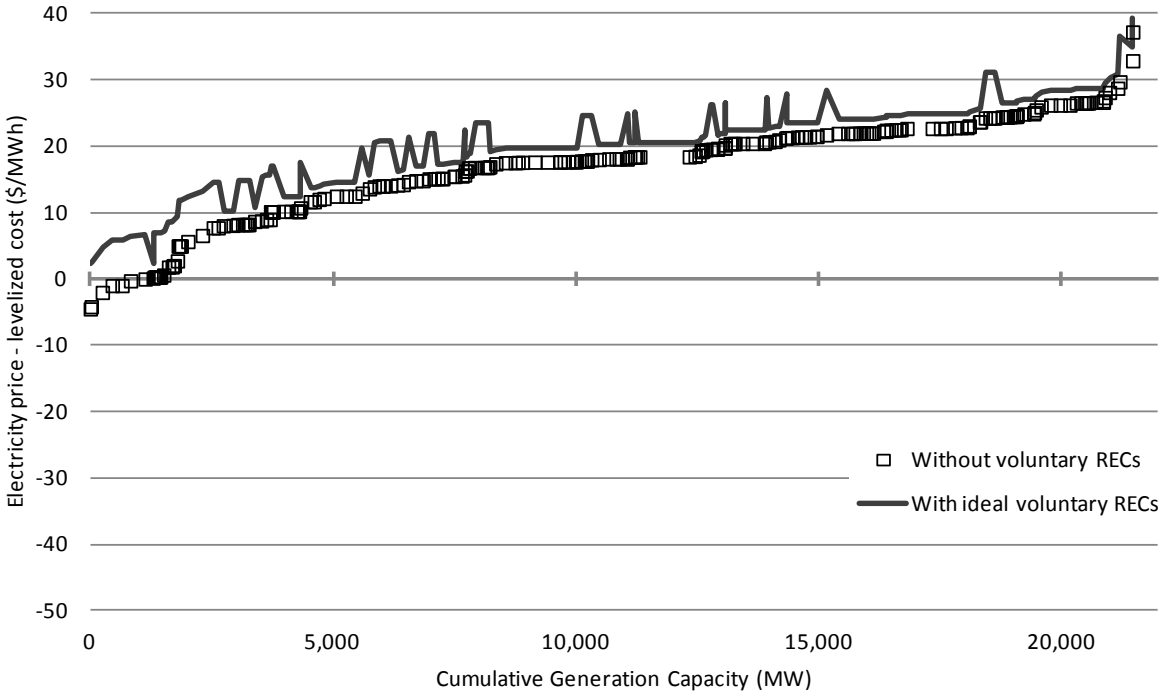
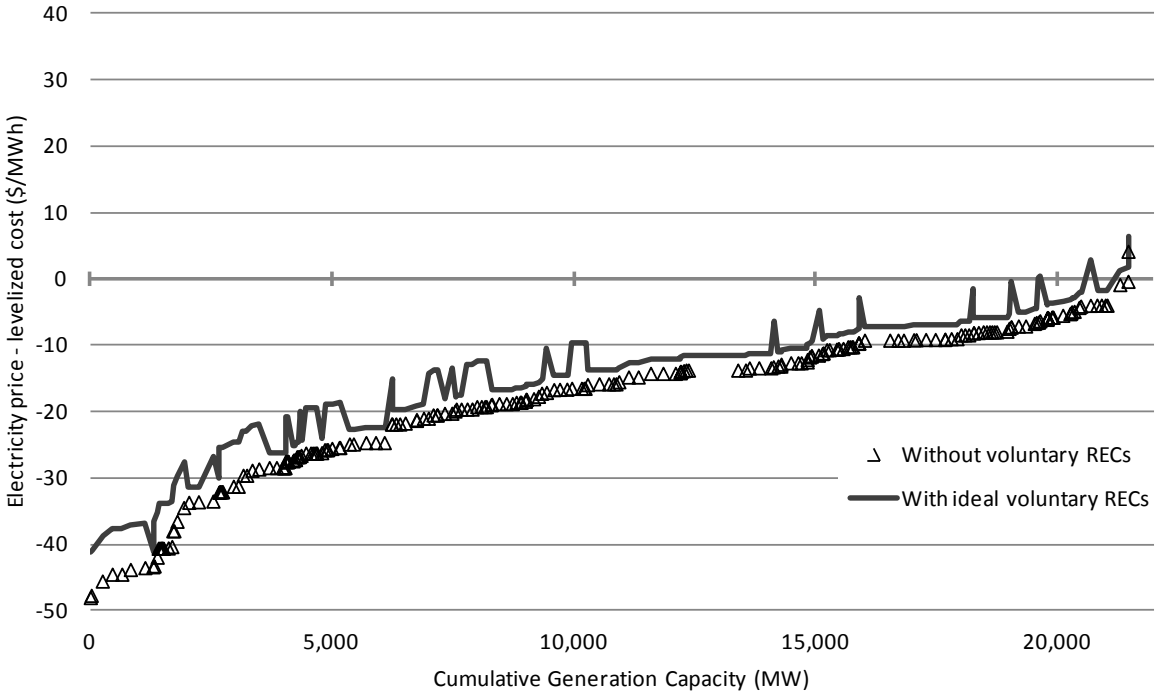


Figure 32. Electricity price and levelized cost spread for high cost scenario



The effect depicted in these figures, however, assumes an "ideal voluntary REC" market, meaning that it assumes a market where investors have sufficient confidence in the demand for voluntary market RECs to factor them into their investment decision making. Specifically, it assumes that investors expect the risk-adjusted real price of RECs over the full 25-year lifetime of the project to be the values assumed. Yet, we have evidence that investors do not hold these expectations. Project investors are rarely able to obtain a contract for the sale of voluntary RECs for more than three years, leading to significant risk exposure (Holt, Sumner et al. 2011). Because of this reality, investors have reported that when making investment decisions they typically discount to zero the expected value of any RECs for which they are unable to obtain a firm contract at the time the project investment decision is made (see Chapter 5) (Holt, Sumner et al. 2011). Correcting Figure 30, Figure 31, and Figure 32 to account the present value of only

three years of contractually confirmed REC revenue would depict an imperceptible effect from voluntary REC markets, and therefore is not shown. The scenarios presented three figures also show that the influence of the voluntary REC market is relatively insensitive to the assumptions in the key cost variables.

For the projects that fall below the horizontal axis (i.e., theoretically should not have been built), if it is not the voluntary REC market that is enabling the projects in the sample to move forward, then what is it? There are a couple potential solutions to this puzzle:

1. Most projects, or at least those with lower capacity factors (e.g., on the left side of Figure 30) are better represented by the low cost scenario.
2. Projects are not limiting their engagement with REC markets to the voluntary market, but instead are obtaining contracts for their RECs in one or more RPS compliance markets or are otherwise obtaining contracts from LSEs to be counted for RPS compliance.

The first potential solution seems plausible. Chapter 5 found that investors in the wind power industry will tend to invest in projects at less windy sites (i.e., lower capacity factor) if they are able to offset the loss in revenue through lower investment costs. And Wiser and Bolinger (2011) have reported that actual project installation costs, the vast majority of which are related to turbine costs, have historically varied. Upon examination, though, the projects in the sample with negative spread values do not show a correlation between the spread variable and facility age (correlation coefficient of 0.09). Less economically viable projects do not appear to have been built in years when turbine prices were atypically low.

The second potential solution has already been supported above by showing that all of the projects in the sample also meet the eligibility under multiple State RPS regulations. And that nearly all of the projects in the sample are eligible to sell RECs into least four RPS compliance

markets, where it is possible to obtain long-term purchase contracts. To further illustrate this finding, Table 20 presents the distribution of wind power nameplate capacity by State and compares this to the total generation capacity in the State reported by the U.S. Department of Energy. Across the States with RPS legislation, 60% of the wind power capacity in those States is also registered with Green-e. Clearly, most of the generation from this capacity is being counted by LSEs for RPS compliance and not supplying the voluntary green power market. Similarly, statistics compiled by the National Renewable Energy Laboratory (NREL) on the total size of the U.S. voluntary green power market indicate that the total generation capacity registered with Green-e is roughly three to four times larger than necessary to supply the entire market (correcting for typical capacity factors) (Heeter and Bird 2011).[93]

[93] See Tables 6 and 8 in Heeter and Bird (2011); assuming an average capacity factor of 0.32.

Table 20. Wind power capacity in dataset by State compared with total in-State wind capacity

State	Capacity in dataset (MW)[a]	Fraction of dataset	RPS in State?	State wind capacity[b]	Percent Green-e registered
Texas	7,033.4	30.5%	Yes	10,089	69.7%
Iowa	3,007.7	13.1%	Yes	3,675	81.8%
North Dakota	2,207.1	9.6%		2,444*	90.3%*
Illinois	2,030.5	8.8%	Yes	2,045	99.3%
Oregon	1,702.2	7.4%	Yes	2,104	80.9%
Washington	1,653.4	7.2%	Yes	2,104	78.6%
Wyoming	1,083.1	4.7%		1,412	76.7%
Minnesota	745.4	3.2%	Yes	2,205	33.8%
California	584.1	2.5%	Yes	3,253	18.0%
South Dakota	562.0	2.4%		709	79.3%
Pennsylvania	424.5	1.8%	Yes	748	56.8%
Colorado	400.5	1.7%	Yes	1,299	30.8%
West Virginia	330.0	1.4%		431	76.6%
Idaho	325.2	1.4%		353	92.1%
Kansas	185.5	0.8%		1,074	17.3%
Missouri	146.0	0.6%		457	31.9%
New York	125.8	0.5%	Yes	1,274	9.9%
Indiana	106.0	0.5%		1,339	7.9%
New Mexico	102.4	0.4%	Yes	700	14.6%
Oklahoma	100.8	0.4%		1,482	6.8%
Michigan	98.9	0.4%	Yes	164	60.3%
Wisconsin	55.0	0.2%	Yes	469	11.7%
Utah	18.9	0.1%		223	8.5%
TOTAL	**23,028**	**100.0%**	**-**	**40,053***	**57.5%***

[a] Total generation capacity registered with Green-e (CRS 2011).
[b] Wiser and Bolinger (2011), Table 2.
[c] The NREL capacity data does not appear to account for Baldwin project (1020.4MW) in North Dakota, which went operational in July 2010. The data in this table has been corrected to include this project.

So, what is occurring here? Wind power project investors appear to be using the voluntary REC market as a backstop market for RECs associated with generation in excess of that already under their long-term contracts with LSEs. These RECs are sold into which ever spot market offers the best price and terms. Importantly, as reported in Chapter 5, any potential revenue from future REC spot market transactions is not generally considered by investors in their upfront

decision making process due to the risk involved. The voluntary REC market is essentially invisible to most investors, and instead is the purview of their REC brokers, who are charged with disposing of excess RECs and RECs associated with any merchant portion of a project's output.[94]

The implications of this finding are that in the United States, the voluntary REC market does not appear to result in additional investments in wind power generation capacity. In other words, there appears to be support for the conclusion that under counterfactual conditions in which the voluntary green power market for RECs did not exist, the amount of electricity generated by wind power in the United States would be little different than what we actually see today.

6.4 Conclusions

Using a spatial financial model and a database of registered Green-e wind power facilities, the analysis in this chapter showed that the voluntary REC market has a negligible influence on their economic feasibility. Nevertheless, voluntary green power marketers at least implicitly claim that buying their products creates additional renewable energy. This study seems to indicate the contrary. Therefore, in the United States consumers appear to be receiving misleading marketing messages regarding the effect of their participation in voluntary green power markets that rely on RECs as a tradable environmental commodity. This study has found that investments in wind power projects registered with Green-e are not additional due to the incentive from the voluntary REC market. Rather, investments in wind projects seem to be more influenced by compliance REC markets. Therefore, causal claims within the voluntary REC market regarding emission reductions are not substantiated by evidence.

[94] The disposition of the revenue from the sale of excess RECs will be governed by contractual terms set out in PPAs between LSEs and project developers. For merchant projects RECs would typically be sold by the wind project developer.

The present study focused exclusively on the voluntary REC market, while the broader voluntary green power market also includes utility green pricing programs and competitive electricity markets in some states. Some, but not all of these other types of programs utilize RECs. Many state voluntary green power rules explicitly forbid that credits marketed under such programs can be counted towards compliance with state renewable energy requirements. It is possible that some programs under these two smaller aspects of the green power are more likely to result in additional wind power investment. And although RECs from wind power account for the majority of the voluntary green power market, RECs from solar energy projects are often traded as a distinct commodity with a separate price. Therefore, the conclusions here may not apply to these projects, which accounted for an estimated 0.2% of the U.S. voluntary green power market in 2010 (Heeter and Bird 2011).

Another key finding of this study was the overlap between voluntary REC markets and compliance REC markets that supply utilities to meet their RPS obligations. The majority of state RPS rules allow for regional or even national sourcing of RECs. The broad eligibility of wind power projects across several states allow them to sell into multiple compliance markets. As a result, wind power project investors appear to be using the voluntary REC market only as a backstop for RECs in excess of demand associated with RPS compliance. A significant increase in both the confidence in and magnitude of the voluntary REC market price signal would alter these conclusions. Alternatively, an aggressive national RPS would present a public policy (versus voluntary) replacement for investors. Area of future research is the degree to which demand for RECs from the voluntary market improves the efficiency of state compliance RECs markets.

Chapter 7. Policy implications

As discussed in previous chapters, the claims made by organisations and individuals with respect to their participation in voluntary green markets are explicitly or implicitly based upon an assumption regarding the impacts of these markets have on renewable energy investment. Previous chapters examined the relationship between green power programs and GHG emission offset credits and concluded that the voluntary REC programs in the United States are unlikely to lead to additional renewable energy investments or generation relative to a baseline condition where these voluntary programs did not exist. Therefore, claims that RECs can be treated as equivalent to emission offset credits are not supported by evidence.

This chapter extends the analysis in previous chapters by looking at select policy implications for other environmental policy issues related to entity-level GHG emissions inventories (i.e., "carbon footprints") and for the integration of generation attribute certificates, such as RECs, with regulatory emissions trading markets. Specifically, section 7.1 expands on the issues of "attribute" ownership introduced in Chapter 4 and explains why even if additionality issues with RECs were addressed, that there is still a problem with the double counting of emissions embedded in the internationally accepted accounting framework for indirect emissions[95] from electricity purchases. Section 7.2 discusses the current problems with integrating RECs into emission trading markets, and the following section then presents some options for redefining what a REC is in an attempt to solve some of these problems. It concludes with a specific policy option addressing integration of RECs with an emissions cap and trade market, which is expanded in detail in Chapter 8. This policy option illustrates one approach for integrating certificates and emission allowances into coupled environmental markets.

[95] See ISO 14064-Part 1.

7.1 RECs and carbon footprint accounting

If organizations are not buying emission offsets when they participate in voluntary green power markets, what are they buying? Another potential application and form of claims made by participants in voluntary REC markets is that they are effectively purchasing electricity from renewable energy sources, and therefore can assign a zero value to their indirect emissions from purchased electricity. But are these entities justified in claiming that by purchasing an intangible certificate that they are doing the equivalent of actually buying electricity produced by renewable energy generators? This section examines the question: How should organizations account for participation in a green pricing programs or REC purchases in their entity-level (e.g., corporate) GHG emissions inventory?

Before discussing the ownership issues related to indirect emission claims, it is necessary to establish the concept of direct and indirect emissions (WRI/WBCSD 2004; WRI/WBCSD 2005). For the purpose of this dissertation, direct emissions are those that occur on the site of an entity (e.g., a renewable energy facility), while indirect emissions are those that occur off-site.

The central issue for RECs relates to ownership claims over indirect emissions from the consumption of electricity and indirect emission reductions assumed to occur at a fossil fuel-fired power plant because electricity was instead generated by a renewable technology.[96] Due to the complex operations of the electric power grid, it is difficult to establish unambiguous causal linkages between renewable energy generation and changes in generation at other power plants on the grid. Since most of the benefits associated with renewable generation result from changes in behavior at off-site facilities that are under the control of other entities (e.g., at fossil fuel-fired power plants), ownership of benefits can be ambiguous without regulatory guidance.

[96] Indirect emissions from electricity consumption are referred to as Scope 2 emissions under the World Resource Institute / World Business Council for Sustainable Development GHG Protocol (WRI/WBCSD 2004).

It is also ambiguous whether consumers wishing to offset their emissions should claim responsibility for the indirect emissions associated with their electricity consumption in the first place, since these emissions occur at fossil fuel-fired power plants. Although regulatory liability to mitigate GHG emissions is more likely to be placed on power plants that emit rather than on end-users of electricity, it is clear that electricity demand is a proximate cause of GHG emissions.

Many entity-level emission accounting protocols have accepted the use of RECs to offset indirect emissions from an entity's electricity consumption (e.g., U.S. EPA Climate Leaders and the WRI/WBCSD GHG Protocol). Their argument is seductive because it seems reasonable that the purchase of green power should offset indirect emissions resulting from electricity consumption. It is easy to agree that the generation of electricity from renewable energy sources does not emit air pollutants. However, this fact does not lead to the conclusion that purchasing a REC is equivalent to consuming electricity from a renewable energy source or that the sale of RECs caused additional renewable energy to be generated.

With ownership issues it is also important to distinguish between legal property rights and customary rights to make marketing claims. It is common to find advocates of voluntary REC markets making statements such as "If a company can claim ownership of a REC it can also claim the environmental benefits of the associated green power" (Pino 2006). However, in the United States and Europe a legal basis for holders of RECs to make property rights claims over indirect GHG emissions or emission reductions (i.e., government-sanctioned emission allowances or offset credits) has not been demonstrated.[97,98]

[97] In countries eligible for CDM projects, renewable energy projects may be able to claim property rights over offset credits because fossil fuel power plants in most developing countries are not currently under the threat of emission caps.

Consumers and green power market advocates are claiming ownership of a public good (e.g., reduced pollution or zero emission energy) or set of public goods (e.g., all environmental benefits). In doing so, they are attempting to make a non-excludable public good (e.g., emissions reduced through generating electricity from renewable sources) excludable (i.e., a private good). Typically, only governments are thought of as being capable of assigning property rights over public goods. In voluntary markets without government oversight, entities can only attempt to exclude others from making marketing claims regarding a given public good.

With government support, certificate and REC-only registries are being established in many states, regions, and countries to facilitate REC markets and deal with ownership and double counting issues (Wingate and Holt 2004). Although these tracking systems will address issues of double counting of certificates themselves (e.g., double selling the same REC), they do not address ownership issues with emission reductions or other environmental benefits.[99]

Renewable energy clearly has a critical role to play in addressing the challenge of climate change. However, with current cost structures, most forms of renewable energy need additional incentives—whether from governments or from voluntary contributions—to economically compete with conventional sources of power generation.

Due to the collective nature of the electricity transmission and distribution grid, organizations and individuals generally cannot identify the precise generation source of the electricity they purchase. Multiple energy generation sources contribute to the energy available on the grid at varying levels depending on the grid's demand and how the grid operator dispatches that energy production to the grid. Despite this reality, some electricity consumers

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[98] For a case describing the allocation of NO_x allowances to entities for their purchase of RECs, see (Jacobson 2007).

