Strategies to Scale-Up U.S. Renewable Energy Investment

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A COLLABORATIVE REPORT BY:

American Council On Renewable Energy (ACORE)

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* Former ACORE staff

AUTHORS

ACORE: Todd Foley, Heidi VanGenderen[1], Jan Siler[2], Jeramy Shays, Lesley Hunter, Evan Schmitt[3], Joshua Gardner[4]
CalCEF: Dan Adler and Bernard Lam
Climate Policy Initiative: Uday Varadarajan, Brendan Pierpont, and Kath Rowley (Modeling)

Special thanks to the Energy Foundation for its support of this project.

Published by:

American Council On Renewable Energy (ACORE)
1600 K St. NW, Suite 650
Washington, DC 20006
202.393.0001

Questions or Comments: hunter@acore.org

[1] A contributor while employed at ACORE, Ms. VanGenderen left ACORE in May 2012.
[2] A contributor while employed at ACORE, Ms. Siler left ACORE in October 2012.
[3] A contributor while employed at ACORE, Mr. Schmitt left ACORE in December 2011.
[4] A contributor while employed at ACORE, Mr. Gardner left ACORE in May 2013.

TABLE OF CONTENTS

I. Executive Summary

This report on United States renewable energy finance policy is the result of extensive research, outreach, and analysis conducted over the last three years. It identifies federal and state government policies that could promote efficient private sector capital formation and investment in the renewable energy industry.

State and federal policies have worked: renewable investment has grown rapidly: Private sector investment in the U.S. renewable energy sector has grown significantly in recent years due in large part to manufacturing and technology cost reductions, state market demand policies, and federal tax policies. The combination of these factors has contributed to impressive growth for the renewable energy industry, and this scale in turn has further reduced technology costs. Over the past five years, more than 35% of all new power generation has come from renewable energy resources, including more than 49% of all new power generation in 2012 – surpassing all other energy sources, including natural gas.[5] Since 2004, more than $300 billion has been invested in the U.S. clean energy market (PREF), including $35.6 billion[6] in 2012, with a corresponding significant increase in jobs. Renewable energy generation also enhances energy security by harnessing clean domestic resources to produce more of the energy we consume here in the United States.

This success was enabled by the alignment of federal, state, and private efforts: The success of policies to date reflects the application of two important American concepts core to the progress of our nation: the role of Federalism to align our national and state governments behind a common objective, and the importance of public-private partnerships to leverage public and private resources. At the state-level, renewable energy portfolio standards (RPS) and policies like electricity market design have established the conditions through which renewable energy technologies have grown in recent years. The production and investment tax credits (PTC and ITC) have been the main federal policies complementing these important market structures.

Further scale up requires cost-effective policies that can drive low-cost private investment: To further scale up the industry and to maintain a leadership role in the global clean energy economy, substantially greater levels of lower-cost capital investment will be needed. Our analysis suggests several principles to guide the formulation of a strategy to achieve this goal, based on these important recommendations:

Build on the success of current policy efforts
The first step to achieving this goal is to continue to build upon the success of existing policy efforts. Reinvigorated state RPS policies and long-term extension of tax credits remain important. Additional policies, including Master Limited Partnerships (MLPs) and Real Estate Investment Trusts (REITs), successful in motivating capital formation in other sectors, should be made applicable to renewable energy investment. These policies can serve to encourage even greater levels of lower cost capital investment. This combination of complementary, yet evolving federal and state policy remains essential to the continued scale up of private low-cost capital investment in the sector.

Provide a level playing field for renewable technologies
Existing federal and state policies have also helped to level the playing field between renewable and conventional resources. However, robust policy support is still necessary to

[5] FERC, "Office of Energy Projects Energy Infrastructure Update For December 2012," January 2013
[6] "Who's Winning the Clean Energy Race," Pew Charitable Trusts, April 17, 2013, 20.

maintain market momentum. A myriad of federal and state fiscal, regulatory and other policies serve to support conventional energy development. Some forms of renewable energy are cost competitive with traditional sources of energy generation now and will be even more so within the next few years. Other renewable energy and emerging technologies, crucial to the clean energy transition, will require support for a longer period of time. During this transitional period when further scale-up is pivotal to the reduction of costs, it is crucial that policy continue to enable this growth. To be clear, this level of policy support is nothing that has not previously been provided to the energy technologies of the past[7] or is currently provided to incumbent, non-renewable energy industries.

Improve the effectiveness and cost-effectiveness of policies to drive low-cost investment
The challenge, in an era of fiscal constraint at all levels of government, is for the renewable energy industry to design and advocate for the most effective and efficient financial incentives in order to achieve rapid scale, leveraging the most value possible. The optimal form of this private finance strategy will result in both the acceleration of capital commitments to the sector, and development of broadly-owned investment assets that provide economic opportunity to a significant portion of the American population.

Reform regulatory and market design to encourage renewable investment
In the power sector, regulatory reforms and improvements in electricity market design, such as greater use of utility rate-basing renewable energy investment and the use of value-based (vs. lowest price) procurement, can also play an important role in encouraging greater investment of private capital in renewable energy. Technology cost reduction and market attributes, such as scalability and relatively quick deployment timelines, provide important incentives for utilities to invest in and deploy renewable energy generation. Power market rules play a central role in governing electricity infrastructure investment decisions. Reforms to align them with renewable energy investment are important to encourage such investment.

Many of these policy techniques are developed and deployed at the state-level. Therefore, a key supposition in this analysis is that state-level policy design for RPS markets will be crucial for industry success.

Renewable energy generation is an increasingly important part of our nation’s energy security and economic growth. A mix of federal and state policy, coupled with electricity market reforms, is key to driving sufficient private capital formation and investment. Properly designed policies can succeed in leveraging existing and new sources of capital and investor pools. However, it is critical that decision-makers continue with the policies that are currently in place, while they explore new policies and regulations. This policy certainty will ensure continued market momentum, while serving as a bridge to a future of far more private sector investment in renewable energy.

[7] “60 Years of Energy Incentives: Analysis of Federal Expenditures for Energy Development,” The Nuclear Energy Institute, October 2011, 10.

II. Purpose of the Report: Problem Statement and Key Questions

Private sector investment in the U.S. renewable energy sector has grown significantly in recent years due in large part to state market demand policies and federal tax credits, including the production tax credit (PTC), investment tax credit (ITC), and the 1603 Treasury Grant.[8] To further scale up the industry and to maintain a leadership role in the global clean energy economy, substantially more dollars will need to be invested in renewable energy. An effective policy framework is essential to ensure the private capital investment needed is available to achieve continued growth of renewable energy deployment.

The challenge is, that while sufficient private capital exists to support accelerated renewable energy growth, current policies are not efficiently mobilizing this capital. This is the result of two main factors. First, the primary federal incentives, the PTC and ITC, are currently structured in a manner that attracts a limited pool of investors. These policies have faced expiration and required periodic extension, sending a mixed signal to the market and investors. Often, only the largest and most sophisticated firms are in a position to take advantage of these credits. Second, the recent financial crisis and weak economic recovery has reduced the amount of available tax equity and shrunk the limited investor pool, further inhibiting the ability of the private sector to take advantage of these important financial incentives.

While Congress enacted the 1603 Treasury Grant to address the lack of tax equity in 2009, it was allowed to expire at the end of 2011. In this era of fiscal retrenchment, it is incumbent upon the renewable energy industry to design and advocate for federal policies that utilize each government dollar to foster the maximum amount of private investment, as well as policies that draw new sources and forms of capital into the renewable energy sector.

The over-arching challenge going forward is to identify the most effective and efficient state and federal government policies in the form of incentives and regulations to promote private sector capital formation and investment in the renewable energy sector. In other words:

- How can policies optimize the existing state-driven market demand and prepare for a functioning national program in order to foster private sector capital formation?
- How can government incentives be utilized in the most efficient way possible, so each government dollar spent leverages the maximum amount of private sector capital formation and investment in renewable energy?
- What are regulatory reforms that will enable more, low-cost capital to be invested in renewable energy?

[8] U.S. Partnership for Renewable Energy Finance, "Renewable Energy Finance and Market Overview," March 2013, 2.

III. Preview: Characteristics of a Model Solution

- State renewable energy policy should be designed to incorporate best practices in order to be most attractive to private capital. In addition, federal policy in the form of incentives and regulatory reform should be coordinated with, and build upon, the state policies that are driving demand for renewable energy in order to attract the maximum amount of private sector investment.

- Policy design must ensure that every federal dollar spent mobilizes the maximum amount of private sector investment and renewable energy development at the lowest cost. These policies should optimize current financial incentives and could include, but are not limited to, technical risk insurance, securitization, loan guarantees, tax credits, grants, guaranteed contracts, and other enhancements.

- Federal policy changes need to unlock new, lower-cost sources of capital, as well as broadly owned capital formation strategies. This can include the utilization of ratepayer funds through policies such as feed-in tariffs. In addition, regulation should be reformed in order to allow for the creation of broad-based public ownership frameworks for retail investors. This would effectuate an "ownership society" participating in, and supporting the expansion and adoption of, renewable energy in the United States. Financing techniques of interest include MLPs, REITs, green bonds, investments via publicly owned utilities, and others.

IV. Status of Renewable Energy Deployment in the United States: State Renewable Portfolio Standards and Energy Market Frameworks

Renewable energy deployment in the U.S. is driven by three macro-level policy forces: state-level RPSs and other programs; actions by state and regional operators of the electricity grid, into which RPS energy is sold or dispatched; and federal incentives, in the form of public finance, land use, and transmission access. To date, these forces are not sufficiently coordinated.

In the following discussion, elements from state RPS design and grid control area policy are synthesized to present best practices that facilitate renewable energy development, with a particular emphasis on leveraging private sector financing. The concluding section describes infrastructure development under these state-level RPS programs, projects the degree of demand for renewable energy over the planning horizon of these programs, and suggests best-practice strategies to increase that demand in a financeable, cost-effective manner.[9]

The narrative below summarizes the characteristics of RPS policies in the U.S. and the impact of those characteristics on the financeability of renewable energy projects. General descriptions of control area activities, in the form of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), are then provided, followed by analysis of policies associated with RTOs and ISOs on the procurement function, i.e. the process whereby RPS-obligated entities purchase renewable electricity.[10] With an understanding of the regulatory environment, this survey then examines these trends from the perspective of the renewable energy developer, with the aim of identifying key factors that influence the financing of renewable energy assets.

A. State-Level RPS Policy Best Practices

A properly designed RPS can provide a stable, long-term market demand signal that will help motivate private sector financing of renewable energy projects. Over the last several decades, states have led the way in U.S. renewable energy development, primarily through the enactment of RPS programs, which are complemented by other important federal, state, and local policies.

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[9] This section draws from the companion piece "Ramping up Renewables: Leveraging State RPS Programs amid Uncertain Federal Support," U.S. Partnership for Renewable Energy Finance, 2012.
[10] Although not every transaction will be related to the wholesale RTO or ISO markets, for instance bilateral contracts, how the transaction fits into an overall portfolio that reflects the market is important.

An RPS that requires electricity retailers to provide a minimum percentage or quantity of their electricity supplies from renewable energy sources sends an important market signal by setting a demand target. Several elements of state-level RPS mechanisms work together to effectively motivate capital investment, including:

Long-Term Market Signal: The design of an RPS should include specific, realistic and long-term objectives that require increasing amounts of renewable energy generation over the baseline case of business-as-usual. Targets should be stable, ramp up steadily over time, and not be subject to sudden or uncertain shifts. Uncertainty about future changes to, or elimination of, binding targets will slow market development and limit investments in renewable energy projects. Predictable, stable market demand policy reduces regulatory risk and creates an investment climate that will drive planning, long-term contracting, and financing.

