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Renewable Power, Policy, and the Cost of Capital

Improving Capital Market Efficiency to Support Renewable Power Generation Projects

UNEP SEFI SUSTAINABLE ENERGY FINANCE INITIATIVE

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Disclaimer

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ABSTRACT

Public policy has played a critical role in creating and shaping global renewable energy markets. Yet 30 years since the passage of the first federal program in the U.S., under the Public Utilities Regulatory Policies Act (PURPA), renewable power generation still constitutes less than three percent of the aggregate U.S. portfolio. In spite of strong growth in project development, many risks and challenges remain, raising the price of capital in the sector and limiting acceptance of new power generation technologies. The project team, in cooperation with the UNEP/BASE Sustainable Energy Finance Initiative (SEFI), conducted a series of stakeholder interviews and related secondary research in order to understand how U.S. renewable energy policy environments influence the cost and overall availability of private financing for renewable power projects. By distilling the perspectives of capital providers and others familiar with the project financing process, we aim to deliver new insight to policy-makers on lowering the cost of capital needed to finance new renewable power projects. Our research findings indicate that although existing renewable energy policies have been effective in driving new development in the U.S., several problems with policy design and consistency contribute to the higher cost of renewable versus conventional power projects. A series of specific policy solutions favored by interviewees are discussed in detail in the report. Overall, the findings emphasize the opportunity for policy to create a more stable, transparent, and predictable market for renewable energy, which in turn will lower financing costs and improve the flow of capital to the sector.

A copy of this report can be found online at: http://sefi.unep.org/english/downloads or http://erb.umich.edu/research/

Contents

Executive Summary

- Key Findings
- Conclusions and Recommendations

THE GROWTH OF RENEWABLE ELECTRIC POWER GENERATION (REPG) in the U.S. has largely been driven by public policy, which utilizes various instruments to stimulate demand and make REPG projects financially viable. While government incentives often account for a large share of a project's cash flows, the bulk of the upfront financing for projects is still provided via private capital markets. Yet due to the inherent risk associated with REPG projects, as well as the complexity and uncertainty of government policies affecting project cash flows, the supply of certain types of capital is limited, resulting in higher costs for REPG. These additional costs have the potential to compromise the viability of projects and hamper further development of the industry.

If the principal goal of REPG policy is to increase the installed capacity of renewable energy generation facilities, the cost efficiency of the associated policy incentives needs to be examined. To the extent that policy measures can be implemented to promote greater transparency and stability in the renewable energy market, the associated transaction costs and perceived risk of investments will be reduced, thereby decreasing the risk premium paid on capital for REPG projects. Therefore, policymakers interested in reducing the cost and increasing the efficiency of REPG installation must consider not only the overall economic costs of renewable energy policy, but also the impact on market conditions as viewed by project developers and the financial community.

Driven by the belief that effective policy is informed by market participants, we developed this study to further the dialogue between policymakers and REPG capital providers in order to increase knowledge about the availability and cost of capital for the sector. While the perspective of the policy community on this subject is needed and was reviewed,[1] the current study focuses on capturing and articulating the viewpoint of the financial community regarding the effect of various public policies on its ability to provide capital to REPG projects. These data were gathered through a series of primary interviews with 28 renewable energy stakeholders, including project developers, capital providers, transaction lawyers, utilities, and others knowledgeable of the interplay between renewable energy policy and project finance.

The report begins by providing background on the evolution of renewable energy policy in the U.S., followed by an overview of renewable energy project finance. The impact that policy has on shaping the market conditions for the financing of REPG projects is discussed. The remainder of the report focuses on the research findings, which are the synthesis of all the primary and secondary research conducted. Our hope is that these findings will help to inform policymakers and to further dialogue, resulting in more effective policy and, ultimately, more rapid expansion of the REPG sector.

Key Findings

The research for this study focused on major policies for promoting development of renewable power generation projects within the U.S., including the federal Production/Investment Tax Credit (PTC & ITC), renewable portfolio standards (RPSs), renewable energy certificates (RECs), state public benefit funds (PBFs), and policies relating to transmission. While there were important findings that related specifically to each policy, there were are also themes that were common among all, or most of, the policies we discussed. Though respondents were well aware of the competing priorities of policymakers, nearly all of them emphasized a preference for policies that: 1) are easy to understand, 2) promote transparency in terms of eligibility and compliance expectations, and 3) provide stability in duration and statute. In short, if the rules for policy are clear and do not change, capital markets are best able to adapt and make the most efficient use of capital.

Production Tax Credit (PTC)

Key Findings – PTC:

- *The PTC represents a major revenue stream for renewable power generation projects.*
- *PTC inconsistency increases revenue risk and constrains the supply of equipment, slowing down development of the U.S. renewable power sector.*
- *Monetizing the PTC creates significant transaction costs for developers.*
- *The PTC should be extended to create greater market stability, thus lowering transaction and financing costs and accelerating development of a permanent, stand-alone market for renewable power.*

Interview respondents overwhelmingly cited the PTC as a significant source of REPG project revenues, accounting for up to 50 percent of the total cash flow in the first 10 years, and up to one-third of a project's entire value. As a result of the PTC, internal rates of return have improved, increasing the number of potentially-profitable projects (particularly wind). However, one drawback of the PTC is the need for most developers to create complicated financial structures in partnership with commercial providers of capital to fully utilize the tax benefits. The complexity of these deals adds significant transaction costs to REPG. However, familiarity the PTC has grown in recent years, and also debt and tax equity liquidity have increased. As a result, more large corporations and financial services firms are monetizing the PTC, ultimately reducing the cost of capital by increasing competition.

When in place, the PTC is quite effective, but its short duration and frequent expiration have long been a problem for the REPG sector. The intermittency of the PTC has lead to a boom or bust climate for the wind industry in particular, prompting capital providers to increase the risk premium associated with capital provided to the industry. Manufacturers have also responded to PTC intermittency by not fully scaling up production in the U.S., which has constrained supply and driven up the price of turbines. Respondents noted on two occasions that a megawatt of wind is between 15 and 25 percent more expensive today due to the inconsistency of the PTC.

Despite its drawbacks, the PTC is viewed as an effective policy that ultimately benefits the retail consumer of electricity by 0.7 to 2 cents per kWh, depending on state or regional utility rate regulations. The PTC would become a much more effective policy in the eyes of developers and capital providers if it were extended to 3 years or beyond.

Renewable Energy Portfolio Standards (RPS)

Since their inception in the late 1990s, state RPSs have promoted a surge in overall installed REPG capacity. However, not all RPSs have been equally effective. Respondents highlighted concerns with the instability, weak enforcement, loopholes, and complexity of some RPS policies.

Instability refers to the ever-changing rules of some state RPSs. Often the intent is to improve the policy, but from the perspective of a capital provider this simply leads to uncertainty. Respondents also mentioned the lack of strong enforcement in some states because it may directly reduce compliance or indirectly give utilities the upper hand when negotiating offtake contracts with developers. This makes projecting the expected number of REPG projects more difficult for capital providers, and increases the chance that some offtake contracts will not yield the required market value for a project. Also, many developers and capital providers said it was more difficult to operate in states with overly complex RPS policies, which lead to significant delays in starting projects, overall uncertainty, and often higher transaction costs. The example of California was mentioned repeatedly, with one financier suggesting that the state has already lost out on at least $1 billion in new wind investments due to the complexity of its RPS.

Respondents emphasized that effective RPS systems should be simple and stable, with clear targets, strict enforcement penalties, and no out-clauses. While many states could improve their policies individually, and while several states already have very effective policies in place, the overwhelming opinion was that regional or national policies were needed. Otherwise, too much disparity among states exists and the need to understand those differences leads to more uncertainty and higher transaction costs. Ultimately, a strong federal RPS would result in a more efficient, competitive national market for REPG projects.

Key Findings – RPS:

- *Many state RPSs are complicated and lack effective compliance mechanisms, increasing risk and negatively affecting cost and availability of capital.*
- *Effective RPS systems should be simple, stable and predictable, in order to encourage long-term investments necessary for renewable power projects.*
- *A federal RPS system may be the best way to improve market liquidity, driving down transaction and financing costs and increasing overall renewable power development.*

Renewable Energy Certificates (RECs)

Key Findings – RECs:

- *Most renewable energy projects are completed without financial consideration of RECs.*
- *The value of RECs is generally discounted in the modeling of project cash flows for financing purposes, due to their volatility and associated risk.*
- *Regional or national markets for RECs would provide greater liquidity and make REC values more reliable for financing purposes.*

Due to price uncertainty and the lack of long-term contracts, most REPG projects are completed without financial consideration of RECs. RECs are largely viewed as "gravy" and are accounted for in "upside" scenarios in financial models for REPG projects. For instance, a project with expected returns in the mid-teens may see present revenue value from RECs adding an additional 100-200 basis points (bps) of annual return to the project on the high side. However, the importance of RECs tends to be project specific, and developers are more bullish on RECs than capital providers.

Implicit in the general observation that RECs are not of significant value to renewable energy projects is an aggressive discounting of their value by capital providers. Again, the general level of discounting is regional and project specific. RECs under long-term contract may receive financing dollar-for-dollar, whereas RECs to be sold in the open market might be discounted by up to 80 percent, depending on the project and capital provider.

Common suggestions to address these concerns included requiring long-term REC contracts as part of an RPS and stiff penalties with strict enforcement for non-compliance with RPS mandates. Implementing these measures on a state-by-state basis would have only limited impact, however, and most participants in the study agreed that a national or at least regional REC market was needed to improve the liquidity of RECs.

Public Benefit Funds (PBF)

Key Findings – PBF:

- *Even when state funds are available, it is doubtful they can be used for external financing.*
- *There is significant risk of PBFs being reappropriated by state regulators.*
- *States should either harmonize their PBF rules with federal policy, or focus their efforts on community, technology, and industry support.*

State public benefit funds (PBFs) are seemingly effective at increasing renewable energy uptake, though we found that their efficacy is clearly dependent on the method in which they are deployed. For non-project finance-related activities, such as funding resource assessment and demonstration projects, PBFs were viewed as effective by most respondents. However, capital providers generally regarded PBFs as unreliable, with limited attractiveness for project finance. Often federal incentives are subject to a reduction when PBFs are employed. There is also a risk that the funds may be re-appropriated in response to political shifts in any given state. In general, most developers and capital providers did not view public-private partnerships in project finance as an attractive scenario and preferred to focus public funds on technology development or municipal business development, or even getting rid of PBFs in order to focus on creating robust RPS policies that eliminate the need for the state funding pools altogether.

Transmission

Problems associated with transmission for REPG projects—including gaining access to the grid, imbalance charges for nonperformance, and lack of transmission in resource-rich areas—are currently stunting the growth of the sector and will likely become an even more significant bottleneck in the future.

Many developers noted the difficulty of negotiating with multiple parties for grid access, due to the complexity of transmission jurisdictions. Several paricipants said that gaining access was easist when negotiationg directly with RTOs in restructured markets. Imbalance charges, initially developed to motivate baseload generators to meet their schedule, also pose significant financial risk for REPG projects, because many renewable energy sources are intermittent by nature. However, most renewable projects have virutally no operating costs and, therefore, have no incentive to withhold power production. If anything, these projects have an incentive to produce when other forms of power are priced out of the market, suggesting that imbalance charges should be either scaled back or eliminated for renewables.

Finally, extending the grid to resource-rich areas with low population densities will be another significant hurdle to continuing growth of the REPG sector. Much of the exisiting capacity, particularly for wind, has been cited in a few resource-rich states where electric grid infrastructure already exists. Building new transmission from other high potential areas such as the Great Plains brings complications. Resolving who will pay for transmission is difficult considering that those who will benefit most are usually not directly affected by siting and construction issues. Though no single answer emerged, many respondents felt that federal coordination would give the best chance for a cohesive, efficient expansion of the sytem.

Key Findings – Transmission:

- *The current U.S. Transmission system does not adequately serve the needs of the renewable power generation sector.*
- *The federal government should exercise more control in order to accelerate expansion and ease the integration of renewables into the system.*

Power Purchase Agreements (PPAs)

Key Findings – PPAs:

- *Unfavorable contract terms (such termination and out-clauses, or guarantees on performance or equipment) may have negative impacts on the cost or overall availability of project financing.*
- *Standardized contract terms may be an effective mechanism for reducing transaction costs and leveling the playing field.*
- *On the other hand, some interviewees felt that imposed standardization of contracts would remove the flexibility needed to find better ways to structure deals as the market develops.*
- *Providing market conditions are appropriate (ability to hedge, strong REC market, etc), a long-term PPA is not a requirement to close a deal.*

The PPA establishes the rate and duration of power purchases from an REPG project with an offtaker such as an electric utility. The associated revenue may account for up to 70 percent of project cash flows, and the level of commercial financing a project will receive is largely based on this contract. Given their complexity and importance, significant transaction costs are associated with negotiation of PPAs, driving up the price for REPG projects further. Some participants in the study pointed to the success of standardized contracts in several markets to address this issue, but many were opposed because most PPAs were already standardized to the extent they can be and flexibility is needed to suit each project.

Due to increased land and equipment costs, coupled with stringent PPA requirements riddled with out-clauses, there has been an increase in cancelled PPAs as of late. This risk has steered some capital providers away from investing in certain states and has increased the overall risk for developers. In the meantime, the market has seen an increasing number of merchant projects that rely on synthetic PPAs, which partially addresses the risks associated with traditional PPAs and may expose investors to larger upside potential for a project. However, synthetic PPAs are only possible in a few places, so further growth in the number of merchant projects will rely on the development of robust markets in individual states, ensuring the long-term demand and market stability needed to make merchant deals attractive. Ensuring a strong market for RECs also was seen as a crucial way to support more merchant projects, which may derive a significant share of their revenues from RECs. Most of the participants agreed that a national RPS and its associated REC market would make for a more robust renewable energy market and support stable prices for RECs over the long-term, thus promoting the long-term growth of merchant projects.

Conclusions and Recommendations

Not one respondent said current policies are not effective in increasing renewable energy development. The important question, however, is whether current mechanisms and incentives are generating the most financially efficient long-term development of renewable energy production. Pressing issues include how to replicate the success of the wind industry with policy incentives, how to stabilize growth within the wind industry to remove long-term policy support needs, and how to ensure the national energy portfolio reflects public interests regarding energy security, climate change, and emissions control.

Our interview data suggested that federal systems are preferred for energy infrastructure and REPG incentives. Broadening these markets will require increased policy stability and transparency, which will lower cross-state barriers to trade and development, increase the number of market participants, and improve market liquidity, which is a key indicator of financial efficiency. Overall, the research provides support for the following policy recommendations to improve market stability and/or transparency:

1. PTC/ITC extensions that reflect the capital cycle for both REPG development and underlying suppliers (~3-5 years).
2. Elimination of passive loss rules under the PTC.
3. Planning for eventual sunsetting of the PTC.
4. An effective national RPS that drives utilities to the bargaining table to increase renewable development.
5. A national REC trading market.
6. More federal action to accelerate transmission expansion.
7. A state, regional, or national loan guarantee fund.

Our interview data suggested that federal systems are preferred for energy infrastructure and REPG incentives.

Introduction

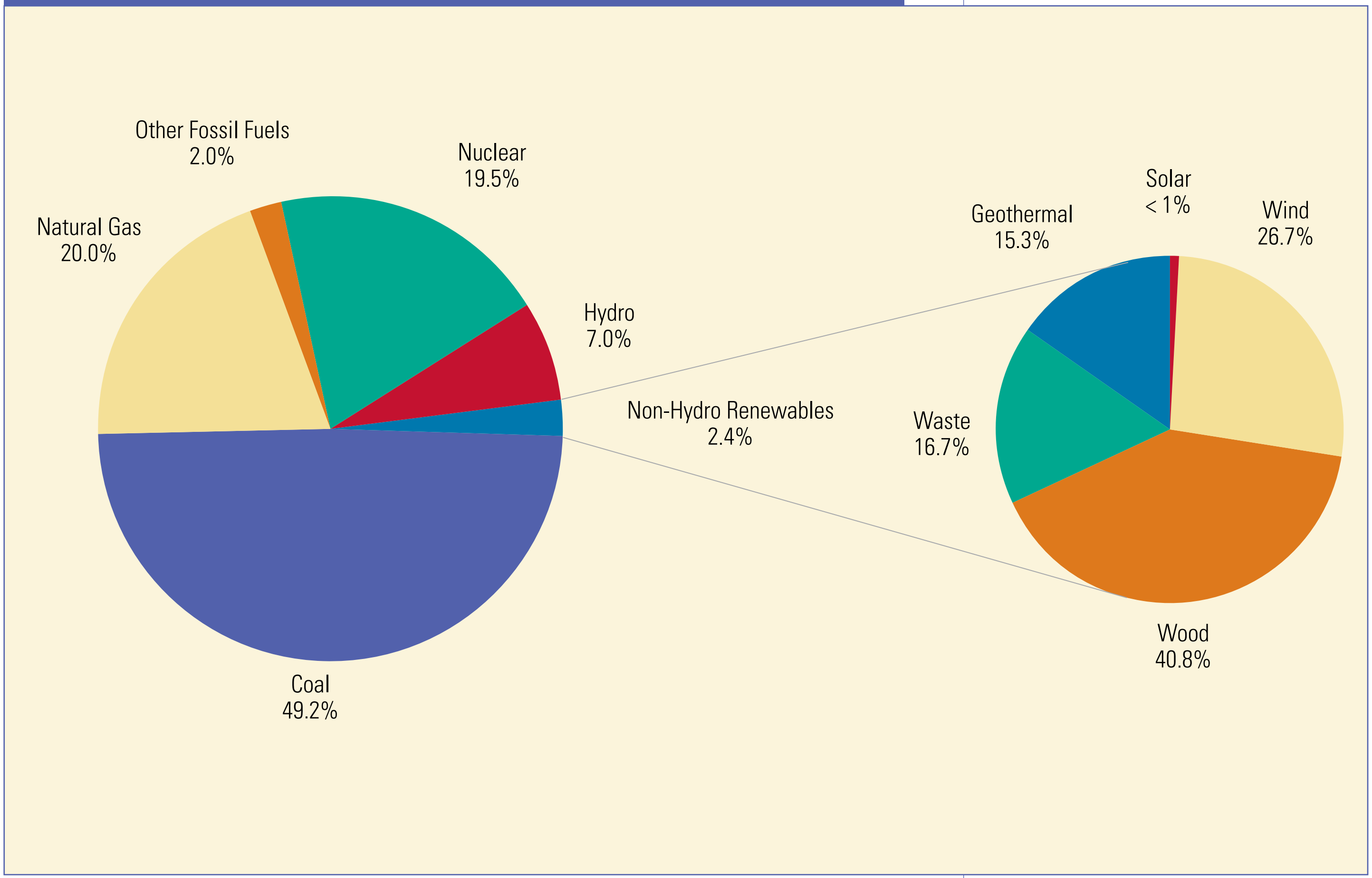
- Need for Study
- Objectives and Methods

THE ELECTRICITY GENERATION SECTOR IS THE LARGEST SOURCE of greenhouse gas emissions internationally and contributes roughly 40 percent of all carbon dioxide emissions related to human activity in the U.S. The sector also contributes significantly to emissions of harmful air pollutants such as sulfur dioxide (SO2), nitrogen oxides (NOx), and mercury (Hg). Energy derived from renewable sources such as wind, solar, geothermal, and biomass has considerable potential to reduce these emissions, while also delivering a host of other public benefits including increased fuel diversity, economic development, and national security. However, in spite of its benefits and three decades of supporting policy, non-hydro renewable power generation still comprises less than three percent of aggregate U.S. consumption (EIA 2007, 15-16).