[99] None of the certificate tracking systems in the United States or Europe track off-site attributes of renewable generation. Massachusetts has attempted to do so by assigning a monthly average emission rate for the grid to certificates with the assumption that it is equivalent to avoided emissions.

wish to be able to claim that their electricity comes from specific energy sources, typically renewable sources.

Voluntary green power markets have developed in parallel with the desire of companies, individuals, and other organizations to make public claims about their environmental bona fides. Rather than attempting to install their own wind turbines or solar panels, consumers are told they have the option to participate in some form of green power market, which, in the United States, are often built around RECs.

Emissions from an organization's electricity consumption are indirect emissions (i.e., Scope 2 emissions (WRI/WBCSD 2004)) because the emissions actually occur at a power plant owned and operated by another organization and are only allocated to electricity consumers based on their electricity purchases. It is standard practice for to calculate Scope 2 emissions by multiplying electricity consumption by an emission factor representing tonnes of carbon dioxide (CO_2) per megawatt-hour (MW-hour). The default practice specified in all major GHG emission registry protocols and programs is to use an emissions factor that represents the annual average emission intensity of the generation supplying the geographically or jurisdictionally relevant transmission and distribution grid (WRI/WBCSD 2004; TCR 2009; USDOE 2010).

A major concern of all of these protocols and programs has been the double counting of emissions. The universally accepted accounting framework, originally established in the GHG Protocol (WRI/WBCSD 2004) created emissions accounting Scopes expressly for the purpose of providing a framework that would prevent double counting. Similarly, the largest certification program for voluntary market RECs, Green-e, stresses how its process prevents double counting in the green power market. However, when it comes to the integration of green power markets and Scope 2 accounting, the language in these protocols and programs historically failed to

properly distinguish between various types of causes of double counting. Specifically, there are three potential causes of double counting at issue in green power and Scope 2 emissions accounting:

1. double counting of MWh or RECs (e.g., selling two RECs for the same MWh);
2. double counting of avoided emissions between a potentially displaced fossil generator and a renewable power generator that claims to have avoided emissions at that fossil generator; and
3. double counting of emissions between the voluntary green power market consumer and other electricity consumers on the grid.

Dealing with the first type of double counting is rarely an issue. Basic tracking of MWh from renewable generators and the use of REC certification and registries addresses it. It is this type of double counting that programs like Green-e are referring to and successfully police and prevent.

The second type of double counting involves assignment of ownership over emission rights and generally remains ambiguous until there is an unambiguous decision from government whether or not to cap emissions from the electric power industry and emission rights (technically, permits) are assigned. For jurisdictions, such as most of the United States, where rights over GHG emissions are still ambiguous (current exceptions are RGGI states and California), then this type of double counting is still only an issue if one assumes renewable energy projects supplying the voluntary REC market are additional.

It is the third type of double counting that protocols and programs have, until recently (TCR 2009), failed to recognize and that invalidates the common assumption that participation in voluntary green power markets is the same as directly consuming electricity produced by zero-

emitting resources. In the language of economics, green power markets do not offer a good that is subject to private ownership because the good or service they are selling is non-exclusive.

Again, when entities calculate their indirect GHG emissions from electricity consumption, they typically use an average emissions factor for all generation supplied to the grid.[100] The problem is that in the United States, these grid average factors include electricity from renewable generators that green power market consumers are claiming that they purchased and own and as *their* zero-emitting electricity.[101] The absence of a mechanism to exclude everyone else on the grid from also claiming this zero-emitting power as part of their average mix causes the basic economic definition of ownership to be violated; green power markets do not offer an exclusive good or service. For the purposes of accounting for GHG emissions, green power market consumers cannot credibly claim to be purchasing zero-emitting electricity because the accounting framework has not been designed to allow such claims to be credibly made.

It has been argued by some advocates that the error in Scope 2 emissions accounting caused by this third type of double counting is insignificant because renewable energy makes up a small fraction of generation on their grid (Harmon 2009). This error is small for the grid as a whole, but the error effectively 100 percent for those organizations claiming zero emission electricity, as every MWh they claim to own is double-counted. And more importantly, why, in a market struggling to establish its credibility, should the fundamental accounting framework for GHG emissions have double counting intentionally designed into it? Such an approach would be in

[100] Another challenge with the default GHG accounting framework is that the definition of "grid" is ambiguous and is left to the user to define, but in almost all cases is based on some form of regional average across generators. Typically, in the United States entities will rely on factors published by U.S. EPA (http://epa.gov/cleanenergy/energy-resources/egrid/index.html) that provide data by NERC region and power pool or they request their local utility provide them with an indirect emissions factor.

[101] In Europe, a tool has been developed to address for this type of double counting, although its adoption is not yet widespread (www.eped.eu/portal/page/portal/EPED_HOME/Calculations/Description%20of%20EPED%20residual%20mix%20model).

direct conflict with the principles outlined in the GHG Protocol and the Organizational for International Standardization (WRI/WBCSD 2004; ISO 2006) for entity-level GHG emission accounting. Further, the aggregate error imposed by neglecting this type of double counting become increasingly less negligible as the voluntary green power market grows. In other words, the more successful the policy of increasing the share of renewable energy on the grid the larger the error.

It is possible to address this third type of double counting through use of a comprehensive and closed accounting and allocation system for the emissions profile of each MWh of electricity supplied to the grid (i.e., covers all electricity delivered to the grid). Ideally, such a system would allocate to customers—through a market or other allocation mechanism—all MW-hours supplied to the grid using generation attribute certificates (or Guarantees of Origin, as referred to in Europe). If comprehensive, this approach would allow organizations to use a specific indirect emissions rate based on their allocation/purchase of certificates that would be equivalent in number of MWhs to their purchases of electricity.

Infrastructure is being put in place for generation attribute tracking systems in parts of Europe and the United States (e.g., Guarantees of Origin and certificates, respectively). These systems can both prevent the double counting of RECs (i.e., type 1 double counting) and establish excludable ownership over generation emission attributes (associated with type 3 double counting).

In the absence of the ideal solution—a comprehensive certification tracking system and allocation system for certificates to all electricity consumers—an approximate solution could be implemented using existing resources and by leading stakeholders in the voluntary green power market (e.g., Green-e or U.S. EPA). This approximate solution would continue with the existing

voluntary REC market and pair it with a credible and consistent average Scope 2 emission factor for the defined sections of the grid that nets out green power participation and REC retirements from a published grid average emissions intensity factor. This residual factor could be published and regularly updated for use by entities preparing their carbon footprint. Organizations participating in voluntary green power programs could apply this residual factor to the portion of their electricity consumption not covered by a voluntary green power market transaction. In theory, such an approach would address the problem of excludable rights to zero emissions power and establish a private claim by green power program participants. Further, it would establish an incentive for green power market participation by penalizing those that fail to support green power (i.e., completely rely on the residual grid average) with a higher emissions rate.

Stepping back, though, even this solution presents a policy design challenge. Currently most organizations and individuals do not calculate their carbon footprint and are unlikely to be concerned that the indirect emissions from their electricity purchases are greater due to the "dirty" generation on the grid accounting for an increasing share of the grid residual emission factor. The fact that there is far from universal participation in the practice of preparing and reporting carbon footprints by end-user customers of electricity results in an adverse selection problem, unless a sufficient fraction of electricity consumers begin to be concerned with their Scope 2 emissions. If the vast majority of electricity consumers neither care nor are even aware that their electricity is getting more "dirty" because no social nor economic cost is associated with this change, then even this allocation approach to a credible green power market fails to provide a clear policy rationale.

In sum, although there is a practical solution to double counting of emissions in voluntary green power markets, the resulting policy outcome from the application of this solution is still likely to be that these markets have little to no impact on renewable energy generation without dramatic growth in public concern and participation. Ultimately, though, one would expect such concern, if present, would e expressed through public policy measures (e.g., and aggressive national RPS) rather than large-scale participation in voluntary initiatives.

7.2 RECs and emissions allowances

Should RECs be integrated into emissions trading schemes covering the electric power sector, and if so, how? Because renewables emit no (or few) pollutants, they are economically advantaged by any policy that puts a cost on emitting pollution within the electric power industry. So this question is better framed as: Should RECs be directly included in an emissions trading system as a tradable instrument?

It is important to distinguish the issue of allowance allocation under an emissions cap-and-trade scheme from the issue of how a REC is defined. Renewable energy advocates often argue for renewable generators to be allocated allowances, typically via an allowance set-aside[102] for renewable energy projects or an allocation of allowances to generators based on their electricity output, versus emissions (Bird, Holt et al. 2007). Under an emissions cap-and-trade scheme the pollutant cap, not the allocation, determines the degree of environmental improvement.

Because most renewable energy generation is produced from technologies with minimal variable operating costs, including wind, allowance allocations to existing renewable generators will not affect the quantity of electricity they produce. However, an allocation biased towards

[102] A set-aside is a reserve of allowances, under the overall cap, that is dedicated for allocation to a specific category of entities or activities.

new renewable generation capacity can provide additional incentives for renewable energy investments, relative to other allocation approaches.

For any pollutants from electric power plants that are capped, emission reductions from renewable energy investments that were actually caused by the voluntary REC market (i.e., projects that were actually additional) will have no impact on total emissions of these pollutants unless a corresponding quantity of emission allowances are removed from the market. Allowances unused by one power plant, for example because its emissions were displaced by the installation and subsequent operation of a new wind turbine, will simply be sold to other power plants under the cap. The total amount of pollution will be unchanged. The only way to reduce emissions of a capped pollutant from entities under the cap is to lower the cap or retire allowances such that they cannot be used for compliance. This is already the situation with sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) emissions in the United States (Bluestein, Salerno et al. 2006) and carbon dioxide (CO_2) emissions in Europe.[103] So, a scheme that allocates allowances to renewable generators versus to other entities will not affect the overall level of pollution.[104] The issue of allocation is a topic for political debate, but it is not the direct cause of confusion in voluntary or compliance REC markets.

The major voluntary REC standards in the United States recognize this issue and marketers are advised to exclude capped pollutants (i.e., SO_2 and NO_x) from their marketing claims. However, the language used by many REC and green power marketers and in many state RPS definitions of RECs is inconsistent on this issue (Gillenwater 2008a).

[103] Renewables are ineligible for Joint Implementation (JI) projects under European Union's Emission Trading Scheme linking directive for this reason.
[104] See Rathmann (2007) for a discussion of how renewable support policies and greenhouse gas cap-and-trade programs interact to effect electricity prices.

Once a greenhouse gas (GHG) cap is placed on power plants in the United States, the purchase of RECs or other form of participation in a green power program will not reduce emissions, regardless of whether the REC or green power sales lead to additional renewable energy generation. Only retiring GHG allowances so that they cannot be used for compliance by an emitting fossil fuel-fired generator will reduce the overall emissions from the electric power sector, regardless of how a REC is defined or what attributes are claimed to be included in a REC.

Recognizing this conflict, REC market advocates, in addition to advocating for the allocation of allowances to renewable generators, have also attempted to define RECs such that they are required to be bundled with emission allowances (CRS 2006). The objective of defining RECs in this way is so that when a REC is retired, emission reductions can be claimed by the retiree because an emission allowance was also retired. It is this question of bundling that is a major cause of confusion in REC markets.

The question has been resolved for existing emissions cap-and-trade markets, such as the U.S. Acid Rain Program or the European Union's Emissions Trading Scheme (EU-ETS). In these existing markets, regardless of the REC definitions used or claims made by advocates, RECs and tradable emission allowances are separate commodities that trade separately and the retiring of a REC does not reduce emissions of a capped pollutant. Consumers that wish to reduce emissions of a capped pollutant can purchase and retire an emissions allowance without involving a REC in the transaction.

However, the debate over REC and allowance bundling is far from resolved with regard to future allocations of GHG emission allowances where cap-and-trade markets have yet to be established. Existing definitions of RECs in both RPS compliance and voluntary green power

markets frequently make claims that RECs include and/or must be bundled with emission allowances under future cap-and-trade schemes.[105] Sometimes these claims are explicit, while others are implicit in the definitions of a REC used (Gillenwater 2007a).

For example, the language used in the California RPS requires that RECs include "any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Unit(s), and its displacement of conventional energy generation" (Gillenwater 2008a). The California definition appears inconsistent with existing federal law governing the ownership of SO_2 and NO_x allowances, which clearly are not included or conveyed with RECs. For GHGs, it is not clear how holders of RECs, even in California, will acquire ownership of allowances allocated to fossil generators in a future cap-and-trade system.

Table 21 summarizes two cases where the process of purchasing and retiring a REC can result in some amount of additional emission reductions from off-site fossil generators. Both of these cases require that the pollutant in question is uncapped and that the REC market creates a scarcity. As discussed in Chapter 4, a market scarcity is more readily created if the BAU supply is eliminated from the market. The BAU supply is how many RECs are awarded to non-additional renewable energy projects (i.e., renewable energy generation capacity that would exist and operate regardless of the revenue from REC sales).

Both RPS compliance and voluntary REC markets can be long (i.e., at a given price supply exceeds demand[106]). However, it is more likely that a RPS compliance market, with defined participation boundaries, will create a scarcity due to the ability of governments to set a quota. A long REC market, however, can exist even with an RPS if the quota established is below the

[105] Often legislation is inconsistent in that it does not place the same requirements on direct purchase of green power under green pricing or competitive electricity markets (i.e., without RECs).
[106] Price does not necessarily decrease to zero in a long market due to the presence of transaction costs.

BAU level of renewable generation in the jurisdiction. Again, for a capped pollutant, retiring RECs or increasing the RPS target will not reduce emissions.

Retiring a REC from a market with a REC scarcity indicates that emissions have likely been reduced somewhere, however, it does not mean that specific claims over emission reductions of an uncapped pollutant are justified. Even under the two cases in Table 21 where emissions have been reduced, there are still problems with renewable energy generators obtaining ownership of and quantifying emission reductions (Gillenwater 2008a).

Table 21. Emission reduction outcomes from various actions related to buying and retiring a REC

Action	Pollutant uncapped	Pollutant capped
Buy from RPS compliance market (REC market scarcity)	Emissions reduced, although quantity and ownership of reductions is ambiguous	None
Buy from RPS compliance market (Long REC market)	None	None
Buy from voluntary REC market (REC market scarcity)	Emissions reduced, although quantity and ownership of reductions is ambiguous	None
Buy from voluntary REC market (Long REC market)	None	None

Although it would not affect the total emissions of a capped pollutant, an RPS does have the potential to alter the cost structure of emission allowance markets by effectively mandating the portion of emissions mitigation achieved with renewable energy technologies. Given that renewables have a number of benefits relative to fossil generation, RPS mandates may be an appropriate policy. Both an RPS and an emissions cap-and-trade scheme regulate the electric power industry. Therefore, it is important that if an RPS mandate is established that the setting of RPS targets and emission caps be coordinated where their jurisdictional boundaries overlap (Morthorst 2003).

If a future federal GHG cap-and-trade scheme in the United States did allocate emission allowances to renewable generators (e.g., through a set-aside or output-based allocation), does it make sense to require that these allowances be bundled with RECs? Many of these RECs, except those sold into the voluntary market, will be purchased by LSEs and then submitted to government authorities for compliance with an RPS. If allowances are inseparable from RECs, then state governments will effectively be taking possession of these allowances.[107] Renewable generators will have received no direct financial benefit from the allocation. It is difficult to see how this arrangement would benefit renewable energy generators or, more importantly, lead to additional investments in renewable energy generation.

Imagine a scenario where a renewable energy generator has signed a long-term contract for the delivery of RECs, which have been defined to include any emission allowances allocated to the generator. Then during the term of the agreement, this renewable generator is allocated CO_2 allowances under a new emissions cap-and-trade scheme. Under the pre-existing agreement, these CO_2 allowances must be transferred, at a previously negotiated price, to the purchaser of the RECs. If the buyer's stated purpose for purchasing RECs was to claim emission reductions then the buyer would need to retire these allowances to make such a claim.[108] Under this

[107] It is not clear what state governments would choose to do with these allowances. Renewable energy generators could choose to sell RECs into the voluntary market, instead of the RPS compliance market, in hopes of capturing the value of both RECs and emission allowances. However, demand in the voluntary market is likely to be price elastic, while the demand in the RPS compliance market is inelastic.

[108] Renewable generators should be cautious about entering into long-term REC sales contracts that would inhibit their ability to sell RECs into a future compliance market (e.g., under federal RPS legislation). This issue can be addressed with a "Change in Law Risk" clause in a REC sales contract. Renewable energy generators may also be entering into agreements that transfer their rights to future emission allowance allocations. It does not appear that the current REC market is pricing in the possibility of future allowance allocations to renewable generators. Renewable generators should realize when they sign long-term or future REC delivery contracts that they may be signing away their rights to another valuable environmental commodity.

scenario, the result of allocating allowances to renewable generators would be that neither the renewable energy generator nor the REC purchaser financially benefited.[109]

The only clear benefit to requiring that allowances be bundled with RECs is that it helps advocates of voluntary REC markets to continue to make claims that RECs are equivalent to emission offset credits even in the case of a cap-and-trade scheme covering the electric power industry. If REC marketers believe that their business is dependent upon the legitimacy of their emission reduction claims, then a perverse incentive has been created. By defining RECs to include or be equivalent to emission offsets, green power market advocates may prefer that pollutants remain uncapped. Once there is a cap in place for GHG emissions from electricity generation, REC marketers will have to purchase and retire allowances in order to continue making claims.

A solution to these problems is to redefine voluntary and compliance market RECs in a manner that allows them to function without conflicting with emission markets. The following sections propose some potential solutions.

7.3 Redefining RECs

Should RECs be defined to include "all attributes?" Under such a definition, is there any public good attribute that a REC does not include?[110] Does it make sense to define RECs in terms of "attributes" at all? By doing so, have we created a system that will foster the expansion and efficiency of environmental markets?

[109] In negotiating the allocation process, if it was obvious that any allowances allocated to renewable energy generators would be retired and removed from the compliance market, entities needing allowances for compliance would likely resist any such allocation to renewable energy generators. If the retirement of emission allowances from the compliance market caused wholesale electricity prices to rise, then renewable generators could benefit, along with all inframarginal generators, from the higher market clearing price.

[110] As discussed in the previous section, regardless of the definition used, RECs effectively exclude allowances for capped pollutants.

Defining RECs using ambiguous terms such as "attributes" or "benefits" of activities that occur off-site of a renewable generator's facility creates a situation in which each REC is a unique bundle of attributes, given that every renewable energy project has its own unique set of social and environmental impacts. Even if it was feasible to concretely specify each of these off-site attributes, quantity them, and affirm ownership over them, it is not clear that such a system or definition would lead to functional environmental markets. Environmental markets are likely to function more efficiently where unambiguous and homogeneous tradable commodities that have clear ownership are used.[111] The lack of a consistent REC definition across and within voluntary and compliance REC markets prevent RECs from functioning as a homogeneous environmental commodity (see Chapter 4).