The state-by-state regulatory patchwork can negatively impact renewable energy investment decisions as it subjects utilities to different regulatory regimes and is in contrast to the regional nature of renewable energy resources. Long-term regional planning can help optimize renewable energy resources and transmission siting that often cut across state lines. A predictable, stable market that decreases risk for investors necessarily requires long-term credibility in renewable energy policy. This stabilizing effect also lowers the cost of capital for developers, producing cheaper power and reducing the need for public incentives over time.

Long-Term Contracting with Credit-Worthy Counter-Party: An RPS should encourage long-term contracting by utilities. Long-term power purchase agreements (PPAs), generally for 10 to 30 years, can help create market security sought by project developers and their financiers. Renewable portfolio standard implementation experience shows that programs have been the most successful when developers have been able to secure long-term contracts with credit-worthy counter-parties. States with such contracting requirements include: California (10+ years), Colorado (20+ years), Connecticut (100 MW for 10+ years), Iowa (own project or "sign long-term contract"), Maryland (15+ years for solar only), Montana (10+ years), Nevada (10+ years), North Carolina ("sufficient length" for solar), and Pennsylvania ("good faith effort," including "seeking…long-term contracts").

While less optimal than long-term contracting, states have pursued other measures to support project financing. Similar to a long-term PPA, a long-term Renewable Energy Credit (REC) based policy can similarly be successful in spurring renewable energy development. Through its complex securitization process, New Jersey has pursued a number of actions to support the use of tradable RECs to achieve RPS objectives.[11] In states and regions where short-term trade in RECs dominates over long-term contracting, RPS policies appear to be a more costly and less certain way of achieving renewable energy objectives. Where long-term contracts – whether PPAs or RECs – are available or required, RPS policies have largely been successful.[12]

The second necessary condition is contracting with a credit-worthy counter-party. In project financing, project debt will be rated largely on the basis of the off-taker's credit rating. Therefore, in addition to a long-term PPA, renewable energy project developers also must find an off-taker that is a credit-worthy counter-party. In the Western United States, credit

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[11] Database for State Incentives for Renewables and Incentives, "New Jersey – Renewable Portfolio Standard," http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R

[12] John Farrell, "CLEAN v SRECS - Finding the More Cost-Effective Solar Policy," Institute for Local Self-Reliance, October 2011. Short-term REC trading used in conjunction with long-term PPAs can also be successful, especially where the RECs have the ability to be swapped for lower-priced RECs (such as in government installations and swapped for cheaper national RECs), thereby creating value through a secondary revenue stream in addition to the PPA revenue.

ratings range from BBB- (Edison International) to A (San Diego Gas & Electric).[13] This is representative of the U.S. electric utility sector as a whole, where 62% of utilities have a BBB rating.[14]

This is in contrast to the overall credit condition of U.S. corporations across all industries and sectors, where the estimated median rating is closer to a BB- and B (non-investment grade).[15] Assuming the utility sector's credit profile remains relatively healthy, contracting with credit-worthy counter-parties should not be a concern for project developers. However, if there is an inability for utilities to balance the high capital spending projected in the near future with certainty in rate recovery, credit-worthiness may suffer. This tension highlights the need for policy-makers to consider utility credit ratings as a priority matter in enabling renewable energy project development.

Supplemental Policies to Long-Term Contracting: Aside from contracting, the most effective RPS policies also address other deployment risks in order to provide greater market certainty. Long-term contracting provides a major step in financial certainty and once that is in place, the next areas of risk then shift to consideration of project development and operational risk. In particular, interconnection risk and transparency in operations have simple solutions when paired with long-term contracting policy solutions. With regard to interconnection risk, mitigation in the form of a guaranteed interconnection if the PPA meets the standardized requirements of the long-term contracting program would be helpful. With respect to transparency in operations, making the contract price known and certain, making the contract duration follow the long-term financing (typically 15-20 years), and operating a procurement system that is clear and easy to participate in (preferably a first-come, first-serve approach) are means to help the renewable developer achieve certainty in interconnection and operation, thereby reducing risk.[16]

Compliance Enforcement: An RPS should have strong compliance enforcement mechanisms to ensure targets are achieved. An Alternative Compliance Payment (ACP) is often used to support compliance with an RPS. An ACP effectively establishes a market ceiling for the price paid for renewable energy. If set below the cost of renewable energy, market participants would likely pay the ACP amount rather than invest in actual renewable energy production. This effect can be mitigated in the regulatory process by establishing different standards for rate recovery covering the utility's fixed and variable costs, i.e. providing greater certainty of cost recovery for energy procurement versus the ACP alternative.

The ACP level will also influence the kind of renewable energy developed. Renewable energy technologies are at different stages of development, serve varying market needs, and often are at different price points. Many states have established carve-outs or other mechanisms to develop a broader array of resources with ACPs set at points to move a particular market class (e.g. wind or solar) or segment (e.g. residential or commercial). In certain states, ACP payments are paid into a renewable energy fund that will facilitate capital deployment to renewable energy initiatives. To the extent the RPS has carve-outs for specific technologies, ACP policies should also direct capital to those specified technologies when ACP payments are triggered.[17] The effect of a wide variation in treatment by technologies is to funnel financing into proven technologies that are treated the same across state borders, mainly solar and wind.

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[13] Standard & Poor's as of April 17, 2013.
[14] Edison Electric Institute, Quarter 4 2012 Financial Updates – Credit Ratings: http://www.eei.org/whatwedo/dataanalysis/indusfinananalysis/pages/qtrlyfinancialupdates.aspx
[15] Standard & Poor's as of October 31, 2011.
[16] John Farrell, "CLEAN v SRECS - Finding the More Cost-Effective Solar Policy," Institute for Local Self-Reliance, October 2011.
[17] See New Hampshire recommendations on APC funds distribution: http://www.puc.nh.gov/Sustainable%20Energy/RPS/RPS%20Review%202011.pdf

Utility Cost Recovery: Utility confidence in securing cost recovery supports long-term contracting and project finance. Success in moving utilities to extend beyond their annual obligations and enter into long-term contracts with generators will depend on mitigation of perceived risks, such as through guaranteed cost recovery. Utilities must have confidence that their cooperation with requirements will not result in financial penalty or loss. Prudently incurred compliance costs by utilities should be recovered in electricity rates that are allocated fairly across all utility customers. This will ensure that the costs and benefits of development are spread and shared equitably.

In regulated markets, utilities generate revenues and earn returns through regulator-approved ownership and operation of generation and other assets. A utility's willingness to rate-base renewable energy investment encourages such investment because it generates a significant and predictable return. This also sends a strong signal to the market of regulatory confidence in this kind of investment. Today, utilities earn returns on assets owned and operated, and on sales of power generated. This discourages third party investment in customer-owned distributed generation that could reduce a utility's sales. Implementation of policies by regulators to encourage utility ownership of renewable energy assets would send a strong market signal to finance markets. In addition, decoupling the sale of electrons from allowed profits would sever the strong disincentive that currently exists for third party investment in customer-owned, distributed generation.

Finally, an emergent regulatory technique would provide incentives to utilities that enter into PPAs that involve priority technologies.[18] This is an important innovation that deserves greater scrutiny.

Other Policy Measures Impacting Project Finance: Other policy measures can encourage or facilitate project finance to meet RPS goals. Feed-in tariffs, which place a legal obligation on utilities to purchase electricity from renewable energy generators at a guaranteed rate for a determined length of time, are most effective in encouraging private finance. They are long-term contracts with a highly credit-worthy entity and a strong balance sheet and have driven relatively fast scale-up of renewable energy markets.

Feed-in tariffs have been implemented or are under consideration in a number of states in the United States. For example, California, pursuant to legislative and regulatory action, is implementing feed-in tariffs as part of the nation's most aggressive RPS, requiring 33% renewable power production by 2020. However, this does not suggest that the feed-in tariffs in California are a subsidy. Instead, the feed-in tariff in California is purely addressing the market need for a long-term contract at a fixed price, a price that is based on the wholesale market price referent or on biddable, reverse-auction price discovery.[19]

[18] See the discussion of the Centralia plant decommissioning in Washington State at page 12 below.
[19] See: http://www.cpuc.ca.gov/PUC/energy/Renewables/feedintariffssum.htm

In response to a request from the California Public Utilities Commission, in January 2011, FERC clarified how California and other states could implement feed-in tariffs, paving the way for broader state use of feed-in tariffs to achieve RPS and other important state policy goals.[20] FERC offered a proposal to employ a multi-tiered resource approach for determining avoided costs. It would set different levels of avoided costs and thus different avoided cost rate caps for different types of resources, and could comply with the Public Utility Regulatory Policies Act (PURPA) and FERC regulations.

If a feed-in tariff is pursued, a 2010 KEMA study identified best practices, which include: long-term contracting with price certainty for all revenues, tenure of 15-20 years, and account for feedstock risk (if applicable).[21] Identified best practices also include allowing for narrowly defined programs that can vary in price based on technology. Technology-based pricing is recommended as a way to help scale various generation technologies and is also designed to put pressure on manufacturers to lower cost of generation over time.[22] This approach is consistent with FERC guidance to employ a multi-tiered resource approach for determining avoided costs.

B. Electricity Market Design

The interplay between state policies and federal policies affects the financing for renewable energy. Specifically, state policies in the areas of RPS design, unbundling or deregulation of utility services, and the frameworks for procurement for all electricity (not just renewables) interact significantly with federal policies as manifested in the functions of RTO and ISO markets.

Market design at the RTO and ISO level also interacts with the level of retail choice available to consumers, which is a state-level policy decision. This interaction further complicates policy relationships by influencing the procurement role of the utility in the marketplace. The role of the utility as a credit-worthy counter-party, when the utility is potentially a buyer, is critically important in the financing of renewable energy projects. But a utility can also be a potential competitor, dependent on the utility's response to the policy environment.

RTOs and ISOs: RTOs and ISOs oversee transmission access, grid reliability, and manage the electric markets. There are four RTOs that operate on a regional basis: Midwest ISO (MISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and Southwest Power Pool (SPP). There are three ISOs that operate in all or almost all of a single state: California ISO (CAISO), New York ISO (NYISO), and Electric Reliability Council of Texas (ERCOT). Generally, these markets operate similarly in structure, containing bid-based spot markets in both a day-ahead and real-time market for energy and certain ancillary services[23]. These markets are FERC jurisdictional and cover the generation and transmission function, as distinguished from the distribution function, which is state jurisdictional.