Interest in renewable energy has grown steadily in recent years, as concerns about anthropogenic global warming and energy security continue to rise, and as the push to wean the economy off petroleum and other fossil fuels gains momentum. U.S. non-hydro renewable generating capacity grew from 16,400 to 23,500 MW between 2000 and 2005, the most recent year for which full data is available (EIA 2006a, 17). The largest share of that growth has been in wind power, which increased by more than 9,000 MW between 2000 and 2006 (roughly 2,800 MW were brought online in 2006), and which is expected to grow another 27 percent in 2007 (AWEA 2007). These numbers prove that a great deal of progress has been made, yet the renewable power sector will have to grow much more quickly in future years if it is to make a significant impact on domestic energy production, energy consumption, and carbon emissions in the United States.

Meeting the potential of renewable electric power generation (REPG) depends on the existence of robust markets for the electricity it produces. Yet renewable energy remains expensive, in part because most of its benefits are not accurately reflected in energy prices. The result has been a market failure, where existing forces strongly limit the uptake of REPG in favor of continuing investment in conventional, non-renewable generation sources. Public policy plays a critical role in correcting this failure, and a variety of state and federal policies have been instrumental in stimulating the development of renewable energy sources over the last 30 years in the U.S. Recently, the growing political significance of climate change and energy security has brought attention back to renewable energy policy, both at the federal level and in many states, with a particular focus on evolving policy to further accelerate the development of renewable power projects.

Figure 1-1
U.S. Electric Power Generation by Fuel Type, 2006



Source: Energy Information Administration.

Need for Study

One of the key challenges for developers of renewable power projects is securing the large amounts of financial capital required to purchase equipment and bring new facilities online. Government financial incentives play an important role in project acceptance, but the majority of funds will ultimately come from private capital markets, where REPG must compete head to head with a range of other investment options. Unfortunately, the unique risks and challenges of developing renewable projects still limit the participation of many private capital providers, and the financing that is available often comes at a high cost. The need to absorb higher financing costs can be a major strain on a project's economics, reducing its ability to provide the required return at prices the market will bear, and possibly short-circuiting the project altogether. Establishing market conditions that attract larger amounts of affordable capital to the sector is expected to bring more projects online at a faster pace.

Lowering the effective cost of capital for projects means ensuring greater liquidity in the market for renewable power project financing. A more liquid market is characterized by a large number of participants and stable prices, and is facilitated by adequate transparency and stability in underlying market conditions. Public policy plays a critical role in shaping market conditions in the renewables sector, so policymakers interested in improving renewable energy uptake must pay special attention to crafting policy environments that will improve market liquidity and promote further investment in the sector.

One important source of insight for policymakers is capital providers who are already familiar with renewable power project investment, and whose operational knowledge in the sector may prove useful in understanding how policy can best contribute to greater market liquidity. A survey of existing reports and papers focusing on the REPG sector indicates a shortage of broad-based analysis of the perspective of private capital providers on how various renewable energy policy mechanisms either help or hinder the liquidity of capital markets for renewable project financing. However, a growing number of project developers and capital providers are active in the sector and are learning through direct experience how major policies interact with the project financing process. This study seeks to leverage the experience of professional renewable energy developers and capital providers to address the gap in information needed to support the evolution of efficient, market-based renewable energy policy.

Objectives and Methods

This report is designed to contribute to dialogue between government policymakers and renewable energy capital providers, in order to stimulate greater flows of capital for development of REPG projects in the United States. It is the result of collaboration between the UNEP/BASE Sustainable Energy Finance Initiative (SEFI) and students and faculty at the Frederick A. and Barbara M. Erb Institute for Global Sustainable Enterprise at the University of Michigan. The primary objectives of the project were to:

1) Compile and analyze perspectives of financial stakeholders, developers and other experts familiar with renewable power project finance, in order to provide input to policymakers concerned with increasing uptake of renewable energy; and,

2) Explore how major renewable energy policy instruments interact with project finance and develop ideas for how they may evolve to lower the cost and improve the overall flow of investment capital to renewable power projects.

Primary research for the project was collected through a stakeholder interview process, supplemented by secondary research to deepen discussion around themes that emerged from the interviews. The interview process targeted stakeholders likely to have experience with the financial structures supporting renewable energy projects and with the factors affecting the pricing and availability of various forms of capital to those projects. Accordingly, interviews were conducted with experts in the renewable energy industry, including developers, debt lenders, equity providers, utilities, lawyers, and consultants. The majority of respondents were active in the development and financing of wind projects, as wind has accounted for the bulk of the activity in the REPG sector in recent years, though some respondents were also familiar with geothermal, solar, biomass, and/or other technologies. The project team ultimately conducted interviews with 28 individuals representing 26 different organizations. The list of organizations (Table 1.1) included six project developers, 11 capital providers, and nine others, including utilities, lawyers, and consultants.

Interviews were conducted using an informal interview guide, a copy of which is provided in Appendix C. Each interview lasted between 45 minutes and two hours, and all interviews were conducted between January 1 and March 10, 2007.

Table 1-1
Interview Respondents

CAPITAL PROVIDERS	DEVELOPERS	OTHERS
ArcLight Capital	3 Phases Energy	*Utilities*
Black River Asset Management	Airticity	DTE Energy
Dexia Groupe (2)	enXco	Duke Energy
Ewing Bemiss & Co.	FPL Energy	Pacific Gas & Electric
GE Energy Financial Services	Horizon Wind Energy	
Goldman Sachs (2)	PPM Energy	*Lawyers*
HSH Nordbank		Baker & McKenzie
Kinetic Group		Milban, Tweed, Hadley & McCloy
Riverstone Holdings		
Sigma Capital		*Others*
U.S. Renewables Group		Evolution Markets
		Global Energy Decisions
		New Energy Finance
		U.S. Energy Hedge Fund Center

Background

- Evolution of U.S. Renewable Energy Policy
- Renewable Energy Project Finance

Evolution of U.S. Renewable Energy Policy

PUBLIC POLICY IS THE DOMINANT DRIVER OF RENEWABLE ENERGY UPTAKE, as various production mandates and/or government-sponsored incentives are needed to spur development in spite of the additional cost of electricity generated from renewable resources. Average U.S. wholesale electricity prices are about five cents per kWh, whereas electricity from wind farms ranges from six to nine cents per kWh (depending on the resource), and electricity from photovoltaic systems costs about 25 to 30 cents (Frantzis 2005, 4). Absent support from public policy mandates or incentives, such as renewable portfolio standards (RPSs) or the federal production tax credit (PTC), renewable power generation (excluding distributed generation) would likely not be available at all. In fact, the emergence of the renewable energy industry in the U.S., as indicated by the growth in installed capacity over time, can be directly correlated with the evolution of major renewable energy policy mechanisms.

Federal Policy

The first major policy to stimulate the renewable energy industry in the U.S. was the National Energy Act (NEA) of 1978. At the time, the U.S. faced socio-political circumstances similar to today's. High oil prices, resulting from an embargo in the early 1970s, drove up the price of electricity and associated capital equipment; environmentalists, with newfound political power, were championing cleaner sources of electricity; and many professional renewable energy organizations, such as AWEA and the Solar Lobby, had just been formed (Sine and Lee 2005, 4).

The most significant component of the NEA of 1978 was the Federal Public Utility Regulatory Policies Act (PURPA). PURPA allowed entrepreneurs to construct qualifying non-utility generation facilities free from the constraint of regulation, and required utilities to purchase power from these qualifying independent power producers (IPPs). IPPs qualified under PURPA if they used alternative energies such as solar, wind, biomass, landfill waste, wood, sewage, sludge, and other low-grade fuels or cogeneration technology. PURPA also set the purchase price for alternative energy at the "avoided cost," or wholesale baseload energy cost, which was determined by individual states. Initially, this spurred development of renewable energy (mainly wind) projects in California and New York, but the avoided cost ultimately was too low for PURPA to make a significant impact over the long-term (Chapman et al. 2004, 3).

While PURPA laid the foundation for renewable energy development in the U.S., the federal Wind Investment Tax Credit, passed in 1980, was the first piece of legislation to invigorate the industry. As a result, several wind projects were developed in California, but development ceased when the tax credit expired in 1986. After several years of stagnation, the renewable energy industry began to pick up again as a result of both advancements in technology and the passage of the federal Production Tax Credit (PTC), part of the Energy Policy Act (EPAct) of 1992. The PTC provided a 10-year, 1.5 cents per kWh, inflation-adjusted tax credit for tax-paying, privately and investor-owned wind and closed-loop biomass projects brought online between 1994 and 1999. Finally, policy had created adequate incentives for investors and developers, and development of renewable energy projects began throughout the U.S. The evolution of the PTC and previous policies, and the impact they had on renewable energy capacity installation, is depicted in Figure 3-1.

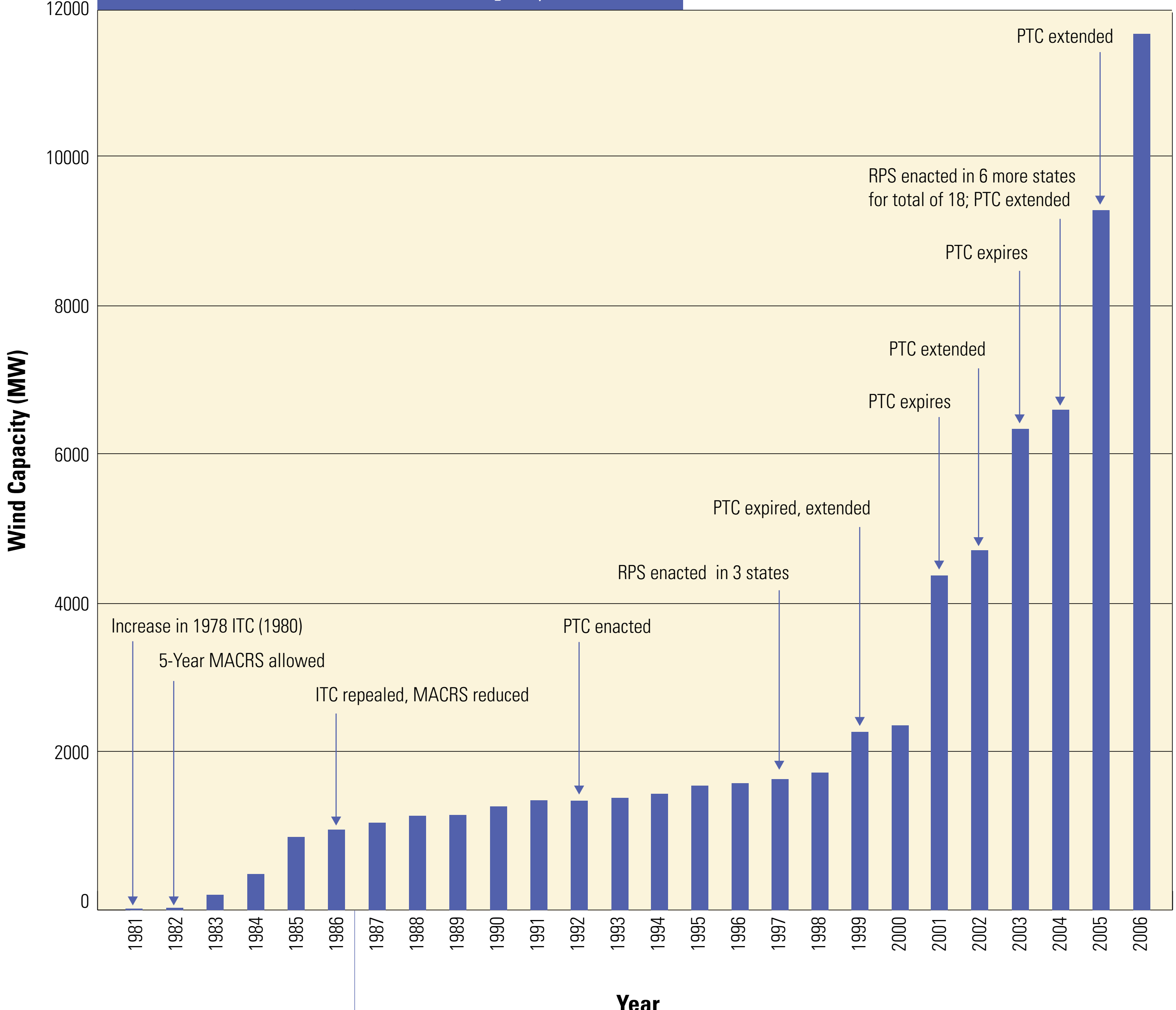
State Policy

While federal policies provide incentives for developers of REPG, essentially stimulating supply, they do not guarantee that projects will be built. To complement incentive-based policies, mandates that compel load-serving entities (LSEs) to provide renewable power are also needed to create demand for REPG projects (see Figure 3-1). Otherwise LSEs are likely to resist incorporating renewable energy into their portfolios, due to the added cost and complexity associated with scheduling and delivering load from these projects. Also, incentive-based policies tend to favor the development of renewable energy projects in only the most resource-rich areas, creating a national subsidy for renewable energy in a select few states. To address these dilemmas, many states have enacted renewable energy policies in the last few years. The most important policy approach has been the "renewable portfolio standard" (RPS), which generally requires LSEs to produce or procure a certain portion of their load from eligible renewable energy sources. As of this writing, a total of 23 states and the District of Columbia have enacted some type of renewables standard that includes either voluntary or compulsory targets (see Figure 3-2).

Since their inception in the late 1990s, RPS policies have contributed significantly to the increase in renewable energy capacity in the U.S. In fact, nearly half of all wind capacity installed between 2001 and 2005 has resulted from state standards, and capacity will have to continue ramping quickly to meet future requirements (UCS 2007). In 2005, it was estimated that existing RPS mandates would require development of between 40,000 and

52,000 MW of new renewables capacity in the U.S. by 2020, though at least three new mandates were passed and several states have increased their targets since that time (Global Energy Decisions 2005, 1; UCS 2003). More new and revised policies are likely in the future as well, with several more states currently either crafting or reviewing their own RPS systems.

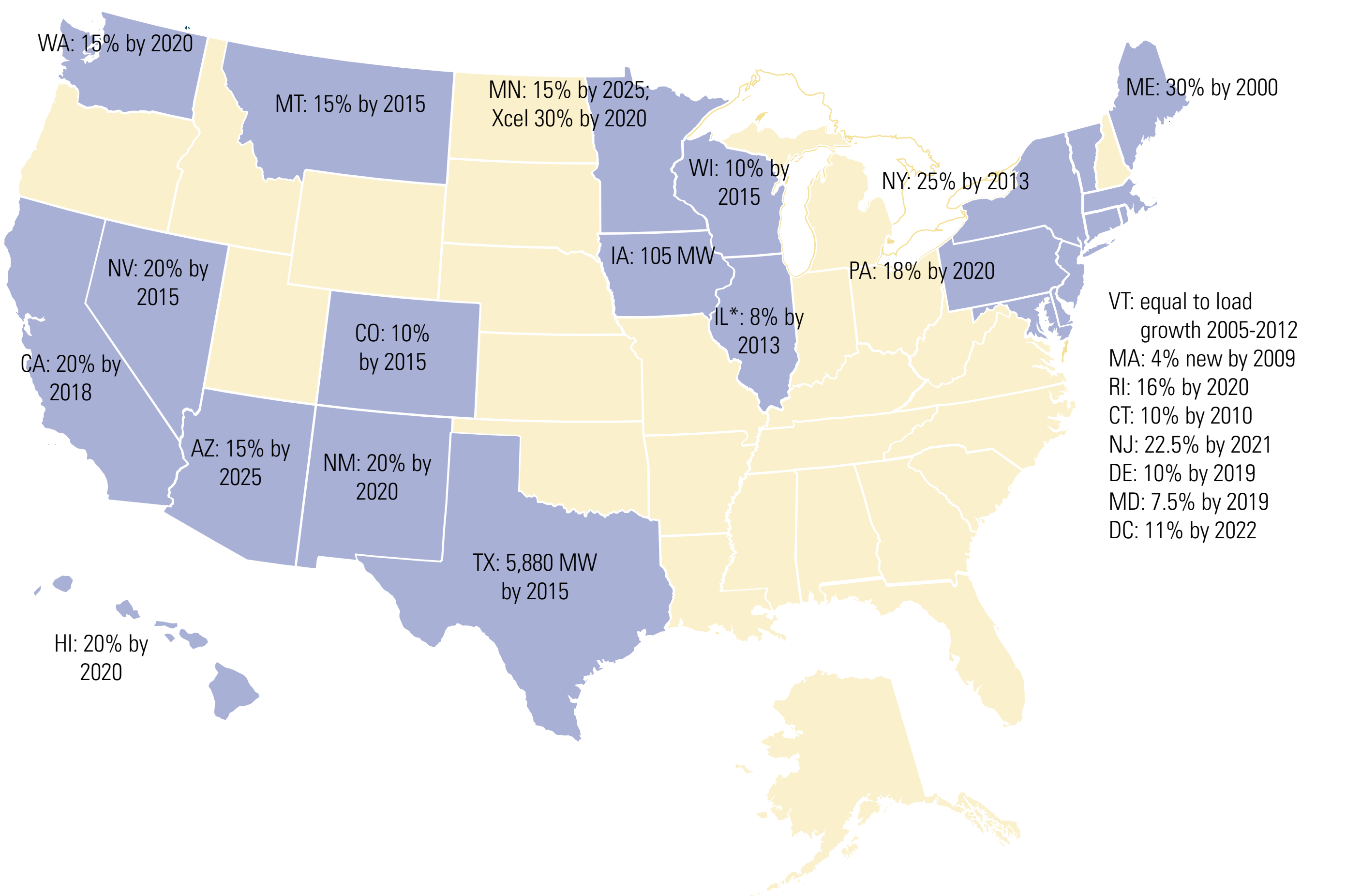
Figure 3-1
U.S. Federal and State Policies & Wind Capacity, 1981-2006



Sources: Global Wind Energy Council, AWEA, US Department of Energy

In addition to RPS, other state policies have helped to increase renewable energy capacity, in particular "public benefit funds" (PBFs), also referred to as clean energy funds. In 2007, a total of 17 states and the District of Columbia now have PBFs which together provide more than $300 million in annual funding to stimulate renewable energy supply (DSIRE 2007). These funds are most commonly used to support educational outreach, provide grants for resource assessment, help with technology development, and cover project financing requirements. Beyond PBFs, states also have implemented local tax incentives, loan guarantees, rules for net metering, and utility profit incentives to further support renewable markets.

Figure 3-2
State RPS Mandates



Source: Database of State Incentives for Renewable Energy (DSIRE) and state websites.

Renewable Energy Project Finance

FIGURE 3-3 DEPICTS THE STAGES of renewable power project development. In addition to resource analyses and various contract negotiations, the debt and equity financing required to deliver the full value of the project are important concerns for developers. Upfront financing is required to complete the pre-feasibility stage, and later, once the contracts are completed, for the construction and operation phases. Developers have two choices of capital to use: debt or equity, and may finance the project using either project finance or corporate finance.

Roles of Debt and Equity Investors

Debt and equity are fundamentally different forms of capital. Although all investments are seen through the prism of risk and return, equity and debt investors focus on different ends of the spectrum. Equity investment confers ownership, which generally includes higher returns on investment for tolerating more risk. Equity capital providers are therefore more likely than debt providers to accept higher risk to maximize their investment return.