For example, the New Jersey RPS included a special requirement for generation that has produced a market scarcity for solar RECs (SRECs). These SRECs have traded at in the range of $200/MWh. Johnson & Johnson, a manufacturing company in the state, took advantage of this situation by installing photovoltaics and selling SRECs into the New Jersey RPS compliance market. The same company then purchased inexpensive RECs in the U.S. voluntary market, where wholesale REC prices ranged from $0.5 to $10/MWh in 2006 with a typical price around $2/MWh (Bird and Swezey 2006; Hathaway 2007). The company then retired these RECs to support its claims that it has reduced emissions through its investment in renewable energy. Despite these claims, this substitution of a voluntary market REC for a RPS compliance market REC negated the additionality of the environmental benefits. A compliance REC with clear additionality was sold into an RPS market and then replaced with a voluntary market REC that

[111] Several organizations have collaborated to develop a "Power Scorecard" to rate different green power products to address the lack of standardization in these markets (http://www.powerscorecard.org/index.cfm). Unfortunately, the solution to the problem in REC markets is not more ratings or information to consumers but the definition of an unambiguous and homogeneous commodity that customers can have confidence in.

did not come from an additional project. If the company had retired its original solar REC instead of selling it, then another solar REC would have been created to meet the New Jersey RPS requirement. Assuming that RECs are a homogeneous commodity and fungible with each other as well as emission reductions (i.e., offset credits) creates opportunities for "environmental arbitrage." Such problems arise in a confused marketplace that lacks clear commodity definitions.

The example above is a case where voluntary market RECs are substituted for compliance market RECs, but less stark examples also exist within the voluntary REC market. The ambiguity of REC definitions also leads to high transaction costs and leads to price differentiation between RECs. For example, RECs from newer facilities and solar generation tend to sell for higher prices (Holt and Bird 2005).

As discussed in previous chapters, RECs sold in voluntary markets suffer from significant additionality problems. Most of the attributes claimed as being included in RECs relate to activities occurring off-site of the renewable generation facility. These off-site attributes, unlike on-site attributes, are far more difficult to quantify, verify, and obtain unambiguous ownership rights to (Table 22).[112]

[112] Holt and Wiser (2007) refer to these as "primary" and "derived" attributes.

Table 22. Summary of factors for REC on-site and off-site attributes

Issue	REC on-site attributes (i.e., MWh generated)[113]	REC off-site attributes (e.g., indirect GHG emission reductions)
Additionality	Ambiguous due to the weak tests applied. (e.g., initiation date & regulatory additionality)	Only if REC income was essential to initial investment decision
Ownership	Unambiguous (i.e., generator or contractual designees)	Ambiguous and lacking legal recognition. Prone to double counting. Depends on the legal requirements or ethical expectations of displaced generators.
Quantification	Unambiguous (i.e., meter readings of MWh)	Inherently uncertain in most cases, but can be assumed.

Why are RECs typically defined in terms of off-site attributes? RECs definitions in both voluntary and RPS compliance markets were created by those with a business interest in these markets. These parties had an interest in defining their product such that they can maximize their ability to make marketing claims. In the past there was little conflict with emission markets and the broad claims of public good benefits within voluntary green power markets.[114] However, this situation is changing with the emergence of voluntary GHG emission offset markets and GHG cap-and-trade markets.

Advocates for voluntary REC markets often assume that the best way to increase the appeal of their product is to convince customers that they are purchasing ownership of something instead of simply making a contribution to a public good. The concept of attributes was

[113] Direct emission reductions, such as those resulting from methane captured by a generator combusting landfill gas, can occur "on-site." Although, these direct emission reductions have unambiguous ownership and quantification properties, they may or may not be determined to be additional. In addition, because direct emission reductions are relevant to only a small subset of renewable energy projects, requiring them to be included in a REC creates a different category of RECs for no obvious purpose. A more efficient approach would be to allow these projects to sell separately RECs and GHG offset credits.

[114] The primary exception being SO_2 and NO_x cap-and-trade markets.

developed with the intention of transforming RECs from an accounting tool to be used to meet an RPS quota, into a consumer product.

Yet, do voluntary REC markets depend on customers believing they are purchasing ownership over attributes? Why do customers buy RECs, knowing that they represent a public good? This question is the same as asking why people give to charity. People are looking to purchase "moral satisfaction" rather than ownership of attributes (Kahneman and Knetsch 1992; Truffer, Markard et al. 2000; Menges 2003). Most green power customers are not concerned with the specific environmental benefits of their green power purchases (Goett and Hudson 2000), but they do believe that their purchase is resulting in some environmental benefits (Bird, Holt et al. 2007). In situations where there is strong government support for renewables, consumers have not abandoned voluntary green power markets (Menges 2003).

Many advocates of voluntary REC markets appear convinced that if they cannot claim emission reductions, the demand for their products will significantly decrease. This belief is contradicted by experience in Europe where there are strong renewable support policies and a cap-and-trade scheme for CO_2 emissions from the electric power industry, yet still active voluntary green power and REC markets. REC marketers in Europe typically do not claim that they are transferring ownership or rights to claim emission reductions or refer to attributes (Niermeijer 2007).[115] It does not appear that it is necessary, at least in Europe, to define RECs in terms of off-site environmental attributes, such as GHG emission reductions, for voluntary green power markets to prosper.

More importantly, the principal objective of REC markets should be to produce additional renewable energy investments. Defining and marketing RECs in terms of ownership over

[115] REC marketers in Europe do state in their marketing materials that the climate is changing and that generating electricity from renewable sources is a good way to contribute to combating this problem.

unsubstantiated attributes does not appear to further this goal. Even more importantly, rooting the voluntary REC market on claims that RECs are equivalent to GHG emission reductions confuses customers and risks discrediting both green power and emission markets because of the flaws in these claims.

Ambiguous language such as "environmental attribute" or "environmental benefit" also does not help to address the relevant coordination issues between voluntary green power markets, RPS compliance markets, voluntary emission offset markets, or emission cap-and-trade markets.[116] Lastly, insisting that emission allowances be bundled with RECs prevents renewable generators from maximizing and optimizing the financial gains from the sale of these two environmental commodities.[117]

7.3.1 Redefined certificate types

Given these problems, are RECs an inherently flawed environmental instrument? Not necessarily. However, RECs do need to be redefined if they are to provide the advantages of a homogeneous commodity for each market application and secure consumer confidence.

[116] California Public Utilities Commission (CPUC) has begun to grapple with some of these issues in their January 2007 decision on the state's emission performance standard (EPS). The California EPS establishes minimum greenhouse gas emissions intensity per energy unit of electricity output for any long-term financial commitment by a LSE to supply baseload generation by power plants outside of California (see California Senate Bill 1368). The CPUC decided that the transfer of RECs would not be factored into determinations of compliance under the EPS. "…RECs cannot be used to offset emissions for EPS-compliance purposes" (CAPUC 2007). This decision is equivalent to saying that neither the direct emissions profile of a generator nor any indirect emissions reductions are embodied in a REC. Renewable generators that sell their RECs are not treated as "brown power" under the EPS, nor are fossil generators that purchase RECs then considered to be zero emission power. The CPUC's reasoning was in part based on the practical difficulties of determining what emission rate should be assigned to renewable generators that sold their RECs. The CPUC noted, though, that their decision regarding RECs under the EPS (phase I) did not prejudice a decision under future regulation, such as a state cap and trade system (phase II).

[117] Under some state RPS legislation, RECs have an expiration date. If allowances are required to bundled with RECs, it is not clear what happens to allowances if a REC expires.

Table 23 proposes four certificate types specifically defined to function as a homogeneous commodities, each for a specific market application.[118] Different definitions are needed, in part, because of the lack of common boundaries among markets. All four certificate types could converge into a single commodity in a scenario with a stringent national RPS (i.e., one that creates a scarcity for RECs) and load-based emission cap-and-trade scheme (described below and in Chapter 8). A national certificate registry for the on-site attributes, similar to that being developed in Europe, of all electricity generation would facilitate the integration of markets.[119]

Table 23. Redefined certificate types, their application, and characteristics

Market application	Type of certificate	Type of instrument	Additionality tests	Ownership	Quantification
Voluntary green power markets	Voluntary Renewable Energy Certificate (V-REC)[a]	Production subsidy	Unnecessary	Generator or contractual designee	Metered MWh
RPS compliance market	RPS Compliance Renewable Energy Certificate (C-REC)[a]	Quota	Unnecessary	Generator or contractual designee	Metered MWh
Voluntary or RPS compliance markets	Renewable Energy Offset Credit (RE-OC)	Offset credit	Similar to CDM projects[b]	Generator or contractual designee	Metered MWh
Load-based cap & trade market	Generation Emission Attribute Certificate (GEAC)[a]	Quota	Unnecessary	Generator or contractual designee	Metered MWh and on-site emissions per MWh

[a] In cases where the jurisdictions of these markets overlap, each of these certificate types are equivalent. Voluntary market customers can also treat C-RECs as being equivalent to REOCs if an RPS creates a market scarcity for RECs.

[118] These four types do not suffer from the flaws of the custom defined RECs in the ACORE/EMA master agreement.

[119] The European terminology is Guarantee of Origin (GoO).

[b] Clean Development Mechanism (CDM) under the United Nation's Framework Convention on Climate Change.

7.3.1.1 Redefining voluntary market RECs as a production subsidy

As discussed in Chapter 4, RECs sold into voluntary markets function as a production subsidy, where the voluntary market buyers are subsidy providers.[120] This framing of RECs is accurate given the conclusion that, in voluntary REC markets, they do not result in additional project investments. The purchase of RECs from voluntary markets is more than an act of charity, however. By commoditizing RECs, consumers can function as a direct subsidy provider because each unit of generation (i.e., MWh) receives a unit subsidy, assuming double counting of certificates is prevented.[121] The amount of this subsidy is set by the market price of RECs.

Under this definition, V-RECs do not include off-site attributes such as emission reductions from displaced fossil fuel generators. Instead, both V-RECs and C-RECs would be defined and certified based on a MWh of electricity generated from a facility using an eligible renewable energy resource. RECs are then simply a tracking tool, in keeping with how they were originally intended when proposed for use under RPS mandates. No determination of additionality is required, which reduces the transaction costs of monitoring and verification. There are also no ownership or quantification issues because no claims are made over emission allowances or emission reductions. Therefore, renewable energy project developers can sell RECs, emission offset credits, and allowances separately to maximize their financial return.

[120] The term subsidy may have a negative connotation with many, but if the subsidy is provided for the purpose of supporting an under-supplied public good, it should not. For marketing purposes, many in European green power markets simply refer to RECs as providing financial support for renewables.

[121] The United Kingdom's draft best practice guidance addresses the issue of double counting of emission reductions from renewable generation when the electric power industry is covered under a cap-and-trade scheme. The guidance states that offsets should be treated like a "charitable donation" and that they may or may not be additional to existing regulatory mechanisms (see paragraph 4.13) (DEFRA 2007). By not defining RECs in terms of off-site attributes, double counting of emissions is avoided.

7.3.1.2 RECs for RPS compliance

Certificates from eligible renewable facilities under an RPS scheme should be differentiated from voluntary market RECs. Ideally, the characteristics of a V-REC and a C-REC should be identical, except that the jurisdictional boundaries of a C-REC may be more restrictive (e.g., from generation within a particular state).[122] Both types of RECs function as a tracking instrument to prevent double counting of mega-watt hours. However, because the drivers of demand for V-RECs and C-RECs differ (i.e., voluntary market demand versus an RPS quota), their prices may also significantly differ.

Assuming that the RPS scheme creates a market scarcity for C-RECs (i.e., the RPS quota is set above the BAU quantity of renewable energy generation), then C-RECs will likely sell at a higher price than V-RECs. If the boundaries of both markets coincide, then the prices for V-RECs and C-RECs will converge because renewable generators will have the option of selling into either the RPS compliance or voluntary green power market.[123]

7.3.2 Defining an a REC with additionality: Renewable Electricity Offset Credits

Although certificates sold in voluntary markets typically come from projects that cannot adequately demonstrate their additionality, there is no reason that a new type of tradable instrument—a Renewable Electricity Offset Credit (RE-OC)—could not be defined in a way that satisfies a credible additionality determination. As discussed above, this determination should be made with reference to a project developer's investment decision, and investors need to be guaranteed a reasonable crediting period over which they can sell offset credits.

[122] Renewable generators within the jurisdiction of an RPS have the option of selling V-RECs into the voluntary market or C-RECs to LSEs for RPS compliance. A single registry system can easily ensure double counting between C-RECs and V-RECs is prevented.

[123] This assumes that the eligibility requirements for generators are identical, which would be preferable to creating a homogeneous commodity that is fungible between markets.

Creating a new offset credit commodity, denoted in megawatt-hours, for renewable energy generation would allow consumers to credibly claim that they caused an additional MWh of renewable energy to be generated for every RE-OC they purchased and retired. As discussed above, such claims are not credible for RECs currently sold in voluntary green power markets. For the same reason, RE-OCs should trade at a higher price than V-RECs.[124]

A RE-OC could also function as an offset credit instrument for RPS compliance markets, similar to how emission offset credits are linked to cap-and-trade markets. Load serving entities could source RE-OCs from renewable projects outside of the RPS boundaries to meet their quota.[125] For example, Klaus Töpfer, former executive director of the United Nations Environment Programme and Germany's former environment minister, has suggested that European countries could meet their renewable energy targets by investing in renewables in developing countries. He suggested that the European Union should decide on a 25 percent target for the renewable share in 2020, of which 5 percent could be located in developing countries.[126]

A RE-OC would provide an instrument for customers to credibly claim they have offset their electricity consumption from non-renewable generation sources (e.g., fossil fuel generation). However, does it make sense for customers to purchase such an instrument? The answer to this question depends on the objectives of the customer.

One approach for voluntary market customers to ensure the additionality of their purchases that does not require the creation of something like a RE-OC is for them to purchase and retire C-RECs from an RPS compliance market where there is a scarce supply of C-RECs.[127] This

[124] REOCs will also face higher transaction costs from the verification of project additionality.
[125] Policy makers may choose to restrict the use of out of region REOCs for RPS compliance in favor of the local environmental benefits of renewable energy generation.
[126] See also Del Rio (2006) for a discussion of how CDM credits and RECs can be sold separately from the same project.
[127] It is unnecessary to burden an RPS market with additionality tests. Policy makers can ensure that additional renewable energy investments result from an RPS simply by setting the quota sufficiently high. A clear sign that an

approach would alleviate the need for a project-specific additionality determination. The RPS mandate has created a demand for C-RECs, so voluntary buyers can be confident that every REC they purchase and retire will likely cause another MWh of renewable energy to be generated to meet the compliance demand of LSEs.

7.3.3 REOCs or emission offsets credits?

Although REOCs address the additionality problems with RECs, they do not address the ownership and quantification issues associated with claims on off-site attributes such as emission reductions (Table 22). Claims on emission reductions are limited to cases in which pollutants from the electric power industry are not covered under a cap-and-trade scheme (see Table 21).

If the objective of consumers or policy makers is to reduce emissions, such as GHGs, then V-RECs, C-RECs, and RE-OCs are all second best instruments. They do not directly measure or modify the desired behavior (i.e., emitting pollution). Second best instruments are appropriate when first best instruments are either unavailable or less cost-effective. However, tradable commodities and instruments addressing direct emissions from power plants are available (e.g., GHG emission allowances under the EU-ETS and offset credits under the Clean Development Mechanism). If the objective of a customer is to offset GHG emissions, whether their direct emissions or indirect from electricity consumption, then it is more appropriate to purchase emission offset credits and thereby utilize a first best instrument. RE-OCs are not measured in terms of a specific environmental benefit—if they were, they would not be a homogeneous commodity—instead they are measured in terms of an activity (i.e., MWh) that is assumed to be a proxy for environmental benefits (i.e., tons of GHG emissions).

RPS has created REC market scarcity is if the market price of RECs is at or near the penalty set for non-compliance (Agnolucci 2007).

If the objective of the customer is to increase the relative amount of renewable energy generation, irrespective of the direct environmental benefit, then RE-OCs could be a useful instrument because they directly measure the desired behavior. Customers purchasing and retiring RE-OCs would be able to credibly claim that they have offset their electricity use with renewable generation. Specific claims regarding emission reductions or other environmental benefits, though, are better addressed with first best instruments. For reducing GHG emissions, a first best instrument would be a GHG offset credit or an emission allowance.

7.4 White tags

A new type of environmental commodity based on energy efficiency savings is in use, especially in Europe (Bertoldi, Rezessy et al. 2005; Bertoldi and Huld 2006; Capozza 2006; Hamrin, Vine et al. 2007). These certificates are referred to as Energy Efficiency Certificates or as "white tags". They are a type of offset credit instrument because they require the application of project-based accounting rules (i.e., additionality, baselines, leakage, ownership, quantification) to determining the amount of electricity saved by a particular energy efficiency project relative to some BAU baseline (Langniss and Praetorius 2006; Mundaca 2007). White tags are denoted in MWh of energy savings and therefore suffer from ownership and quantification issues similar to RECs if the objective is to claim emission reductions and integrate them into emission trading markets. In Europe, white tags are not linked to the EU-ETS (Oikonomou, Rietbergen et al. 2007).

Like RE-OCs, white tags could function as an offset credit instrument under an RPS or as the commodity under a separate energy efficiency portfolio standard. Unlike RE-OCs, they could

be obtained from projects within the boundaries of the RPS.[128] An RPS that was expanded to allow the use of white tags for compliance would allow LSEs to utilize additional energy efficiency investments as a compliance strategy.

7.5 Tradable certificates for a load-based cap-and-trade scheme

If GHG emissions are capped and RECs are disaggregated from off-site attributes, voluntary REC market advocates worry how renewable generators will benefit from their production of zero emission electricity. Again, any policy that places a cost on emitting GHGs will economically privilege renewable energy generators. However, green power advocates often demand that renewable generators be able to participate directly in emission commodity markets to ensure renewable energy generators are advantaged by policies.[129] Despite the discussion above, the design of a policy to enable such participation is possible.

In its debate over the implementation of Assembly Bill 32, California considered the implementation of a load based cap-and-trade scheme to regulate GHG emissions (Burtraw 2008). A generator-based cap-and-trade schemes, such as the U.S. Acid Rain Program or the EU-ETS, places regulatory requirements on power plants to obtain and submit emission allowances for each ton of pollution they emit. In contrast, a load-based scheme operates similar to an RPS in that load serving entities (LSEs), rather than generators, are the target of regulation. Instead of placing a quota on the portion of renewable electricity LSEs supply, such as under an RPS, a load based cap-and-trade scheme places a cap on the total GHG emissions that can be associated with a LSE's electricity purchases (Cowart 2006a; Cowart 2006b). Tradable emission allowances are allocated to LSEs and the emissions intensity of each MWh of wholesale electricity

[128] The assumption here is that a MWh of electricity saved is at least equivalent to a MWh of electricity generated from a renewable source in terms of its environmental benefits.