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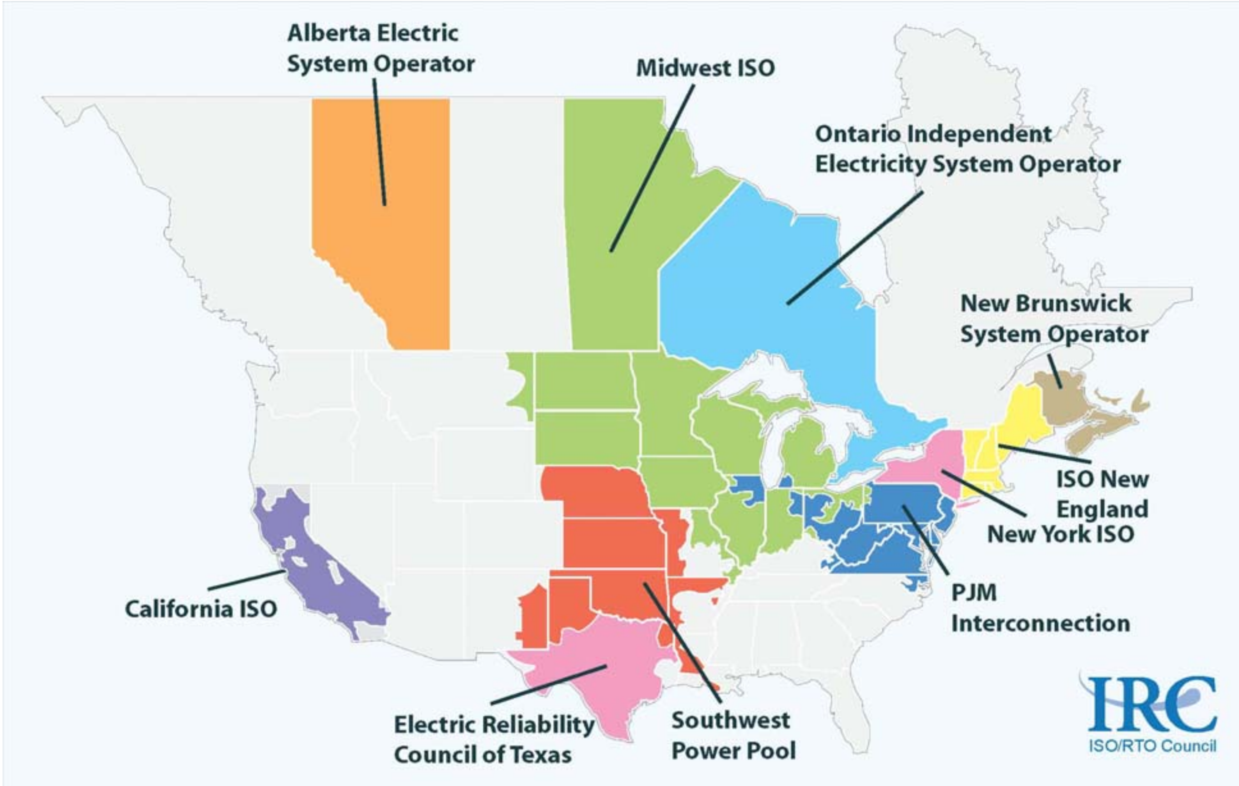
[20] Federal Energy Regulatory Commission, "FERC Clarifies California Feed-In Tariff Procedures," http://www.ferc.gov/media/news-releases/2010/2010-4/10-21-10-E-2.asp, October 21, 2010.

[21] Corfee, Karin et al. "Feed-in Tariff Designs for California: Implications for Project Finance, Competitive Renewable Energy Zones, and Data Requirements," CEC Publication Number CEC-300-2010-006, available at: http://www.energy.ca.gov/2010publications/CEC-300-2010-006/CEC-300-2010-006.PDF

[22] Staff Draft Report on Renewable Power in California: Status and Issues. CEC Publication Number. CEC-150-2011-002, available at: http://www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002.pdf

[23] Allison and Williams, the Effects of State Laws and Regulations on the Development of Renewable Sources of Electric Energy, December 2010 at 48.

RTO/ISO Regions



The FERC jurisdictional entities are charged with multiple missions, including meeting energy and policy goals, maintaining reliability, understanding ramping requirements, stabilizing generation fleet characteristics, managing costs, and accurately forecasting demand and supply. FERC also prioritizes the development of deep, competitive wholesale electricity markets.

In ISO-NE, the use of bundled or unbundled RECs, alternative compliance payments contributing into funds that encourage renewable development, and mandates segregated by specific technologies in "classes" or "tiers" are all common features. The industry typically contains restructured utilities that divested generation assets. Retail choice is common.

In PJM, there is less consistency. The definition of RPS-qualifying renewable technologies broadens. In West Virginia's Alternative Energy Standard, where there are no minimum requirements for renewable energy, advanced technologies (clean coal, carbon sequestration, or energy efficiency) qualify under its mandate. It is conceivable that carbon sources coupled with energy efficiency could fulfill the entire compliance requirement without any use of renewable energy sources. Some states deregulated (e.g. Pennsylvania) and other states maintain the traditional industry structure (e.g. West Virginia). In New Jersey, strong incentives and policy direction created a robust solar industry and corresponding SREC market.

Just like PJM, MISO contains a collection of states representing different mixes of deregulation and procurement regimes. Michigan and Illinois are deregulated with retail choice, while other states (e.g. Wisconsin) have not undertaken deregulation. States have different variations on renewables procurement, creating different incentives for different policy goals.

In the West, in-state certification regimes are used instead of regional REC markets and technologies are less likely to be segregated into classes or tiers. Oregon has deregulated and introduced retail choice. The remaining states have stopped deregulation or have maintained traditional market structures.

In the Mountain Region and Southeast, traditional vertically integrated utilities retain a significant portion of the generation market (~80-20 split) and although RECs are used for compliance there are usually preferences for in-state renewable generation built into the RPS programs.

RTO and ISO Market Design Implications for Renewable Energy Finance: The structure of the electricity market plays a substantial role in the price of electricity for retail end-users and the resultant power mix that is procured by utilities. The unit of analysis is the RTO and ISO wholesale generation market, where grid operators have control over the operation, planning, and functioning of the markets.

Though still in the early stage of FERC Order 1000 implementation, the general impression from the order and the general policy trajectory is that the transmission system will be more integrated in the future which may subsequently extend into how wholesale markets work.[24] Broader markets and a built out transmission grid will reduce obstacles to transmit electric energy over longer distances. This will level the playing field among generators and create a larger and more diverse pool of generation to purchase from, increasing competition and lowering the cost of renewable electricity.

Moreover, an expanded grid could also normalize fluctuations across a much larger system and reduce the costs associated with balancing the system. For example, the WECC West Wide Balancing Market is a means to aggregate the variability of generation and load over many balancing authorities, thereby reducing the total amount of required reserves. However, expanding the wholesale market and providing access to lower-cost electricity generation may have the inadvertent effect of disadvantaging renewable energy in commodity markets where electrons are not differentiated and dispatchability is highly valued.[25]

Therefore, in order for renewable energy to use wholesale generation markets as a source to bolster financing, renewable energy procurement must move beyond a strictly price driven framework. To facilitate capital formation for renewable energy, wholesale generation markets should attribute value beyond electricity as a commodity. Policy options include attributing value to the unique characteristics that renewables provide to the distribution and transmission grids, such as pricing reactive power and mitigating regulated pollutants and greenhouse gas emissions within wholesale generation markets. Or, inversely, capturing the costs of traditional pollutants and greenhouse gas emissions associated with all forms of generation in how the wholesale generation market operates. As with state-level best practices, if federal policy options at the wholesale generation market are explored, then long-term market signals and contracting should be the cornerstones**.**

C. RPS Program Design Interaction with Procurement Models

The RPS regime in each state establishes a procurement framework that transcends price-only competition. Common elements among state RPS programs are a percentage requirement, specified technologies or preferred characteristics of the renewable energy, and a cost-cap. These considerations all move state RPS procurement away from commodity-based price competition to procurement of a differentiated product, which serves to mitigate the wholesale market effects identified above.

[24] FERC Order 1000 can be found at http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp
[25] Allison and Williams at 66.

Traditional Industry Structure: States with a traditional, vertically-integrated industry structure are a rich opportunity for policies that drive the development of renewable energy. States can achieve quicker development through the regulatory apparatus by requiring utilities to build or buy renewable energy and by providing for cost-recovery of prudently acquired resources through retail rates. The implication for renewable energy financing is clear. So long as the regulatory regime is consistent in its promotion of renewable energy development, utilities or independent developers will step into the market to provide renewable energy generation.

Colorado's approach to procurement is instructive. Colorado specifies a minimum term of 20 years, fixed prices or price that varies by year, and provides explicit guidance to utilities on the procurement process. Specifying the parameters of key terms is helpful in driving down transaction costs in the negotiations process.

Another example of a state in a traditional industry structure accelerating the development of renewable energy through RPS and other policy designs is Texas. Texas is virtually a self-contained policy island with jurisdictional control over generation, transmission and distribution, but it is also one of the few states that has met or exceeded its renewable energy goals ahead of schedule. Texas implemented renewable energy zones, constructed transmission to access these renewable energy zones, and moved forward various policies providing financial backing for projects. All of these policies provided financial markets with certainty of where the regulatory regime was headed and complementary policies that facilitated investment into renewable energy projects.

States such as Washington and Wisconsin have made progress to re-align incentives by implementing debt equivalency rules and other policies. For example, Washington recently implemented a narrow policy that allowed the decommissioning of its Centralia coal plant. As part of the transition away from the Centralia plant, which represented about 10 percent of the power generated within the state, a deal was struck where certain PPAs used in the transitioning process could earn an equity return, thereby making the transition away from the coal-burning Centralia plant much more economically attractive for the utility.[26] This type of innovative policy, if applied to renewable energy that is used to transition away from traditional sources of electricity generation, can create new financial incentives to encourage utility support for renewable energy deployment.

In short, states that have a traditional electricity industry sector have the ability to remove obstacles to financing renewable energy through the introduction of innovative policies.

Deregulated Markets Without Retail Choice: States with a deregulated power markets have the ability to engage in integrated resource planning, while also benefitting from a competitive generation market, allowing a wide amount of latitude for RPS design.

These states may have the benefit of proscribing procurement policy that spurs renewable energy development while also taking advantage of deep wholesale markets. Many states allow the procurement of renewable energy to count towards RPS requirements if it is delivered into the RTO, ISO, or other organized market. In theory, the deep wholesale market for procurement allows several utilities to aggregate their demand for renewable energy and provide a consistent source of demand for renewable energy development. A renewable energy developer in a large wholesale market can then theoretically sell into multiple states with RPS requirements if they allow delivery into the market to count. Accordingly, financing for renewable energy projects should also be more favorable as demand is less of a risk.

[26] See Legislative Report at: http://apps.leg.wa.gov/documents/billdocs/2011-12/Pdf/Bill%20Reports/Senate%20Final/5769-S2.E%20SBR%20FBR%2011.pdf

The wholesale market's depth is primarily due to its interstate geographic reach, but the intended benefits of a deep market have the potential to be frustrated by RPS design. Interstate geographic reach should provide a broader opportunity for renewable energy projects to sell into various states, but many states have incentives and/or requirements for in-state production of renewable energy. For instance, Missouri is a member of two RTOs: the majority of the state is in MISO and some parts are in SPP.[27] Even though Missouri has theoretical access to two broad pools of wholesale generation, implying access to a very broad pool of renewable energy resources, the state's renewables policy provides for a clear preference for in-state renewables by awarding a 25% credit bonus for in-state resources. Therefore, even if a jurisdiction has an RPS mandate and is a member of a large wholesale market, the benefits of membership in the market can be diminished by the RPS policies that undercut the benefits of a broader market, such as providing in-state only incentives or specifying in-state requirements for renewables.

Deregulated Markets with Retail Choice: In theory, retail choice combined with a deep wholesale market promotes renewable energy development. The logic is that retail choice will provide the avenue for end-users to aggregate and contract with a renewable energy provider. These end-users can be aggregated across an RTO or ISO, and provide the financing support for renewable energy development.[28]

However, one important consideration in RPS design for restructured industries concerns the financial viability of procurement entities. Given the ability of customers to change providers, contracting with renewable developers is problematic as there exists some amount of risk regarding the off-takers' ability to buy electricity in a future of uncertain load service. One method to overcome this problem is the use of a centralized procurement administration.