Debt is usually preferred by capital seekers, because they do not have to share ownership with another equity investor and because debt is generally cheaper to service than equity (Brealey and Myers 1991). Debt is an obligation (usually fixed) that confers no ownership or profit beyond a certain, contracted level. At the same time, debt providers are more cautious and concerned primarily with the risk of default on their obligation by the borrower. To protect themselves, debt providers tend to analyze projects and firms with a worst-case scenario framework; at some level of project or company debt, capital providers will stop lending money and equity investors will need to be sought (Kahn and Stoft 1989).[2]

Figure 3-3
Power Generation Project Value Chain

Pre-Feasibility	Feasibility	Permitting/ PPA Negotiation	Construction	O&M
• Resource potential • Proximity to transmission • Expected power purchase price	• Technical modeling • Financial modeling • Cost assessment • Environment impact assessment • Resource assessment • Stakeholder management	• Permitting process • Grid interconncetion and transmission access • Off-take agreement negotiation	• Construction of power generation facility	• Operation and maintenance of facility

Project versus Corporate Finance

Investments in single purpose, capital-intensive assets such as roads, telephone lines, and power plants are unique in their size and importance to the public. Consequently, developers typically establish independent corporate structures called "special purpose vehicles" (SPVs) to manage the project and bear the higher-than-normal risk of default. In the case of default on such a capitally-intensive project, developers are generally spared financial collapse because of these SPVs. Capital used in these cases is referred to as "non-recourse" (because damages are limited to project revenues) and the general financing structure is called "project finance." In project finance, capital providers try to avoid bearing this risk themselves by focusing their analysis on the strength of revenue contracts for the project, rather than on the balance sheet of the parent developer. In REPG, debt investors must look very closely at power purchase agreements (PPAs), applicable RPS policies, and any associated revenues from the sale of RECs or the use of government incentives.

For large corporations in good standing with credit agencies, borrowing capital from public markets or banks may be less expensive than project-specific financing. This form of financing, known as corporate or balance-sheet financing, draws attention to the health of a company's entire balance sheet, as opposed to the specific details of any one project or contract. Debt service is still a main concern of corporate financing, but to the extent the debt does not imperil the borrower, the funds may be used for electric utility construction. An REPG example is FPL Energy, which as the nation's largest renewable developer, has raised several billion dollars in public corporate financing for its REPG projects.

Project finance has several advantages and disadvantages compared with corporate finance. Because project finance loans are non-recourse, projects have limited effect on the balance sheet of the parent developer. As a result, developers seek to maximize their debt-to-equity ratios to drive down financing costs as much as possible. Our interviews and previous research suggested that REPG debt-to-equity ratios are between 50 and 60 percent (Wiser 1997, 15). The most significant disadvantage to project finance is the extra costs associated with the longer and more detailed contract negotiations needed to give capital providers confidence in the deal.Role of Policy in Promoting Market Liquidity In standardized market systems, such as stock or bond exchanges, high levels of liquidity are the key to reducing the cost of capital (debt and equity) (Amihud and Mendelson 2004).

Liquidity is positively correlated to market rules encouraging transparency and access to information, which both reduce investment uncertainty. Investment uncertainty results in non value-added costs, which in project fi nance relates to contract negotiations and fees (commonly referred to as "execution fees," "bid-ask spread" and "market moving costs"). In standardized markets, reforming these asymmetries can be a matter of logistics and should increase liquidity and reduce the overall cost of capital. Because large infrastructure-related projects like REPG affect public use goods and have non-market stakeholders, reducing transaction costs is more than a logistical exercise.

If we accept that the goal of REPG policy is to increase uptake at the least cost (maximizing utility), the cost efficiency of the associated policy incentives needs to be examined. As noted, project finance differs from corporate finance in a number of ways. Part of what determines the shape of the credit curve is the political risk that plays a significant role in project finance (Sorge 2004, 97). To reduce capital costs for project finance, political risk and uncertainty must be reduced. As uncertainty dissipates, more capital providers will enter the market, reducing the non-value added costs with added liquidity.

Research Findings

- Overview
- Federal Production Tax Credit (PTC)
- Renewable Portfolio Standards (RPS)
- Renewable Energy Certificates (RECs)
- Public Benefit Funds (PBF)
- Transmission
- Power Purchase Agreements (PPAs)

Overview

IN DISCUSSIONS WITH EXPERTS IN THE REPG SECTOR, we explored various policy approaches to promoting development of renewable power generation projects, including market-based trading systems, production tax incentives, and system tariffs. What we found is a complex web of potential externalities resulting from any single policy action, muddying the picture of the "best" course of action in energy policy. In our 28 interviews, many different perspectives emerged on how to develop public policy to lower the cost of capital and improve the uptake of renewable energy in the United States. While opinions varied on 1) how to optimize federal policy, 2) how important renewable credits are to market development, 3) what the best use of state funds is, and 4) how to address the incredibly perplexing issue of energy transmission, there was broad consensus on two strategic policy goals. First, energy policy should promote market stability in order to reduce project financial risks and attract more capital providers to the REPG sector. And second, there needs to be increased transparency in applying for and receiving incentives in order to increase competition among developers and reduce costs. Achieving these two goals will go a long way towards creating liquidity in renewable power project finance, and ultimately a more efficient energy market.

Regardless of technology or geography, system stability is a necessity for capital providers considering whether to commit time and resources to developing capital-intensive renewable power projects. The most commonly cited examples of policymakers creating more market stability included extending the federal production tax credit (hastening the day when federal subsidies are no longer needed) and creating more robust renewable portfolio standards (RPS, federal, or state), thereby creating greater market clarity on policy goals. By extending the PTC to match development cycles, equipment manufacturers will be encouraged to increase capacity, reducing the largest single cost pool for REPG. It will also help developers and investors with the long-term financial forecasts needed to bring projects online. Ultimately, extending the PTC may result in substantial savings on the delivered cost of energy, due to savings in equipment procurement, contract negotiations, and project closing costs. In addition, capital providers will feel more comfortable entering new markets if they are supported by strong RPS mandates with clear penalties for non-compliance. Because market power has traditionally belonged to utilities, many renewable developers avoid unclear markets (where the potential for protracted PPA negotiation is significant), since very few have the financial resources to bear the costs of waiting for "feet-dragging" utilities more than once.

One way to improve market stability is through clear application processes, state-mandated performance metrics, and clear direction on the who, what, where, when, and how of financial incentives. In states where the process is clear and open, such as Texas, developers are willing to dedicate the required resources to bid on and develop REPG projects. In states with less clarity on the application and allocation process, such as New York, large-scale development is limited to those developers with knowledge of the unique political landscape, potentially raising system costs to develop renewable assets.

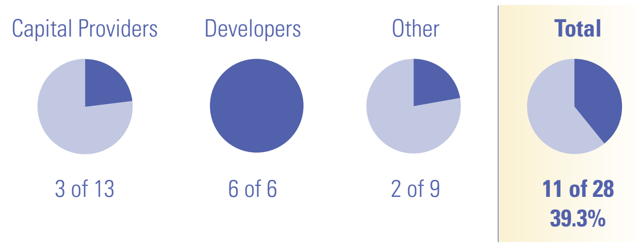
Given the myriad potential options to improve policy aimed at renewable energy production, we asked capital providers to prioritize their ideas on improving public policy. An overwhelming number of our interviewees pleaded for more stability in the federal production and investment tax credits. As a corollary to a tax credit extension, capital providers also said that national policy must be harmonized to improve market performance. The consensus viewpoint was that a national RPS— considered in the last five congressional sessions—and a liquid trading market for renewable energy credits will further reduce costs. The combination of a national RPS and PTC would likely resemble the very successful European feed-in tariff (FIT) model, though the price support would be much less and the credit trading market would likely be a key market-based pricing mechanism. The success of the FIT has been due largely to the clear and reliable price support it provides to projects, which is ideally suited to the interests of capital providers. When asked, some of our interviewees showed interest in a FIT application in the U.S. to encourage further investment, though there was healthy skepticism about whether the system efficiently allocates capital. Furthermore, we were told that policy preferences made the adoption of a FIT extremely unlikely in the U.S.

If the policy imperative is to promote efficient market development, market liquidity is the key (Ross, Westerfield and Jaffe Ch. 9, 2005). Liquidity, in project finance and power project deals, is created through policy stability and transparency. These conclusions are supported by over 25 interviews with top-tier renewable energy developers and capital providers. In the following sections, we detail our discussions on federal and state incentives, as well as credit trading markets and transmission.

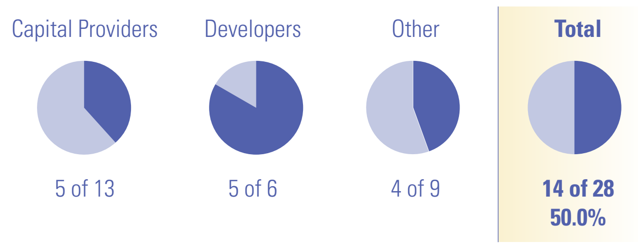
Federal Production Tax Credit (PTC)

KEY FINDINGS

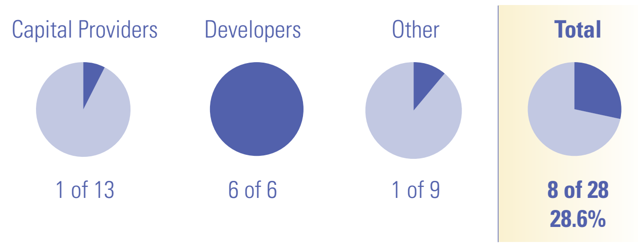
The PTC represents a major revenue stream for renewable power generation projects.



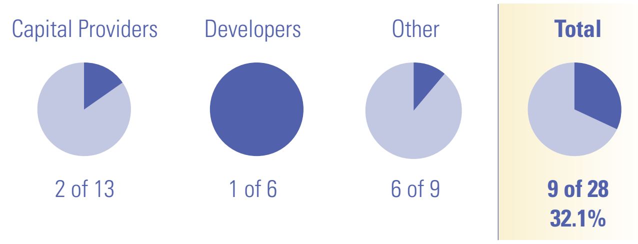
PTC inconsistency increases revenue risk and constrains the supply of equipment, slowing down development of the U.S. renewable power sector.



Monetizing tax credits creates significant transaction costs for developers.



The PTC should be extended to create greater market stability, thus lowering transaction and financing costs and accelerating development of a permanent, stand-alone market for renewable power.



These graphics indicate the proportion of respondents in each category that made statements supporting a given theme. Note that many respondents did not comment directly on each theme and that the lack of comment does not necessarily indicate an opposing point of view."

THE PRODUCTION TAX CREDIT (PTC) is a supply-side revenue subsidy for developers, complemented well by the Renewable Portfolio Standard (RPS), which stimulates utility or offtaker demand. In 2005, the PTC was based at 1.5 cents per kWh for wind, closed-loop biomass, and geothermal energy. The credit was indexed for inflation, based on 1992 rates, and now stands at 1.9 cents per kWh for these technologies (all others were based at 0.75 cents per kWh and now stand at 1 cent per kWh). The credit lasts for the first 10 years of project operation and can be reduced by federal or state grants, tax-exempt bonds, subsidized energy financing, or other credits.[3] The credit is also phased out on a rolling basis, as electricity prices rise.

First enacted in 1992, the PTC did not have much of an impact on development until 1998, after the first RPS appeared and tax-based investors started paying more attention to wind energy. Since then, wind development has experienced vicious boom-bust cycles, correlated to the credit's 12-to-18 month renewal cycle (see Figure 4-1). Interview respondents cited the PTC as a significant source of REPG project revenues, accounting for up to 50 percent of the total cash flow in the first 10 years, and up to one-third of a project's entire value. As a result of cash flows from the PTC, internal rates of return have improved, increasing the number of potentially-profitable projects (particularly wind). Concurrently, debt and tax equity liquidity have grown significantly, attracting large corporations and financial services firms, and, in the end, reducing the cost of capital by increasing competition.[4] Ultimately, interviewees noted that the PTC benefits retail consumers by 0.7 to 2 cents per kWh, depending on state or regional utility rate regulations. As one respondent remarked, "It is a very blunt policy instrument, and it is very effective." However, the production tax credit is not without its problems. Interview respondents generally agreed on two major issues: the unpredictability of the tax credit's renewal, which creates the boom-bust development cycles, and the high cost of monetizing the tax credit.

PTC Renewal Uncertainty

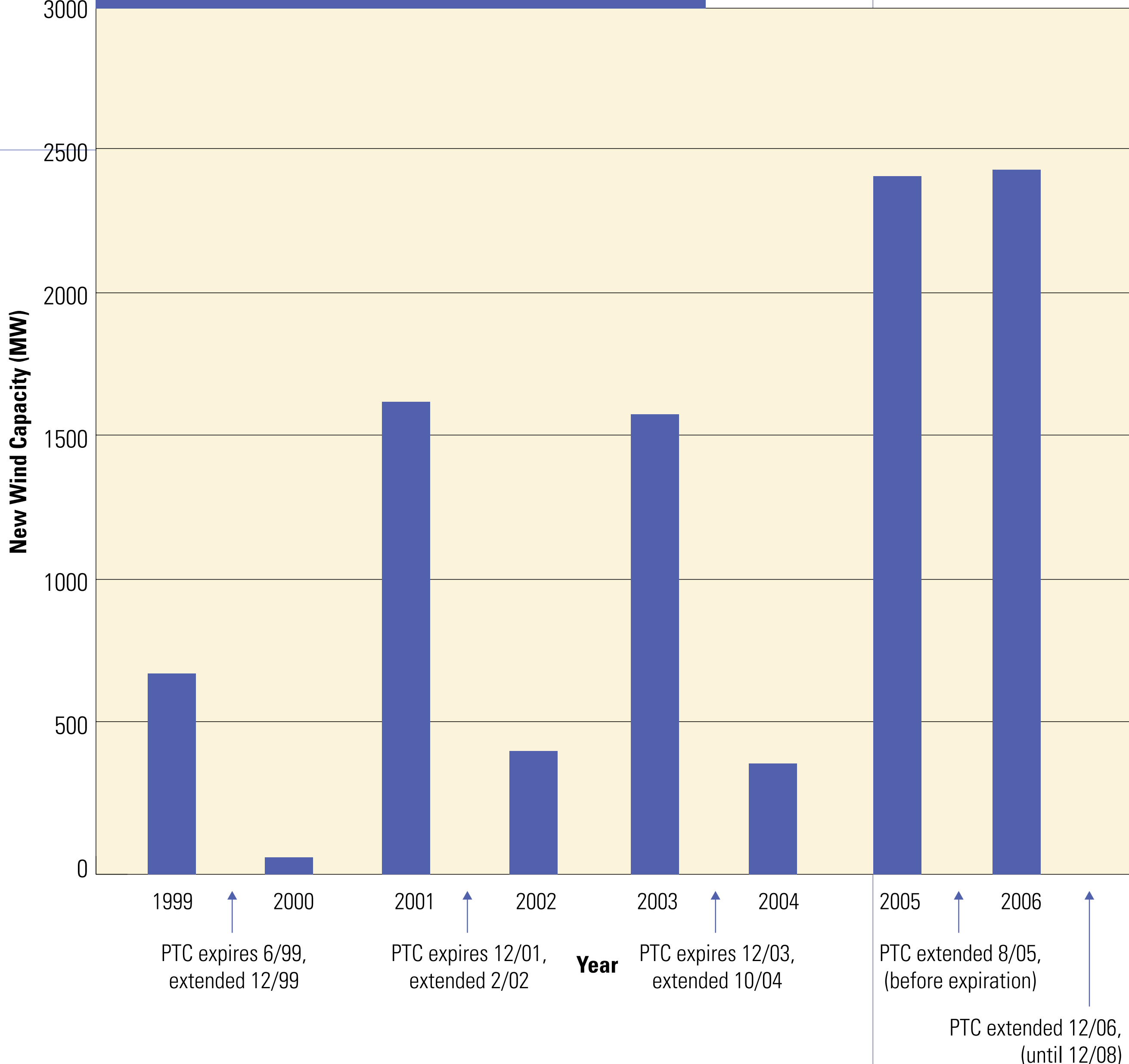
The politics surrounding the renewal of the PTC are often debated. None of our respondents believed that the inconsistency of the policy is simply an oversight by the federal government. As one respondent put it, “The argument is that a long-term PTC will hurt the federal budget. Right now, it’s an off-budget rider, similar to the concept of off-balance-sheet financing in the private sector.” The question is whether there are tradeoffs between the political game of hiding costs through an intermittent tax credit policy and the ultimate benefits realized by ratepayers. From the capital provider’s standpoint, especially with debt capital, volatility is expensive. Our data suggest two dimensions to the market effect of PTC volatility: the revenue risk, or the difficulty of accurately predicting project cash flows, and the inability to ensure the timely and cost-effective supply of equipment.

Revenue Risk

There is a fundamental misalignment of the PTC with capital investment cycles. Although project-development lead times can be up to three years and transmission upgrades require between four and seven years, the PTC is extended for shorter, 12-to-18-month periods. This mismatch creates a significant revenue risk for developers: if planning starts while the PTC is active, there is a risk that when the project is ready to become operational the tax credit will not be available. Given the significant potential value of the tax credit to REPG projects, the uncertainty of its renewal can threaten the viability and capital structure of each project. Respondents held a range of views about the degree to which PTC uncertainty has reduced project financing levels. On one end of the spectrum, equity investors might assign a slightly higher risk premium and demand a higher payout, but nothing that would dramatically alter a deal’s profitability (perhaps due to increasing liquidity in the sector). At the other end, the risk of a project shut down if the PTC is not renewed can be seen by capital providers as a “ticking time bomb.” One respondent even suggested the uncertainty of PTC renewal results in some positive, though fatalistic action: a sense of urgency is felt among investors to complete any projects they can before the tax credit expires.

A belief that the PTC will be extended further in the future—especially with the political shift in the 110th Congress—was widely held by our interviewees. However, the current uncertainty affects debt lender’s contracts. Tax credit cash flows are given weightings, based on the probability of the revenue being realized by the project, of between 25 and 99 percent, which are used by tax equity and debt investors to calculate the amount of capital to give to a project.[5] Probabilities and developers are unique, so valuation becomes more of an art than a science, meaning mitigating PTC risk is an iterative, cumbersome process and can hinge on the past track record of the developer. Some developers believe project profit would rise by several percent if the PTC was certain to be renewed, because capital providers would not have to consider discounting the tax

Figure 4-1
U.S. Wind Power Capacity Additions, 1999-2006



equity funds provided to a project, which would, in turn, allow developers to pursue more debt leverage and, thereby, reduce the overall cost of capital for the project. One developer explained, "We look at the probability that [PTC] will get renewed, and if it is 50/50, our return will be eight or nine percent. With a [certain] PTC [the return] goes up to 12 or 13 percent."

The insurance industry has begun offering PTC insurance to help cover some of this risk, but the incremental benefits are not quantified. If capital has been committed and equipment ordered, the looming PTC expiration comes with the threat of a lawsuit. It is expensive to shield the developer from this uncertainty; PTC premiums are an expensive, contrived use of capital, given the alternative of extending the tax credit. As one respondent proclaimed, "If we are going to go through a deal, do all the long-term planning [to] only do one or two deals and we don't see a long-term market, we charge more on capital."