[129] There are a number of ways that policy makers can provide inventives for renewable energy investments that do not involve directly integrating RECs into emission markets, such as guaranteed feed-in-tariffs, exemption from property taxes, an accelerated depreciation option, tax credits, and generation quota (i.e., an RPS).

purchased by the LSE is tracked. A benefit of such a system is that it has the potential to better address emissions leakage resulting from electricity imports and exports from and to jurisdictions outside the cap.

One approach to a load-based scheme would be to use unbundled certificates to track the emissions associated with an LSE's electricity purchases (Gillenwater and Breidenich 2009). An LSE would be required to purchase Generation Emission Attribute Certificates (GEACs) from generators equivalent to its delivered load. Each certificate would provide information on the emissions intensity of the generator that sold the certificate. Each LSE's total emissions for the purpose of compliance would then be determined by the sum of the emission rates on its certificates. An LSE would then have to submit allowances equivalent to that amount of emissions.

This approach would result in a subsidy for renewable and low GHG emitting generators from the revenue they would receive from certificate sales. Demand by LSEs for electricity generated from coal and other GHG intensive sources would be reduced because LSEs would have to submit more allowances for electricity purchases from these sources. GEACs could also be used by LSEs for RPS compliance and for public disclosure purposes.[130]

In the United States and in Europe, certificate tracking systems are being developed and implemented that would support this type of load-based scheme, as well as support a variety of policies, including RPS compliance, environmental disclosure in LSE billing, and voluntary certificate markets.[131] These tracking systems function like registries for other environmental

[130] Even under this type of emission trading scheme where on-site emission attributes are represented by a certificate, consumers who wish to reduce emissions should still purchase and retire emission allowances instead of GEACs because it is ambiguous how many tonnes of emissions are avoided by removing a GEAC with a zero emission rate.

[131] Certificate tracking systems in operation in the United States include the Generation Attribute Tracking System (GATS) in the PJM Interconnection, the Generation Information System (GIS) for ISO New England, and a system for the Texas RPS. The Western Renewable Energy Generation Information System (WREGIS) and the Midwest

commodities. Certificates could be created not only for renewable generation, but also for non-renewable generation. A certificate would be created for each MWh generated within the boundaries of the system. The certificate can include information on a variety of attributes associated with that generation, such as its GHG emission intensity (i.e., tonnes of CO_2 equivalent emitted per MWh). These are on-site attributes (e.g., direct emissions from the facility) not off-site attributes; therefore, their ownership and quantification are unambiguous (see Table 22).

A full discussion of a proposal that uses unbundled certificates with a load-based cap-and-trade scheme is provided in Chapter 8. In sum, a load-based scheme offers the potential to make tradable emission allowances and RECs fungible within the electric power industry.

Renewable Energy Tracking System (M-RETS) are expected to be operational in 2007. The European Energy Certificate System (EECS) is being developed under the Association of Issuing Bodies.

Chapter 8. Integrating certificates with emissions cap-and-trade

If it is i) incorrect to treat voluntary market RECs as offsets, and ii) RECs involve double counting with respect to corporate carbon footprints, is there any role for RECs in environmental markets that would achieve a beneficial environmental policy end? This chapter present one approach for how unbundled Generation Emission Attribute Certificates (GEACs), of which RECs would be one type, could be used in the implementation of an emissions cap and trade system. This approach avoids the problems identified and analyzed in earlier chapters, although it does increase the complexity of emissions trading systems by adding a new tradable commodity with uncertain implications for the broader price dynamics of wholesale electricity markets.

In the United States, a lack of regulatory initiative to address greenhouse gas emissions (GHG) at the federal level has induced state governments to develop their own or regional policies (C2ES 2011). The electric power industry is the largest contributor to U.S. GHG emissions, accounting for just over 33 percent, and so has been the focus of several state-sponsored initiatives (USEPA 2007a).

The policy approach for regulating emissions from the electric power industry adopted in the European Union's Emission Trading Scheme (EU-ETS) and most frequently proposed in the United States is to cap industry-wide emissions at the source and allow emission allowances to be traded between regulated entities. These emission "cap-and-trade" schemes specify that power plants (i.e., electricity generators) that directly emit pollutants, such as carbon dioxide (CO_2), are the regulated entities responsible for compliance.

In general, this type of source-based (SB) cap-and-trade scheme is an effective means of reducing emissions of the electric power industry. However, if the boundaries of the scheme that

specify which entities are capped do not include all or most of the entities operating in the regional electricity market, then emissions reductions from a capped region can be countered by increases in emissions from entities outside the scheme's boundaries. This problem is referred to as emission "leakage."

In attempting to address this problem, several western states considered utilizing an alternative regulatory approach for the electric power industry, referred to as a load-based cap-and-trade scheme (Burtraw 2008). A load-based (LB) approach differs from the traditional SB cap-and-trade approach in that the emission reduction obligation is placed upon Load Serving Entities (LSEs), rather than electric generators.[132] LSEs purchase power wholesale or generate it themselves and then distribute it to retail (i.e., residential, commercial, and industrial) consumers. Allowances, that convey the right to emit one ton of a pollutant, are distributed to LSEs who are then required to surrender allowances to cover aggregate emissions associated with the electricity they sell.

The LB approach to regulating GHG emissions from the electric power industry has been proposed for several states and regions because it can potentially reduce the problem of emissions leakage. States do not have the legal authority to regulate power plants located in other states; however, they do have the authority to regulate LSEs serving retail customers in their state, and thus emissions from all electricity consumed.

Oregon[133] and California[134] actively considered a LB approach. Not surprisingly, imports account for a significant fraction of the electrical load served (i.e., retail sales) in each state. In

[132] Depending on regulatory definitions, LSEs may be referred to as retail electric providers or retail electric suppliers.
[133] The Oregon Legislative Assembly introduced House Bill 3545 in 2006, which would have establish a LB cap-and-trade scheme for LSEs in Oregon. (http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf)
[134]California enacted Assembly Bill 32 in September 2006. The Bill explicitly requires that the state account for emissions from both in-state electricity generation and electricity imported from outside the state

California, net electricity imports accounts for around 30 percent of total load,[135] but roughly 50 percent of the GHG emissions (CEC 2007). In contrast, Oregon is a net exporter of electricity in years when snowfall is sufficient for hydroelectric facilities to operate near capacity. However, because of the seasonal nature of hydroelectric power, Oregon's overall consumption of electricity is still heavily dependent on imports from coal-fired power plants in Utah, Wyoming, and Montana (GAGGW 2004; ODP 2005).

States in the West and Northeast have also considered a LB approach to a cap-and-trade program. Participants in the Western Climate Initiative, which includes Oregon and California, considered developing a regional LB scheme. And states that are part of the Regional Greenhouse Gas Initiative (RGGI) also considered supplementing their SB cap-and-trade scheme with a LB approach that targets only the portion of electricity imported from states not participating in RGGI (e.g., Pennsylvania) (RGGI 2007).

For any LB scheme to be effective, it must be compatible with modern, and increasingly competitive, wholesale electricity markets. These markets are no longer dominated by vertically-integrated utilities. Instead, independent power producers, power marketers and brokers, and spot markets play significant roles.

Because much (and in some cases, all) of the load served by a LSE is purchased from other entities, LSEs are unlikely to know the emissions associated with their power purchases. Therefore, a key challenge for a LB scheme is how to assign emissions to each LSE.

(http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf). Initially, the California Public Utilities Commission (CPUC) stated its intention to develop a LB emission trading scheme for the electric power sector. However, in March 2008 the CPUC and California Energy Commission jointly recommended to the California Air Resources Board that it instead designate "deliverers" of electricity to the California grid as the point of regulation. (http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/80131.htm)

[135] http://www.energy.ca.gov/electricity/gross_system_power.html

One of the more detailed models for assigning emissions to load was proposed in Oregon. The Oregon model required that regulators track financial transactions for wholesale power by following the contract-paths between generators and LSEs. This chapter discusses the problems with the contract-path model, and proposes an alternative, using unbundled GEACs. This alternative model offers several benefits, most important of which is that it is more compatible with competitive wholesale electricity markets. Although this chapter will briefly contrast the LB approach to an emissions cap-and-trade scheme with a SB approach, it does not take a position on whether a SB or LB approach is preferable. Rather, it solely aims to elaborate and justify this alternative model for a LB approach.

8.1 Load-based cap-and-trade scheme

The LB approach represents an evolution of electricity procurement policies, such as Renewable Portfolio Standards (RPSs) and Emission Performance Standards, both of which mandate the type of electricity procured by a LSE. A LB approach is in many ways analogous to an RPS; however, whereas an RPS requires the tracking of generation from eligible renewable energy technologies that supplies a portion of a LSE's load, a LB approach requires the tracking of all generation, and associated emissions, supplying a LSE's entire load. Regulators and experts in California, in particular, have developed procurement policies to reduce emissions from the electric power industry over the last several years (Potts 2006).

The tracking and capping of emissions associated with all load served inside a jurisdiction, as opposed to only generation inside a jurisdiction, creates the potential to address emissions from imports and control emissions leakage from a shift to dirtier electricity imports (Burtraw, Farrell et al. 2006; Cowart 2006b; Cowart 2006a). This shift can take the form of moving facilities, production, or purchases to an unregulated jurisdiction. Because electricity can

easily be imported from uncapped sources that do not face emission compliance costs, the potential for leakage is of particular concern for the electric power sector (RGGI 2007).

8.1.1 Comparison to a source-based approach

Under a traditional SB cap-and-trade scheme, regulators determine a cap on allowable emissions, and distribute emission allowances (i.e., emission permits) to regulated sources (i.e., electricity generators) equal to the level of the cap. These sources can then trade allowances so that reductions are achieved at the lowest aggregate cost to society.[136] Each source monitors and reports emissions and then surrenders allowances equal to the quantity of its emissions. A SB approach internalizes the cost of pollution at the generator-level, because higher emitting generators face higher compliance costs than low-emission generators. This additional cost reduces the differential between the variable costs of these generators (e.g., coal and gas, respectively), with the result that cleaner generators dispatch more frequently and displace dirtier generation.

A LB approach also regulates emissions through the allocation and surrendering of emission allowances; however, allowances and the obligation to surrender them are assigned to LSEs, rather than generators. Under a LB approach, generators face no direct compliance requirement to reduce emissions. However, faced with compliance penalties if they exceed the emissions cap, LSEs will prefer to procure generation from lower emitting sources. Over time, the wholesale electric market should value less-emitting generation.

Advocates of a LB approach over a SB approach commonly cite three advantages. The first is that a LB approach provides regulated entities with a low-cost mitigation option not available to generators under a SB scheme. LSE can invest in improvements in the energy

[136] In the case of CO_2 and other GHGs, the ability to trade allowances is especially appropriate, given that the environmental impacts of GHGs are independent of the location of emissions.

efficiency of their retail customers, thereby lowering their overall load and emissions burden. For the electricity sector, energy efficiency may be the lowest cost mitigation strategy (IPCC 2007), and many LSEs have extensive experience in managing demand side management programs (Berry 1993). However, the significance of this effect is questionable, as LSE have not historically demonstrated a willingness to heavily invest in end-user energy efficiency (Wirl 1994).[137]

A second argument claims that a LB approach provides a better incentive for LSEs to procure electricity from renewable energy generators, because such procurement lowers their emissions, and thus, compliance burden. However, proponents of a SB approach argue that it provides an equivalent incentive for renewable energy investments by raising the relative costs of fossil fuel-fired generation.

Finally, because allowances would be distributed to LSEs, rather than generators, a load-based scheme would eliminate windfall profits accrued by generators under a SB scheme in which allowances are freely allocated (e.g., grandfathered).[138] However, distribution of allowances through auction could also eliminate windfall profits to generators under a SB scheme.

Overall, it is the advent of competitive wholesale electricity markets, where generators and LSEs operate as independent economic actors, that creates a key distinction between a LB approach and a SB approach. In some jurisdictions where the electric power industry has not been restructured and electric power utilities continue to operate as vertically integrated

[137] The revenue and profits for most LSEs are based on electricity sales. Therefore, unless profits and sales volume have been decoupled, a LSE will have an incentive to invest in energy efficiency only if the emissions compliance cost savings are greater than the lost profits from reduced sales.

[138] Retail electricity prices charged by LSEs are governed by utility commissions, who only allow rate increases for actual costs incurred by LSE. Therefore, grandfathered permits would provide no legitimate argument for raising rates.

monopolies, with generation, transmission, and distribution owned and operated by a single entity, a LB and SB approach are almost equivalent.[139] In these jurisdictions, the advantages of a LB approach over a SB approach will be limited to the issue of controlling emissions leakage.

The key challenge with implementation of a LB approach is assigning emissions to individual LSEs. Because it is physically impossible to track electron flows through a transmission grid, this requires some means of determining which generators are supplying a LSE's power portfolio.

8.1.2 Contract-path model

The LB approach developed by the Oregon Carbon Allocation Taskforce[140] and integrated into Oregon House Bill 3545 attempts to determine the mix of generators supplying an individual LSE's load based on the contract-path for power purchases and assigns emissions based on the emission rates of those generators. Where a LSE has a bi-lateral contract with a specific generator or owns a generation asset, the emission rate of that generator is applied to each mega-watt hour (MWh) purchased or produced.

However, much of the power purchased by LSEs is not in the form of unit-specific bilateral contracts. Instead, most LSEs procure a significant fraction of their electricity supply in the form of wholesale contracts that specify the quantity, price and delivery point of power but do not specify a particular generator. Unit-specific emission information is typically unavailable for such power purchases. In some cases, it is possible to track power backwards from a delivery point to a control area[141] using NERC e-tags[142], but not back to a specific generating unit.

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[139] Assuming that the same emission sources were covered by both a SB and LB scheme.
[140] http://www.oregon.gov/ENERGY/GBLWRM/CATF.shtml
[141] A control area is a set of interconnected electrical generation sources and sinks overseen by a common 'balancing authority'. The balancing authority is responsible for ensuring that electricity generation, imports to, and exports from a control area are balanced with load in that control area.

Similarly, day-ahead and real-time spot markets do not provide information that would allow LSEs to identify individual sellers or generators, as such information could be used for collusion or market manipulation. For the purposes of this paper, power purchased on the spot market or through contracts that are not unit specific is referred to as "unspecified power".

To get around this problem, the Oregon contract-path model assigns a common "residual emission rate" to unspecified power purchases based on an average emission rate of all generation within the Northwest Power Pool not accounted for with unit-specific bilateral contracts or as owned assets. A similar approach was considered for adoption in California (CEC 2007).

8.1.3 Contract-path model flaws

The contract-path model has several serious flaws. The objective of any model for implementing a LB approach should be to give preference to the dispatch of existing clean generation, and to promote additional investments in new and repowered low-emitting generation capacity.

Despite what one might think, even a LSE's unit-specific bilateral contracts do not necessarily determine which generators are dispatched in competitive wholesale electricity markets.[143] Rather, real-time factors determine dispatch. In U.S. competitive electricity markets, the primary market factors affecting dispatch are the wholesale electricity price in the day-ahead and hour-ahead markets. Generators or marketers bid into these markets based on consideration of the variable cost of operating each generator. The balancing authority or market operator may further adjust this dispatch of individual units based on resource availability, load conditions and

[142] North American Electric Reliability Corporation (NERC) e-tags are required for power scheduled between control areas. E-tags are not required to schedule power exchanges within a control area.

[143] There are exceptions. Generators will occasionally enter into inflexible contracts that require the generator to bid into the market at zero cost to ensure that the generator will be dispatched. These contracts are considered risky for both the generator and LSE and are thus the exception rather than the norm.

transmission constraints. In centrally operated markets, a market operator selects the lowest cost combination of generators to match a given real time load (plus reserves) on behalf of all the LSEs in the control area. A complex financial settlement process then corrects for the differences between contract payments and actual generation through side payments between generators and LSEs (Stoft 2002).

The implication of contracts not determining generator dispatch is that LSEs can meet their emission obligations through contract shuffling. In contrast to emissions leakage, which involves the actual shifting of generation activities from capped to uncapped sources, contract shuffling refers to a change in the arrangement of power contracts to cleaner generators without a corresponding change in dispatch or emissions. Bushnell et al. (2007) argue that contract shuffling will negate most of the emission reduction benefits from a California LB approach using the contract-path model. Regulators could attempt to eliminate the potential for contract shuffling by requiring unit-specific contracts, but such a requirement will add risk, inefficiency and, hence, costs to electricity markets.

The second flaw in the contract-path model is that it does not distinguish between electricity from low and high emission generators when it is sold as unspecified power. Therefore, the model does not signal the cost of pollution to these generators. Instead, the model provides an incentive for dirty generators to hide behind the default emission rate by selling power through unspecified contracts or the spot market.

Some analysts have suggested the further disaggregation of emission rates for unspecified power by source control area and by base/peak load periods, using marginal dispatch analyses (Alvarado and Griffin 2007). Such an approach could more accurately estimate the system

emission mix at different load periods, but it would not reduce the ability of LSEs to use contract shuffling to reduce their apparent emissions.

Further, because the contract-path approach does not capture the carbon price at the generator level, it has the potential to bifurcate electricity sales in centralized wholesale markets, such as the evolving California Independent System Operator markets. Specifically, low-emission generators will have an incentive to sell power through bilateral contracts so that the purchasing LSE can unambiguously claim the lower emission rate, while higher emitting generators will participate in wholesale day-ahead and spot markets. By reducing the quantity and type of power available in wholesale markets, a contract-path approach will interfere with the liquidity and efficiency of wholesale power markets (CAISO 2007).

Finally, the proposed formulation of the contract-path model provides LSEs no control over their emissions burden from unspecified power purchases. The only option for a LSE to lower the emissions associated with its load is to move from a system power purchase to unit-specific contract. This is problematic, as unspecified power purchases play an important role in ensuring the reliability and efficiency of electricity markets.

8.2 Tradable certificate model

Instead of relying on the tracking of contracts and a default emission rate for unspecified power, an alternative model would use generation emission attribute certificates (GEACs) to assign emissions to each LSE. A GEAC would be created for each mega-watt-hour (MWh) of net generation and contain data on the direct (i.e., on-site) emission rate (e.g., tons CO_2/MWh) of a specific generator (e.g., renewables would create GEACs with a zero emission rate) (Breidenich and Gillenwater 2007; Gillenwater 2007a).[144] These certificates would be registered

[144] Renewable Energy Certificates (RECs) are another type of generation attribute. As RECs are not designed to track emissions associated with generation, the authors consider them distinct from a GEAC.

and issued based on metered generator output and verified emissions rates, and tracked within a registry database.

Each LSE would be required to purchase GEACs equivalent to its load served and its total emissions would be calculated by summing the emission rate of each certificate. The LSE would then be required to surrender emission allowances equal to its final emission burden.

Because GEACs would be traded separately from electricity (i.e., unbundled), unit-specific contracts would not allow a LSE to claim a generator's emission rate.[145] Rather, the LSE must acquire and surrender GEACs in order to claim a specific emission rate.