In New Jersey, the PSE&G Solar 4 All™ program aimed to install 80 MW of solar power to the PSE&G electrical system, including utility power lines, by early 2013.
Image Credit: Petra Solar

New York and Illinois use centralized administrators to facilitate the purchase of renewable energy, instead of delegating that activity to the utilities. The New York State Energy Research and Development Authority (NYSERDA) is funded by an RPS surcharge collected from ratepayers and NYSERDA then pays the generator the production incentive. The benefits of using this structure include realization of economies of scale, solving of coordination and planning problems, and shifting of risk of noncompliance away from the utilities as NYSERDA is ultimately responsible for achieving the targets. However, there are trade-offs. By using a centralized procurement model, the benefits of a decentralized system are not captured, namely technology experimentation among the regulated utilities, geographic specificity and expertise in resource selection, and pain of penalty as incentive to comply.

[27] Missouri is not a restructured state, but is used here because it straddles two wholesale markets.
[28] Allison and Williams at 70.

The main purpose of using a centralized procurement agency, though, is to reduce the counter-party credit risk that some utilities may have. If a utility has imperfect credit, perhaps driven by uncertainty regarding load forecasts, then the off-take agreement is considered risky and the renewable energy generator will have difficulty financing the project. It is not clear if using this structure actually reduces the cost of capital for the parties involved. Since NYSERDA only pays for the production incentive, NYSERDA's credit-worthiness as a counter-party does not help renewable developers reduce the overall cost of capital of the transaction since the bulk of the purchase price will be in the commodity and therefore subject to production and/or technology risk. In addition, the commodity purchase by the utility is still subject to utility credit-worthiness.

A further analysis should be made to determine if the market results do, indeed, prove that counter-party credit risk is inhibiting contracting for renewable energy in restructured markets. If so, and if New York's model does in fact lower this risk, then either adoption of a central administrator or a separate RPS surcharge should be within the consideration set for states with utilities experiencing financial difficulties. Alternatively, a centralized procurement mechanism that provides a credit-worthy counter-party for the entire transaction can be used, instead of the NYSERDA model that extends its umbrella over just the production incentive.

D. Alternative Transaction Structures

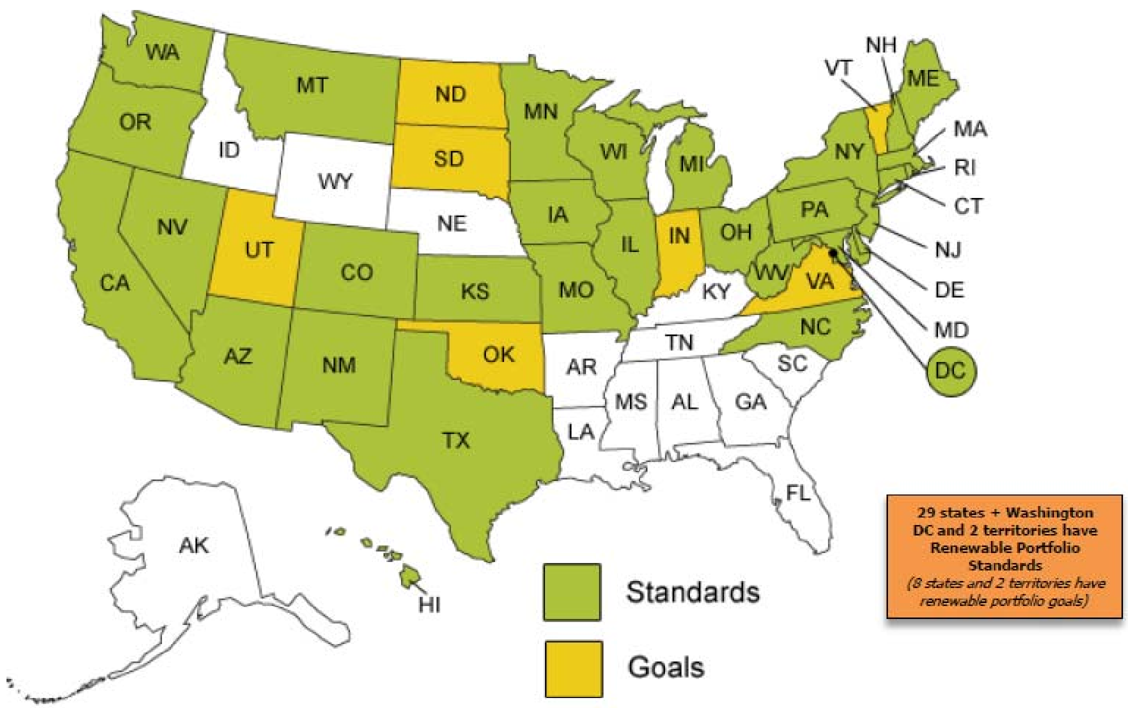
The Role of RECs: The development of Renewable energy credit (REC) markets can help the financing of renewable energy projects by providing alternative revenue streams. Renewable energy credit markets are subject to regional variations mainly associated with which RTO or ISO governs the region. Additionally, there are various forms of RECs, such as SRECs which are specifically generated by solar installations, which take into account a state's unique technology procurement preference. Given that the REC markets are not uniform, using a REC as an alternative revenue stream to enhance the bankability of a project may not be as beneficial as it would be under a regime where all RECs in the nation were the same and the finance community could easily forecast the value of that revenue stream. So long as there is a lack of a nation-wide common REC market, regional and state variations will need to evolve instruments that can help the financing of projects. The depth of the market and price signaling of a strong REC market would provide more certainty for financing purposes and drive down the cost of capital for projects by providing a reliable and bankable alternative revenue stream over a significant period of time.

Although REC or SREC markets can be designed to successfully achieve RPS objectives, they are more complex than long-term contracting. The pricing of RECs and SRECs, as well as their viability as an alternative revenue stream for project financing, depends on the procurement target, the quantity of generation with respect to that target, and any compliance or enforcement mechanism. Basic supply and demand principals also apply. Market expectations about sufficiency of supply impact REC and SREC pricing. The net result of the market experience is a level of volatility and unpredictability for this potential alternative revenue stream, especially when compared with a long-term

contracting policy.[29]

Pre-payment Mechanisms: RPS design can also be used to restructure the PPA concept by allowing the use of pre-payments. Renewable developers can benefit greatly from a revenue stream that is structured as pre-payments that provide upfront capital to help with initial capital costs followed by deeply discounted energy prices in later years.[30] This transaction structure follows the lumpy capital allocation that is inherent with renewable energy (i.e. high capital costs upfront followed by low capital and operations and maintenance costs after the plant is in service). Since the renewable project does not have the same type of input costs as other forms of generation, this payment structure could potentially be a good fit. In essence, the buyer then would become a source of cash for the developer instead of a revenue stream that is then borrowed against with interest accumulating against the principal. The payment stream structure can also be paired with a source of low-cost capital to further enhance the economics of the deal, such as municipal entities raising municipal bonds for the prepayment of electricity if the municipal entity is purchasing the electricity.[31] The ability to do this would likely require amendment to current federal income tax law.

States with Renewable Portfolio Standards (Mandatory) or Goals (Voluntary)



Source: Energy Information Administration (EIA)

E. Renewable Energy Infrastructure Development under Existing RPS Programs[32]

Twenty-nine states and the District of Columbia currently have RPS requirements. The duration of these programs varies, with some extending out as far as 2030. While the design details also vary to important degrees, in aggregate these programs create a steady

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[29] John Farrell, "CLEAN v SRECS - Finding the More Cost-Effective Solar Policy," Institute for Local Self-Reliance, October 2011
[30] See http://financere.nrel.gov/finance/content/prepay-good-way-solar
[31] See http://financere.nrel.gov/finance/content/prepay-good-way-solar
[32] This section draws from the companion piece "Ramping up Renewables: Leveraging State RPS Programs amid Uncertain Federal Support," U.S. Partnership for Renewable Energy Finance, 2012[32] U.S. Partnership for Renewable Energy Finance, *Ramping Up Renewables: Leveraging State RPS Programs Amid Uncertain Federal Support*, June 2012, 16.

demand signal to the domestic renewable energy industry. Analysis by the U.S. Partnership for Renewable Energy Finance (U.S. PREF) finds that meeting existing RPS targets through 2030 will require the addition of at least 3.25 GW of new renewable capacity per year.[33]

RPS procurement against these existing targets will increase the total contribution of renewable energy from 5.4% of U.S. generation in 2012 to 7.9% in 2020 and 9.6% in 2030.[34] However, it is important to note that these annual capacity increases are relatively small, and only a fraction of recent infrastructure development in the renewable energy industry. For example, in 2012 more than 16 GW of renewable energy power capacity was added in the U.S. As U.S. PREF notes, meeting RPS requirements through 2030 requires increasing generation of renewable electricity each year by just one-third as much as this generation increased in 2011 or one-quarter as much compared to new capacity in 2012.

Effectively, RPS market demand is poised to plateau while technology maturation, cost reduction, capital formation, and the policy imperative of increased clean energy production could support a much greater amount of growth. The plateau in RPS-driven demand for renewables suggests that policy support for investment will be stagnating just as America's need for the energy diversity and security benefits of renewable energy are increasing, to ensure that as more new gas plants are built power markers are not overly reliant on a single source of generation and exposed to volatile and uncertain long-term fossil fuel prices.

The challenge, therefore, is to cost-effectively stimulate increased demand through state-level RPS programs while encouraging supply of renewable energy through targeted, efficient economic incentives at the federal-level.

Demand via RPS programs can be increased through a combination of stronger targets applied to a greater percentage of the state's electric load, better procurement and planning processes (including crucial transmission investments), and the broadening of markets to enable access to the best renewable resource areas[35]. Best-practice procurement methods include Reverse-Auction Mechanisms (RAMs), Feed-in Tariffs that utilize the new FERC-authorized flexibility to establish avoided cost targets, careful utilization and securitization of REC trading that preserves the benefits of local renewable generation, and the enforcement of meaningful compliance penalties for RPS underperformance.[36]

U.S. PREF summarizes its review of state RPS programs in a manner that we endorse: "coordinating transitional, supply-focused federal tax incentives with longer-term, demand-focused (state) RPS programs can be explored as part of an integrated renewable energy strategy for America."[37]

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[33] *Id.,* 18.
[34] *Id,* 12.
[35] In transmission planning, Texas and California have pioneered the use of "Renewable Energy Zones" to identify and streamline access to the best renewable energy resources. California has recently paired this planning process with a financing solution (the Location Constrained Resource Interconnection facility) that allows prospective development of transmission, with costs recovered pro-rata from renewable generators as they come online.
[36] See US PREF "Ramping Up Renewables" for case studies of these examples and more detailed analysis of the concepts underlying them.
[37] U.S. Partnership for Renewable Energy Finance, *Ramping Up Renewables: Leveraging State RPS Programs Amid Uncertain Federal Support*, June 2012, 28.