The existence of the PTC creates tax equity investment in REPG. We found that PTC cash flows are so significant that few, if any, large-scale deals are signed without the tax credit. In a recent report by the California Energy Commission on contract failure, the intermittent nature of the PTC was also cited as being a factor in the cancellation of PPA agreements (for more on this report, refer to Section 4.7) (KEMA, Inc. 2006). Project value improves dramatically with the inclusion of the PTC. In fact, one developer mentioned that two sets of pro forma statements may be constructed for a project, one with the PTC and one without. In cases in which all other risks were minimized, the model did not require PTC cash flows to complete the project. Generally, however, wind projects have significant intermittent resource risk, equipment procurement risk, and grid access issues.[6] With stable, predictable tax credits, one developer ventured a forecast of a 40-percent increase in the number completed wind projects each year. While it is not clear if any organization has analyzed the price effect on the ratepayer from this uncertainty, suggestions are that contracted pricing for renewable power generation could drop as much as 30 percent—which would likely benefit ratepayers directly—if the PTC were extended for 10 years.

Equipment Manufacturing

The inconsistency of the PTC also affects the manufacturing of renewable energy equipment, which accounts for the majority of the cost of renewable power generation projects.[7] On two occasions, it was noted that a megawatt of wind is between 15 and 25 percent more expensive today due to the PTC's inconsistency. The primary cause: manufacturers have difficulty ramping up production and achieving economies of scale in the current boom-or-bust market environment. One capital provider said, "Not enough investment has occurred in turbine and spare parts involved in turbine manufacturing (gearboxes, bearings, etc.) to maintain a steady growth of supply, and stable or declining prices as one would be entitled to expect from a maturing industry. It has been an equipment sellers' market for years, which means projects are more expensive than they should be and you, as the taxpayer, pay too much to support the system."

In the years when the PTC was lapsed, developers avoided signing contracts with equipment manufacturers. The inconsistency resulted in turbine and component manufacturers exiting the U.S. market (Gosselin 2005). One developer asked, on behalf of its subcontractors, "Why should I, as a U.S. manufacturer, make a casting for a mold and invest in the infrastructure if I am unsure of a reliable U.S. market?" This constraint on U.S. equipment supply has had an adverse impact on developers, who not only have difficulty acquiring necessary equipment from overseas, but also are hurt by a depreciating currency (many equipment contracts are now priced in Euros). This has a disproportionate effect on undercapitalized developers. On the other hand, some larger developers speculate on the market's future development by ordering several years worth of turbines in advance.[8]

One respondent remarked that this is an area where policy should not play a role, but it does, indirectly. While renewable energy policy is often politically substantiated as a jobs benefit—as the PTC was in 2004 under the H.R. 4520 American Jobs Creation Act—the instability of the rule may lead to job elimination in the space. Respondents agreed that a PTC with a longer horizon would immediately benefit turbine manufacturing and reduce the problem of constrained supply.

The problems of intermittency have been discussed by Congress on several occasions. In May 2005, Dean Gosselin, Vice President of FPL Energy Development, said:

> *Under the circumstances it is difficult to persuade businesses to invest in the U.S.-based production capacity. […] Emblematic of this is that, at present, only GE and Mitsubishi currently price wind turbines in U.S. dollars. Other major suppliers (e.g., Vestas, Siemens, Gamesa, Nordex, Enercon, and Suzlon) still predominantly price based on the Euro, indicating their inability to commit to U.S. manufacturing of equipment. While unfortunate, this is understandable, given the unpredictability of the credit. […] We believe that this unpredictability leads to 20% greater inefficiency in energy production costs for the domestic wind energy market. These inefficiencies make the PTC an even more important revenue stream for wind developers. […] Unless and until the domestic industry can attain a level of sustained predictability that can justify the needed investments in U.S.-based manufacturing capacity, it will continue to be dependent on the PTC.*

…suggestions are that contracted pricing for renewable power generation could drop as much as 30 percent if the PTC were extended for 10 years.

Monetizing the Tax Credit

Most renewable energy developers do not have the tax appetite to take advantage of the PTC themselves; credits are often part of a contracted relationship with a "tax equity" investor. Though the tax credits are in effect free for the project, there are fixed transaction costs to utilize the credits that reduce the overall financial benefit to the developer and, ultimately, to the ratepayer. The number of investors with a foreseeable 10-year tax appetite is limited, which means finding and agreeing upon financing terms with a tax equity investor requires significant time and money. In addition, contracting costs of project studies and legal fees are significant. Since the PTC is a major revenue source for projects, these fixed costs are unavoidable, making projects under roughly 50 million dollars in value prohibitively expensive to develop.

Costs of Monetizing

Because there is no regulated, liquid secondary market for capitalizing credits, monetizing structures are engineered by capital providers (see Appendix D for discussion of a typical monetization structure). The prevailing view among respondents was that this adds significant transaction costs, though there were some responses that suggested that the market for tax equity

is maturing and the associated transaction costs are declining. For those who considered the costs to be prohibitive, the magnitude of the effect did vary somewhat. One financier suggested that the complexity associated with monetization hindered capital flow but that it was not enough to trickle down to the ratepayer. On the other hand, we heard a financier complain that monetizing the tax credit is inefficient and costly, and required a "backroom full of tax attorneys to make sure the entire project is good to go." For this investor, the time and financial costs of utilizing the PTC significantly reduced the value of the tax credit to the project. Most respondents who made a statement regarding the difficulty of monetizing tax credits cited execution/closing costs as material and problematic for REPG projects.

There did seem to be a threshold for the deal size that could effectively take advantage of the tax benefit, below which associated costs made a tax equity investment unappealing. One developer felt that the threshold was in the neighborhood of 50 to 60 million dollars. Effectively, the smaller the developer, the more difficult and costly it is to monetize the credits.

Lmited Tax Appetite

The amount of tax appetite is also important to consider. Typically, large financial institutions like banks or insurance companies will act as equity investors to assume the tax benefits of the PTC. Generally, the credits and accelerated depreciation benefits will determine the size of the investment. However, tax equity players are not always readily available, requiring developers to devote time and resources to chasing them down. In addition, some debt providers have thresholds for these corporate partners, limiting the potential universe to investment-grade rated companies, which significantly shrinks the number of utilities (who might otherwise be natural players in this market) eligible to act as tax investors. Currently, the number of corporations to choose from is limited to roughly 20. From our interviews, we determined this resulted from three main factors:

1. **Lack of Taxable Income** – Only a handful of corporations have a stable, predictable tax bill to utilize a 10-year tax credit. In addition, tax equity is constrained by the alternative minimum tax (AMT). Though the PTC is exempt from the calculation, if a company's tax liability is less than 20 percent of an adjusted income (Alternative Minimum Taxable Income – it would include the tax benefit from the federal MACRS accelerated depreciation program for renewable generation assets), the company's tax liability is adjusted to match that 20 percent. Tax equity investors who are constrained by the AMT are limited in their tax-advantaged investing pool. The Investment Tax Credit (ITC) for solar projects is not AMT-exempt.

2. **Competing Investments** – Low-income housing and leveraged leasing are investment substitutes for tax-advantaged investors. Though the PTC is currently a more lucrative investment, returns that were once two to three percent better than low-income housing are now a much narrower 100 basis points.

3. **Passive Loss Rules** – Current tax rules about offsetting income from the PTC disallow all but large corporations from investing in REPG, by preventing minority ("passive") investors from offsetting investment income with gains from the PTC. If this rule were changed, the wider investment market could take minority positions in REPG deals, increasing overall market liquidity.

Some respondents suggested that the PTC-monetization learning curve is flattening and that corporate tax appetite will not constrain market growth in the future. One developer mentioned that tax equity investors are becoming much more comfortable with the renewable power generation asset class, which reduces market uncertainty. New project structures are being negotiated and terms are improving, which ensure attractive investment returns. When prompted about tax appetite, one of our respondents mentioned that there is no loss of appetite from tax equity investors, but was quick to remind the audience that the policy intermittency is always a potential problem.

Support for PTC Extension

With PTC inconsistency as the major concern of capital providers, it came as no surprise that the most frequently identified recommendation was to extend the PTC. However, there was some disagreement over the optimal length of the recommended extension, ranging from three to ten years. Some larger developers were concerned about extending the PTC too far, for fear it may incentivize utilities to begin developing their own projects, and thus recommended a limited, three-to-five-year extension. Other capital providers called for a 10-year extension, to reduce supply risk and increase the stability of investments with more predictable revenues.

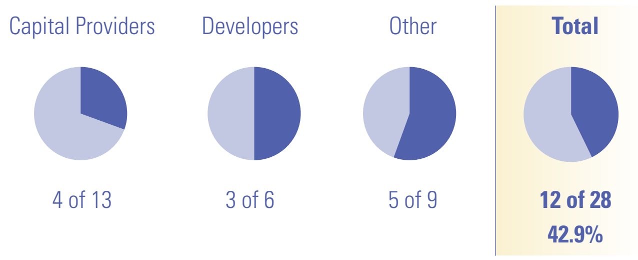
With PTC inconsistency as the major concern of capital providers, it came as no surprise that the most frequently identified recommendation was to extend the PTC.

There were some complaints about the PTC's overall market effect. One issue was that the policy does not encourage development in the most efficient areas. For example, in terms of wind development, the PTC does not distinguish between resource-rich areas (e.g. the Dakotas) and resource-poor areas (e.g. New York). As such, the PTC struggles to create an equitable development market on its own. As we found out, a renewable portfolio standard (RPS, covered in the next section) is needed to drive utilization of the tax credit, as is being done in New York, but not in North or South Dakota. Another concern was that the taxpayer was disproportionately subsidizing energy in fast-developing renewable power markets (e.g. Texas). To remedy this, some called for a policy similar to the feed-in tariff, popular in Western Europe. Others preferred what they saw as a more efficient national RPS, in combination with, or replacing, the PTC. Several considered tax credits to be the most cost effective federal incentive, but suggested not only extending the credit, but adding modifications to accommodate emerging technology growth (e.g. the investment tax credit for solar energy).

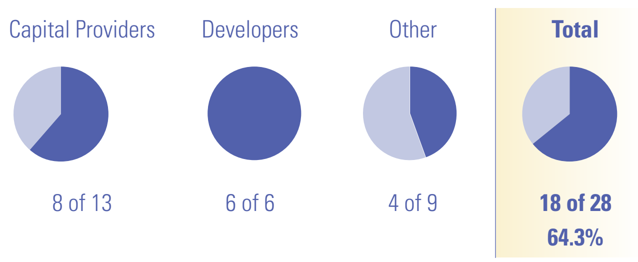
Renewable Portfolio Standards (RPS)

KEY FINDINGS

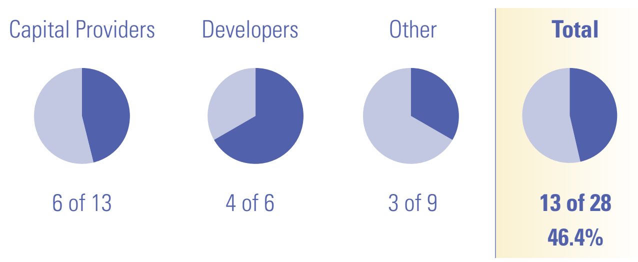
Many state RPSs are complicated and lack effective compliance mechanisms, increasing risk and negatively affecting cost and availability of capital.



Effective RPS systems should be simple, stable and predictable, in order to encourage long-term investments necessary for renewable power projects.



A federal RPS system may be the best way to improve market liquidity, driving down transaction and financing costs and increasing overall renewable power development.



These graphics indicate the proportion of respondents in each category that made statements supporting a given theme. Note that many respondents did not comment directly on each theme and that the lack of comment does not necessarily indicate an opposing point of view.”

THE RENEWABLE PORTFOLIO STANDARD (RPS) has become an increasingly popular policy tool for stimulating renewable energy development. Just the pace at which RPS systems have multiplied in the U.S. underscores the role they frequently play as the centerpiece of state-level renewable energy policy frameworks, and they have been instrumental in driving REPG development in many states. Few in the sector doubt that RPS will remain one of the dominant drivers of new capacity growth in the near future, yet the opportunity remains to expand or refine many RPS systems in ways that could accelerate renewable energy development even more.

Several interview respondents observed that RPS policies help to catalyze demand for renewable energy projects, by requiring utilities to either build new capacity or procure generation from qualifying sources. Since development and operation of renewable projects differs significantly from more traditional generation assets, most utilities have chosen to purchase power from independent power producers (IPPs) via long-term contracts. Whereas financial incentives (e.g. PTC) are seen as the 'carrot' to stimulate renewable energy supply, RPS is seen as the 'stick' that drives utility demand. Two respondents emphasized that while an RPS is not a requirement for completing a deal, it is often what drives a utility to offer a power purchase agreement (PPA), improving deal stability and economics.

RPS Design

For the purposes of this study, we were interested in how specific RPS requirements interact with the project development process, and particularly how variations in RPS design affect the pricing and availability of project financing. Among the key design choices for an RPS are the mandated target (either a percentage of overall energy supplied or a capacity requirement), resource eligibility (wind, solar, geothermal, etc.), regulatory oversight, enforcement mechanisms, flexible compliance mechanisms (such as tradable renewable energy certificates or RECs), cost recovery and/or escape clauses and a host of other implementation details (a comparison of major state policies is

available in Appendix E) (Wiser et al. 2004, 6). There is no de facto standard for RPS design, and states have taken a wide variety of approaches to crafting existing systems. This diversity in part reflects legitimate variations in market circumstances in each state; however, not all the existing regimes are equally effective in meeting their goals, suggesting additional non-market factors. Nearly half of the interview respondents, including at least a third of those in each category, noted that many existing RPSs have design issues that adversely affect project financing. The most prominent issues cited were policy instability, weak enforcement and administrative complexity (see also discussion of REC markets in Section 4.4).

Instability

By far the most significant concern with state RPS systems was their instability. To the extent that the market for REPG depends on RPS mandates, and many respondents emphasized that it does, developers and capital providers need to be as certain as possible that the policies will not radically change in the future. A cross-section of the respondents made it clear that instability is already a problem in some states, where frequent policy shifts can "change the very ground you walk on." Examples mentioned included New York, Connecticut and other northeastern states, where strong support for renewables has driven a flurry of activity and a willingness to repeatedly refine policies in search of marginal improvements in their effect. Policy improvement is certainly a worthy goal, but one that must be balanced against the need for a stable market environment. Policy stability is particularly important where projects are reliant on the revenue from tradable RECs, since shifts in policy can and do have dramatic effects on REC values. Most in the sector are familiar with the example of Connecticut, which expanded the eligibility definitions in its RPS in August 2005 and quickly saw REC prices drop by 30 dollars per MWh (Wiser 2006, 41). Needless to say, problems such as these have a substantial effect on the development of REPG markets, and our respondents were very clear that more stability was needed in order to support long-term investment horizons and improve the flow of capital to the sector.

Weak Enforcement

Respondents explained that many RPSs "lack teeth"—no clear penalties for non-compliance, too many clauses allowing non-compliance—allowing some utilities to delay or avoid procurement of renewable energy. The result is uncertainty for developers working to bring projects online, since the majority of projects are not viable until a suitable PPA is signed. Furthermore, even where PPAs are available, the lack of credible enforcement mechanisms gives utilities added power to negotiate favorable contract terms with developers (see section 4.7 for further discussion of PPAs). Capital providers will in turn assign higher risk to projects with less-favorable contracts, so developers may have less capital available or else must achieve a higher debt-service coverage ratio in order to secure debt financing. Stronger enforcement mechanisms increase the certainty that utilities will in fact contract for renewable generation, attracting more developers and capital providers to the market and driving greater competition and liquidity over time. Multiple respondents said that compliance penalties greater than $50/MWh—currently found in CT, MA, RI, TX and WA—are essential to RPS effectiveness.

Complexity

A few respondents noted that the complexity of some RPS systems—in terms of regulatory oversight, the structure of targets, generator eligibility requirements, compliance verification, etc.—is also a hindrance to project development and financing. At least one respondent in each category mentioned either California or New York (or both) as examples of states with overly-complex mandates. The general concern among respondents was that complexity delays overall RPS implementation, leaves critical design variables (such as contracting standards, compliance penalties or regulatory procedures) unspecified and/or creates too many hurdles for market players to negotiate. The result is again additional risk and uncertainty, and often higher transaction costs, all of which deter new development and investment. One financier suggested that California has already lost out on at least $1 billion in new wind investments due to the complexity of its RPS.

Respondents were also concerned that many state policies are overly politicized and full of various off-ramps, escape clauses and loopholes. Many acknowledged that loopholes and exceptions may be politically necessary, but stressed that they do create added risk, by either favoring certain technologies or creating opportunities for utilities to avoid compliance with the mandate. Two respondents, one developer and one consultant, specifically mentioned that technology carve-outs (provisions that a certain portion of the RPS mandate must be met by a specific technology, such as solar) are problematic. Both noted that carve-

Table 4-1
State RPS Compliance Penalties

STATE	RPS PENALTIES
Arizona	Discretion of ACC
California	Discretion of CPUC
Colorado	Discretion of CPUC
Connecticut	$55/MWh
Delaware	$25-50/MWh
District of Columbia	$0.025/kWh "tier one", $0.01/kWh "tier two", $0.30/kWh solar
Hawaii	None
Illinois	None
Iowa	None
Maine	License revocations and fines, discretion of PUC
Maryland	$0.02/kWh for Tier 1, $0.015/kWh for Tier 2
Massachusetts	$55/MWh
Minnesota	Fin. penalties not to exceed est. cost of compliance
Montana	$10/MWh
Nevada	Discretion of PUC
New Jersey	Fin. penalties greater than market cost of RECs or new generation
New Mexico	None
New York	None
Pennsylvania	$45/MWh; 200% of PV REC value for solar
Rhode Island	$50/MWh
Texas	Lesser of $50/MWh or 200% of REC value
Vermont	None
Washington	$50/MWh
Wisconsin	$5,000 to $500,000

A substantial majority (64%) of the interviewees emphasized that an effective RPS policy, in terms of its ability to attract more investment in projects, must be simple, stable and predictable.

outs interfered with development of the most competitive projects, and one was concerned that projects dependent on another layer of state incentives for economic viability were subject to too much political risk to be financeable. Two other respondents highlighted problems that occur when utilities are subject to retroactive prudence reviews of their rate cases—in other words, when a utility receives approval from the PUC to pass on the higher costs of renewable energy procurement to ratepayers, but that pass-through may later be challenged. The result is more uncertainty for utilities, which may delay the purchase of renewable power to ensure they don't overcomply and get forced to absorb the extra costs later on.

Simplicity and Stability Are Key

The dominant theme from our discussions of RPS design was the need to reduce the uncertainty and complexity found in some state RPSs. A substantial majority (64%) of the interviewees emphasized that an effective RPS policy, in terms of its ability to attract more investment in projects, must be simple, stable and predictable. Multiple developers and capital providers summarized the perfect RPS as one with "an aggressive goal, clear penalties and no outs." The result is a more stable environment which makes the development cycle less risky and project cash flows easier to predict and model, both of which will draw more players into the market and increase the availability affordable project financing. Capital providers in particular offered multiple versions of this thesis. Asked whether more competition in the market might disappoint lenders seeking higher returns, one financier responded, "A more potent, predictable policy will drive more deal flow, which makes bankers happy as well. I think of the raising boats theory, rather than a zero-sum game."

Several respondents cited the Texas RPS system as "best in class." In particular, they commended its strong penalties and overall simplicity, which have helped drive development of a robust market for renewable power projects and financing. "Keep it simple," said a developer. "The Texas model was simple, then they let the markets figure it out." Or, as one capital provider put it, "Texas has good legislation that was well implemented. The Texas RPS is two paragraphs; California's is 25 pages, complex. Simpler is better. You want clear numbers, with clear penalties and no outs." Of course, it is important not to discount other circumstances that have made the Texas law successful, such as its strong wind resource and robust commitment by ERCOT to expand in-state transmission. However, respondents were clear that the simplicity of the Texas RPS should serve as an example to other states.