Registries to track the creation, transfer and disposition of generation attribute certificates are already in operation in the Middle-Atlantic states (i.e., the PJM Interconnections Generation Attribute Tracking System[146]), New England (i.e., ISO New England's Generation Information System[147]), and Texas,[148] the Midwest (Midwest Renewable Energy Tracking System[149]), and the Western states (Western Renewable Energy Generation Information System[150]) that includes California and Oregon (Holt and Wiser 2007).

8.2.1 Model description

Under a simplified version of tradable certificate model, each LSE would be required to purchase and surrender a quantity of GEACs, denoted in MWh, equivalent to its load served.[151] A LSE's attributed emission would be calculated by adding the emission rates of all of its GEACs. Each LSE would then be required to surrender allowances equivalent to its attributed emissions for compliance (Equation 5).

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[145] Although LSEs could contract to purchase both electricity and certificates from a given generator.
[146] http://www.pjm-eis.com/gats/gats.html/
[147] http://www.nepoolgis.com/
[148] http://www.texasrenewables.com/
[149] http://mrets.net/
[150] http://www.westgov.org/wieb/wregis/
[151] The issue of line-losses is discussed in section 8.2.4.3.

$$A = \sum_{i=1}^{C} (CR_i), \quad \text{subject to the constraint that } C = L \qquad \text{[Equation 5]}$$

where,

A = number of allowances required by a LSE for compliance

C = the number of certificates submitted by a LSE

CR = the emission rate of an individual certificate (tonnes/MWh)

L = load delivered to end-use customers by a LSE (rounded up to the nearest MWh).

The simplified model above works if the generation within the capped area is equal to load, and if all generation is certified and sold to LSEs. However, if the generation within the capped area is less than total load (which would be expected in state or country which is a net importer of electricity), then the quantity of certificates will be insufficient to cover each LSE's load. Further, while a state could require that all in-state generators must certify their output, such a legal requirement would be difficult to apply to out-of-state generators.

To address these limitations, a more practical version of the model employs a default emission rate for the portion of a LSE's load not matched with GEACs. The use of a default emission rate eliminates the constraint in Equation 5 that the supply of certificates must equal the load of all LSEs, since the default emission rate would be applied to any load not covered by certificates. It also eliminates the need to track generation and emissions from all facilities. If the supply of GEACs can be constrained (see section 8.2.3), generators with emission rates below default rate will receive a positive price for their GEACs, and thus will have an incentive to certify their output. Generators with emission rates at or above the default rate will have no need to register GEACs, as these would have little or no market value.

Each LSE's emissions burden is then calculated based on the GEACs it purchases from low or zero emitting generators. The fraction of a LSE's load not matched with certificates is assigned a default emissions rate (Equation 6). To signal the cost of pollution to all generators, the default emission rate should be set at or just below the emission rate of the dirtiest generators serving load.[152] If the default emission rate is set at a lower value, such as the average emission rate of all generators, then all generators with an emission rate higher than the default would be attributed the same emission rate. Thus, the use of a high default emission rate provides an incentive for generators to reduce their emissions and certify their power production in order to gain certificate revenue. It also provides an incentive for LSEs to purchase GEACs to avoid being attributed emissions based on the high default rate.

$$A = \left[(L - C) \times DR\right] + \sum_{i=1}^{C} (CR_i) \qquad \text{[Equation 6]}$$

where,

DR = the default emission rate (tonnes/MWh).

Figure 33 provides an example of how the purchase of GEACs reduces a LSE's obligation to surrender allowances.

Figure 33. Example calculation for determining LSE compliance using the certificate-based model

Default emission rate:	1 metric ton CO_2/MWh
Total load-served by LSE:	100 MWh
Starting allowance obligation:	100 metric tons CO_2 (100 MWh · 1 metric ton/MWh)

[152] Setting the default rate at a level significantly below the dirtiest generator would effectively allow that portion of generators with emissions above the default rate to claim a cleaner emission rate and would fail to capture potential emission improvements above the average rate. Therefore, we do not recommend setting the default rate below that of an inefficient coal-fired unit.

GEACs purchased and surrendered:
50 certificates at 0.5 metric tons/MWh
20 certificates at 0 metric tons/MWh

LSE's allowance obligation: 55 metric tons CO_2
(50 MWh · 0.5 metric tons/MWh) + (20 MWh · 0 metric tons/MWh) + (30 MWh · 1 metric ton/MWh)

8.2.2 Advantages and disadvantages

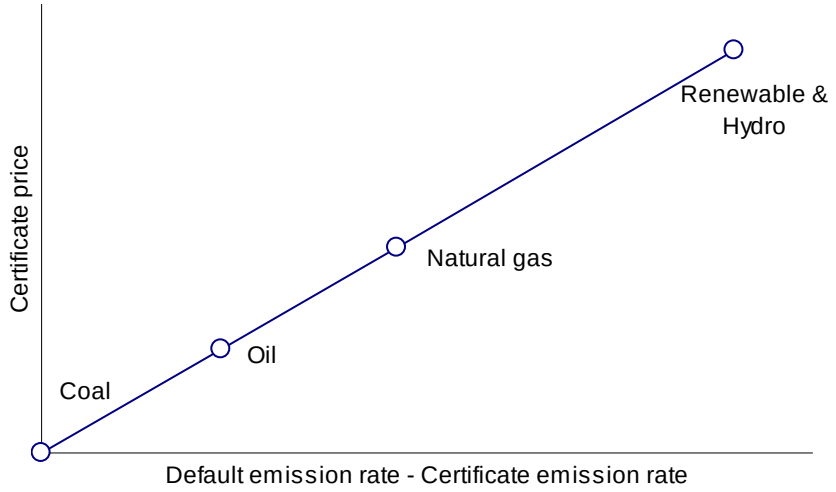
The tradable certificate model has several advantages over the contract-path model. Most importantly, the certificate model internalizes the cost of pollution at the generator-level because it preferentially provides lower emission generators with a new revenue stream. Eligible electricity generators would be able to sell GEACs to LSEs and other market participants, thereby gaining an additional revenue stream. Lower emission rate certificates should trade at a premium price, as they would lower the quantity of allowances that the LSE must surrender for compliance. The GEAC revenue should reduce the variable cost of generation for low-emission generators, allowing cleaner generators to bid in at lower electricity prices. GEACs thus should have the effect of subsidizing low and zero-carbon generation, with the subsidy provided by LSEs and other market participants rather than government agencies (Gillenwater 2007a).[153]

The market price of GEACs, on an emission rate weighted basis, is expected to track the price of emission allowances, since purchasing these certificates represent an alternative compliance option to submitting allowances; the purchase of GEACs reduces the quantity of allowances the LSE must surrender. Therefore, as shown in Figure 34, the equilibrium price of

[153] The effect of this subsidy on the dispatch of existing hydroelectric and nuclear units is likely to be negligible, assuming they are fully dispatched when available. The authors have considered excluding existing large existing hydroelectric and nuclear generators from the scheme, and reducing the total load for which LSE much purchase GEACs accordingly. Alternatively, the government could appropriate the certificates from these facilities and use the revenue from their sale for program administration and public benefit investments. However, this subsidy would provide an incentive for the development of new hydroelectric and nuclear capacity. An elaboration of these issues is beyond the scope of this dissertation.

each GEAC should equal the difference between the certificate's emission rate and the default emission rate, multiplied by the allowance price.

Figure 34. Certificate price as a function of emission rate



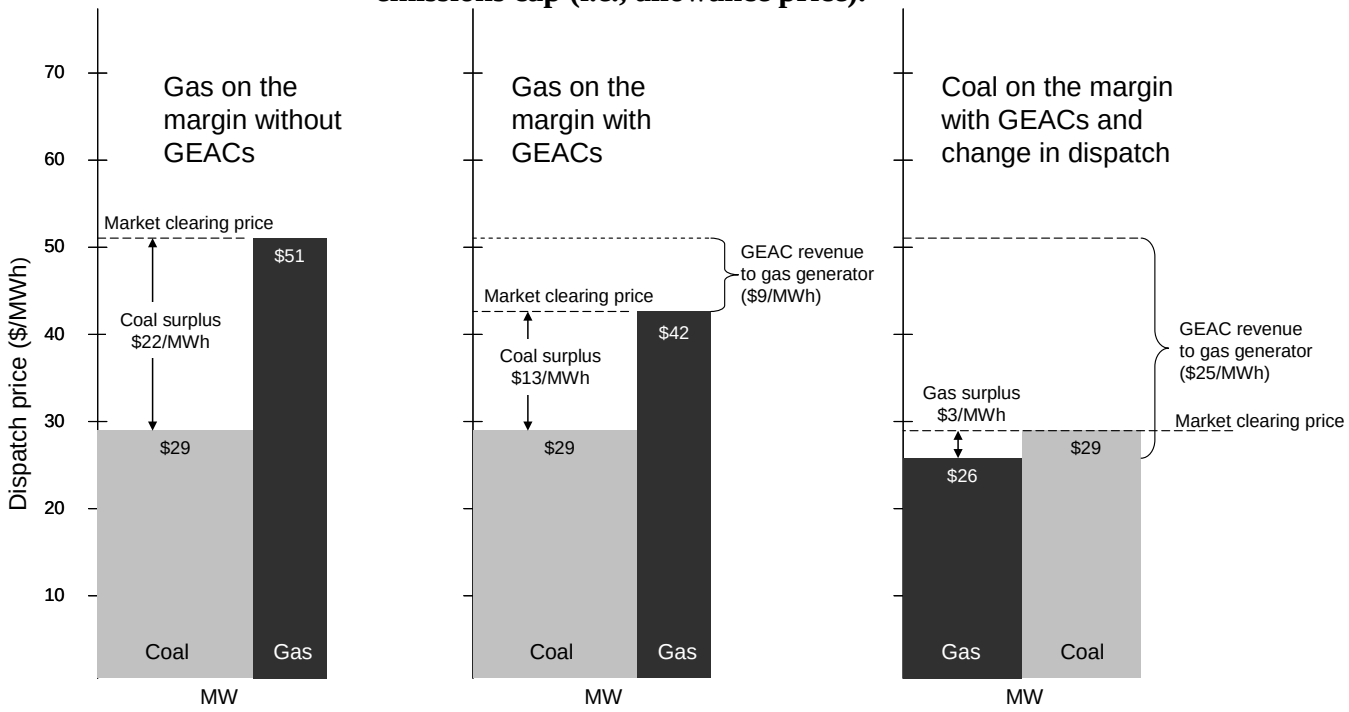
Note: Assumes that default emission rate is set at a level equivalent to a typical coal-fired unit.

The additional revenue from certificates is particularly important for renewable generators and natural gas-fired plants. The additional revenue from certificate sales is expected to cover a portion of a generator's levelized costs enabling that generator to submit lower bid prices into the wholesale electricity market. The certificates thus should provide a clear financial incentive for more frequent dispatching of higher variable cost generators with lower emission rates. It should also provide a direct financial incentive for investments in zero and low-emitting generation capacity.

In a SB system with allowance allocation based on historical emissions, allowance prices are incorporated into, and thus raise wholesale electricity prices. In a LB system, allowances incent LSEs to shift to lower emitting generators, which raises wholesale electricity clearing

prices. However, GEACs should also place downward pressure on wholesale electricity prices because certificate revenue will enable some low-emission generators to dispatch at lower electricity prices than possible in the absence of GEAC revenue. During load periods when a lower emitting unit (e.g., gas) is on the margin, the market clearing price for all generators will likely be reduced by approximately the GEAC value for that marginal unit.[154] While the reduced wholesale electricity price paid to this marginal unit will be offset by payments by revenue from the sale of its GEACs to LSEs, infra-marginal units with higher emission rates (i.e., coal) will see their wholesale electricity revenue drop with no revenue from GEAC sales to compensate the decrease in market clearing price (Figure 35).

Figure 35. Simplified dispatch curves showing hypothetical effect of GEAC revenue on wholesale electricity prices and dispatch. GEAC prices will reflect the stringency of the emissions cap (i.e., allowance price).



[154] At times when a high-emission unit would be on the margin (e.g., off-peak), the market clearing price would remain relatively unchanged, because the GEAC revenue for these units would have low or no value.

The extent to which this decrease in wholesale electricity prices would offset the additional costs that LSEs would incur for purchase of GEACs would depend on changes in dispatch and is beyond the scope of this chapter.[155] Modeling of the price dynamics within competitive wholesale electricity markets where electricity, certificates, and allowances are all simultaneously transacted is recommended as an area for future research to examine the impacts on retail electricity prices. Moreover, it is unclear how the implementation of an LB approach with certificates would affect the ability of electricity markets to operate without interruption.

Burtraw (2008) and Hobbs, Bushness et al. (2010) have pointed out that although combining certificates with a LB approach is elegant, that it would be expected to provide an output subsidy to generators that are cleaner than the default rate, which would lead to expanded production from those facilities. The effect should be to lower electricity prices and thereby distort the electricity market more than a SB approach and have a corresponding efficiency cost. However, electricity, unlike other products that can be stored, cannot easily be oversupplied, so the actual impact on electricity and allowance prices is unclear. To the degree that it does decrease electricity prices to consumers relative to a SB approach, this is likely to be seen to have political advantages by policy makers. Further, the effect of the output subsidy should be to further accelerate investment low emitting capacity, such as renewables relative to an SB approach.

Lastly, the GEAC model also avoids the difficulties and complexity with tracking contract-paths associated with other LB approaches. By unbundling certificates from wholesale electricity transactions, GEACs can trade in a separate market from electricity. The only data

[155] We speculate that a LB scheme using GEACs would have a smaller impact on retail electricity prices than a SB scheme (Burtraw, Palmer et al. 2001).

required for implementing the tradable certificate model is metered output and emission rate data.

8.2.3 Certificate supply

If the boundaries of a LB scheme match those of the regional wholesale electricity market, as would be the case if all states within the Western Interconnect adopted a LB scheme, then the output of all generators in the region would equal the region's total load. Assuming that the scheme's emissions cap creates a scarcity in emission allowances, then certificates from low-emitting generators will have a positive price. Under these conditions, GEAC revenue can be expected to alter the dispatch of generators and thus emissions within the capped region.[156]

However, if the boundaries of the scheme are narrower than the wholesale electricity market, then the potential supply of low-emission certificates may greatly exceed the scheme's demand (i.e., regulated load). The result will be that certificate prices will reflect the market's transaction costs only and provide little or no financial incentive for greater dispatch of or investments in cleaner generation capacity. In addition, the supply of low emission certificates would free up allowances that would otherwise be surrendered to cover emissions, thereby resulting in emissions leakage. This problem is analogous to the contract-shuffling problem discussed above, in that under this scenario, the purchase of low-emission certificates will have no effect on generator dispatch and thus will not reduce emissions.

[156] The extent to which the GEAC model will affect dispatch will depend on allowance prices, just as would be expected under a SB system. Analysis suggests that allowance prices in the range of $20 to $50/metric ton, depending on gas prices and available generation, would be required to equalize the variable cost of natural gas and coal generation and thus affect dispatch (Niemeyer 2007).

The challenge, then, is constraining the supply of certificates that may be used in the capped region.[157] Any approach to restricting certificate supply should meet several basic criteria:

- First, it should limit the supply of certificates that can be used in capped market to a quantity that is approximately equal to the load served in the capped area.
- Second, the approach must be consistent with the open exchange of power in competitive electricity markets, and should not provide new incentives or disincentives for unspecified power purchases.
- Third, it should minimize the uncertainty generators face regarding their eligibility to sell certificates into a capped region, so that they can factor any expected certificate revenue into their electricity bids.

For California, which is a net importer of power, the central problem is restricting purchases of out-of-state certificates to the quantity of net imported power, since in-state generators can reasonably be assumed to be serving in-state load. However, while restricting the quantity of imported certificates would not directly restrict power imports, it would potentially be vulnerable to legal challenges that it violates the Interstate Commerce Clause of the U.S. Constitution. The Commerce Clause has been interpreted as imposing two basic limitations on state authority: state regulations may not explicitly discriminate against other states and these regulations must not disproportionately impact other states. The latter requirement, in particular, requires balancing of the regulating state's interest, against the potential harm to neighboring states. Although an analysis of the legal implications of the certificate model is beyond the scope of this chapter, the equivalent treatment of in-state and out-of-state power is a fourth criterion

[157] See Grace and Wiser (2002) for discussion of various methods to address certificate imports and exports.

that any approach to restricting supply must meet.[158, 159] Any approach that limits the eligibility of certificates to generators within the capped region (or state) may fail this test.

For states or regions that are net exporters of power, the tradable certificate model can also lead to an oversupply of certificates. This problem is easier to address because regulators would not face legal impediments to placing reporting or other requirements on generators within their jurisdiction. Net exporting states could exclude the electricity exported from their LB scheme, thereby maintaining a balance between certificate supply and demand. Alternatively, if exports are small relative to electricity consumed within the capped region, exports could be disregarded. Any oversupply of certificates would then be compensated through setting a tighter cap on emissions. In effect, certificate purchases by in-state LSEs would then result in emission reductions for all electricity generated in the state, whether or not it was consumed in the state.[160]

8.2.3.1 Scheduled delivery restriction

The ideal approach to limiting the certificate supply would be to restrict certificate eligibility to power delivered into the capped area. This approach has conceptual appeal in that certificate revenue would accrue to generators actually supplying load. Because of the impossibility of tracking electricity from source to sink, this restriction is not feasible. However, a reasonable proxy could potentially be achieved by restricting valid certificates to generation *scheduled for delivery* into the capped area. For an area that is a net importer of electricity, in-

[158] See Potts (2006) and Engel (1999) for discussions of the potential commerce clause issues, including the Pike balancing test (*Pike v. Bruce Church, Inc*., U.S. Supreme Court, 1970). It should be noted that many state RPS requirements that discriminate between in-state and out-of-state renewable generation appear to be vulnerable to commerce clause challenges, yet have not been challenged (Rabe 2006). However, this may be because affected generators have more to gain from RPS legislation than from challenging any individual state requirement.

[159] The first seller approach recommended to the state of California by its Market Advisory Committee, may suffer from similar legal and federal regulatory challenges (e.g., under the Federal Energy Regulatory Commission) due to the requirements it places on out of state entities to purchase allowances. <http://www.climatechange.ca.gov/policies/market_advisory.htm>l

[160] Although not a feasible scenario at this time, the limit to this alternative is where the supply of zero emission certificates from in-state generators exceeds the total demand for certificates in the capped region.

state generators would be assumed to be supplying native load (electricity exports are discussed below). Thus, all GEACs generated would be valid for use within the capped area.

For out-of-region generators, only certificates associated with power scheduled for delivery into the capped region would be eligible for use within the capped region. This restriction could be implemented using NERC e-tags. Regulators would need to establish a rule that out-of-state generators must produce valid NERC e-tags for scheduled delivery into the region in order for the associated certificates to be used within the region. Although generator-specific information is not typically provided on most NERC e-tags (Rush and Hoffman 2007) the potential certificate revenue would provide the incentive for generators to provide that information.[161] If necessary, the e-tags could be verified against the records of the appropriate control area.