V. INTERACTION OF FEDERAL FINANCIAL INCENTIVES WITH STATE-LEVEL RENEWABLE ENERGY DEPLOYMENT

A. Overview

The combination of federal and state policies to encourage and leverage private investment has yielded impressive U.S. market growth in renewable energy generation. State RPS requirements implemented by 29 states and the District of Columbia (seven other states have enacted RPS goals) have provided investors with important market demand targets. Federal production and investment tax credits with a cash grant option up to 30% of project cost (1603 Grant Program expired at the end of 2011) have motivated significant private sector financing in projects to meet and exceed state RPSs. The option of a cash grant in lieu of the tax credits expanded the pool of renewable energy investors beyond the limited number of tax equity providers and attracted significant amounts of private capital. The current balance of federal and state policies is an effective example of how federalism can encourage private sector capitalization and deployment of that capital to diversity the nation's energy mix with clean and abundant domestic renewable energy resources. This strategy has had a material impact on U.S. energy markets. In 2012, more than 49% of all new power generation came from renewable energy resources, more than any other source including natural gas.[38] In 2012, more than 13,000 MW of wind energy capacity was installed, more than was installed in any one year in the past.[39] The U.S. solar market doubled and also set a domestic record, installing 3,300 MWs in 2012.[40] This impressive growth, even more so at a time following the financial crisis and an overall stagnant economy, yielded a total investment of more than $44 billion in the U.S. renewable energy market, with an associated benefit of adding jobs.[41]

As has been the case with other energy industry sectors, as the renewable energy market has scaled, costs have come down. On a levelized-cost basis, wind and solar are now at or approaching cost competitiveness with new conventional sources of power (see chart below). United States wind power generation in 2012 was roughly 40% cheaper than in 2008. Installed costs for utility-scale solar generation dropped by 30% in 2012 alone.[42] A combination of technology improvement, market scale and stiff global and local competition has produced these expected achievements, but even faster than most had projected. A closer look shows that wind and solar costs have come down at a much faster rate than conventional sources and over a period of significant but much less scale. As the renewable energy market continues to scale, we can expect even more cost reduction.

These market developments directly correlate to policy. United States federal policy to encourage private sector renewable energy investment and development has been characterized as 'boom and bust' due to the intermittent nature of the policy incentives. The PTC has been enacted only for two-year periods, and sometimes retroactively after it has expired. Wind and solar investment and installation curves track this 'boom and bust' timeline exactly. With regard to solar, the market ramped up significantly when the ITC was expanded to 30% of project costs (from 10%) in 2007 and made available to home owners and utilities in addition to commercial operations.

[38] Office of Energy Projects, " Energy Infrastructure Update," December 2012.
[39] U.S. Partnership for Renewable Energy Finance, *Renewable Energy Finance and Market Overview*, March 2013, 6.
[40] *Id.*
[41] *Id*, 2.
[42] Solar Energy Industries Association and GTM Research (2013), "U.S. Solar Market Insight Report – 2012 Year in Review – Executive Summary"

Clean Energy Moves Toward Grid Parity: Energy Technology Scale vs. Energy Cost

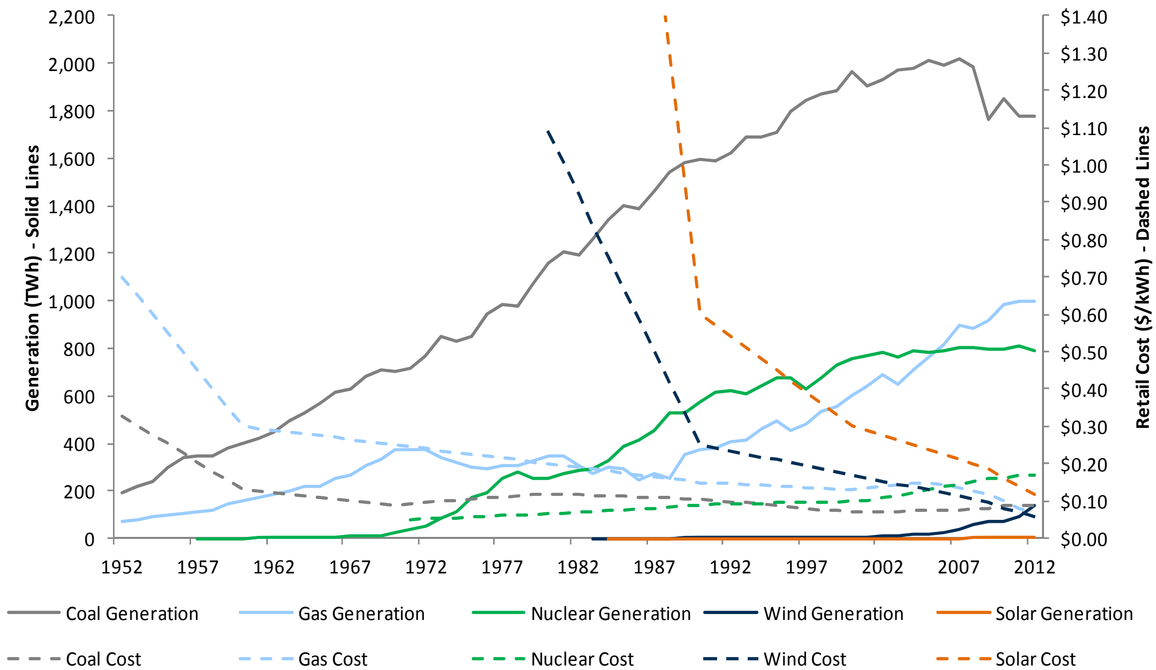


Image: Hudson Clean Energy Partners
Sources: EIA, MIT, American Energy Independence; NREL; Cooper; Hudson estimates.

The financial crisis and recession that hit the market at the end of 2008 exposed a limitation of the tax code as a source of renewable energy incentives. Taxable income dropped dramatically and the private tax equity market necessary to offset the tax credits shrank. This led to a corresponding drop in project investment and development. As part of the economic recovery package, Congress enacted the 1603 Cash Grant in Lieu of Tax Credits to fill this tax equity gap and to encourage private capitalization, with impressive results. During this period of financial crisis and recession, the market was able to monetize approximately $7 billion in tax credits and leverage an additional $24 billion in private investment, producing the significant renewable energy market growth in the 2007 to 2011 time frame.[43]

The renewable energy tax credits (PTC, ITC and 1603 Grant Program in lieu of tax credits) have played an important role in mobilizing the private capital and investment that has produced the recent impressive market growth and cost reduction. These incentives are essential for continued scale up and market momentum as they generate the competitive internal rates of return investors require. They also effectively address the particular capital intensive nature of renewable energy. Renewable energy systems typically have high upfront capital costs but zero fuel costs. The federal tax incentives help offset these relatively high upfront capital costs. They are also needed for renewables to compete on a level playing field against conventional energy resources which continue to benefit from over 100 years of permanent tax and other incentive support, and with utilities which receive indirect economic support by virtue of being allowed to operate under an avoided cost regulatory system.

While renewable energy is increasingly cost competitive and has experienced impressive growth rates in recent years, in 2012, non-hydroelectric renewable generation accounted for only 5.4% of total U.S. power generation. To scale up at the levels we have seen throughout the history of conventional power generation, a robust finance policy regime will

[43] U.S. Partnership for Renewable Energy Finance, *ITC Cash Grant Market Observations*, December 2011, 4.

be necessary. This new path could be a mix of the following measures applied to and at greater scale to motivate private sector capitalization and investment in renewable energy resources.

B. Production Tax Credit (PTC) and Investment Tax Credit (ITC)

The federal renewable electricity production tax credit (PTC) is a performance-based, per-kilowatt-hour tax credit for electricity generated by qualified energy resources. The PTC is paid out over a 10-year period at a rate of 2.3(cents)/kWh,[44] (1.5¢/kWh in 1993 dollars and indexed for inflation) for wind, geothermal and closed-loop biomass.[45] For other eligible resources, including open-loop biomass, municipal solid waste, landfill gas, qualified hydropower and marine & hydrokinetic energy, the rate is 1.1(cents)/kWh.

The PTC was created in the Energy Policy Act of 1992 and is found in Section 45 of the Internal Revenue Code. The PTC has been extended many times since being enacted and expired on four occasions. In 2009, it was extended by the American Recovery and Reinvestment Act (ARRA) through December 31, 2012 for wind and December 31, 2013 for all other technologies. On New Year's Day 2013, the PTC was again extended, but for only one year.[46] However, the legislative language was changed allowing projects to qualify when they commence construction (versus when placed in service), which is expected to enable some PTC qualifying project development past the end of 2013.

The federal investment tax credit (ITC) reduces federal income taxes for qualified tax-paying owners based on their capital investment in renewable energy projects. It is a onetime payment the day the facility is placed in service equal to 30% of the total investment for solar, fuel cells and micro-turbine equipment and 10% of the total investment for geothermal and combined heat and power systems.[47] The ITC was originally created in the Energy Policy Act of 1992 and is found in Section 48 of the Internal Revenue Code. The Energy Improvement and Extension Act of 2008 (EIEA) extended the date eligible facilities must be placed in service to December 31, 2016. The American Recovery and Reinvestment Act (ARRA) stated that property eligible for the PTC can elect to claim an ITC equal to 30% of property expenditures in lieu of the Section 45 PTC.[48]

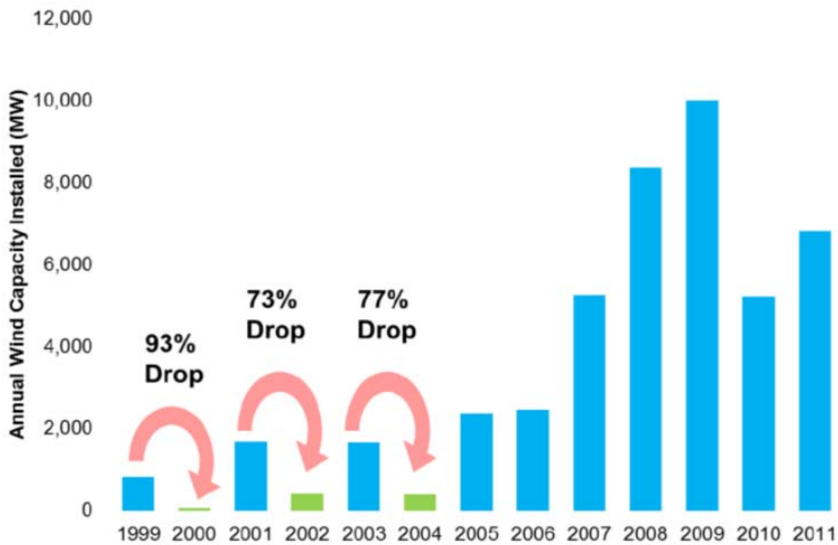
[44] The IRS increased the PTC to 2.3 cents per kilowatt hour from 2.2 cents in April 2013.
[45] Database of State Incentives for Renewables & Efficiency, "Renewable Electricity Production Tax Credit," http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F
[46] *Id.*
[47] Database of State Incentives for Renewables & Efficiency, "Business Energy Investment Tax Credit," http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F
[48] Database of State Incentives for Renewables & Efficiency, "Business Energy Investment Tax Credit," http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F

Analysis of PTC and ITC: The PTC and ITC enhance project economics, complementing state renewable energy policies, and as such have been major drivers responsible for growth of the wind and solar sectors respectively. These policies have resulted in substantial amounts of private capital invested and an increasingly significant amount of installed renewable energy capacity. To support continued scale-up, these tax credits should be modified as two major challenges hinder their effectiveness: (1) the stop-start cycle of investment attributable to repeated extensions and expirations of these programs and (2) the structural challenges of these tax-based incentives — namely a limited investor pool with limited liquidity, which in turn creates higher financing costs and ultimately requires more tax dollars per-megawatt of clean energy installations.