RPS Scope

One of the significant, ongoing debates in the REPG sector concerns the optimal scope for RPS mandates. As the sector grows, more and more players are operating in multiple states, and the fragmentation of current state-level RPS systems is thought to create inefficiencies that might best be addressed through either multi-state cooperation or federal policy. Problems include variations in definitions of eligible renewable resources; the definition, tracking and tradability of RECs (see discussion of RECs in section 4.4 below); and both the difficulty and added transaction costs faced by developers and capital providers as they move across state lines. One of the capital providers we spoke with explained, "We can't run around all 50 states and be experts in each one and in several different technology types. Policies at the federal level would have a more immediate effect on market participation."

Some states are already working together in an attempt to improve the effectiveness of RPS policies in each of their jurisdictions. One prominent example is the Western Renewable Energy Generation Information System (WREGIS), an 11-state initiative that hopes to create a regional tracking system which would facilitate a broader and more liquid market for RECs, and ultimately more flexibility for compliance with the RPS mandates in the individual states (Rabe 2006, 24). However, a growing number of REPG advocates are calling for a federal RPS policy, which many believe would further resolve some of these inefficiencies.

Support for Federal RPS

More than half of the interview respondents—four out of six developers, six out of eleven capital providers and three out of nine others—support a federal RPS policy, and not one strongly opposed it. Reasons expressed in favor of a federal mandate included the restrictiveness of state regimes on national and international companies; the potential for fewer loopholes and a better allocation of development resources in a federal system; the greater price stability and value of RECs that a large-scale, national market would promote; and cost savings from greater interstate contract consistency, creating more opportunity for growth in the sector. Again the general consensus was that a more simple, stable and predictable policy environment is needed to promote market growth and attract cheaper capital to projects. Several respondents said that a federal RPS should be the number one priority for further policy development in the U.S.

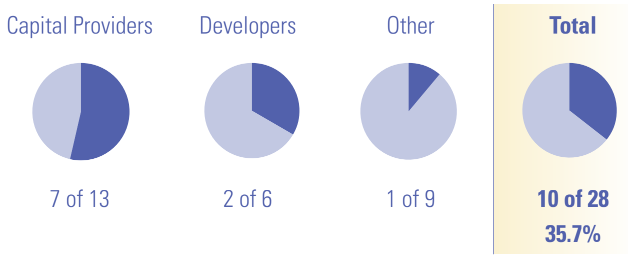
A few respondents were not strongly for or against a federal RPS policy, and they were among several that highlighted reasons why one may never be enacted. One of the major arguments against a federal standard is the difficulty states without strong renewable resources, such as those in the southeast, face in complying. Absent the opportunity to construct their own renewable energy facilities, those states would be forced to pay for transmitting renewable energy from other regions, or purchase large amounts of RECs, to comply with the federal mandate (the cost would depend on how the mandate was enforced). The fear is that this would amount to a substantial transfer of wealth away from those states, particularly since they would not be able to capture the local economic and environmental benefits associated with renewable energy development. At the other end of the spectrum are the many states with existing RPS standards, many of which are now deeply engaged in sector development. The concern here is that a new federal system might delay or otherwise interfere with states pursuing aggressive targets. Between these two interest groups, a wrong move could shut off much of the political support for a federal mandate. A few respondents emphasized that any federal system that is enacted should only be a backstop and would need to be crafted in a way that allows states to pursue more aggressive targets if they choose to do so.

Both arguments underscore the larger political context of the debate over a federal policy. As one respondent explained, "The politics of RPS are fierce because resource planning and procurement have historically been a state-regulated activity. The states have been adamant about keeping control over this issue. And in fairness to them, the circumstances of each state and region are different." In other words, whether or not a state is relatively rich or poor in terms of renewable resources, it is not likely to welcome a federal policy. The other problem is that the goals of a federal RPS are likely to overlap significantly with those of a federal climate change policy, which many observers consider to be politically inevitable. Harmonizing an emerging climate policy with already-evolving renewable energy policies will be a lengthy and challenging process, and for now it is unclear whether the idea of a federal RPS will survive long enough to be enacted. A few respondents suggested that a federal carbon policy, in the form of a carbon tax or a cap-and-trade system, could eventually displace the current, RPS-dominated landscape of renewable energy policy.

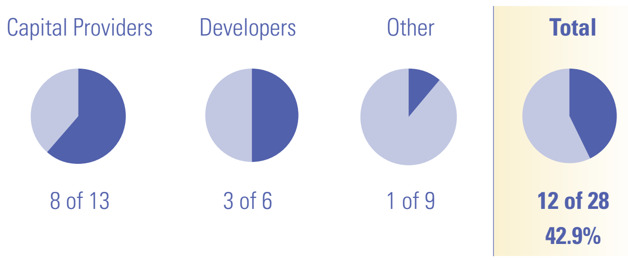
Renewable Energy Certificates (RECs)

KEY FINDINGS

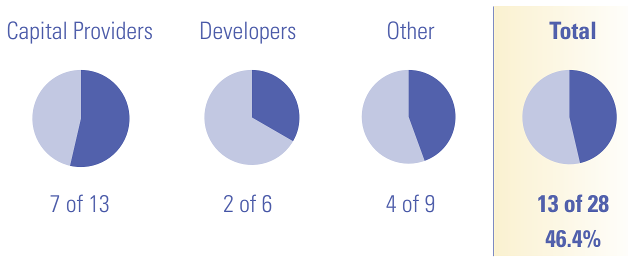
Most renewable energy projects are completed without financial consideration of RECs.



The value of RECs is generally discounted in the modeling of project cash flows for financing purposes, due to their volatility and associated risk.



Regional or national markets for RECs would provide greater liquidity and make REC values more reliable for financing purposes.



These graphics indicate the proportion of respondents in each category that made statements supporting a given theme. Note that many respondents did not comment directly on each theme and that the lack of comment does not necessarily indicate an opposing point of view.”

RETAIL ENERGY PROVIDERS HAVE THREE OPTIONS for meeting RPS requirements. They can 1) invest in renewable energy generation projects and produce their own renewable energy; 2) purchase renewable energy directly from a renewable energy producer; or 3) when permitted, purchase renewable energy certificates, or RECs—provided RECs are part of the RPS policy design. Fundamentally, RECs represent the positive environmental attributes (i.e. absence of certain emissions) associated with renewable energy generation. In some instances, these attributes can be separated, or "unbundled," securitized as a REC, and then traded or sold separately from the electricity, thus providing a vehicle to transport the benefits of renewable energy across state and regional boundaries independent of the grid. The credits are created and issued in 1 MWh increments upon generation of electricity from an eligible renewable energy source. To fulfill RPS obligations, energy providers will typically obtain RECs by either purchasing them on the spot market or through longer-term bilateral contracts with renewable energy producers. Short-term or spot contracts are most commonly employed in restructured markets where retail suppliers are less likely to enter into long-term contracts with renewable energy generators. Most short-term contracts are executed in northeastern states with RPSs.

In addition to providing a means for RPS compliance, RECs can also provide an alternative stream of revenue for the owner of a renewable energy generation facility, thereby helping to offset the additional costs of renewable energy. Ultimately, this extra revenue stream is meant to encourage additional investments in renewable energy projects.

General Findings

Unfortunately, REC price uncertainty and a lack of long-term contracts (for both energy and RECs) have made financing for RECs difficult to obtain, thereby reducing their utility in project finance. The large majority of renewable energy investors and developers interviewed for this project agreed that most deals are completed without financial consideration of RECs. Even in cases where developers are unable to obtain long-term PPAs and RECs become more important for a project's cash flows, capital providers are not likely to rely on REC values to make up for the revenue shortfall. In short, RECs do not provide the same level of certainty as a PPA. Rather, RECs are commonly seen as cheap options on future scenarios for higher energy prices, considered to be "gravy" or a "cherry on top."

While RECs are commonly considered as an afterthought in project finance, their value and importance is often project-specific and highly dependent on the technology employed, the local REC market, and the financier's perspective and internal rate of return. In general, the economics of biomass and geothermal tend to be competitive and do not rely as heavily on federal and state incentives such as RECs, whereas solar projects, for example, are much more capital-intensive and more likely to need incentives to be profitable. Also, developers tend to be more bullish about RECs compared to bankers, who are openly risk-averse. For instance, a developer unable to obtain financing for RECs might take a chance on a marginal project in an area with a locally constrained REC market, if the current REC price is high enough (Massachusetts, for example). However, most capital providers are uncomfortable taking that risk without concrete assurances from local market regulators, as these projects are admittedly riskier and there are many instances in which such projects have proven to be unprofitable.

REC Prices

The difficulty in financing RECs has much to do with geographic and temporal price fluctuations and the complexity that a federated REC system presents. REC prices tend to be the lowest, as low as two dollars per MWh, in states with good resources that include RECs as part of a PPA, like Texas. Fortunately, in Texas there are good wind resources and accessing the grid is relatively easy, and therefore the state has seen some of highest growth in renewable energy capacity. REC prices tend to be the highest, in excess of 50 dollars per MWh, in resource-constrained states with high penalties, such as in Massachusetts. Recently Massachusetts implemented a forward auction of RECs to drive down the price for RECs, but the system has not been in place long enough to have a significant impact. Where there have been significant drops in the price of Northeastern RECs is in states like Connecticut, which changed the rules for resource eligibility mid-stream. In August 2005, the Connecticut DPUC declared that existing biomass and new gas pipeline expansion qualified as a Class 1 REC, thereby sending prices plummeting from 30 dollars per MWh to 3 dollars per MWh. From the perspective of a capital provider, such price fluctuations and the lack of long-term contracts in most instances introduce too much uncertainty to place much value on RECs.

REC Discounting

Implicit in the general observation that RECs are of insignificant value to renewable energy projects is an aggressive discounting of value by capital providers. As observed before, REC discounting is often market or project-specific. However, unbundled RECs to be sold in the wholesale market are generally discounted much more than RECs under long-term contracts. Most capital providers offer some value for wholesale RECs, but only a small amount. For instance, if RECs were trading at five dollars per MWh in a given market, one developer indicated RECs would be discounted to one dollar, without a contract. Similarly, another developer indicated that if RECs were trading at six dollars, they might get financing at a value of two dollars. Another developer indicated that RECs are commonly discounted by 30-40 percent without a contract.

In contrast, RECs under long-term contracts will be discounted much less and may be financed dollar for dollar. However, the extent of discounting is dependent upon the terms of the contract as well as the creditworthiness of the offtaker. For these contracts, most capital providers want to see a term approaching 10 years, and they will heavily discount RECs beyond the contracted period. Capital providers also become uncomfortable when contracts contain performance clauses or an opportunity to review the terms of the contract at a later date. As far as the creditworthiness of the offtaker goes, a developer may only get 50 cents on the dollar for RECs (even with a long-term contract) if the offtaker is a third-party broker with a poor credit rating.

A common provision within many state RPSs that leads to significant discounting of RECs is credit multipliers that are applied to specific renewable energy resources. For instance, RECs associated with solar electricity production can be counted 1.25x-3x towards achieving a state RPS. While this provision will increase the value of the associated RECs and ultimately increase capacity for certain renewable energy resources, there is also heavier discounting applied to these RECs. Capital providers do not like the added complexity and lack of transparency of credit multipliers and, therefore, shy away from them.

From the perspective of a capital provider, such price fluctuations and the lack of long-term contracts in most instances introduce too much uncertainty to place much value on RECs.

Improving REC Markets

While RECs do not currently provide a significant source of financing for renewable energy projects, several states have implemented policies to address this issue. Massachusetts has strictly enforced stiff penalties for non-compliance, thereby providing the proper incentive for utilities to purchase RECs. Massachusetts has also created a green power partnership that offers 10-year REC price insurance, and under NYSERDA's central procurement, developers can enter into long-term REC contracts with the State of New York. These provisions create revenue certainty for RECs over a longer period, congruent with renewable energy project financing cycles. While these are steps in the right direction, there are still concerns that the funding for these programs, which is derived from state-controlled funds, might not have the required funding 10 years in the future.

Support for Regional/National REC Markets

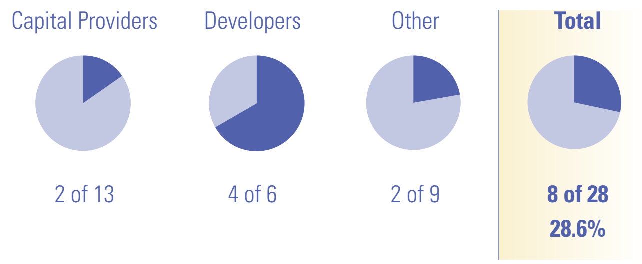
While there are steps that states can take to improve local REC markets, almost all of the capital providers and developers interviewed would prefer regional and/or national REC markets. In the current, balkanized REC market landscape, transactions are unnecessarily complex, which leads to the higher rate of REC discounting. Most of the participants in this study suggested that a national market would rectify this situation by increasing policy transparency and improving REC liquidity, thereby creating a nationally-traded commodity that is highly fungible. A national market might decrease the value of RECs in certain states, but this would be offset by reduced levels of discounting and greater overall financing, resulting from improved market clarity and the structural certainty and homogeneity of RECs. This would ultimately increase the importance of RECs for renewable energy project financing, as revenues derived from RECs would make many deals more attractive to investors and, therefore, lower the cost of available financing. A national REC market with a more readily traded commodity would also support a trend towards merchant wind, granting greater bargaining power to developers rather than offtakers.

Looking to the future, many of the interviewees see a carbon-constrained world and are not sure of the role of RECs in that scenario. Currently, RECs are used for RPS compliance, but their associated value might increase significantly under a cap-and-trade system, as a REC also embodies the associated carbon value of a MWh of energy. Thus, RECs might become more valuable for their carbon offsetting potential than for their ability to comply with RPS standards. Therefore, there may need to be a means for reconciling the value of RECs under a 10-year contract if a cap-and-trade system is only five years away.

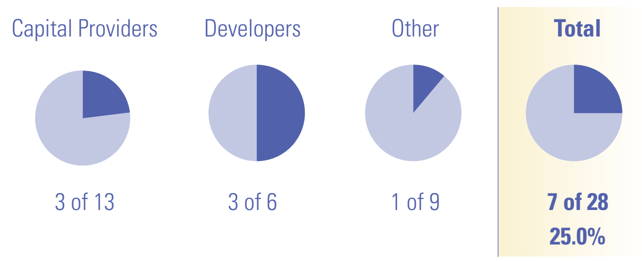
Public Benefit Funds (PBFs)

KEY FINDINGS

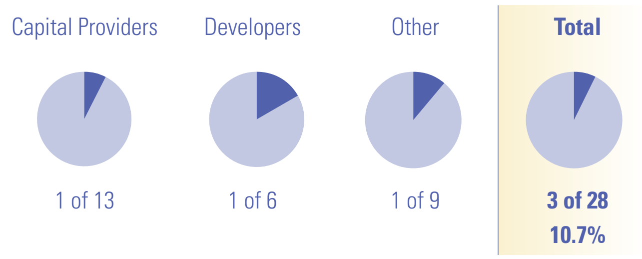
Even when state funds are available, it is doubtful they can be used for external financing.



There is significant risk of PBFs being reappropriated by state regulators.



States should either harmonize their PBF rules with federal policy, or focus their efforts on community, technology, and industry support.



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FUNDED STATE INCENTIVES FOR CLEAN ENERGY amount to over $800 million annually, of which more than $300 million is dedicated to renewable project financing (DSIRE 2007). These funds are a large potential source of funding for renewable power projects, typically raised through small tariffs, referred to as system benefit charges (SBCs), and levied on all retail electricity consumers. Generally, these tariffs are used to create "public benefit funds" (PBFs): pools of money used to fund technology development, resource feasibility studies, and sometimes, project finance cash flows. According to some estimates, funding from PBFs has contributed to over 2,642 MW of renewable energy capacity since 1998, with another 56 projects totaling 1,133 MW currently in the pipeline (Bolinger and Wiser 2006, 2).

Public benefit funds are used in many states, often in conjunction with an RPS, although some states with PBFs do not have an RPS. Each state deploys its funds differently, but three general models of PBFs exist: the investment model, the industry development model, and the project development model (Bolinger and Wiser 2001, 11). The most effective model for attracting external financing is the project development model, whereby the state offers specific grants, tax abatements, and rebates to project developers. This model has been applied in several states, including Oregon, Pennsylvania, Illinois, Minnesota, and California, particularly through the use of state production tax credits. Notwithstanding the appeal of the project development model, the makeup of PBFs and their relation to federal incentives largely determines their value to investors.

General Findings

These funds are seemingly effective at increasing renewable energy uptake, though we found that their efficacy is clearly dependent on the method in which they are deployed. Many of our capital provider respondents regarded these state funds as unreliable, with limited attractiveness for project finance. Of our 28 interviews, 19 interviewees told us whether they include PBFs in their current renewable power projects forecasting. Of the 19 respondents, eight said they do not consider potential cash flows from PBFs. Nearly all of the seven affirmative responses were contingent; without specific policy pre-conditions, the respondents would likely not include PBFs in their project forecasts. Generally, interviewees appeared wary of direct public-private financial partnerships, However, the respondents identified specific situations in which these funds proved valuable and how they could be put to better use, including technology investment, municipal project financing, and crisis lending reserves.

Risks Associated with PBFs

One of the main detractions of state funds to the investment community is that federal funds, specifically those raised by utilizing the federal production tax credit, can be unwittingly offset and reduced by up to 50 percent by tapping into state financial incentives. For this reason, and because state funding pools are smaller than federal incentives (e.g. PBF vs. PTC), investors considering pursuing PBF support are likely to require more assurances from policymakers that the state dollars are available. In our interviews, we found that in some cases, this means that state funds have to be provided upfront, before a project is developed. Otherwise they are not considered.

A significant market risk associated with PBFs arises out of state policy flexibility. We were told that with a change of administration or if the state finds itself in a budget crunch, there is a danger that policymakers could redirect funds away from their original purpose. This drove several of our respondents to suggest that even when state funds are available to investors, it is doubtful the cash flows can be used as collateral for outside financing, which limits their use in project finance.

PBFs Should Be Focused Where They Are Most Effective

Based on the relatively small size of state incentives, the questionable ability to use them to secure private capital financing and the fear that they will offset federal incentives, investors are wary of using PBFs in financing REPG projects. A few respondents suggested that states should either harmonize their incentives with federal rules and policy or focus public funds on technology development, municipal business development, or on "lender of last resort" reserves. In this last scenario, states would not have to administer any cash outlays, and could avoid potentially prickly public-private partnerships. Other solutions include backing the PBFs with the full faith and credit of the state (assuming it is creditworthy), providing the funds upfront for developers or getting rid of PBFs and focusing on creating robust RPS policies that eliminate the need for the state funding pools.