Therefore, a scheduled delivery restriction would require a specific generator, to be eligible to sell GEACs into the capped region, show both that electricity was scheduled for delivery into the region and that at least electricity of the amount scheduled was actually generated by the unit during the compliance period. In contrast, a contract path model would allow a LSE to use a unit-specific emission rate for specified power contracts, regardless of whether that generator actually produced power or delivered it into the capped region. This action is what is referred to as contract-shuffling.

If electricity exports from the area are substantial, a scheduled delivery restriction can also be used to prevent use of GEACs associated with electricity exports. Regulators could require that all in-region generators certify all dispatch, and provide all export schedules (i.e., NERC e-tags) to the tracking registry. Any electricity scheduled for export by a generator would

[161] Note that collection of this information would *not* require that a NERC tag indicate a particular generator but only that the tag be matched with unit-specific dispatch records for that generator.

be subtracted from total generation, so that GEACs are issued only for power delivered in-region.

A scheduled delivery restriction would ensure that the supply of eligible GEACs is approximately equal to load within the capped region. There may be some discrepancies due to real-time balancing (with no associated e-tags), but these are likely to be minor. A scheduled delivery restriction would allow generators to factor expected certificate revenue into their bid schedules within the wholesale electricity market in the capped region. Finally, because it makes no distinction between in-state and out-of-state generators, this model should not be vulnerable to Commerce Clause challenges. Further research is necessary to investigate fully the use of e-tags and related schedule tracking instruments for a LB approach.

8.2.4 Design issues and implementation

A number of other issues must be considered in the design and implementation of a LB cap-and-trade scheme based on the tradable certificate model. First, the appropriate level of the cap must be determined. Second, a formula for allocating or auctioning emission allowances to LSEs must be established. Third, pre-existing contractual, financial, and regulatory arrangements with electricity generators would need to be assessed to establish rules regarding the ownership of certificates. Fourth, reliable emissions and generation monitoring procedures must be defined. Lastly, rules and systems to ensure efficient and liquid markets for allowances and GEACs must be created.

8.2.4.1 Baselines and allowance allocation

Under a SB scheme, allowances are either given away to generators or auctioned. The revenue from auctions is typically then used for some public benefit purpose. For a LB scheme, similar decisions are required for the allowances allocated to LSEs.

Regardless of whether generators pay for allowances (i.e., under an auction) or receive them free (i.e., grandfathered), under a SB approach, with allowance allocation based on historical emissions, the opportunity cost of the allowance is passed on to consumers in higher wholesale electricity prices. Therefore, auctioning of some fraction of allowances under a SB scheme is often advocated to avoid windfall profits being captured by generators (Palmer, Burtraw et al. 2006; Sijm, Neuhoff et al. 2006).

Under a LB scheme, however, free allocation of most allowances to LSEs is likely to be preferable. Whether allowances are freely allocated or auctioned to LSEs, it will not affect the dispatch or investment patterns of generators (Burtraw, Farrell et al. 2006). Further, retail electricity rates are not based on a marginal market clearing price of electricity, but are instead regulated by public utility commissions. Therefore, the ability of LSEs to raise prices and gain windfall profits is limited. Under the GEAC model, while LSEs must pay for GEACs, these payments should largely be returned to the LSE through lower wholesale power prices. Regulators may still wish to auction a fraction of allowances to raise revenue for some public benefit programs, but LSEs would then have a valid rationale for raising retail electricity rates to recover the costs of purchasing allowances beyond what is necessary to recover costs from purchasing electricity from lower emitting generators.[162] Although the LB approach may avoid the necessity of deciding whether and how much to auction, it is still necessary to decide on the method for distributing allowances to individual LSEs.

The contract-path model typically calls for setting an emissions baseline for each LSE. For example, under the Oregon proposal each LSE's baseline is based on the emissions rate of its

[162] The possibility of reduced incentives for energy efficiency due to any generation output subsidy effect on retail electricity prices could be addressed by auctioning a small portion of allowances to LSEs.(Burtraw, Palmer et al. 2001). Modeling work to evaluate the implications for the wholesale and retail prices could help determine the extent to which this might be a problem under the GEAC model.

historical electricity purchases, accounting for unit-specific bilateral contracts, system power, and imports. This is necessary to create a baseline that is consistent with how emissions are calculated and assigned during the compliance period. Collecting and verifying this data is a significant administrative burden for both LSEs and regulators.

Under the tradable-certificate model, however, the allocation process can be simplified. Because each LSE's emissions are calculated independently of its power purchases or power assets and all LSEs have access to GEACs, it is not necessary to factor historic emission into the calculation of a LSE's baseline. Rather, all LSEs should receive an equal allocation of allowances on a load-weighted basis. Only data on each LSE's forecasted load in MWh are necessary.

8.2.4.2 Certificate ownership issues

GEACs will have a market value related to their assigned emission rate because generators and other wholesale electricity market participants will have a strong interest in claiming ownership of certificates. For example, a wholesale electricity broker with an existing contract with a wind power generator may claim that his contract implicitly transfers ownership of GEACs. These types of certificate ownership issues could be especially problematic during the start of a scheme until language filters into all wholesale market contracts explicitly identifying ownership of certificates. Uncertainties regarding the ownership of GEACs would significantly weaken the incentives for certification of power and for new low-emitting generation investments.

For this reason, policy decisions prior to the launch of a LB scheme will be needed to address certificate ownership issues under all possible scenarios to avoid unnecessary litigation and uncertainty. Renewable Energy Certificate (REC) markets have started to address similar

certificate ownership issues, in particular with qualifying facilities (QFs) under Public Utility Regulatory Policies Act of 1978 (PURPA), net metered generation, and other generators receiving some type of financial assistance (Holt, Wiser et al. 2006). Experiences in the REC markets can provide lessons for addressing ownership issues under the GEAC model.

8.2.4.3 Compliance monitoring

Identical to a SB scheme, a LB scheme requires reliable emissions data to be collected from generators. The lessons regarding emissions monitoring from existing cap-and-trade schemes such as the U.S. Acid Rain Program and the EU-ETS can be applied here (Stavins 1998; Kruger and Pizer 2004). In addition to emissions data, net generation data (MWh) must also be collected in parallel to calculate a generator-specific emission rate. This rate should be updated at a regular frequency.

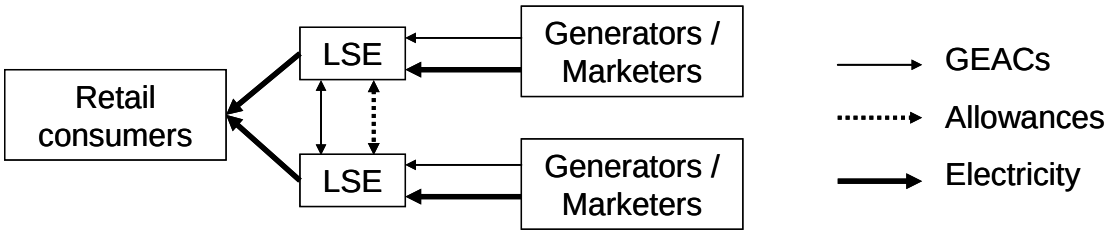
Once data is collected and verified, a GEAC for each MWh generated can then be created in a registry database and recorded with a specific emission rate. Certificates in the registry can then be transferred, submitted for compliance, or voluntarily retired.

A unique issue with a LB approach is that it must account for electrical losses due to transmission and distribution. The national average for these losses is about 7 percent (CCTP 2005), although loss values can vary significantly by region, with rural areas having higher loss percentages. Failing to account for these losses could lead to an excess supply of GEACs on the market. The simplest approach to address this problem would be to upwardly adjust each LSEs load served value (i.e., L in Equation 6) by a percentage that accounts for the region's average transmission and distribution losses. If the difference in line losses varies significantly between LSEs, individual adjustments in L and the number of allowances allocated may be appropriate.

8.2.4.4 Market efficiency and liquidity

Both the SB and LB schemes create a new allowance market in parallel to the existing wholesale electricity market. Under the tradable certificate model, a third market in GEACs is also created (Figure 36).

Figure 36. Three commodities under the tradable certificate model for a load-based cap-and trade scheme



Under a LB scheme, the number of participants in the allowance market is likely to be less than in a SB scheme (i.e., fewer LSEs in a jurisdiction than generators). Therefore, liquidity and market manipulation risks are likely greater with a LB scheme. The addition of generators as participants through the GEAC market will likely add some complexity to the marketplace, but may improve market liquidity, because it adds generators as market participants, and GEACs as allowance substitutes.[163] Allowing banking of allowances across compliance periods should further improve both market efficiency and liquidity.

To achieve these improvements, especially given the added complexity of having three commodity markets, it is important that systems be put in place to ensure a transparent market. Such systems include transparent certificate and allowance registries, open commodity exchanges, and frequent reporting of generation and emissions rate data. The addition of a

[163] Modeling of the electric power industry with the addition of both allowance and certificate markets may help clarify the likely market dynamics.

market for certificates also has the potential to serve as a price discovery mechanism for allowances because certificate prices will have a predictable relationship with allowance prices.

8.3 Linkages with other trading schemes and policies

A LB cap-and-trade scheme using the tradable certificate model can be linked with SB trading schemes and used to support a variety of other energy and environmental policies.

Because an allowance represents a legal permit to emit a ton of pollutant under both a SB or LB scheme, there should be no barriers to linking a LB scheme with a SB scheme addressing the electric power industry, such as the EU-ETS or RGGI, or a broader economy-wide SB scheme, provided that the boundaries of the two schemes do not overlap.[164] However, while allowances would trade freely across the SB and LB system and across sectors, GEACs would only be traded within the electricity sector of certificate-based LB systems. Similarly, emission offset crediting could just as easily be integrated with a LB scheme using either model and would function the same as it would under a SB scheme.

It would also be technically feasible to establish a national or multinational certificate based LB cap-and-trade scheme for the electric power industry. The benefits of such an approach would be similar on a national and multinational level as they are on regional level (e.g., addressing emissions leakage, facilitating energy efficiency, integration with RPS mandates). However, a national or multinational scheme would need to satisfy international trade rules with respect to the treatment of imported power (Horlick, Schuchhardt et al. 2002). In addition, the current design of emissions accounting under the United Nations Framework Convention on Climate Change and the Kyoto Protocol is based on the geographic location of sources.

[164] If the boundaries of a LB system and a SB system overlap, as would be the case if California adopted a LB system and other neighboring states adopted a SB system, then emissions could be regulated and priced twice – once at the generator level and again at the LSE level. This problem could be addressed by treating all generators subject to a SB scheme as zero-emissions under a LB scheme.

Therefore, a unilateral LB approach that accounted for emissions from international electricity imports would be inconsistent with the reporting framework for these treaties. However, Article 4 of the Kyoto Protocol allows two or more countries to cooperatively account for emissions, and would thus provide an opportunity for these countries to implement a LB system within the framework of the treaty.

GEACs can be used to support utility public disclosure policies, and voluntary green power markets. Voluntary green power and emission market participants can be allowed to purchase and retire both GEACs and emission allowances. If a consumer wishes to claim emission reductions, then emission allowances, not GEACs, are the appropriate commodity to retire because the exact amount of emissions reduced will be unambiguous (i.e., one ton).

GEACS are also compatible with existing RPS mandates. If regulators determine that a REC also conveys the emission attribute of the power (i.e. the GEAC), then RECs used for compliance with an RPS should also be counted towards a LSE's emissions burden. An RPS then becomes a policy that requires a certain percentage of LSE compliance with the LB cap to be met with renewables.[165]

8.4 Summary

Regardless of whether a LB approach is preferable to a source-based approach, the contract-path model for a LB emissions trading scheme has several flaws that undermine its effectiveness at reducing emissions and its compatibility with the evolution of competitive wholesale electricity markets. By providing a mechanism to internalize an emissions price signal at the generator dispatch level, the alternative tradable certificate model described here addresses both these problems and provides incentives identical to a SB system.

[165] Similarly, the GEAC model can be combined with an energy efficiency portfolio standard that uses tradable certificates for compliance (i.e., "white tags"). Similar to an RPS, this approach would mandate a certain portion of the LB cap be met through energy efficiency.

Whether the alleged advantages of a LB system in encouraging renewable energy and energy efficiency justify the added complexity of a third commodity market for GEACs is beyond the scope of this chapter. For further work, we recommend modeling of the price dynamics within competitive wholesale electricity markets where electricity, certificates, and allowances are all simultaneously transacted to illustrate the impacts on retail electricity prices.

Chapter 9. Conclusion

This dissertation has examined the voluntary REC market in the United States with the purpose of understanding its environmental benefits and whether these benefits are consistent with the claims typically made by those actively engaged with and participating in voluntary green power programs. Fundamentally, most of these claims are built upon an assumption that the voluntary green power market leads to more renewable energy investment and generation than would exist in the absence of this market activity. In environmental markets, the assumption that the revenue from the sale of an environmental commodity "caused" a public good to be produced, is referred to as "additionality." This dissertation provided the first quantitative analysis of the effect of the voluntary REC market on project investment.

The core research question of this dissertation has been whether project developers respond to the voluntary REC market in the United States by altering their decisions to invest in wind turbines. The hypothesis offered, that the voluntary REC market in the United States has had, at most, a small marginal effect on the generation of electricity from renewable energy sources, was found to be true with a high probability. Most renewable energy projects in the United States have been implemented without financial consideration of any revenue from voluntary market REC sales, and therefore are not additional.

Using two datasets and two modeling approaches, it was found that the voluntary REC market has little influence on the viability of wind power project investment in the United States. Further, it was found that purchasing a REC is not necessarily equivalent to using electricity without causing any emissions. More specifically, I found that:

1. RECs should be not treated as equivalent to emission offset credits,

2. there is no clearly credible role for voluntary market RECs in emissions trading markets without dramatic restructuring of one or both markets and the environmental commodities they trade, and
3. the use of RECs in entity-level GHG emissions accounting (i.e., "carbon footprinting") leads to double counting of emissions and therefore is not justified as a sound environmental accounting practice.

Alternative ways of defining RECs and REC markets were examined and dismissed followed by a detailed policy proposal for how the voluntary REC market could be restructured through government regulation and integrated with a load-based emissions cap and trade system for the electric power sector.

In sum, I found no clear environmental benefit resulting from the voluntary REC market for wind power in the United States, which forms the bulk of the U.S. voluntary green power market. RECs appear to function as a simple production subsidy for renewable energy generators, but one that is insufficient to have even a marginal impact on wind power investment. Further, there appears to be no simple change that could be made to the definition of a REC in the voluntary market that would correct this problem. Though, there are more complex policy options, such as the use of certificates for tracking compliance under a load-based emissions cap-and-trade system for the electric power sector, that avoid the problems in the existing voluntary REC market.

Although the majority of the U.S. voluntary green power market is based on wind, the findings from this dissertation may not extrapolate to the entire voluntary green power market. Specifically, solar energy RECs were not considered in the analysis presented here. Solar RECs often trade with a separate and higher price from other RECs, but it is noted that they account for

less than one percent of the voluntary green power market. The research here also did not explore voluntary green power markets in other countries and regions, the dominant one being Europe, where factors not present in the United States could play an important role in renewable energy investment decisions.

I speculate that the origin of the misunderstanding by those who purchase RECs through the voluntary green power market is the assumption that they are "buying" electricity from renewable energy projects, versus fossil fuel-fired facilities, through participation in voluntary green power program. Marketing messages communicate to consumers that, through their participation and premium payments for a green label, they are:

- causing additional renewable energy generation and reducing emissions, and/or
- taking ownership over the rights to claim that their consumption of electricity is associated with zero emissions.

RECs are intended to provide an economic incentive to investors to increase the amount of electricity generation capacity from renewable energy sources. The voluntary green power market in the United States, like almost all voluntary environmental markets, has gone largely unregulated. Instead, the market has been shaped by the interests of various stakeholder organizations, which have been focused on promoting market growth.

I found no effective mechanism currently operating within voluntary green power markets for differentiating between non-additional and additional renewable energy projects. This failure to differentiate violates an essential requirement that defines an offset credit. Additionality ensures that an offset credit is distinct from a production subsidy. With a production subsidy, any producer receives the subsidy (i.e., credit). While with an offset, only additional projects (i.e., producers that meet certain criteria) are issued credits. The alternatives available to address this

failing of the U.S. voluntary green power market include: i) the sale of emission offset credits from renewable energy projects into the voluntary carbon offset market, ii) the imposition of a national RPS through federal government legislation, and/or iii) the implementation of a more complex load-based cap-and-trade system as described in Chapter 8.

The experts interviewed as part of this research reported that the impotence of the voluntary REC market was, at least in part, due to the small magnitude of the REC price signal and lack of long-term contracts that would reduce the risk of relying on revenue the voluntary green power market. Although not the subject of investigation here, I speculate that the misleading claims within the U.S. voluntary green power market have two enabling origins. The first is that none of the actors in the voluntary green power market have a strong incentive to challenge unsubstantiated environmental claims or advocate for environmental instrument quality. The current actors that set standards and certify renewable energy projects, such as the Center for Resource Solutions through their Green-e program, appear to be primarily focused on promoting green power markets. The second origin is the ambiguous definitions in both green power and emissions markets around terms like REC, attribute, and additionality, which leave the interpretation of what is a legitimate environmental claim largely subjective.

Numerous questions are possible topics for further research, including, but not limited to: i) what indirect effect has the voluntary green power market had on the public acceptance and support for renewable energy policies; ii) are projects other than wind power, such a solar, more likely to be additional due to the voluntary REC market; iii) what effect would the GEAC load-based approach have on wholesale electricity market price dynamics; and iv) what incentives would be necessary for consumers to pay higher prices for RECs and commit to long-term purchase contracts. A similar study of voluntary green power markets in Europe and other

countries outside of the United States could potentially illumniate new factors relevant to the influence of these markets on renewable energy investment that are not current in operation within the United States. Lastly, if individuals and companies ceased participating in voluntary green power markets, because they understood their assumptions about these markets were erroneous, what would they choose to do instead and what would be the environmental benefits associated with these alternatives is another worthy research topic; this question would be a valuable for policy makers and be something that could be answered through a variety of formal interview techniques. A question that is likely to be of more interest to policy makers is to use the models and research techniques employed in this dissertation to investigate the question of what influence RPS compliance REC markets have on investment in wind power.

Appendix A – REC and environmental attribute definitions

Table A1. Definitions of a REC and "environmental attributes" for select RPS compliance and voluntary REC markets (as of end of 2006)

Reference	Definitions
State RPSs	
Texas[166]	"A REC represents one megawatt hour of renewable energy that is physically metered and verified in Texas and is generated by a facility eligible for producing RECs." Eligible facility must be either less than 2 MW in size or placed into service after 1 September 1999.

[166] Chapter 25. Substantive Rules Applicable to Electric Service Providers; Subchapter H. Electrical Planning; Division 1. Renewable Energy Resources and Use of Natural Gas.