Stop-Start Policies Result in Stop-Start Investment
The problems with inconsistent financing incentives have been well documented ever since the PTC was first allowed to expire in 1999. In recent years, the window during which projects could qualify for the PTC has been extended for at most two to three years at a time, and, on four occasions since 1999, the credit has expired before being renewed. The stop-start nature of the PTC has created boom-and-bust cycles for the renewable energy industry, constraining consistent growth in renewable energy capacity and complicating project supply chains. While the PTC has been successful and essential to U.S. market development, this policy uncertainty has impeded the effectiveness of the policy and U.S.-based manufacturing and supply chain economic development. Similar uncertainty has characterized the PTC for geothermal energy and the ITC for solar power. A permanent or longer-term policy would be even more effective and optimize taxpayer return and private investment.

By failing to encourage steady, long-term investments in the case of the PTC, U.S. policies have not fostered stable industry growth. As a result, domestic manufacturers have not captured all possible reductions in technology costs, thereby undermining the long-term competitiveness of renewable energy options. Additionally, intermittent incentives have discouraged long-term planning for complementary investments in manufacturing capacity, transmission infrastructure, and private-sector technology R&D and have hindered the growth of the skilled workforce needed to build and service renewable energy projects.

Wind Boom and Bust Cycle with Expiration of Production Tax Credit (PTC)



Source: American Wind Energy Association (AWEA)[49]

While successful in driving significant investment to date, the tax-based nature of the PTC and ITC limits their effectiveness. These tax incentives are still needed, but they are complex instruments that are difficult to utilize and are accessible to a small fraction of U.S. investors (i.e. tax equity providers). These limitations constrain the industry's access to a small pool of corporate investors, whose numbers were further reduced during the recent economic downturn.

Investors who utilize the PTC and ITC are called "tax equity" investors. Tax equity is a term used to describe the passive financing of an asset or project, where an investor receives a return on investment based not only on cash flow from the asset or project but also on federal income tax deductions through the utilization of tax credits. Tax equity providers are typically large tax paying financial entities that can use the tax incentives to offset future tax liabilities. Renewable energy developers themselves typically do not have sufficient taxable income to benefit directly from these tax credits and must partner with tax equity providers in order to finance projects. Typically, they participate in a partnership structure that "flips" ownership of the project from the tax equity investor to the developer-owner once the tax benefits are realized.

Tax Equity has a Limited Market
The limited number of U.S. corporate entities that are in a position to forecast their tax situation for the duration of the period over which renewable energy tax credits can be monetized indicates that only the largest and most sophisticated financial firms and utilities can be considered likely investors. As a result, the investor pool for these types of projects has historically been relatively small – and has not shown signs of expanding. In fact, approximately 15 tax equity investors participated in deals in 2011 with a total volume of approximately $3.6 billion – 41% *lower* than the $6.1 billion volume from 2007.[50] In 2012, the tax equity market was expected to increase some but still be well below renewable energy market demand. The extent to which the supply of tax equity can grow significantly beyond this level is limited by the structural challenges described above.

Tax Equity is Expensive

[49] See: http://www.awea.org/issues/federal_policy/upload/PTC-Fact-Sheet.pdf
[50] U.S. Partnership for Renewable Energy Finance, *Tax Equity Market Observations*, December 2011, 4.

As a consequence of limited participation in the tax equity market, financial intermediaries charge renewable energy developers a premium (or add a friction cost) to use their tax capacity. Consequently, tax equity financing is typically more expensive than other financing options because of this additional friction cost associated with tax equity instruments in contrast to cash transfers. Mintz-Levin (2012) estimated that the (after-tax) returns required by tax equity investors in wind ranged from 7-10%, about 350-600 basis points or 3.5-6% higher than the after-tax cost of project debt (6-7% interest rates, yielding an after-tax cost of 3.5-4%).[51] The additional friction cost reduces the amount of production capacity that can be installed per dollar spent. By contrast, renewable energy projects financed with project debt and cash-based incentives are usually cheaper and easier to finance.

The Tax Equity Market is Illiquid
Tax-based project investment is rigid and hampers the ability of markets to create securities that would deepen the market and widen the pool of potential investors. For example, the tax code restricts the transfer of asset ownership using tax equity financing for significant time periods. Furthermore, each tax equity investment is structured to meet the individual tax strategy and appetite of the originating investor. This limits the fungibility that is necessary for the formation of a viable secondary market.

C. 1603 Cash Grant in Lieu of the Investment Tax Credit

The 1603 Grant allowed project developers eligible for the ITC to elect to obtain an equivalent grant from the Treasury Department in lieu of the ITC. The 1603 Grant, created in the American Recovery and Reinvestment Act (ARRA) of 2009, originally required projects to begin construction by December 31, 2010. The Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Sec. 707) extended the date facilities must begin construction for one year, through December 31, 2011. The facilities must be placed in service by the date that would be required if the developer was instead claiming the PTC or ITC.[52]

Analysis of 1603 Grant: The 1603 Grant was enacted to specifically address the shortage of tax equity and many of the financing challenges created by the recent recession and financial crisis. The 1603 Grant provided certainty for tax equity financing and boosted the insufficient tax equity supply to meet the demand of developers.[53] As of March 21, 2013, $18.2 billion worth of grants have been allocated to over 77,000 renewable energy projects. These grants leveraged private, state, federal, and regional funds leading to a combined total investment of $62.9 billion in renewable energy projects.[54]

The 1603 Grant was more efficient than tax credits because it attracted a broader pool of lenders and reduced transaction costs. As a result, the $18.2 billion of government money spent on the 1603 Grant resulted in the development of significantly more renewable energy capacity than would have been installed under an identical amount of taxpayer dollars in the form of tax code based credits. A study conducted by Bloomberg New Energy Finance estimated the 19 GW of wind installed between 2005 and 2008, which cost the government $10.3 billion using the PTC, could have been achieved through only $5 billion in 1603 Grants.[55] This is roughly consistent with the results of our model analysis (discussed in

[51] Mintz-Levin, "Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook," January 2012.
[52] U.S. Renewable Energy Tax Equity Investment and the Treasury Cash Grant Program. U.S. Partnership for Renewable Energy Finance (US PREF). April 2010
[53] Renewable Energy Policy Supply Chain. U.S. Partnership for Renewable Energy Finance (US PREF). April 2011
[54] United States Department of Treasury, "Overview and Status Update of the § 1603 Program," Updates March 21, 2013.
[55] Reassessing Renewable Energy Subsidies Policy Brief. Bipartisan Policy Center. March 2011. Page 14.

Section VI), which found that a slightly smaller 1603 Grant could have provided the same benefit as the current PTC at a third of the cost to government.

D. Department of Energy's Loan Guarantee Program (LGP)

The Department of Energy's (DOE's) 1703 and 1705 Loan Guarantee Programs provide loan guarantees for 80% of renewable energy projects' cost for the greater of 30 years or 90% of their useful lives. The 1703 LGP was enacted in the 2005 Energy Policy Act to support innovative technology that is not yet commercially available, including renewable energy technology. The FY 2009 Omnibus Appropriations Bill authorized $18.5 billion in loan guarantee authority but did not provide any funding to cover credit subsidy costs, which is needed by developers to make projects economic.

The American Recovery and Reinvestment Act (ARRA) created the 1705 LGP to issue guarantees for innovative renewable projects that are commercially available and could be placed in service by September 30, 2011. ARRA provided $6 billion to cover credit subsidy costs although Congress diverted $3.5 billion to fund other initiatives.[56] To expedite the 1705 LGP, DOE initiated the Financial Institutions Partnership Program (FIPP), a collaboration between DOE and lenders. Under FIPP, pre-qualified commercial lenders (PQL) apply to DOE for eligible loans and hold the unguaranteed portion. PQL assists DOE with due diligence to manage government risk and accelerate applications.[57]

First Wind's Kahuku Wind Project in Hawaii received funding through the Loan Guarantee Program.
Image Credit: First Wind

On April 14, 2011, Congress approved a Continuing Resolution (CR) that reduced DOE's loan authority for renewable energy projects under 1703 to $1.18 billion. The CR also provided an additional $170 million for credit subsidy costs that could be used for either 1703 or 1705 eligible projects.[58]

Analysis of LGP: The LGP has been the main policy tool to address the market failure known as the "Commercialization Gap," often referred to as the "Valley of Death," that occurs when promising technologies are unable to move from the pilot phase to the commercial marketplace, due to the large amounts of upfront capital required to demonstrate commercial viability.[59] The required capital spending during this commercialization phase is beyond the capacity of venture capital investors, while the risk is too high for private equity and debt financing.[60]

[56] The Importance of the Loan Guarantee Program in Financing Innovative Renewable Technologies. U.S. Partnership for Renewable Energy Finance (US PREF). January 2011. Page 1.
[57] Loan Guarantee Solicitation Announcement. Solicitation Number: DE-FOA-0000166. U.S. Department of Energy Loan Guarantee Program. October 7, 2009. Page 6-8 https://lpo.energy.gov/wp-content/uploads/2010/09/CTRE.pdf
[58] Final FY 2011 Continuing Resolution 224-225;
[59] The Importance of the Loan Guarantee Program in Financing Innovative Renewable Technologies. U.S. Partnership for Renewable Energy Finance (US PREF). January 2011. Page 1
[60] The Clean Energy Deployment Administration (CEDA): Key Aspects and Improvements to the Department of Energy (DOE) Loan Guarantee Program. U.S. Partnership for Renewable Energy Finance (US PREF). June 2011,1.

The loan guarantees help to mitigate the risk-return profile, thereby encouraging the private sector to come off the sidelines and finance the promising technologies that would otherwise be stuck in the "Commercialization Gap."[61] As of May 2013, under 1705, DOE had closed on 26 loans totaling $15.7 billion.[62] The LGP has been an efficient way to leverage private sector investment. As of July 21, 2011, $2.5 billion of government spending through the LGP has leveraged $40 billion in private sector investment.[63]

Yet, the structure of the LGP provides significant limitations to its impact and effectiveness. Under the LGP, the only financial product available to DOE is a loan guarantee. Therefore, DOE is not able to utilize equity or quasi-equity instruments, sell letters of credits, charge revenue generating fees or take equity or convertible debt stakes in lieu of credit subsidy costs. The lack of financial tools hampers DOE's ability to provide support to many promising renewable energy technologies. In addition, the prohibition on revenue generating tools makes the LGP program entirely reliant on unpredictable government appropriations.[64]

E. Advanced Energy Manufacturing Tax Credit ("MTC" or "48C")

Enacted as part of the American Recovery and Reinvestment Act (ARRA) of 2009, Section 48C of the tax code offers manufacturers a pool of $2.3 billion in income tax credits to promote the modification or establishment of facilities dedicated to the production of renewable energy products. Projects compete for recommendations from the DOE before consideration by the Treasury for a tax credit for up to 30% of the investment. Final applications for recommendation and certification were due, respectively, in October and December 2009. The property must be placed in service within four years of certification.[65] Entities receiving the MTC may not also take advantage of the ITC. Unused tax credits may be carried back one year or carried forward 20 years.