Table 4-2
Public Benefit Funds

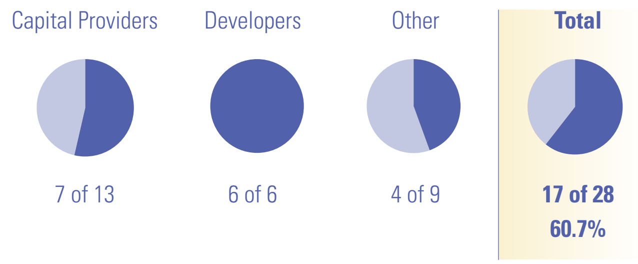
STATE	TOTAL ANNUAL FUNDING	FUNDING FOR REPG
California	$440 mln	$150 mln
Connecticut	$65 mln	$0
Delaware	$2.3 mln	Under $1.5 mln
District of Columbia	$10.5 mln	$0
Illinois	$8 mln	$5 mln
Maine	$9.6 mln	$0
Massachusetts	$124 mln	$0
Michigan	$66.3 mln	$0
Minnesota	$16 mln	$9.4 mln
Montana	$14.9 mln	Less than $2 mln
New Jersey	$180 mln	$29 mln
New York	$175 mln	$36 mln
Ohio	$10 mln	NA
Oregon	$64 mln	$12 mln
Pennsylvania	$77.8 mln	$18.4 mln
Rhode Island	$17 mln	$2.4 mln
Vermont	NA	$6 to $7.2 mln
Wisconsin	Variable ($82.4 mln 2005)	Approx. $40 mln

Sources: Database of State Incentives for Renewable Energy (DSIRE), Union of Concerned Scientists, Alliance to Save Energy

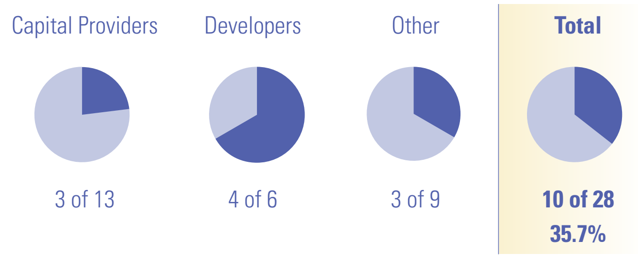
Transmission

KEY FINDINGS

The current U.S. Transmission system does not adequately serve the needs of the renewable power generation sector.



The federal government should exercise more control in order to accelerate expansion and ease the intregration of renewables into the system.



These graphics indicate the proportion of respondents in each category that made statements supporting a given theme. Note that many respondents did not comment directly on each theme and that the lack of comment does not necessarily indicate an opposing point of view.”

ELECTRIC TRANSMISSION IS THE KEY to delivering the energy produced by power generation projects to end users (see Appendix F for an overview of the U.S. transmission system). Transmission is particularly important in the REPG sector, because renewable power projects must typically be sited in areas far from electric load centers. Unfortunately, because the existing U.S. transmission system was designed primarily to deliver power from traditional, large-scale fossil-fuel and nuclear power plants, integrating renewables into the system has been a significant challenge.

General Findings

When asked about the state of the U.S. grid in the context of the renewable power sector, respondents described it variously as "a morass," "in shambles," and "a bottleneck to growth." Looking at the main transmission challenges to renewable energy, three main themes emerged: reliable access to the transmission grid system, imbalance charges, and lack of transmission in resource-rich areas. In terms of policy implications, our respondents primarily focused on the priority of creating flexible, uniform markets and expanding transmission through federal coordination.

Reliable Grid Access

Reliable grid access is crucial to securing financing for renewable projects. Seventeen out of 28 interviewees commented on the importance of grid access and its ability to make or break a project, with only one capital provider saying he would finance a deal without negotiated grid access. Most external cash equity, tax equity, and/or debt will enter the deal only after access has been secured.

Depending on where a project is sited, a number of different factors affect the developer's ability to negotiate grid access. Projects must apply for access either through (a) a bilateral contract with a vertically-integrated utility that owns and operates the transmission lines, (b) a Regional Transmission Organization (RTO) such as PJM or MISO, or (c) an Independent System Operator (ISO) like ERCOT or the California ISO. The process of connecting to the grid via any of these channels can be challenging. Many respondents highlighted the difficult and costly process associated with negotiating bilateral contracts given the inconsistent requirements and procedures across regions and states. For instance, each transmission owner requires a separate, unique application that increases bureaucratic red tape and associated transaction costs. One developer noted that when direct ISO/RTO negotiation was possible, the firm preferred it over bilateral contracting.

After the grid connection is negotiated, REPG projects often experience curtailment of transmission during peak periods of electricity demand, at rates typically between two and five percent over the lifetime of the project, according to one developer. Generators locked out of transmission space cannot sell their electricity, effectively reducing the facility's capacity factor and, therefore, the profitability of the project.

Through our interviews, several policy solutions emerged to aid developers in accessing the grid. Many interviewees saw real-time, transparent markets similar to those incorporated into the PJM RTO as a clear need throughout the market. Interviewees saw restructured transmission systems with RTOs as the best vehicle to deliver flexible pricing, given their independence from the utilities and their status as FERC-regulated, non-profit organizations. Without RTOs, standalone generators are forced to negotiate grid access with utilities that may prefer to allocate their own electricity more than that of a competing generator. Respondents saw the flexible pricing pioneered by ERCOT, PJM, and the NE ISO as a tool for reducing barriers to entry and curtailment risk.

To remedy a complex and balkanized system, one developer recommended simple and uniform application procedures which reduce the time and effort required to apply for grid access. This would presumably lower transaction costs and reduce project development lead times.

Imbalance Charges

Grid connection contracts often contain stipulations regarding imbalance charges, requiring the generator to pay penalties when actual energy output to the grid differs significantly from the planned amount. These charges vary depending on region. For example, the NY ISO allows a range within 500 MW from the planned amount. ERCOT has a boundary of +/- 50 percent. In contrast, the PJM ISO does not impose imbalance penalties, but rather allows real-time markets to adjust (National Grid 2006, 8).

Interviewees expressed frustration with these charges, noting their particular harm to intermittent resources like wind and solar. These charges add additional costs, increasing the volatility of project cash flows and adversely impacting project financing. Respondents pushed for removal of the charges, or at least more lenient requirements for intermittent resources such as renewables. In fact, FERC's recent order 890 seeks to alleviate the costs imposed by imbalance charges, by implementing a new tiered fee schedule. It also exempts intermittent resources from the most expensive "band" of fees (FERC 2007, 4).

Lack of Transmission in Resource-Rich Areas

The lack of transmission lines near areas rich in renewable resources hinders significant REPG expansion potential. This is particularly true in the case of wind energy, in which states such as South Dakota, Iowa, and Wyoming have tremendous wind resources, but few nearby population centers to utilize that electricity. The hundreds of miles of transmission lines needed to transport the electricity to nearby cities do not exist. Respondents highlighted main challenges to transmission expansion:

1. **Equitably Allocating Line Development Costs (the "Chicken and Egg" Problem)** – Four interviewees specifically mentioned the allocation of costs as a key barrier to building new transmission. In this scenario, REPG is not built because there is no transmission grid access and project developers cannot absorb all the costs and risks required to build out the lines. One interviewee stated, "North Dakota is the Saudi Arabia of wind, but I won't develop there until it's certain that we can evacuate the power to Minneapolis or Chicago." By the same token, transmission owners do not build out because there is no guaranteed generation to feed electricity to the transmission lines. This creates an impasse, which necessitates some form of coordinated regulatory action.

2. **Not in My Back Yard (NIMBY)** – Landowners and stakeholders block transmission development in their own areas, presumably because it is viewed as unsightly or detrimental to the community. Nine respondents discussed the difficulties of dealing with NIMBY issues, especially in areas such as California, where population density is high.

3. **Wealth Transfer Between States** – Building new transmission across state lines potentially creates a seemingly unfair transfer of wealth between states, depending on the relative electricity rates of each state. Different rates between two regions will begin to converge once the two markets are connected. This will impose higher costs on ratepayers in the less expensive market as rates rise, and a net gain for ratepayers in the more expensive market as their rates fall. One interviewee mentioned New York and Ohio as an example, saying that

However, the majority of our respondents favored a federal approach to siting transmission, in which an agency such as FERC or the DOE would coordinate large-scale, interstate expansion.

Ohioans fear connecting to the more expensive New York energy market because the aggregate potential wealth transfer could ultimately be as high as 70 billion dollars.

4. **Intermittency** – Intermittent renewable resources face further challenges, since generation may only occupy 30 percent of the capacity of the lines on average. This makes it difficult to justify building long, expensive, transmission corridors to these resources.

Support for a Federal Solution

Transmission expansion is a complex issue, and no definitive solutions arose from our interviews. However, the majority of our respondents favored a federal approach to siting transmission, in which an agency such as FERC or the DOE would coordinate large-scale, interstate expansion. Of the 28 interviewees, 14 favored a federal approach for transmission expansion, three preferred it to be handled locally, and the rest did not offer an opinion.

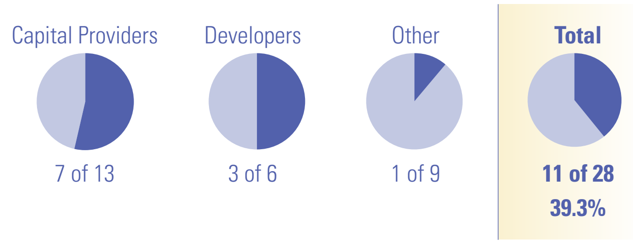
Interviewees provided several reasons for a federal approach. One stakeholder drew parallels between FERC's role in electricity transmission and its role in overseeing natural gas transport; in the latter case, FERC was able to use eminent domain to site natural gas lines. Another developer saw transmission ownership increasingly crossing state boundaries, as utilities expand their footprint throughout the country and begin to welcome a federal approach for financial and strategic reasons. Federal oversight of transmission may also help to further address market rules and other conditions that currently bias the system against renewables. Overall, the sentiment from the interviewees was that federal coordination would give the best chance for a cohesive, efficient expansion of the system.

However, a small number of respondents—primarily capital providers—favored a regional approach. They offered three general arguments. Some interviewees believed NIMBY issues would best be handled by local authorities, given their local knowledge and expertise. Secondly, state resistance to federal involvement in local governance will likely lead to protracted court battles and turf-fighting. And finally, one interviewee pointed out that locals will "live with" and "pay for" the expanding transmission lines, so seeing locals own the issue is the fairest measure.

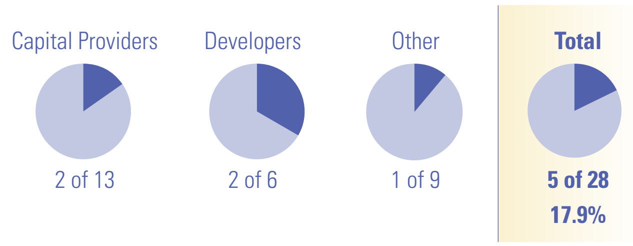
Power Purchase Agreements (PPAs)

KEY FINDINGS

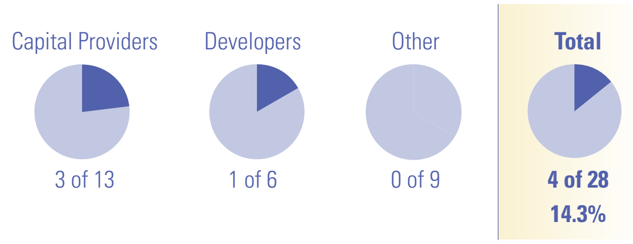
Unfavorable contract terms (such termination and outclauses, or guarantees on performance or equipment) may have negative impacts on the cost or overall availability of project financing.



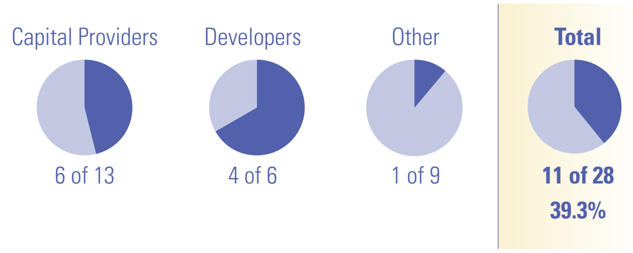
Standardized contract terms may be an effective mechanism for reducing transaction costs and leveling the playing field.



On the other hand, some interviewees felt that imposed standardization of contracts would remove the flexibility needed to find better ways to structure deals as the market develops.



Providing market conditions are appropriate (ability to hedge, strong REC market, etc), a long-term PPA is not a requirement to close a deal.



These graphics indicate the proportion of respondents in each category that made statements supporting a given theme. Note that many respondents did not comment directly on each theme and that the lack of comment does not necessarily indicate an opposing point of view."

THE POWER PURCHASE AGREEMENT (PPA) is a form of energy offtake because it is a contract that sets the price and duration of power purchases by an offtaker (usually a utility) from an energy generator. This agreement is the result of a negotiation to allocate risks and benefits in the production and delivery of energy. Some of the factors that affect this agreement include: timeliness of construction, equipment supply, operations and maintenance, type of technology, resource availability, policy incentive stability, and grid access. The four primary elements of the PPA are the length of the contract, the product being sold (i.e. electrons and renewable energy certificates), the quantity to be purchased, and the price that will be paid (Global Energy Concepts 2004).

Generally, this agreement is negotiated after tax equity capital has been committed to a project. Up to 70 percent of the revenue from a renewable power project comes from energy sales, which means the structure of the PPA can significantly impact the cost and quantity of term financing. One capital provider emphasized the need to examine every negotiated contract, including the PPA, REC sales agreements, engineering forms, and any other offtake agreement. The aggregated data is then "memorialized in the pro-forma" and the amount of capital offered is decided accordingly.

Because the terms of the offtake are so important, mandating standardized PPA contracts has been debated as a possible way to reduce project risks and transaction costs, yet it remains highly contentious. While contract negotiations do not involve policy, offtake agreements are influenced by federal and state incentives. On one hand, policy risks can raise the price of energy delivered in the PPA, and various policy out-clauses can ultimately result in contract failure. On the other, mandates and incentives in some regions have also created robust enough markets to accommodate alternative offtake structures such as merchant contracts and synthetic PPAs.

Standardized Contracts

According to the Global Energy Concepts Wind Power Toolkit, some countries and regional jurisdictions have adopted standardized PPAs. The publication states that almost all of the wind power developed in California in the 1980s was contracted using a standard set of PPA terms adopted by the California Public Utilities Commission. We prompted several interviewees about standardization, but of those who commented, only five suggested it would be a useful policy.

The primary reason for standardizing PPAs would be to reduce contract negotiation costs. By reducing these costs, policymakers can achieve two goals: 1) making projects, now considered marginally profitable, more attractive; and 2) giving smaller developers a chance to enter the market with smaller projects. Proponents of standardization stressed the need to have greater consistency in the contracting process. One respondent who favored standardization pointed out that every power agreement is already based on standard documents and every interest rate hedge is based on a standard agreement from the International Swaps and Derivatives Association. Three respondents—all developers—suggested that the Edison Electric Institute (EEI) would be a good home for such an industry standard, like a wind annex to the current EEI standard contract.

Six of our respondents were skeptical, and three of those were clearly opposed to the idea. The most frequently cited reason was that PPA contracts are necessarily customized due to a number of factors, including differences in laws, grid access, and market conditions. Some respondents held very strong opinions, suggesting that the financial community was sophisticated enough and that contract flexibility allowed for increased market efficiency. One developer exclaimed, "If you can't afford a good lawyer to sort out the terms, you shouldn't be building a wind project." Still another financier pointed out that the transaction costs associated with contract negotiations are trivial and essentially end up being "a rounding error."

Contract Failure

Certain policy attributes can result in contracts that burden the developer with too much risk to be financed. The direct effects such as PTC uncertainty, overly-aggressive RPS mandates, and poorly designed REC markets can all result in an increase in the negotiated offtake price. In addition, indirect policy effects, like out-clauses and guarantees, were mentioned 11 times, 10 of which were unfavorable. Policy requirements cited as causes for contract renegotiation or termination included state taxes, employment rates, and changes in law or adverse legislation. These "off-ramps" make capital providers wary: two suggested they affect the financing, a third stated he would be unwilling to accept them, and another mentioned that the exclusion of them was actually more important overall than contract pricing.

Equipment supply shortages, associated by interviewees with the uncertain renewal cycle of the PTC, create PPA contract failures. The dampening effect the PTC has on retail electricity rates would be reversed if the credit expired resulting in higher-priced, or altogether cancelled, renewable energy PPA contracts. In addition, overly aggressive and complicated RPS policies can lead to contract failures, along with associated requests for proposal (RFP). Aggressive Public Utility Commissions (PUCs), and key parties gaming the system, can also contribute to contract failure. Examples were mentioned of developers in California signing undeliverable contracts.

Support for Alternative Structures

Typically, long-term contracts have been viewed as essential to adequately mitigate project risks. This view is changing, as design and understanding of policy improves, resulting in greater market liquidity. Given this opportunity, and the complexities of the PPA, many developers are opting for alternative agreements, such as merchant offtake and synthetic PPAs. Fundamentally, these structures are made possible through the design of the RPS, the liquidity of the REC market, and other market factors that make hedging possible. Eleven of our respondents suggested a willingness to enter an alternative agreement, whereas only one mentioned that a PPA with a minimum length of 10 years was a project requirement.

Policy changes that facilitate greater use of alternative offtake structures may be an effective way to encourage more investment in renewable power projects. Ensuring the appropriate conditions in every market will take time, but improving the liquidity for REC trading and/or developing new mechanisms for hedging project risks would be steps in the right direction. These changes would give projects more flexibility to avoid long-term PPAs, providing investors with greater exposure to potential upsides and, ultimately, attracting additional capital to the REPG sector.

Conclusions and Next Steps

- Policy Recommendations
- Next Steps

THE OVERALL INTENT OF THIS RESEARCH WAS TO ASSIST in the relatively recent dialogue that is occurring between renewable energy capital providers and the policymaking community. In recent years, policy in the U.S. has been very effective in encouraging REPG uptake as capacity has increased dramatically. With up to 66 percent of project values tied to policies, the financial community is responding as the number of capital providers has also increased significantly. However, political preferences and a lack of market expertise create cumbersome, unpredictable, and complicated policy, thus adding to the risk of developing renewable energy projects.

Not one respondent said current policies are not effective in increasing renewable energy development. The important question, however, is whether current mechanisms and incentives are generating the most financially efficient, long-term development of renewable energy production. Pressing issues include how to replicate the success of the wind industry with policy incentives, how to stabilize growth within the wind industry to remove long-term policy support needs, and how to ensure that the national energy portfolio reflects public interests regarding energy security, climate change, and emissions control.

Our interview data suggested that federal systems are preferred for energy infrastructure and REPG incentives. Broadening these markets will require increased policy stability and transparency, which will lower cross-state barriers to trade and development, increase the number of market participants, and improve market liquidity, a key indicator of financial efficiency. To ensure results, coordination of these resources should seek simplicity. Incentives with frequent modifications and changes do not increase market confidence or reduce the cost of development, and an overly-aggressive or weak mandate with unclear covenants and penalties is not useful.

In addition to U.S. policies, 12 respondents noted the effectiveness of the mainly European feed-in tariff (FIT) policy at increasing REPG uptake.[9] It is possible that feed-in tariffs work well in Europe because the renewable resource (mainly wind) is not abundant. It was mentioned that German wind farms have an average capacity of 20 percent, whereas U.S. wind farms average well over 30 percent. Consequently, seven respondents felt that a FIT-like policy, while attractive from a project-financing standpoint, would be an inefficient use of capital in the United States. While the transparency of the FIT creates direct cost feedback for energy consumers, interviewees speculated that it would be at odds with policy preferences in the U.S. and might eventually erode public support for renewable energy policy. One capital provider even suggested that the FIT needed to be phased out in Europe to instill some market discipline and drive down costs.

Our interview data suggested that federal systems are preferred for energy infrastructure and REPG incentives

Policy Recommendations

Our interviews and secondary research provided us with data to support several policy recommendations which we think will improve market stability and/or transparency independently of any national renewable energy strategy:

1. **PTC/ITC extensions that reflect the capital cycle for both REPG development and underlying suppliers (~3-5 years).** Extensions will help jumpstart capital investment and give capital providers less reason to discount potential PTC revenues, allowing developers to pursue more debt leverage for their projects, making existing projects more profitable and previously unprofitable projects viable. The PTC/ITC should be reinstated with a similar regard to time for equipment manufacturing and the commercialization of new technologies to further lower the cost of renewable energy.