California[167, 168]	"Renewable energy credit means a certificate of proof, issued through the accounting system established by the Energy Commission pursuant to Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource." "Renewable energy credit includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels." "Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Unit(s), and its displacement of conventional energy generation. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO_2), methane (CH_4) and other greenhouse gases (GHGs)…; and (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program… [One] Green Tag represents the Environmental Attributes associated with one (1) MWh of energy. Environmental Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Unit(s), (ii) production tax credits associated with the construction or operation of the energy projects and other financial incentives in the form of credits, reductions, or allowances associated with the project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Unit(s) for compliance with local, state, or federal operating and/or air quality permits. If Seller's Unit(s) is a biomass or landfill gas facility and Seller receives any tradable Environmental Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Environmental Attributes to ensure that there are zero net emissions associated with the production of electricity from such facility."

[167] California Public Utilities Code, Section 399.11-399.20

[168] Opinion Adopting Standard Contract Terms and Conditions, Public Utilities Commission of the State of California, Decision 04-06-014, 9 June 2004. /www.cpuc.ca.gov/PUBLISHED/Final_decision/37401.htm/

New Mexico[169]	"[A REC is a] document evidencing that the enumerated renewable energy kilowatt-hours have been generated from a renewable energy generating facility." "Renewable energy certificates shall contain the following information: (1) the name and contact information of the renewable energy generating facility owner and/or operator; (2) the name and contact information of the public utility purchasing the renewable energy certificate; (3) the type of generator technology and fuel type; (4) the generating facility's physical location, nameplate capacity in MW, location and ID number of revenue meter, and date of commencement of commercial generation; (5) the public utility to which the generating facility is interconnected; (6) the control area operator for the generating facility; and (7) the quantity in kWh and the date of the renewable energy certificate transaction."
Colorado[170]	"Renewable Energy Credit means a contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly attributable to a specific amount of electric energy generated from an Eligible Renewable Energy Resource."
Massachusetts[171]	Generation Attribute [is a] non-price characteristic of the electrical energy output of a Generation Unit including, but not limited to, the Unit's fuel type, emissions, vintage and RPS eligibility." "Renewable Generation Attributes [are] documentation from the NEGIS administrator of the total electrical energy sales to End-Use Customers in the Compliance Year associated with Renewable Generation Attributes"
Arizona[172]	"If an Affected Utility trades or sells environmental pollution reduction credits or any other environmental attributes associated with kWh produced by an Eligible Renewable Energy Resource, the Affected Utility may not apply Renewable Energy Credits derived from that same kWh to satisfy the requirements of these rules."
Nevada[173]	"Portfolio energy credit means a unit of credit which: equals 1 kWh of electricity generated or saved by a portfolio energy system or efficiency measure."
Montana[174]	"Renewable energy credit means a tradable certificate of proof of 1 megawatt hour of electricity generated by an eligible renewable resource that is tracked and verified by the commission and includes all of the environmental attributes associated with that 1 megawatt-hour unit of electricity production."
Maine[175]	"GIS certificates mean certificates created pursuant to the NEPOOL Generation Information System that represent attributes of electric power and that may be traded separately from the energy commodity."

[169] New Mexico Administrative Code; Title 17. Public Utilities and Utility Services; Chapter 9. Electric Services; Part 572. Renewable Energy for Electric Utilities
[170] Colorado, Code of Colorado Regulations 4 CCR 723-3
[171] 225 CMR 14.00 - Renewable Energy Portfolio Standard
[172] http://images.edocket.azcc.gov/docketpdf/0000063561.pdf/
[173] Revised Adopted Regulation of the Public Utilities Commission of Nevada; LCB File No. R167-05
[174] Montana Code 69-8-1003.

Delaware[176]	"Renewable Energy Credit means a tradable instrument comprised of all the Generation Attributes equal to 1 megawatt-hour of electricity derived from Eligible Energy Resources and that is used to track and verify compliance with the provisions of this Regulation. A REC does not include emission reduction credits and/or allowances encumbered or used by a Generation Unit for compliance with local, state, or federal operating and/or air quality permits associated with the 1 megawatt-hour of electricity."
New Jersey[177]	"Renewable Energy Certificate means a certificate representing the environmental benefits or attributes of one megawatt-hour of generation from a generating facility that meets the requirements of this subchapter." "Attribute means a characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, State program eligibility, or other characteristic that can be identified, accounted, and tracked."
Maryland[178]	"Renewable energy credit means a credit equal to the generation attributes of 1 megawatt-hour of electricity… that is located: (1) in the PJM region or in a state that is adjacent to the PJM region; or (2) outside the area…but in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region."
Pennsylvania[179,180]	"Alternative Energy Credit [is a] tradable instrument that is used to establish, verify and monitor compliance with this act. A unit of credit shall equal one megawatt hour of electricity from an alternative energy source."[181] "[T]he Commission concludes that it has no authority to find that an alternative energy credit includes [environmental or emissions attributes]. Generators are of course free to include those attributes in their sales of alternative energy credits. They may also sell, assign or trade them separately. Our expectation is that the disposition of these emissions and environmental attributes will be governed by specific, contractual language, and that parties will not look to the Commission to resolve ownership disputes."
District of Columbia[182]	"Renewable energy credit means a credit representing one megawatt-hour of electricity consumed within the PJM Interconnection region that is derived from a tier one renewable source or a tier two renewable source that is located: (A) In the PJM Interconnection region or in a state that is adjacent to the PJM Interconnection region; or (B) Outside the area described in subparagraph (A) of this paragraph but in a control area that is adjacent to the PJM Interconnection region, if the electricity is delivered into the PJM Interconnection region."

[175] Maine 65.407 Chapter 311- Eligible Resource Portfolio Requirement
[176] Delaware Public Service Commission, Rules and Procedures to Implement the Renewable Energy Portfolio Standard
[177] New Jersey Administrative Code Title 14. Board of Public Utilities; Chapter 8. Renewable Energy and Energy Efficiency; Subchapter 2. Renewable Portfolio Standards; N.J.A.C. 14:8-2.1 et seq. (2006)
[178] Code of Maryland; Public Utility Companies; Title 7. Gas, Electric, And Water Companies; Subtitle 7. Renewable Energy Portfolio Standard; Md. Public Utility Companies Code § 7-701 Et Seq. (2005)
[179] Pennsylvania Statutes Title 73. Trade and Commerce; Chapter 18f. Alternative Energy Portfolio Standards Act; 73 P.S. §1648.1 et seq. (2005)
[180] Pennsylvania Public Utility Commission, Implementation of the Alternative Energy, Docket No. L-00060180, Portfolio Standards Act of 2004
[181] Includes waste coal and coal mine methane.

Voluntary REC standards	
Green-e®[183]	"Green-e only certifies renewable energy products that are fully aggregated to the extent possible under law." "Green-e certified MWhs (electricity or REC) must contain all the greenhouse gas emission reduction benefits, including carbon dioxide (CO_2) reduction benefits, associated with the MWh of renewable electricity when it was generated." "Emission reductions of capped and traded pollutants where allowances are not routinely assigned to renewable electricity generators, which include sulfur dioxide (SO_2) nationally, mercury (Hg) nationally, and the oxides of nitrogen (NO_x) regionally, are not required to be included in Green-e Certified renewable electricity or RECs."
EcoPower®[184]	"RECs are unbundled from and do not include or convey any property rights associated with direct emission reductions resulting from the generation of electricity from renewable energy sources. All current or future government granted emission allowances or reduction credits for air or other emissions (e.g., sulfur dioxide and NOx allowances under the U.S. EPA's Acid Rain Program) are separate commodities, which may be sold or transferred apart from RECs. The initial allocation of any emission allowances or reduction credits is a function of government laws and regulations, and is not contractually affected by the transfer of RECs." "Marketers of RECs may not claim RECs include ownership rights of current or future government granted emission allowances or reduction credits for air or other emissions. Such claims cannot be substantiated from a legal perspective." "RECs do transfer to the buyer any and all rights or claims to any indirect emission reductions that may have occurred due to the displacement of fossil-fueled electricity generation by renewable electricity generation. The magnitude of these indirect emission reductions are not quantified or certified with an REC."

[182] D.C. Code Title 34. Public Utilities; Subtitle III. Electricity; Chapter 14a. Renewable Energy Portfolio Standards; D.C. Code § 34-1431 et seq. (2006)
[183] Sponsored by the Center for Resource Solutions.
[184] Sponsored by Environmental Resources Trust.

ACORE/EMA[185]	A REC is "a measure of the societal benefit attributes of renewable electricity." The contract recognizes three general types of RECs: A standard REC, a specified REC[186], and a basic REC. The standard REC includes all Environmental attributes, whether or not they have been verified or certified by a governing program. A basic REC represents solely the certification of the generation of electricity from a renewable energy source. And a specified REC includes only those environmental attributes that are specified in a contract (or may include all attributes not otherwise excluded). "Environmental Attribute means an aspect, claim, characteristic or benefit associated with the generation of a quantity of electricity by a Renewable Energy Facility, other than the electric energy produced, and that is capable of being measured, verified or calculated. An Environmental Attribute may include one or more of the following identified with a particular megawatt hour of generation by a Renewable Energy Facility designated prior to Delivery: the Renewable Energy Facility's use of a particular Renewable Energy Source, avoided NO_x, SO_x, CO_2 or greenhouse gas emissions, avoided water use (but not water rights or other rights or credits obtained pursuant to requirements of Applicable Law in order to site and develop the Renewable Energy Facility itself) or as otherwise defined under an Applicable Program, or as agreed by the Parties. Environmental Attributes do not include production tax credits or other direct third-party subsidies for generation of electricity by any specified Renewable Energy Facility." "A REC may include some or all additional Environmental Attributes associated with the generation of electricity, and those Environmental Attributes may, but need not be, Verified or Certified by the same or different Verification Authorities or Certification Authorities, and disaggregated and retained or sold separately, all as the Parties agree in a Product Order."
RECS International[187]	European RECS certificate states that a REC represents "the entire benefit of [renewable energy based electricity] over electricity from non-renewable resources."
EC Renewable Energy Directive[188]	A Guarantee of Origin specifies at least the following items: the amount of energy injected into the public grid, the character and maximum capacity of the facility, the generation period and generation place, the energy sources used for generation.

[185] http://acore.org/programs/rectrading.php
[186] There are actually two type of specified RECs. Positive specified, which require what is included to be specified, and negative specified, which only require that what is excluded from the RECs be specified, thereby assuming all other attributes are included.
[187] RECS International is an NGO working to establish a European-wide voluntary market for renewable energy certificates. http://www.recs.org/.
[188] Article 5 of the European Directive 2001/77/EC of 27.09.2001.

European Energy Certification System[189]	"[A EECS Certificate is a] unique Certificate specifying and representing the quality and method of production of a specific quantity of energy output, which is maintained on a EECS Registration Database, and Issued in accordance with the provisions of a Domain Scheme;
EUGENE[190]	Defines REC eligibility using project initiation date (entered operation after national market was liberalized) and regulatory additionality tests. Suggests that green power suppliers "be creative" in how they address additionality.
Miscellaneous advocates, marketers and brokers in voluntary REC market	
Clean Power Markets, Inc.	"…represents the positive environmental attributes associated with the MWh…delivered to the grid." "…represents the environmental attributes of the renewable generator." RECs "are the *non-physical products*, representing the air, water, land, and other benefits or avoided impacts associated with renewable energy production." [emphasis added]
Chicago Climate Exchange	Requires that RECs be bundled with and/or retired if GHG offset to be sold from renewable project.
(Wingate and Holt 2004)	RECs "represent the separate bundle of non-energy attributes (environmental, economic and social) associated with the generation of renewable electricity."
(Pepper and Swanson 2004) (Pepper and Swanson 2002).	"[A] PV system owner who sells RECs cannot also claim that they are 'green-powered,' 'solar-powered,' or 'renewable-powered', just that they are hosting a PV system." RECs are "non-physical products, representing the air, water, land, and other benefits or avoided impacts associated with renewable energy production."
(Pino 2006)	A REC represents the "technology and environmental attributes" or renewable generation. Companies that purchase and retire RECs should not claim to be "powered" by renewable power, but they can claim that they are "matching" their electricity consumption with RECs or buying RECs "equivalent" to their electricity consumption, or that they are "greening up" their electricity.

[189] Basic Commitment being The Principles and Rules of Operation of Members of the Association of Issuing Bodies for the European Energy Certification System, Version Release 3, 2 June 2006. EECS Certificates are defined to be consistent with European Guarantees of Origin.

[190] /www.eugenestandard.org/mdb/publi/17_factsheet%20add%20&%20el%20final.pdf/
/www.eugenestandard.org/mdb/publi/3_Eugenestandard.pdf/

Appendix B – Expert elicitation protocol

Wind Power Investment Decision Making Research Study
Expert Elicitation Protocol

MICHAEL GILLENWATER
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Purpose

The purpose of this research study is to quantify the value and uncertainty in key variables affecting investment decisions in the wind power industry when those investments are made to supply the voluntary green power market in the United States.

You are being asked to participate in this research study. Your resulting expert judgments will provide inputs, primarily in the form of probability distribution functions, to a financial model of a typical U.S. wind power project investment.

The underlying research question is: **"Do project developers respond to the voluntary Renewable Energy Certificate (REC) market in the United States by altering their decisions to invest capital in wind turbines?"**

The information you provide will be used to support my academic research at Princeton University and will not be used for any other purposes without your permission. This research is not funded by any industry or interest group and is free of other conflicts of interest.

You should NOT fill out this protocol, but please review it. I will record your answers during a telephone interview. This document, though, is provided to you in advance of the interview so you can prepare.

Scope

This research study is narrowly focused on the portion of wind power project investments that supply the voluntary REC market in the United States. The focus is on the wind power industry because wind energy supplies the majority of RECs to the voluntary green power market in the United States.[191] You should not to consider projects that are intended to sell RECs for RPS compliance.

More specifically, I am interested in the distribution of values of key variables for the year 2010, recognizing that wind power project developers and investors face a number of uncertainties. These uncertainties include, but are not limited to:

[191] Lori Bird and Blair Swezey, *Green power marketing in the United States: A Status Report (9th edition)* (NREL, 2006), http://www.nrel.gov/docs/fy07osti/40904.pdf

- capital costs (e.g., turbine and other capital equipment costs);
- expectations for future performance (i.e., capacity factors);
- expectations for future interest rates;
- expectations for future wholesale electricity prices;
- expectations for future value of RECs in the voluntary green power market (whether bundled or unbundled with power);and
- expectations for future operating and maintenance costs (e.g., curtailment and interconnection).

The model being used to investigate the above question is a standard cash flow analysis that produces an internal rate of return estimate based on costs and revenues for a specific project scenario. The information you provide as an expert will be used as inputs to this model and an associated Monte Carlo analysis. You will also be asked for a range of values that represent a typical target or hurdle rate of return for a project investment. Any significant findings from this study are expected to be related to the effect the voluntary REC market in the United States has on wind power investment.

The expert elicitation process is designed to take approximately 60 minutes of your time. Approximately 5 to 10 subjects will be interviewed as part of this study.

Confidentiality and informed consent

All possible steps will be taken to preserve the confidentiality of your judgments.

If you participate in this study, we will record information including your name, organization, job title, etc. We will only publish this information in our report if it is OK with you. If you let us publish your name, no one will be able to connect your name to the individual responses you provide during the elicitation interview. While the responses will be published in the report, all responses from all subjects will have the names/company names removed so that no response can be linked with a specific name.

1. Your participation in this survey is voluntary. You may withdraw your consent and discontinue participation in the project at any time. Your refusal to participate will not result in any penalty.
2. You do not waive any legal rights or release Princeton University, its agents, or the investigator from liability for negligence.
3. You have given consent to be a subject of this research.
4. Copies of your interview responses will be securely stored and archived for three (3) years after which they will be destroyed or offered to Princeton library for longer term storage after obtaining your permission.

For answers to any questions you may have about your rights as a research subject, please contact:
Princeton University Office of Research Integrity and Assurance
Email: irb@princeton.edu
Phone: (609) 258-3077

Confidentiality		
Do you have any questions about how your confidentiality will be protected?	☐ Yes ☐ No	
"I agree to participate in this research study as an expert."	☐ Yes	☐ No
Can we publish your name as one of the experts interviewed?	☐ Yes	☐ No
I have signed the informed consent form.	☐ Yes	☐ No

Post Elicitation / Verification

Following your interview, I will send to you for your review my summary of your responses, including a graphical presentation of your quantitative responses. The purpose of this review is for you to verify that I have properly recorded your expert judgment and for you to revise or add any information you consider relevant.

When completed, I will also provide you a copy of the resulting research report resulting from this work for your reference.

Expert Background

You have been selected as one of approximately ten experts because it is understood that you have experience making wind power project investment decisions, conducting related analyses to support these decisions, or are involved in providing data that is used in making these decisions.

You are requested to disclose any potential conflicts of interests with this research or any strongly held opinions or biases you might affect your responses.

Expert background questions				
Please confirm that you received and have been able to review this elicitation protocol.	☐ Yes ☐ No *[If answer is "no" then interview will be rescheduled.]*			Letter Code
Name				
Title				
Affiliation, Company, or Organization				
Years of relevant experience	☐ 0-2	☐ 3-5	☐ 6-8	☐ >8
Role in industry (check all that apply)	**Project developer** ☐	**Broker** ☐	**Investor** ☐	**Researcher** ☐

	Legal ☐	Utility ☐	REC marketer ☐	End user ☐
	Other ☐	Please Describe:		
Number of projects:	☐ 0-5	☐ 6-10	☐ 11-15	☐ >15
Typical project size	0.1-20 MW ☐	20.1-60 MW ☐	60.1-140 MW ☐	>140 MW ☐
Please describe your experience with and expertise in wind power projects and the voluntary green power market.				

Elicitation Process and Format

I will be documenting your responses to the questions in this expert elicitation protocol. This document serves as both a briefing for you as well as a template for me to document your interview responses in the boxes presented along with each question below. In addition, this interview will be recorded for quality control purposes. This protocol has been developed in keeping with good practice as described in IPCC (2006).

A consistent finding across studies of expert elicitation is a tendency for experts to be over confident in the bounds of their estimates (i.e., overly narrow confidence interval) (Morgan and Henrion 1990). Therefore, it is important that your judgments reflect your knowledge of each parameter and should consider both what you know from experience as well as what you are aware that you not know (i.e., as Donald Rumsfeld says, "known unknowns").

You should keep in mind a number of specific cognitive biases when you provide your judgments (Kahneman, Slovic et al. 1982; Morgan and Henrion 1990; IPCC 2006). These include, but are not limited to:

- *Availability and representativeness biases*. Basing your judgments on outcomes that are most recent or easily remembered without reflecting on your full range of experience, consideration of the limits in your experience, or consideration of other evidence.
- *Anchoring and adjustment bias*. Fixating on a particular value in a range and making insufficient adjustments away from it in constructing representative estimate.
- *Motivational bias*. Desire to be seen as an expert, leading to overconfidence or bias.