Analysis of Manufacturing Tax Credit: The MTC serves two economic purposes: first, to accelerate job growth in a newer manufacturing industry during the economic recession, and second, to promote scaling of renewable energy technologies and to bring down the cost of production. This tax credit does not incentivize generation from renewable energy sources. By January 2010, 183 projects across 43 states had been awarded the allotted $2.3 billion.[66] The adjoining private sector investment was over $5 billion, and the chosen projects estimated they would create over 17,000 jobs. [67]

[61] The Clean Energy Deployment Administration (CEDA): Key Aspects and Improvements to the Department of Energy (DOE) Loan Guarantee Program. U.S. Partnership for Renewable Energy Finance (US PREF). June 2011. Page 1
[62] Department of Energy Loan Guarantee Webpage. https://lpo.energy.gov/?page_id=45
[63] Silver, Jonathan. "US Energy Department Celebrates Loan Guarantee Successes as Stimulus-Supported 1705 Program Comes to Close." Biofuels Digest. 7/22/11. http://biofuelsdigest.com/bdigest/2011/07/20/us-energy-department-celebrates-loan-guarantee-successes-as-stimulus-supported-1705-program-comes-to View http://www.acore.org/wp-content/uploads/2011/02/Article-By-Silver-Re-1705-LGP-7-21-11.pdf
[64] The Clean Energy Deployment Administration (CEDA): Key Aspects and Improvements to the Department of Energy (DOE) Loan Guarantee Program. U.S. Partnership for Renewable Energy Finance (US PREF). June 2011. Page 2-4
[65] Department of Energy. Tax Credit – 48C. http://www.energy.gov/recovery/48C.htm
[66] List of award winners. http://www.whitehouse.gov/sites/default/files/48c_selection_011310.xls
[67] Department of Energy. January 2010. http://apps1.eere.energy.gov/news/progress_alerts.cfm/pa_id=283

VI. Modeling the Impacts of Existing Federal Incentives on Renewable Energy Deployment

Federal policy incentives are playing a critical role in moving toward scaled financing for renewables. Efficient and effective incentives can help achieve this goal sooner and at lower cost to society. In this section we address two specific aspects of federal policy effectiveness and efficiency:

1. **How important are federal incentives for encouraging renewable deployment?**
2. **How cost-effective are these incentives as currently structured?**

We used financial modeling to evaluate the impact of federal incentives on the cost of electricity generated by typical renewable energy projects.[68] We found that:

1. **Federal incentives have been critical to the viability of most renewable projects:**
    - The federal incentives available to projects financed in 2010[69] bridged roughly half the gap between the costs of renewable electricity generation and expected market prices for electricity.
    - To bridge the remaining gap, projects were deployed in areas that meet one or more of the following requirements: complementary state policies apply, there are significantly higher than average wholesale electricity prices, or development of conventional electricity generation is constrained.
    - The recession and resulting state fiscal constraints meant that in the absence of federal incentives, it is unlikely that states and ratepayers alone would have filled the gap.

2. **Wind is now viable with federal incentives alone, and the gap for solar has narrowed considerably:**
    - Recent cost reductions and performance improvements mean that a large wind project coming online in 2014 receiving the PTC and accelerated depreciation will be cost-competitive without any additional revenue.
    - Steep reductions in solar PV costs mean solar PV projects will be more cost-competitive in 2014, but will still need some state or ratepayer support to be viable in most markets.

3. **The 1603 Grant Program and ITC are more cost effective than the PTC, particularly for small projects, but shift some project risks to the government:**
    - The PTC costs federal and state governments roughly $14/MWh. If the same level of assistance was provided through an ITC, government costs would fall 7%; if assistance was provided through a 1603 Grant Program, government costs would fall 33%.
    - The ITC and 1603 Grant Program shift some project performance risks to the government, as the government pays a fixed fraction of the project's cost

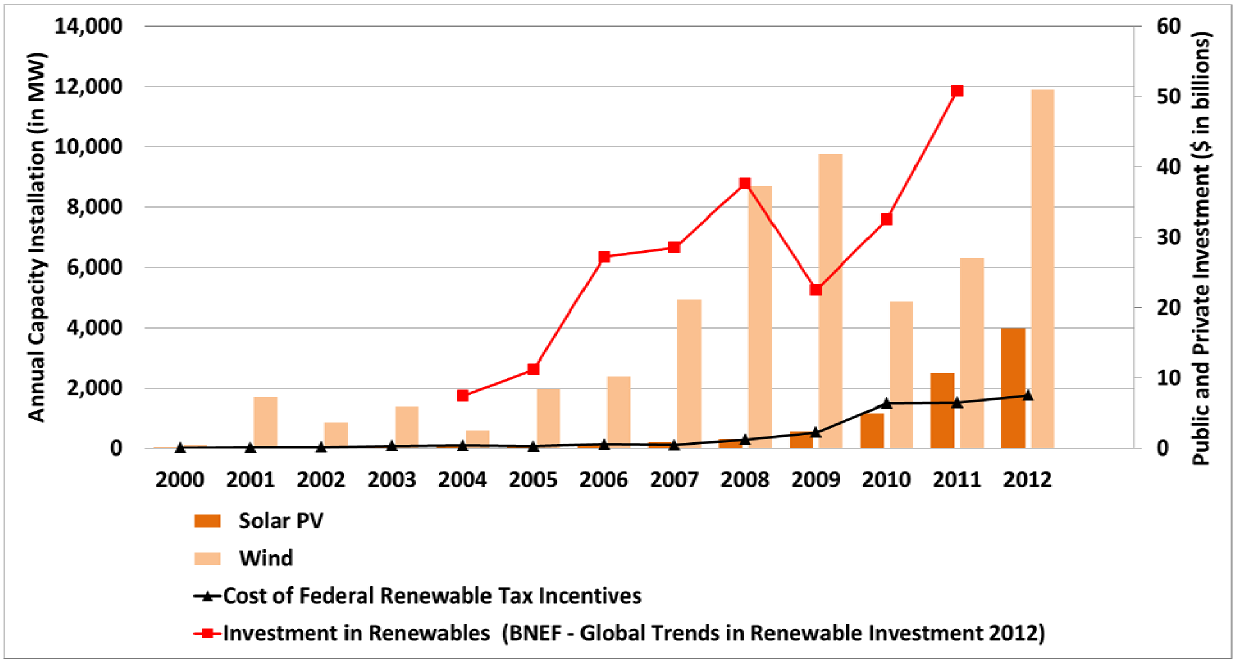
[68] The work discussed in this section is an updated account of some key results from Climate Policy Initiative (2012), "Supporting Renewable Energy While Savings Taxpayers Money," - http://climatepolicyinitiative.org/publication/supporting-renewables-while-saving-taxpayers-money
[69] These were the 30% 1603 Grant Program, accelerated depreciation, and 50% bonus depreciation.

regardless of project performance. This is not the case under a PTC, which is based on energy production.
- The 1603 Grant Program was particularly cost effective for small renewable facilities due to the high fixed transaction costs of tax equity financing.

We use project financial modeling to evaluate the impact of current federal incentives on the cost of electricity generated by three typical utility-scale renewable energy projects—a large wind, a small solar PV, and a large solar PV facility. We focused on utility-scale projects because they represent the bulk of renewable energy generation. These three cases represent the majority of currently installed capacity (large wind), the majority of installed projects (small solar PV) and fastest growing sector (large solar PV). Assumptions are based on the actual costs, financing, and operation of renewable energy projects financed over the last few years. Assumptions for each case are based on the actual costs, financing, and operation of renewable projects financed over the last few years.[70]

A. Importance of Federal Incentives

Federal tax incentives have been critical to the rapid growth of renewable electricity generation in the U.S. over the last decade. But, booming renewable deployment and private investment has led to rising incentive costs to the federal government:

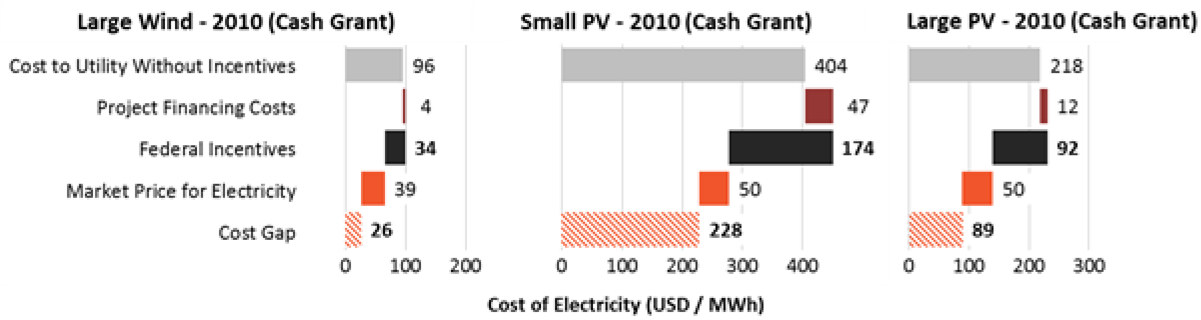


On the other hand, substantial deployment over the last few years has leveraged significant direct private sector investment in projects and indirect investment down the supply chain and across the country as well. Here, we provide an estimate of the impact of federal incentives—the extent to which federal incentives help bring the cost of electricity from solar and wind projects down towards market prices for electricity. This provides one measure of the importance of the contribution of federal incentives to the recent growth of renewable

[70] We used the median costs, timelines, and size of the large U.S. wind, small solar, and large solar projects contained in Bloomberg New Energy Finance's (BNEF) renewable project database. We based the financing costs, fees, structures, and requirements on work by
Mintz-Levin (2012) - http://www.mintz.com/publications/3055/, NREL's REFTI survey - https://financere.nrel.gov/finance/REFTI, and US PREF - http://uspref.org/white-papers
We based project performance on project level electricity generation reported by producers to the EIA over the last three years. All projects were assumed to have achieved financial closure in mid-2010.

deployment.

Specifically, to address the question of how important federal incentives are, we modeled the most widely used incentive and financial structure for each project type; calculated the cost to the government of providing the incentive; and computed its impact on the cost of electricity.[71] The results are shown below and factor in the following:



Cost to utility without incentives: The cost of electricity ($96/MWh for wind) in the absence of federal incentives, assuming on-balance sheet financing by a utility with roughly 8% weighted average cost of capital in the middle of 2010.

Project financing costs: The costs or savings associated with using project-level equity and debt financing as compared to balance sheet financing by a utility. This includes the relative cost of capital (for wind, a $5/MWh saving), financing fees ($1/MWh cost for wind), and costs associated with carrying tax benefits forward ($9/MWh cost for wind).

Federal incentives: The reduction in the cost of electricity due to federal incentives (roughly 35% of total costs for wind, including $24/MWh from the 1603 Grant Program and $11/MWh from accelerated depreciation and 50% bonus depreciation).

Market price for electricity: The expected after-tax revenue from electricity sales at projected future wholesale market prices (taken from EIA's 2010 Annual Energy Outlook) adjusted for the time of use (about $39/MWh for wind). PV facilities connected directly to distribution networks can offset much higher retail electricity prices; these would face a much smaller cost gap than shown here.

Cost gap: The difference between the final cost of electricity and expected market price for the electricity generated ($26/MWh for wind). This gap must be covered by additional project revenues from ratepayer or state/local government funds.

Note that the final cost of electricity for the project, the after-tax revenue needed per MWh of electricity generated to meet investor return requirements after federal incentives, is the sum of the market price for electricity and the cost gap ($65/MWh for wind).