2. **Elimination of passive loss rules under the PTC**. The passive loss rules of the PTC should be stripped, in order to broaden the pool of tax equity investors. This would enable investors to securitize the tax credits for sale into the secondary market, thereby reducing the need for the primary owner to shoulder the entire tax credit. This could be modeled after the "master limited partnership" (MLP) structure already in place for the oil and gas industry.

3. **Planning for eventual sunsetting of the PTC.** The credit per kWh should be clearly scheduled to decrease after several years, in order to spur market movement towards independent sustainability.

4. **An effective national RPS that drives utilities to the bargaining table to increase renewable development**. This policy should not supplant state RPSs, but rather provide a lowest common denominator on which states could add additional requirements. This would instill confidence in capital providers that markets will remain robust. The policy would need to be simple, clear, and achievable (~15%).[10] Strict penalties, above $40/MWh, would ensure policy effectiveness. Consideration would need to be made, potentially through acceptance of carbon-neutral technologies like nuclear, or through some managed wealth transfer allocation, for states without rich renewable resources, predominantly in the Southeast.

5. **A national REC trading market**. Given the fragmentation of existing REC markets, a national market would increase liquidity and stabilize values, likely in concert with a national RPS. A national REC registry would be created, presumably by FERC or the EPA. The same organization should also be a registry for any future national carbon credits, to ensure that there will be no double counting.

6. **More federal action to accelerate transmission expansion**. Replicate the ERCOT Competitive Renewable Energy Zones (CREZ) policy at the national level, with FERC identifying areas of rich renewable resources (>1000 MW), procuring monetary commitments from renewable energy developers to build projects in that corridor and then compelling transmission owners to build out the lines. Also, pass legislation which gives FERC the ability to fine utilities in the U.S. (outside of ERCOT) who do not transition grid operation and pricing to a Regional Transmission Organization (RTO). Establish education and incentives to help RTOs move toward real-time and efficient pricing, and push for uniform procedures and requirements across the many RTOs.
7. **A state, regional, or national loan guarantee fund**. REPG capital providers have cancelled projects in the pre-feasibility and feasibility stages for numerous reasons related to policy, including transmission bottlenecks, uncertain state procurement cycles, and stalled project applications. To avoid potentially contentious public-private partnerships, and these potential cancellations, benefit fund dollars should be committed as last resort financing guarantees. A guarantee fund might generally resemble the Federal Deposit Insurance Corporation (FDIC), which promotes market certainty and confidence by insuring bank deposits up to the first $100,000 at risk per individual.

In addition, we contend that for the purposes of REPG uptake, U.S. policy decisions must address issues of stability and transparency, and significant barriers to creating a federal energy system. These decisions will now be made in an environment in which climate change is on the minds of many Americans, and corporate endorsement of a national carbon taxing or trading policy is reaching critical mass.

We realize the advent of a carbon tax or a cap-and-trade policy in the U.S. would affect all of the renewable policies we researched and analyzed for this paper. While we had many discussions about the possible implications for existing renewable energy policies, we do not have quantitative analysis or interview data to determine what may happen to RECs, the PTC, or a national RPS in that environment. Nor do we have any clear data on what could happen with transmission, which is consistent with the general ambiguity we found in our interviews and research on the topic. The conclusion that transmission should fall under federal oversight was rife with exceptions and contradictions when we discussed existing state energy policies. However, a carbon policy is unique because it has not been governed by any municipalities, states, or regions (though California is trying). Consequently, a drive to harmonize national infrastructure might be easier if there were a federal carbon policy. Any harmonization of different regulatory regimes would likely lower barriers to trade (think RECs and carbon credits) and make it easier to employ national quotas (RPS or a federal carbon cap) on emissions from energy production facilities. This national market would have more participants, resulting in higher market liquidity and lower aggregate development costs.

Any harmonization of different regulatory regimes would likely lower barriers to trade and make it easier to employ national quotas on emissions from energy production facilities. This national market would have more participants, resulting in higher market liquidity and lower aggregate development costs.

Next Steps

As with any research project, while we worked hard to be as comprehensive as possible, we have ended up with more questions than answers. The following list represents a few of the questions that we think would help further this body of research and continue to build communication between renewable energy capital providers and policymakers.

1. We were often told about the transaction costs associated with various aspects of REPG development that are tied to policy. We think a clearer understanding of these costs would help provide greater insight as to the effect on ratepayers. Our research was exploratory and collected data through the eyes of capital providers, developers, and others who are integral to the process. We suggest a case study analysis to look beyond such qualitative perspectives to quantify the costs based on historical REPG development. This list of attributes could include monetization, PPA negotiation, closing costs, permitting, and grid access.

2. Given that there may need to be a transition between RECs and carbon credits, we are interested in a study of possible transition scenarios. In addition, we would like to hear more about what an acceptable transition would be for the financial community.

3. While the research presented in this report focused on the interaction between policy and project finance, we are mindful that existing renewable energy policies also have important trickle-down effects on financing for early-stage development and commercialization of newer

REPG technologies. Action on the above recommendations would certainly have a positive impact on the cost of capital for projects, but further study is needed to understand precisely how various policy changes would affect the dynamics of technology development in the sector.

4. Additional analysis is needed to understand the financing structures that create the lowest combined cost of capital given cash equity, tax equity, various classes of debt, and potentially other financing vehicles for REPG projects. What is the optimal structure? What are the unique risks and associated concerns for each type of capital provider? This information may be useful to policymakers focused on evolving policy to further support the efficiency of REPG project financing.

5. It was suggested that a long-term extension of the PTC could cause utilities to begin developing their own projects, rather than buying from IPPs. How would this affect the pricing and availability of development financing, and/or the participation of current investors in the sector? What would be the impact on capacity and aggregate system costs for renewable energy development?

6. A few respondents told us about the ways some developers try to game the current project development system. Some respondents believed there are potentially significant opportunities for developers to create riskless profits (arbitrage), while others disagreed, saying REPG financing is fair and efficient. It would be interesting to explore the various financing structures of REPG deals to see if there are opportunities for developers to theoretically make riskless profits.

Endnotes

1. Sources for policy viewpoints included the Congressional Budget Office (CBO), the Energy Information Administration (EIA), Congressional testimony, and the Joint Committee on Taxation (see References for full citations).
2. An important ratio for a debt provider to determine its risk appetite is the Debt-Service Cover Ratio (DSCR); the ratio is calculated as (annual operating income/annual debt-service obligation) and is used as a debt lending constraint.
3. IRS Form 8835 explains that the PTC can be reduced by up to one half in any given year in which a developer utilizes other federal, state, or local tax-advantaged benefits; using the Modified Accelerated Cost Recovery System (IRS Form 4562) reduces PTC appetite, but is not expressly detailed in the reduction.
4. Overall wind costs have risen by 40% in the past 5 years due to U.S. dollar weakness and rising input costs.
5. Consequently, the debt-service coverage ratio (DSCR) assumption changes, resulting in less debt capital or a higher interest rate, and the cost of capital rises for all projects.
6. In fact, Over over 200 MW of undeveloped wind projects were sold in 2006 due to lack of turbines; . Shiloh Wind was sold to PPM Energy and Wolverine Creek Wind was bought by Invenergy.
7. For wind, this can range between 80 and 95 percent of total project costs.
8. Horizon Wind is reportedly buying 800+ MW worth of wind turbines in anticipation of projects being developed after December 31, 2007, when the most recent PTC expires (EER 2006).
9. A feed-in tariff policy requires energy suppliers to pay a specified rate, set by the government, for any power produced by eligible private generators.
10. A 15 percent national RPS is cited in research by Palmer and Burtraw (2005) as the most cost effective single federal policy, with greater public benefits if placed in a carbon-taxed environment.

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Appendix A: Acronyms and Abbreviations

AWEA	American Wind Energy Association
BASE	Basel Agency for Sustainable Energy
DSCR	Debt-Service Coverage Ratio
EIA	Energy Information Administration
EPAct	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRR	Internal Rate of Return
ISO	Independent System Operator
ITC	Investment Tax Credit
KW	Kilowatts
kWh	Kilowatt-Hours
LFG	Landfill Gas
LSE	Load-Serving Entities
MACRS	Modified Accelerated Cost-Recovery System
MISO	Midwest Independent Transmission System Operator
MW	Megawatts
MWh	Megawatt-hours
NERC	North American Electric Reliability Council
NYSERDA	New York State Energy Research and Development Authority
OASIS	Open-Access Same-Time Information System
PBF	Public Benefit Fund
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PUC	Public Utilities Commission
PURPA	Public Utility Regulatory Policy Act of 1978
REC	Renewable Energy Certificate
REPG	Renewable Electric Power Generation
RFF	Resources for the Future
RFP	Request for Proposal
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SBC	Systems Benefit Charge
SEFI	Sustainable Energy Finance Initiative
WREGIS	Western Renewable Energy Generation Information System

Appendix B: Glossary of Terms

Accelerated Depreciation – A form of accounting or tax depreciation which allows for greater deductions in the earlier years of the life of an asset.

American Wind Energy Association (AWEA) – A U.S. trade association representing wind power project developers, equipment suppliers, services providers, parts manufacturers, utilities, researchers, and others involved in the wind industry.

Baseload Power Plant – A power generator that provides a steady rate of power regardless of demand from the grid.

Bid-Ask Spread – The price differential between the highest price (bid) that a buyer is willing to pay for an asset and the lowest price (ask) for which a seller is willing to sell it.

Bilateral Contract – An agreement negotiated between two separate parties, wherein each exchanges promises concerning the purchase and sale of energy products and services.

Biomass – Organic non-fossil material of biological origin used as a fuel energy resource, such as wood, agricultural waste.

California Energy Commission (CEC) – The State of California's primary energy policy and planning agency.

Capacity Factor – The ratio of a power plant's average electrical production to its rated capability.

Cap-and-Trade Legislation – Policy which caps the level of emissions, allocates or auctions pollution permits to that level, and then allows the actors to trade those permits.

Capital Cost – The cost of field development, construction, and the equipment required for the generation of electricity.

Cash Equity – Equity derived from the direct contribution of cash to a project.

Credit Spread – The price spread between treasury and non-treasury securities, which differ only in quality rating.

Debentures – Debt which is not secured by assets or other types of collateral, but rather by the general creditworthiness of the issuer.

Debt Service – Cash needed to repay interest and principal on a debt over a given period.

Debt-Service Coverage Ratio (DSCR) – The amount of cash flow available to meet required payments for annual interest and principal on debt.

Economies of Scale – The increase in production efficiency as the amount of production escalates, typically lowering the average cost per unit given certain fixed costs.

Electric Reliability Council of Texas (ERCOT) – One of the 10 regional reliability councils that make up the North American Electric Reliability Council (NERC). ERCOT's mandate as an independent system operator (ISO) is to ensure the operation of the electric throughout much of Texas.

Energy Information Administration (EIA) – An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and performs analytical and modeling analyses of energy issues.

Energy Policy Act 2005 (EPAct) – A statute passed in 2005 to address energy security issues, as well as to provide incentives to increase energy production and supplies.

Escape Clauses or Valves – Provisions within policies or contracts which allow for the participants to avoid penalties or responsibilities given certain circumstances.

Externalities – Benefits or costs, generated as a byproduct of an economic activity, that do not accrue to the parties involved in the activity.

Federal Energy Regulatory Commission (FERC) – The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Flexible Compliance Mechanisms – Policy instruments which allow participants flexibility in achieving mandated goals.

Geothermal Energy – Energy extracted from hot water or steam from geothermal reservoirs in the Earth's crust that drives steam turbines to produce electricity.

Independent Power Producer (IPP) – Any entity that owns or operates an electricity-generating facility that is not included in an electric utility's rate base.

Independent System Operator (ISO) – A neutral, independent, and typically non-profit organization that administers the operation and use of the transmission system.

Internal Rate of Return (IRR) – When applied to all cash flows associated with a project, this discount rate creates a net present value equal to zero. Typically, this allows investors to make capital budgeting decisions.

Investment Tax Credit for Solar (ITC) – Under the Energy Tax Incentives Act of 2005, this provision allows purchasers of solar energy property and hybrid solar lighting systems to credit their taxes by 30 percent of the capital cost.

Investor-Owned Utility (IOU) – A privately owned, publicly traded electric utility that is regulated and authorized to achieve an allowed rate of return.

Landfill Gas – Gas that is generated by decomposition of organic material at landfill disposal sites. Landfill gas is approximately 50 percent methane.

Lender of Last Resort – An institution willing to extend credit when no one else will, usually a government agency.

Leverage – The use of debt to increase the potential return of an investment or finance acquisition of assets.

Liquidity – The ability of an asset or security to be bought or sold in the market without affecting its price, usually through high levels of trading.

Load Serving Entity (LSE) – The utility company that provides the distribution, customer, and energy services for natural gas and electricity.

Load Shape – A method of describing peak load demand and the relationship of power supplied to the time of occurrence.

Modified Accelerated Cost Recovery System (MACRS) – The method of accelerated depreciation of an asset as part of the U.S. Income Tax Code.

Merchant Facility – A generating facility that recovers revenue based on sales on an open power market rather than regulated rate-of-return pricing.

Mezzanine Financing – A hybrid of debt and equity, giving the lender the rights to convert to ownership if the borrower defaults on the loans.

Midwest Independent Transmission System Operator (MISO) – Founded in 1996, MISO is the FERC-regulated RTO that serves the Midwest, including parts of Illinois, Wisconsin, Michigan, Indiana, Minnesota, North Dakota, South Dakota, Ohio, and Iowa.

Monetization – The process of converting something into currency.

New England Power Pool (NEPOOL) – A regional consortium of 98 utilities which coordinate, monitor, and direct the operations of major generation and transmission facilities in New England.

North American Electric Reliability Council (NERC) – Formed in 1968 by the electric utility industry transmission to ensure reliability and adequacy, the NERC council encompasses essentially all the power regions of the contiguous United States, Canada, and Mexico.

Not In My Back Yard (NIMBY) – This term illustrates the concept of landowners and stakeholders who refuse to allow development in their own area, presumably because it is viewed as unsightly or detrimental to the community.

Non-Recourse Debt – An arrangement in which the borrower takes on loans backed by collateral (typically physical property) but is not personally liable for any of the payments.

New York State Energy Research and Development Authority (NYSERDA) – Established in 1975, this public-benefit corporation funds research into energy supply and efficiency, as well as into energy-related environmental issues.

Open-Access Same-Time Information System (OASIS) – An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously, as required and defined in FERC Order 889.

Off-Balance-Sheet Financing – A method of financing which allows sizable capital expenditures to be kept off of a company's balance sheet.

Passive Loss Rules – Rules which restrict passive investors–those who do not materially participate in the investment–from taking advantage of the associated tax credits.

PJM Interconnection – The RTO that coordinates the planning and operation of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Power Purchase Agreement (PPA) – A bilateral contract entered into by an independent power producer and an electric utility, which specifies terms and conditions of the electricity sales.

Production Tax Credit (PTC) – An inflation-adjusted 1.5 cents per kilowatt-hour payment for electricity produced using qualifying renewable energy sources.

Project Financing – A common method to finance the construction of independent power facilities, whereby the developer usually pledges the value of the plant and a portion of the expected revenues as collateral to secure financing from lenders.

Public Benefit Fund (PBF) – Programs coordinated typically at the state level to support renewable energy resources, energy efficiency initiatives, and low-income support programs.

Public Utility Commission (PUC) – Generic term for a state agency holding regulatory power over energy pricing and issues related thereto.

Public Utility Regulatory Policy Act of 1978 (PURPA) – Federal legislation which, among other provisions, requires utilities to buy electric power from private qualifying facilities at an avoided cost rate.

Regional Transmission Organization (RTO) – These organizations control and manage transmission of electricity over a particular region of the country and are regulated by FERC.

Renewable Energy – Energy derived from regenerative resources or from resources which cannot be depleted. Renewable resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave, and tidal action technologies.

Renewable Energy Certificate (REC) or Green Tag – A market mechanism, often utilized in conjunction with a portfolio standard, that represents the environmental benefits associated with generating electricity from renewable energy sources.

Renewable Portfolio Standard (RPS) – A mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

Request for Proposal (RFP) – A document distributed by a customer seeking offerings and bids from suppliers of services.

Restructured Markets – Electricity markets in which the various utility functions of vertically integrated electric utilities have been separated into individually operated and owned entities.

Solar Energy – The radiant energy of the sun which can be converted into other forms of energy, such as heat or electricity.

Solar Thermal – A system that actively concentrates thermal energy from the sun by means of solar collector panels.

Spot Market – Any venue in which purchases and sales of a commodity such as electricity are made by a large number of buyers and sellers, with new transactions being made continuously or at very frequent intervals.

Syndicated Loan – A sizable loan wherein a team of capital providers works in tandem to provide funds for a borrower, typically with one capital provider acting as an arranger.

Synthetic PPA – A term that refers to an arrangement wherein the power generator is able to create a price floor for its electricity, even though the electricity is sold on the spot market. This is done by the purchase of natural gas hedges. In this way, the generator can simulate a power purchase agreement.

System Benefit Charge (SBC) – A surcharge levied to electricity consumers, which is used to create state managed funds (Public Benefit Funds) dedicated to promoting and supporting state renewable energy and energy efficiency goals.

Tax Appetite – Refers to the ability of a company to fully realize government tax incentives, which is dependent upon the magnitude of the taxable income of a company.

Tax Equity – An equity investment in a tax-advantaged vehicle (such as a REPG project) whose returns primarily consist of tax credits.

Transmission – In the context of energy, transmission refers to the bulk transfer of electrical power, commonly from the power plant to the substation.

Watt (Electric) – Refers to power produced as electricity, and is commonly used to indicate the power production potential for an electricity-generating asset, such as a wind turbine.

Western Renewable Energy Generation Information System (WREGIS) – A regional renewable energy tracking system covering 11 western states that supports regional tracking and substantiation of renewable energy generation.

Appendix C: Informal Interview Guide

(1) Rate the importance of each element of a renewable energy project listed below, relative to your willingness to provide (ability to secure) financing.

- A rating of 5 indicates a minimum requirement for financing. A rating of 1 indicates little to no impact on financial terms.
- Blank spaces are provided for adding other factors not already listed.

Project Components	Importance (circle one)	Does Policy Address?	Should Policy Address?
a) Validated Renewable Resource	1 2 3 4 5	Y N	Y N
b) Established Equipment Commitments	1 2 3 4 5	Y N	Y N
c) Acquired Necessary Permits	1 2 3 4 5	Y N	Y N
d) Established EPC Wrap	1 2 3 4 5	Y N	Y N
e) Signed PPA	1 2 3 4 5	Y N	Y N
f) Assured Creditworthiness of Offtaker	1 2 3 4 5	Y N	Y N
g) Creditworthiness of O&M Contractor	1 2 3 4 5	Y N	Y N
h) Negotiated Grid Access	1 2 3 4 5	Y N	Y N
i) Established O&M Contracts	1 2 3 4 5	Y N	Y N
j) Ability to trade RECs	1 2 3 4 5	Y N	Y N
k) Ability to utilize PTC/ITC	1 2 3 4 5	Y N	Y N
l) Ability to utilize MACRS	1 2 3 4 5	Y N	Y N
m) Secured Equity Investors	1 2 3 4 5	Y N	Y N
n) Secured Debt Investors	1 2 3 4 5	Y N	Y N
o)	1 2 3 4 5	Y N	Y N
p)	1 2 3 4 5	Y N	Y N

(2) What is your view of the overall effectiveness of state and federal policy in mitigating the financial risks of renewable energy projects? Are critical investment risks associated with renewable energy being addressed by the appropriate level of government?