In the next section you will be introduced to a set of assumptions and scenarios that will frame the questions in this protocol. In your interview you will first be asked to comment on these assumptions and scenarios.

The interview procedure will next provide you brief background information on each question. You will then be asked to provide your estimate for the minimum, maximum, and median values for a given parameter (e.g., the cost of turbines) as well as your rationale for these estimates. Specifically, the general format for interview questions on specific parameters will be in the following format:

What is the typical size (in MW) of a wind energy investment project based on your experience?

min (5%)_____ max (95%)_____ median (50%)_____

If you provide the following responses,

What is the typical size (in MW) of a wind energy investment project based on your experience?

min (5%) 65 MW max (95%) 310 MW median (50%) 110 MW

it means that you believe there is a 5% chance (1 in 20 chance) that the actual number is below 65 MW; there is a 50-50 chance that it is below 110 MW, and a 95% chance (19 in 20) that it is below 310 MW.

Letter Code

Assumptions and Scenarios

A table summarizing all assumptions for this interview is provided at the end of this section.

Again, for this interview, we are only interested in wind power projects that will sell RECs into the *voluntary green power market*. You should not to consider projects that are intended to sell RECs for RPS compliance. The projects relevant to this interview may be based in States without an RPS (or ineligible to sell into a State with an RPS) or in States where there is wind power generation in excess of RPS market demand. In 2009, compliance REC prices were low in Texas, Maryland, Pennsylvania, and the District of Columbia due to a surplus of supply relative to the RPS mandated demand (Wiser and Bolinger 2010).

For the purpose of this elicitation, we will focus on a limited number of distinct scenarios which mainly differ in terms of the size of the wind power project and the buyer of the project's electricity output.

Table 1: Project size scenarios

Scenario	Project generation capacity	
Small project size	33 MW	(22 x 1.5 MW turbines)
Medium project size	120 MW	(80 x 1.5 MW turbines)
Large project size	297 MW	(108 x 2.75 MW turbines)

For all questions, we will assume projects were scheduled to begin operation on 1 January 2011. Both the small and medium size projects use the General Electric (GE) 1.5 MW turbine model, while it is assumed the large project uses the GE 2.75 MW turbine. The financial analysis will consider a fixed 25 year project lifetime.

The 1.5 MW GE turbine model has been selected because it accounted for the largest fraction of wind turbines supplied to the U.S. wind power market from 2006 to 2010, accounting for 50% and 40% in 2010 and 2009 of wind power capacity installed in those years, respectively (Wiser and Bolinger 2011). Larger projects tend to select larger turbine sizes.

The average nameplate capacity of wind turbines installed in 2010 in the United States was 1.79MW.(Wiser and Bolinger 2011).

All scenarios assume that the wind power project is owned by an independent power producer (IPP) rather than an electric utility. IPPs account for the vast majority of new and existing wind power capacity (Wiser and Bolinger 2011). Although some utilities have begun investing in their own wind capacity (Barradale 2010).

IPPs can sell the electricity they generate from wind power projects under a Purchase Power Agreement (PPA), as a merchant plant (i.e., to a wholesale electricity spot market), or some combination of the two. Most purchasers of PPAs are utilities. PPA terms range from 10 to 20 years. In 2009, 58% of wind capacity installed was under long-term PPA (Wiser and Bolinger 2010). In 2010, projects with some portion of their output intended for sale to the spot market

accounted for 23% of added capacity (Wiser and Bolinger 2011). Most of this merchant activity occurred in Texas, New York and Illinois (Wiser and Bolinger 2010). Three sales scenarios are considered for this elicitation:

Table 3: Electricity sales scenarios

Scenario	Output under PPA	Merchant output
PPA	100%	0%
Merchant	0%	100%

The U.S. Production Tax Credit (PTC) is an income tax credit for electricity produced from qualifying wind turbines and other renewable energy facilities. It has been adjusted upwards annually for inflation, reaching $0.021/kWh ($21/MWh) in 2010. Renewable energy facilities receive the PTC for their first 10 years of operation. The PTC was created under the Energy Policy Act of 1992 and expires frequently, requiring renewal by the U.S. Congress. Between 1992 and 2011 it has been renewed seven times, usually for one or two year at a time (Barradale 2010; Lu, Tchou et al. 2011). Most recently it was extended by Congress through 2012. It is assumed that all projects utilize the PTC and the annual inflator for the PTC is 2%.[192]

It is common for the structure of wind power project finance to be designed around a need to accommodate the PTC (i.e., finding investors with appetite for the tax credit). A simple summary of typical financing structures is as follows:

- Equity financing structures
    - Single developer corporate equity (i.e., corporate balance-sheet finance). A single developer funds all of the project costs and has sufficient tax appetite to use all of the government tax benefits (no other investors or debt financing is initially involved) (Bolinger, Harper et al. 2009).
    - Investor flip structures (structure that involves institutional tax-equity investors such as major banks and insurance companies)
- Project-level debt financing structures (debt taken on by project developer against future cash flows and PTC benefits)

For the purpose of this elicitation, you should assume a single developer corporate equity structure (i.e., #1a above), which has been the most common financing structure in the U.S. wind power industry (Wiser and Bolinger 2008). Few new projects have been reported to utilize significant project debt (Harper, Karcher et al. 2007); however more recently debt has been increasingly relied upon for project finance.[193]

In 2010 the annual U.S. inflation rate was reported to be 1.64% (www.inflationdata.com); a rate of 2% is assumed in the model over the project lifetime.

We assume a combined 39% federal and state income tax rate as well as the following accelerated depreciation schedule as is allowed under Section 168 of the Internal Revenue Code (Schutzer 2010).

[192] Congress has also permitted some projects to substitute the PTC for a cash grant or investment tax credit, the latter being a temporary option. To simplify this analysis, we will only consider the PTC.
[193] A detailed discussion of wind power financing structures is available in Schutzer (2010), Barradale (2010), Bolinger, Harper et al. (2009), Bolinger and Wiser (2009), Cory and Schwabe (2009), and Harper, Karcher et al. (2007). You may request a briefing on these issues or a copy of these articles prior to your elicitation.

Table 4: Accelerated depreciation schedule

Years	Rate (%)
1	9.8
2	35.4
3	21.3
4	12.8
5	7.8
7	6.2
8	5.4
9-17	0.1

Certain wind project equipment (turbines, generators, power conditioning equipment, transfer equipment and related parts up to the electrical transmission stage) may qualify for a 5 year, double (200%) declining-balance depreciation. Roughly 95% of a wind project investment can be depreciated under this accelerated schedule (Bolinger, Harper et al. 2009).

Assumptions used in the model include:

Table 5: Summary of interview assumptions

Parameter	Assumption
Project size scenarios	Small: 33 MW (22 x 1.5 MW turbines) Medium: 120 MW (80 x 1.5 MW turbines) Large: 297 MW (108 x 2.75 MW turbines)
Turbine model and size	General Electric (GE) 1.5 MW Expect for large project size: GE 2.75 MW
PPA vs. merchant	100% PPA 100% Merchant (wholesale)
Use of PTC	Yes
Financing Structure	Single developer corporate equity structure
Inflation rate	2%
Accelerated depreciation schedule	(see table above)
First year break in output	95% of capacity factor
Landowner royalties	3% of electricity revenues for first 10 years 4% of electricity revenues starting in year 11
Warranty fees	$45,000 per turbine per year for first 2 yrs $50,000/year per turbine for years 3 thru 5
Operations & Maintenance costs	$6-14/MWh, with mean of $10/MWh[194] Following end of 5 year warranty period
Project energy usage costs	$1,800/MW each year
Site administration costs	$7,000/MW each year
Insurance costs	$5,000/MW each year
Other hard capital costs 1. Development costs 2. Balance of plant 3. Interconnection	 4% of turbine costs 20% of turbine costs 8% of turbine costs
Other soft capital related costs (i.e., equity closing costs, developer fees, working capital, and contingency costs)	10% of turbine costs

[194] Based on data from Wiser and Bolinger (2011)

Do these assumptions seem appropriate to you? If not, what do you feel would be a more reasonable assumption for…?	
Project size scenarios	
Turbine model and size	
PPA vs. merchant	
Use of PTC	
Financing Structure	
Inflation rate	
Accelerated depreciation schedule	
First year break in output	
Landowner royalties	
Warranty fees	
Project energy usage costs	
Site administration costs	
Insurance costs	
Other hard capital costs	
Other soft capital costs	

Overall, do you believe that a financial analysis model a reasonable approach for predicting decision making by wind energy project developers and investors?

Parameter Encoding

In this section of the elicitation, I will ask you to provide your estimates of likely values, based on your expertise, for the following parameters:

- Wholesale electricity prices for wind power
- Wholesale REC prices in the voluntary green power market
- Wind turbine capital costs
- Assumed average capacity factor
- Minimum investment rate of return (i.e., investment hurdle rate of return)

Again, the assumptions presented in the previous section should frame your responses. The values you offer should also reflect your uncertainty in the value of a given parameter in 2010 and/or forecasted into the future. Your responses should also account for the range of values across possible locations (e.g., States or NERC regions) for projects that in your expert opinion would actually be built.

Wholesale electricity prices

For wind power projects built in 2010 under a PPA, the U.S. Department of Energy (DOE) has reported that the capacity weighted average price received by these project for the electricity they generate was $73/MWh. These numbers include the value of any RECs generated by the project (i.e., RECs are bundled with electricity) and exclude any merchant plants. For projects built in 2009, this value was $62/MWh (Wiser and Bolinger 2011). Lu, Tchou et al. (2011) reported bus bar prices for wind ranging from $29 to $81/MWh, with an average of $47/MWh.

In your judgment, what would be the expected forward curve of wholesale electricity prices that the medium size (120 MW) wind power project would be expected to sell at? Assume a 100% if electricity is sold under a PPA.

Do you need me to clarify anything regarding this question?

Would you prefer to provide values on a nominal (uncorrected or inflation) or real (2010 dollars) basis? ☐ Nominal ☐ Real

For the first 5 years of the project (2010 to 2014)…

5%_____ ($/MWh)
(1 in 20 chance below this value)

95%_____($/MWh)
(19 in 20 chance below this value)

50%_____($/MWh)
(equally likely could be higher or lower)

In your judgment, what would be the expected forward curve of wholesale electricity prices that the medium size (120 MW) wind power project would be expected to sell at? Assume 100% under PPA. ($/MWh)

	2010 - 2014	2015 - 2019	2020 - 2024	2025 - 2034
Medium project (120 MW)	5% [see above]	5% _____	5% _____	5% _____
	95% [see above]	95% _____	95% _____	95% _____
	50% [see above]	50% _____	50% _____	50% _____

Would your responses change for a small or large project size? ☐ No ☐ Yes				
	2010 - 2014	2015 - 2019	2020 - 2024	2025 - 2034
Small project (33 MW)	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____
	2010 - 2014	2015 - 2019	2020 - 2024	2025 - 2034
Large project (297 MW)	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____

Would your responses change if project was a fully (100%) merchant plant that relied on spot market wholesale prices? (Medium project size) ☐ No ☐ Yes				
	2010 - 2014	2015 - 2019	2020 - 2024	2025 - 2034
100% Merchant	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____

What do you consider to be the probability of the value being [half]? What about [twice]?

Can you tell me more about why you think these are the appropriate values? Why do you think the low value is appropriate? The high value is appropriate?

Is there anything that your estimates are conditional on that has not been listed in the assumptions? Are there other uncertainties or biases that qualify your answers?

Wholesale voluntary REC prices

DOE reported that voluntary market REC wholesale prices in 2010 ranged from an annual average of less than $1/MWh for national wind RECs (which were correlated with Texas RECs) to roughly $6/MWh in the Western United States (Wiser and Bolinger 2011). The National Renewable Energy Laboratory NREL has reported that wholesale RECs used in voluntary green power markets generally traded in the range of $1 to $10/MWh and that in 2009, prices for nationally sourced RECs ranged from about $0.88 to $3.00/MWh (Bird and Sumner 2010). In the past, wind RECs from the Western Electricity Coordinating Council (WECC) commanded higher prices in some years.

Table 6: Reported range of voluntary REC prices in 2009 ($/MWh)

Source	2008 Vintage	2009 Vintage	2010 Vintage
National wind	0.88-1.40	1.00-2.75	1.35-3.00
WECC wind	1.15-5.25	5.50-8.75	1.53-2.08

(Bird and Sumner 2010)

In general, the liquid portion of the futures contract market for voluntary RECs has only been about 3 years; therefore we will elicit REC prices for the first 3 years separately. Your estimated values for the questions below should factor in your expectations and sense of risk for the future of the voluntary REC market in the United States.

What would be the expected forward price curve of wholesale RECs sold into the voluntary green power market for a medium size (120 MW) wind power project? Assume 100% under PPA. ($/MW)

Would you prefer to provide values on a nominal (uncorrected or inflation) or real (2010 dollars) basis? ☐ Nominal ☐ Real

	2010 - 2012	2013 - 2017	2018 - 2022	2023 - 2034
Medium project (120 MW)	5% _____	5% _____	5% _____	5% _____
	95% _____	95% _____	95% _____	95% _____
	50% _____	50% _____	50% _____	50% _____

Would your responses change for a small or large project size? ☐ No ☐ Yes				
	2010 - 2012	2013 - 2017	2018 - 2022	2023 - 2034
Small project (33 MW)	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____
	2010 - 2012	2013 - 2017	2018 - 2022	2023 - 2034
Large project (297 MW)	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____

Would your responses change if project was a fully (100%) merchant plant that relied on spot market wholesale prices? (Medium project size) ☐ No ☐ Yes				
	2010 - 2012	2013 - 2017	2018 - 2022	2023 - 2034
100% Merchant	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____	5% _____ 95% _____ 50% _____

What do you consider to be the probability of the value being [half]? What about [twice]?

Can you tell me more about why you think these are the appropriate values? Why do you think the low value is appropriate? The high value is appropriate?

Is there anything that your estimates are conditional on that has not been listed in the assumptions? Are there other uncertainties or biases that qualify your answers?

Wind turbine costs

DOE reported that, in 2008, turbine prices ranged from $900/kW to $1960/kW, with a capacity weighted average of roughly $1420/kW. Larger turbine transactions were reported to be typically priced lower due to negotiating power and economies of scale, and smaller transactions are priced higher (Bolinger and Wiser 2009).

What would you predict to be the cost per kW (or per GE 1.5 MW turbine) for a medium size (120MW) project in 2010?

5%_____ 95%_____ 50%_____

Would your responses change for a small project size? ☐ No ☐ Yes

Small project (33 MW)
5%_____ 95%_____ 50%_____

Would your responses change for a large project size that uses a GE 2.75 MW turbine?
☐ No ☐ Yes

Large project (297 MW and GE 2.75 MW turbine)
5%_____ 95%_____ 50%_____

What do you consider to be the probability of the value being [half]? What about [twice]?

Can you tell me more about why you think these are the appropriate values? Why do you think the low value is appropriate? The high value is appropriate?

Is there anything that your estimates are conditional on that has not been listed in the assumptions? Are there other uncertainties or biases that qualify your answers?

Capacity factor

DOE reported that the average capacity factor for wind projects built in 2009 and 2010 was roughly 30-31% (adjusting for output curtailment) and ranged from 20 to 46% in 2010 (Wiser and Bolinger 2011). Overall average capacity factors were generally in the 30 to 35% range (Wiser and Bolinger 2010). NREL assumed the following capacity factor scenarios in one study:

Table 7: NREL Capacity factor assumptions

Scenario	(%)
High cost	22
Base case	34
Low cost	48

(Cory and Schwabe 2009)

What would you assume as the average capacity factor (%) for the project over its 25 year lifetime?

5%_____ 95%_____ 50%_____

Would your responses change for a small or large project size? ☐ No ☐ Yes

Small project (33 MW)
5%_____ 95%_____ 50%_____

Large project (297 MW)
5%_____ 95%_____ 50%_____

What do you consider to be the probability of the value being [half]? What about [twice]?

Can you tell me more about why you think these are the appropriate values? Why do you think the low value is appropriate? The high value is appropriate?

Is there anything that your estimates are conditional on that has not been listed in the assumptions? Are there other uncertainties or biases that qualify your answers?

Target rate of return

NREL used in its models the following target internal rate of return (IRR) values, where the ranges depend on the structure of the project's finance.

Table 8: NREL target IRR assumptions

Scenario	(%)
High cost	12 to 15
Base case	6.5 to10
Low cost	6 to 8

(Cory and Schwabe 2009)

In another study, Harper, Karcher et al. assumed (2007) an IRR for corporate investors of 10% over 20 years when the project was fully corporate financed and an IRR of 6.5% when it was financed through a institutional investor flip structure. They also reported based on information from the law firm Chadbourne & Parke, LLP that investor hurdle rates over a 10 year period typically ranged from 7 to 10%.

What would you require as the minimum IRR for an investment in a wind power project over a 25 year period? Assume medium size (120MW), 100% PPA, and fully financed through corporate equity (i.e., no debt).

5%_____ 95%_____ 50%_____

Would your responses change for a small or large project size? ☐ No ☐ Yes

Small project (33 MW)
5%_____ 95%_____ 50%_____

Large project (297 MW)
5%_____ 95%_____ 50%_____

Would your responses change for a 100% merchant facility? ☐ No ☐ Yes
5%_____ 95%_____ 50%_____

What do you consider to be the probability of the value being [half]? What about [twice]?

Can you tell me more about why you think these are the appropriate values? Why do you think the low value is appropriate? The high value is appropriate?

Is there anything that your estimates are conditional on that has not been listed in the assumptions? Are there other uncertainties or biases that qualify your answers?

Qualitative interview questions

What percentage of new wind power projects (i.e., those not already under construction) do you think would go forward even without the voluntary REC market and broader voluntary green power market? Answer in terms of capacity fraction (% of MW).

Of all projects in the United States

☐ None at all (0%) ☐ Very few (1-10%) ☐ Some (11-40%) ☐ About half (41-60%)

☐ Most (61-80%) ☐ Almost all (81-99%) ☐ All (100%)

Of your own projects

☐ None at all (0%) ☐ Very few (1-10%) ☐ Some (11-40%) ☐ About half (41-60%)

☐ Most (61-80%) ☐ Almost all (81-99%) ☐ All (100%)

Imagine a world in which the voluntary REC market and the broader voluntary green power market never existed and that there was no prospect for its creation. How many wind power projects that you are involved in would still have gone forward? Answer in terms of capacity fraction (% of MW).

☐ None at all (0%) ☐ Very few (1-10%) ☐ Some (11-40%) ☐ About half (41-60%)

☐ Most (61-80%) ☐ Almost all (81-99%) ☐ All (100%)

How would you describe the relationship between the voluntary green power and REC market and wind power investment? Are you aware of any evidence to support or contradict your view?

What role do derivatives (e.g., natural gas price hedges) play in how you manage investment risk?

What is your overall view of the future of the wind power industry in the United States?

Would you describe your view as…

☐ Optimistic ☐ Neutral ☐ Pessimistic

Do you have other colleagues that you would recommend as interview subjects for this research?

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