(3) Please describe one or more typical revenue structures for the RE projects you are involved in. What does a typical project's revenue composition look like? Do you prefer certain revenue streams/structures over others?

(4) How would policies geared toward setting/controlling the price of renewable energy (e.g., feed-in tariff—if it was available to you) affect your willingness to provide (ability to secure) more or cheaper capital?

Federal Policy

(5) What is your view on the effectiveness of the PTC/ITC as it is currently structured? Are there added transaction and/or capital costs associated with utilization of the PTC/ITC?

(6) Are there investment risks related to the use of the Modified Accelerated Cost-Recovery System (MACRS)? Would you favor any changes to the treatment of renewable energy equipment under MACRS?

State Policy

(7) Various states take different approaches to subsidizing and/or capping excess rate costs for renewable energy (rate pass-through, Public Benefit Funds, rate premiums, etc). Do you prefer certain approaches over others? Are you able to provide (secure) more or cheaper capital under one approach versus another?

a. How important are the size and term of available state subsidies?

(8) Many states utilize Public Benefit Funds (PBFs) to promote renewable energy development. How is your willingness to provide (ability to secure) more or cheaper capital affected if the project relies on PBF funding to defray certain development costs?

a. What are your chief concerns with the utilization of PBF funding for RE project development?

b. Three of the most common methods for PBFs utilization include: 1) provide debt/equity to a RE project; 2) provide direct subsidy to RE projects (e.g., rebates, state PTC); and 3) create REC price stability. Do you have a preferred method?

(9) What aspects of a power purchase agreement (PPA) or energy service agreement (ESA)—such as contract term, options for term extension, fixed or variable supply amount, purchase price, purchase price for excess, etc—are most important relative to the pricing and availability of capital?

a. How do variations in specific contract terms affect your willingness to provide (ability to secure) financing?

b. Do you or would you prefer standard contract terms?

(10) Requests for Proposals (RFPs) vary substantially by state and RPS policy in the U.S. How well do various RFPs address the interests of capital providers versus other stakeholders? How does the contracting process affect your willingness to provide (ability to secure) financing?

(11) Are RECs a viable substitute for long-term PPAs? Are there other policy mechanisms that provide similar revenue security to long-term PPAs?

(12) How does a project's ability to utilize unbundled RECs as a revenue stream affect your willingness to provide (ability to secure) more or cheaper capital?

(13) Do you favor particular policy approaches for improving the value, stability and liquidity of RECs? What is the optimal geographic scope for a REC market—state, regional or national?

(14) At what point do transmission risks begin to hinder renewable energy projects from coming on-line? How and when do transmission risks and/or policies affect your willingness to provide (ability to secure) financing?

(15) How do transmission costs factor into your willingness to provide (ability to secure) financing?

(16) How do you imagine policy can address the question of who bears the costs transmission risk?

(17) Would you prefer a national regulatory authority (such as FERC) to assume control of all siting and transmission expansion the way it does for gas pipelines, or would you prefer regional/state agencies to maintain control?

(18) Please explain more about other critical risks/issues that you noted in question 1, or that have occurred to you during the course of the survey.

a. Why is this issue important?
b. How does this issue affect your willingness to provide (ability to secure) financing?
c. What is the current and/or potential impact of policy on this issue?

(19) In your opinion, what are the most important priorities in the development of policy to encourage the flow of capital to new renewable energy projects?

a. How should current policies be changed?
b. What new policies would you like to see?

Appendix D: Sample PTC Monetization Structure "Partnership Flip"

There are two primary reasons for a developer to monetize the tax credits allowed under Section 45 of the IRS tax code. First, the developer often does not have the tax appetite to adequately take advantage of the credit independently. Second, monetizing the credit up front can provide a much needed source of capital for developing a renewable power project (Duffy 2005, 5).

There are several structures that can allow for monetization, including "partnership flip," "service contract," and "sale and leaseback" (this structure is not available for wind projects). Among these options, one of the most common for wind facilities is the partnership flip. This structure has several variations that can include non-tax equity investors and debt capital in addition to the developer and tax equity investor. This appendix offers an overview of the partnership flip structure in order to provide a sense of the complexity of monetization. Note that the concepts presented are very general, as most monetization structures are highly customized to fit the circumstances of individual projects.

Under Section 45, there are limitations to transferring credits, primarily as a function of eligibility. Currently, only owners of a given power facility can take advantage of the tax credit (one exception is the result of a special rule, which allows open-loop biomass power plant operators or lessees to claim the credits) (Martin 2007, 20). Therefore, it is necessary to establish a limited liability company (LLC) or a joint venture that results in the partners (developer and equity investors) each being classified as owners. The partners are then allocated credits in proportion to their ownership. In addition, there are other limiting factors according to Section 45, including (Zaelke 2005, 20):

Subject to all tax equity investors:

1. Tax credits from the PTC can be diminished by other state, federal, and local incentives that help pay the capital cost of the facility.
2. The PTC will begin to phase out as the power price exceeds 10.7 cents per kWh.
3. The PTC only can be used to offset the alternative minimum tax for the first four years.

Not subject to large institutional investors and corporations who are supplying the tax equity in partnership flip deals:

1. Passive loss rules require that the taxpayer must be actively engaged in the business or must be using the credit only to offset other passive investments.
2. At-risk rules that restrict individuals and smaller companies in claiming full depreciation from a project, limiting the amount to the amount of equity the investor has invested.

The LLC is generally structured with the developer as the managing member and the tax equity investor as a passive participant with limited voting rights, but with 90 to 100 percent of the economic returns from the entity. In return, the tax investor will provide the majority of the equity contribution to finance the construction of the facility. For the first 10 years, the tax equity investor will usually draw the tax credits and revenue in proportion to its economic ownership. Effectively, the LLC is treated as a partnership to take advantages of the tax benefits, though according to IRS regulations, the partners must share the PTCs in the same ratio as taxable income. By the end of this cycle, but not before the tax equity investor has reached a predetermined rate of return, the equity proportions will switch between the tax investor and the developer, hence the term "flip." At this point, the interest of the tax investor usually drops to five percent (Martin 2007, 9).

To provide the developer, who is also commonly the managing member in charge of day-to-day operation of the facility, with cash during the period of minimal equity, an upfront development fee and/or ongoing management contract is often part of the agreement. Many times, after the flip has occurred, the developer has the option to buy the tax investor's remaining interest at the current fair-market value (Zaelke 2005, 31).

Risk allocation between the tax equity investor and developer is negotiated when developing the operating agreement for the LLC as well as any separate purchase or equity commitment agreements. If the forecasts made by the developer during these negotiations fail to materialize, the investor will have a claim against the developer, the damages from which are usually capped. The equity investor accepts the risk that the deal will deliver the tax credits. In addition to damages, the equity investor can delay the flip until the target return is reached.

There are several variations to this structure. First, leverage can be added to the initial capital. Upon completion of the project, construction lenders expect to be repaid. However, there is occasionally some level of debt remaining on the project from a "term" lender. Any term financing is then usually serviced over the same period as the PTC, so when the equity flips, the developer owns the facility debt-free. Non-tax equity investors also may have invested during the development phase of the project. In this case, cash is initially paid to this investor to cover the amount of the original investment, while returns are earned over the same period as the tax equity investor.

In addition to, or in lieu of, an upfront payment, the tax equity investor also can make quarterly equity payments on an ongoing basis. The developer can borrow against these payments like a stream of revenue, used to securitize the debt, effectively monetizing the future tax credits. This structure is commonly referred to as "pay-as-you-go." Whereas in acquisition deals the investor makes payments to the developer to buy the project, tax investors in new projects generally make a capital contribution to the LLC to repay the construction debt. The pay-as-you-go structure is typically a way for the tax investor to spread risk by not providing the entirety of the project's equity capital upfront (Duffy 2005, 18).

The sophistication inherent in these structures often results in significant legal and accounting fees. Thus flips and other monetization structures may not allow for smaller projects to effectively take advantage of the incentive. To overcome this barrier, small developers may elect to combine their projects into a single entity to pool tax credits for a single tax investor. Even so, there are currently only about a dozen large institutional investors supplying tax equity to REPG projects and often they do not want to spend time with small deals (Duffy 2005, 22).

PTC syndication has allowed for investors such as banks and insurance companies to participate in the renewable power sector, in addition to traditional energy and project finance investors. The result has been greater transfer of PTC value to the developer. In addition, the fact that the structure allows for the developer to remain in control makes it attractive to developers.

Appendix E: State RPS Comparison Table

Table E-1
State RPS Comparison Table

State	Standard	Enacted/ Revised	Applied To	Administration	Penalties	Set-Asides/Multipliers	Credit Trading
Arizona	15% by 2025	2001/2006	Utilities	Arizona Corporation Commission (ACC)	Discretion of ACC	30% of req from distributed generation	Yes
California	20% by 2010, goal of 33% by 2020	2002/2005	IOUs (ESPs and CCAs later)	California Energy Commission (CEC), California Public Utilities Commission (CPUC)	Discretion of CPUC	None	Yes (WREGIS)
Colorado	10% by 2015	2004	Utilities with 40,000+ customers	Colorado Public Utilities Commission (CPUC)	Discretion of CPUC	4% of load from solar, 1.25x in-state generation	Yes (WREGIS)
Connecticut	10% by 2010	1998/2006	Utilities	Connecticut Dept. of Public Utilities (DPUC)	$0.055/kWh	7% of load from Class I renewables, 3% from Class I or II	Yes (NEPOOL)
Delaware	10% by 2019	2005	Retail Suppliers	Delaware Public Service Commission (PSC)	$25-50/MWh	3x for solar, 1.5x for wind sited in Delaware	Yes (GATS)
District of Columbia	11% by 2022	2005	Utilities	DC Public Service Commission (PSC)	$0.025/kWh "tier one", $0.01/kWh "tier two", $0.30/kWh solar	0.4% of load from solar; allowance for "tier two" resources, but 100% "tier one" beyond 2022; 1.1x for wind, solar, LFG or wastewater-methane before 2010	Yes (GATS)
Hawaii	20% by 2020	2004	Utilities	Hawaii Public Utilities Commission (PUC)	None	None	No
Illinois	8% by 2013 (voluntary)	2005	Utilities	Illinois Commerce Commission (ICC)	None	75% from wind	No
Iowa	105 MW	1983	IOUs	Iowa Utilities Board (IUB)	None	None	No
Maine	30% by 2000	1999/2003	Competitive Electricity Providers	Maine Public Utilities Commission (PUC)	License revocations and fines, discretion of PUC	None	Yes (NEPOOL)
Maryland	7.5% by 2019	2004	Electricity Suppliers	Maryland Public Service Commission (PSC)	$0.02/kWh for Tier 1, $0.015/kWh for Tier 2	2x for solar, 1.1x for wind or methane through 2008	Yes
Massachusetts	4% by 2009, then 1% more per year	1997/2002	Retail Suppliers	Massachusetts Division of Energy Resources (DOER)	$55/MWh	None	Yes (NEPOOL)
Minnesota	25% by 2025, Xcel 30% by 2020	1997/2007	Utilities	Minnesota Public Utilities Commission (PUC)	Fin. penalties not to exceed est. cost of compliance	25% wind, 5% other technologies for Xcel; None for other utilities	Yes
Montana	15% by 2015	2005	IOUs	Montana Public Service Commission (PSC)	$10/MWh	75 MW from community renewable energy projects	Yes

Table 4-1 continued
State RPS Compliance Penalties

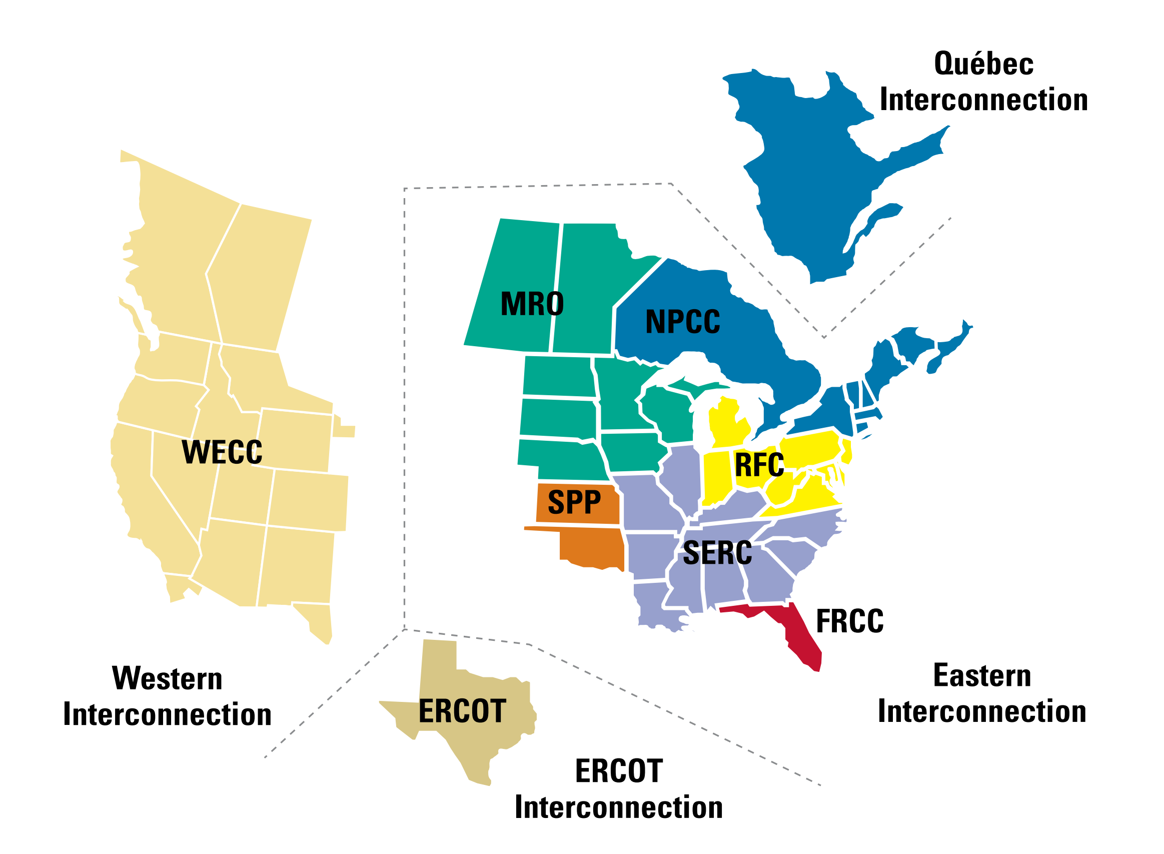
State	Standard	Enacted/ Revised	Applied To	Administration	Penalties	Set-Asides/Multipliers	Credit Trading
Nevada	20% by 2015	1997/2006	IOUs	Public Utilities Commission of Nevada (PUCN)	Discretion of PUC	5% of load from solar; 2.4x for solar + 1.05x for distributed generation	Yes
New Jersey	22.5% by 2021	2001/2006	Retail Suppliers	New Jersey Board of Public Utilities (BPU)	Fin. penalties greater than market cost of RECs or new generation	20% Class I (2.12% solar), 2.5% Class I or II	Yes (GATS)
New Mexico	20% by 2020	2002/2007	IOUs	New Mexico Public Regulation Commission (PRC) New York	None 25% by 2013	2x for biomass, geothermal, LFG or fuel cells; 3x for solar 2004	Yes (WREGIS) IOUs
New York Public Service	None	1% of goal from voluntary		No Commission (PSC), NY State Energy Research and Development Authority (NYSERDA)		market; 2% of incremental RPS req (7.71%) set-aside for Customer-Sited Tier	
Pennsylvania	18% by 2020	2004	Utilities	Pennsylvania Public Utility Commission (PUC)	$45/MWh; 200% of PV REC value for solar	8% Tier I, 10% Tier II; 0.5% of load from solar	Yes (GATS)
Rhode Island	16% by 2020	2004	Retail Suppliers	Rhode Island Public Utilities Commission (PUC)	$50/MWh	None	Yes (NEPOOL)
Texas	5,880 MW by 2015	1999/2005	Competitive Retailers	Public Utility Commission of Texas (PUCT)	Lesser of $50/MWh or 200% of REC value	500 MW from sources other than wind	Yes
Vermont	Load growth by 2012 (voluntary; mandatory after 2013 if goals not met)	2005	Retail Suppliers	Vermont Public Service Board (PSB)	None	None	Yes
Washington	15% by 2020	2006	Utilities with 25,000+ customers	Dept. of Community, Trade, and Economic Development; Washington State Utilities and Transportation Commission	$50/MWh	2x for distributed generation	Yes
Wisconsin	10% by 2015	1999	Utilities	Wisconsin Public Service Commission (PSC)	$5,000 to $500,000	None	Yes

Source: Database of State Incentives for Renewable Energy (DSIRE)

Appendix F: Transmission Overview

The U.S. transmission system today is divided into three interconnected regions: the Eastern Connection, the Western Systems Coordinating Council Interconnection, and the Electric Reliability Council of Texas (ERCOT). A patchwork of federal, regional, and state regulatory organizations oversees the transmission system.

Figure F-1
NERC Interconnections



Source: North American Electric Reliability Corporation

The Federal Energy Regulatory Commission (FERC) controls the pricing and terms of interstate transmission. FERC's powers were expanded in the 1990s to allow transmission access to third-party producers through price and cost controls, and to require utilities to institute electronic tracking of their transmission through the Open Access Same-time Information System (OASIS). In 1999, FERC Order 2000 further strengthened FERC's position, commanding transmission owners to hand over operation to Regional Transmission Organizations, further allowing third-party access to the national grid. Order 2000 has not been fully implemented, however, as many states are resisting the change.

At the regional level, the North American Electric Reliability Corporation (NERC) administers regional "reliability organizations" to ensure grid reliability by managing installed capacity, scheduling energy flows, evaluating new transmission projects, and planning contingencies for unforeseen events. FERC Orders 888 and 889 pushed utilities to create Independent System Operators (ISOs), later formalized as Regional Transmission Organizations (RTOs) by Order 2000, in California, Texas, New York, New England, Pennsylvania/New Jersey/Maryland, and the Midwest. The ISO/RTOs are responsible for managing and operating the nation's transmission lines, though they do not own the lines themselves (Joskow 2004, 1).

State Public Utility Commissions (PUCs) traditionally regulate in-state distribution reliability and electricity rates. The PUCs also control new transmission line siting. For instance, the Public Utility Commission of Texas (PUCT) administers the Competitive Renewable Energy Zones (CREZ) process, which approves siting and funding for transmission expansion into areas which will typically provide more than 1,000 MW of new renewable energy capacity.

The balkanization of U.S. energy policy means the country generally lacks a national strategy for electric power transmission. This creates added risks for large-scale renewable energy projects, which generally require new transmission to become grid-tied resources. Some have called for a consolidation of siting authority at the national level, similar to the regulation of natural gas pipelines, which is wholly controlled by FERC. The Energy Policy Act of 2005 gave FERC so-called "backstop" authority (FERC can step in if and when the relevant state authority does not act for a full year) to site new transmission lines in DOE-designated National Interest Electric Transmission Corridors (NIETCs). The first corridors were designated in mid-2006, and it is still too early to assess whether the change will significantly affect the siting of new lines for renewable energy projects.

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