Key Results: *In 2010, Federal incentives were critical to reducing the cost of new wind and solar PV projects nationally, bridging roughly half the gap (58% for wind, 48% for small PV, 52% for large PV) between median project costs and expected future market prices for the electricity generated.*

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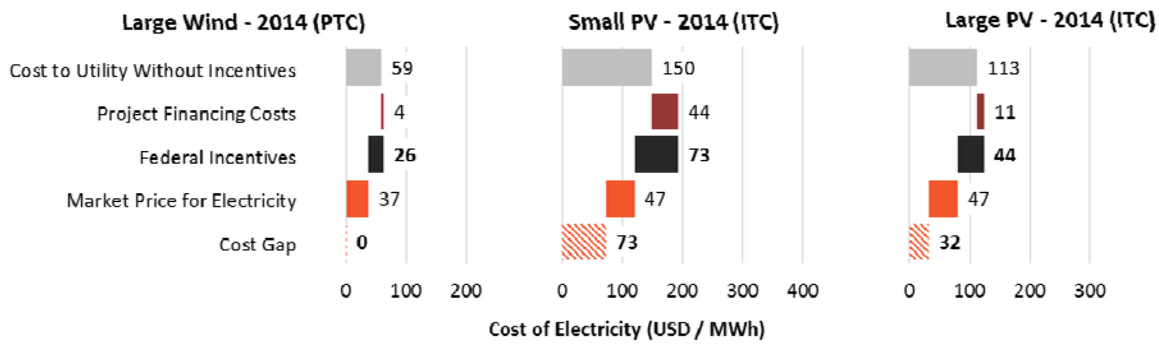
[71] We relied heavily on the recent work of Mark Bolinger and collaborators at LBNL and NREL regarding the specific tax equity structures used (see, for example - http://eetd.lbl.gov/ea/ems/reports/lbnl-2909e.pdf). Financial modeling was performed using Climate Policy Initiative's (CPI) project finance tool described in http://climatepolicyinitiative.org/publication/the-impacts-of-policy-on-the-financing-of-renewable-projects-a-case-study-analysis/

While project costs varied across technologies and sizes, the vast majority of projects financed in 2010 required a combination of federal support and state/local/ratepayer support – often in the form of RPS requirements or state-level incentives – to bridge the gap between their costs and market prices for the electricity they generated. Therefore, deployment of wind and solar has proceeded largely in areas where complementary state policies apply, or, alternatively, with significantly higher than average electricity costs and/or constraints for the development of conventional electricity generation.



Tremendous cost reductions enabled performance improvements and by deployment driven by federal and state incentives are substantially narrowing the gap between renewable costs and market prices for electricity. If these trends continue, the PTC at current levels could begin to drive wind deployment in states without RPS or other support policies.

Due to turbine performance improvements and lower wind turbine contract prices, the cost of electricity without incentives for large wind projects coming on-line in 2014 could drop by nearly 40% from $96/MWh in 2010 to $59/MWh.[72] At those costs, the PTC (along with accelerated depreciation benefits and tax equity financing at current costs) could cover the entire cost gap, leading to a final cost of electricity of $37/MWh, roughly equivalent to the revenue from expected market prices for the electricity generated.

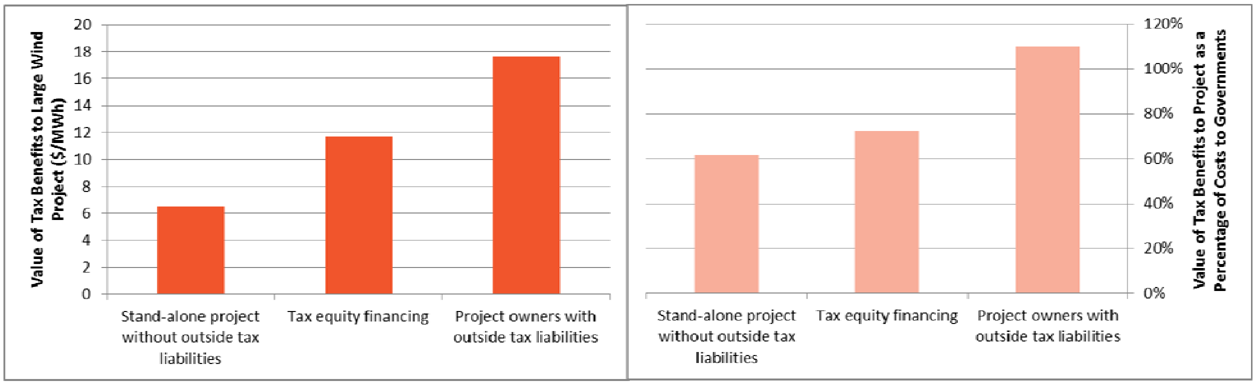
Solar PV has seen even steeper cost reductions but still requires some support beyond federal incentives to bridge the cost gap. If U.S. utility-scale installations are able to reduce costs to match the average installed costs reported for small ground-mounted PV installations currently being deployed in Germany (around $2.20/W), large PV costs would be halved, dropping from $218 to $113/MWh, leaving a market price gap after federal subsidies of about $32/MWh, about a third of the gap at 2010 prices.

However, there a number of headwinds that could significantly diminish the competitiveness of renewable technologies in the near term, such as a significant fall in future expected electricity prices driven in large part by much lower natural gas prices as well as reduced demand due to lower economic growth, the risk of curtailment, and trade issues, among others.

B. Cost-Effectiveness of the PTC, ITC, and 1603 Grant Program

The form of the incentive can significantly impact the cost of financing the project. For example, the inability of investors to use the tax incentives as they are generated can significantly reduce the value of the tax incentive to the project, as illustrated below:

[72] Our assumptions are based on work by LBNL and NREL on recent trends in wind turbine costs - http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf



To quantify these impacts, we compared the total cost to the state and federal government of each project in hypothetical scenarios in which they were either provided with a PTC, ITC, or 1603 Grant Program, each with equivalent costs to the federal government.[73]

The cost to state and federal governments of financing a PTC for a representative large wind project coming on-line in 2014 is under $14/MWh. The same benefit to the project can be achieved with a 40% ITC, reducing government costs by 7% relative to the PTC. A 1603 Grant Program for 28% of eligible project costs could achieve the same benefit while reducing government cost by 33%.[74]

The differences in cost to the government among the PTC, ITC, and 1603 Grant Program at the project level can largely be understood as the consequence of differing levels of risk associated with the timing and nature of the benefits delivered:

The timing of the incentive: Up-front investment incentives reduce the overall need for, and cost of, financing. The difference in cost between the PTC and the 1603 Grant Program or ITC is due in part to the greater benefit to investors associated with up-front benefits.

The ability of investors to use the tax benefits: Cash incentives can be used by any investor, but tax benefits require tax liabilities. As discussed in the previous section, the pool of investors with the capacity to utilize these tax benefits – tax equity investors – is limited. Tax law demands that tax equity investors must have a risk-bearing, equity stake in a project in order to make use of the tax incentives. Not many investors have both large, predictable future tax liabilities and the strategic interest to devote substantial resources to build a team to assess and renewable projects and structure tax equity financing. As a result, tax equity financing is generally more expensive than debt financing. The difference between the cost to government of the ITC and the 1603 Grant Program reflects the cost associated with tax equity financing. The difference between the PTC and 1603 Grant Program is further impacted by the timing of delivery of tax benefits, and the level of annual production from the facilities – investors need to be sure that they have tax liabilities every year over ten years with enough of a cushion to account for varying levels of annual production to make full use of PTC benefits.

[73] This is not consistent with current policy, as the ITC is fixed at 10% or 30% of project costs, while the PTC is fixed at either $0.011/kWh or $0.023/kWh – however, it is necessary to make a meaningful comparison of their relative efficiency. In addition, we did not include the loan guarantee program in our analysis as it has generally been a complementary policy used in combination with one of these three and largely for innovative or first-at-scale projects.
[74] This result is qualitatively consistent with the conclusions of work by US PREF - http://uspref.org/wp-content/uploads/2011/09/Tax-Credits-Tax-Equity-for-Clean-Energy-Financing.pdf, as well as BNEF for the Bipartisan Policy Center on renewable subsidies: http://bipartisanpolicy.org/sites/default/files/BPC_RE%20Issue%20Brief_3-22.pdf. See also related work by NREL and LBNL – http://eetd.lbl.gov/ea/emp/reports/lbnl-1642e.pdf

While the ITC and the 1603 Grant Program are less expensive than the PTC for the average project, they shift some project cost risks onto the government.

The cost to the federal government for every MWh of renewable electricity produced is fixed for the PTC. In contrast, investment-based incentives (ITC or 1603 Grant Program) provide the same support for any given investment, independent of the quality of the renewable resource, or the performance of the project. Our analysis suggests that if all existing PV power plants received comparable investment-based incentives, the cost to the federal government for each unit of renewable electricity generated would vary by nearly 70% across projects.

Investment-based support enables the government to share the burden of technology cost risks with investors. This makes sense for the scale-up of innovative technologies, but is less justified for mature technologies such as wind and solar PV, where developers and investors can manage cost risks through market measures such as contractor cost guarantees and competitive sourcing. Further, as investment-based support allows investors to realize targeted returns very early, it provides a weaker incentive to invest in the best resource or maintain or improve ongoing production. We can see some hints of this in the variation in capacity factors observed in EIA PV power plant operations data.

The 1603 Grant Program is particularly valuable for smaller projects where the fixed transaction costs of tax equity financing can exceed the value of those benefits.

For the small PV facility, a financing structure with a 1603 Grant Program, project debt, a grant construction loan, and sponsor equity (assuming the sponsor could not monetize accelerated depreciation benefits) led to a cost of electricity at least $15/MWh lower than any financing structure with a tax credit rather than the 1603 Grant Program. This is largely due to the fixed financial fees associated with obtaining tax equity financing for small projects, which contribute between $29-38/MWh to the cost of electricity.

VII. NEW MODELS AND SOLUTIONS: SCALING THE MARKET, OPTIMIZING PUBLIC INCENTIVES

- ***Key Thesis:*** *Policy can create investable markets via good RPS design at the state and federal-levels, and reforms to federal investment regulation can drive private capital formation with less reliance on public support.*
- *In this section, a select group of capital formation strategies is highlighted, chosen for their policy potential or their proven ability to amass capital in other industries.*
- *Our aim is to initiate focused discussion regarding the potential for each of these techniques to catalyze renewable energy project finance, and to identify the specific legislative and regulatory changes needed to unlock this potential. Moreover, we hope to identify further finance strategies that are not present on this list.*

A. Master Limited Partnerships (MLPs)

Master limited partnerships are well-established mechanisms for the organization of tax-advantaged pass-through entities in infrastructure finance. An MLP is a business structure that is taxed as a partnership, but has ownership interests of a corporation, including publicly-traded stock, liquidity, limited liability, and dividends.[75] The funding advantages of corporations and tax advantages of partnerships make MLPs highly attractive to private sector investment. Through MLPs, projects can access a lower-cost capital that is more liquid than traditional financing methods.

Current law only permits MLPs to be utilized by investors of depleting energy resources such as oil and natural gas. As with REITs, there has been recent activity seeking to apply the MLP model to renewable energy, and similar issues of asset qualification under tax law are in play. In May 2013, Senators Coons (D-DE) and Moran (R-KS) introduced legislation, S.3275 - Master Limited Partnerships (MLP) Parity Act,[76] which would make MLPs available to investors of renewable energy projects in both the electricity and fuel sectors. Representatives Poe (R-TX) and Thompson (D-CA) introduced identical companion legislation in the House of Representatives. There is increasing bipartisan support for this legislation in both houses of Congress.

Renewable energy MLP status would be a very important policy addition that, when combined with existing tax driven policies, would not only support, but also accelerate growth in renewables. MLPs would open up a whole new pool of investors to renewable energy, including retail and institutional investors that are largely excluded from renewable energy projects under current law. In addition, MLPs would provide a new and appealing way for utilities to invest in renewable energy projects that would produce a higher rate of return than holding the renewable energy asset within the utility entity.[77] MLPs have historically performed well in a variety of market conditions and provide predictable cash flow over long periods.[78] With a market capitalization exceeding $400 billion, and average dividends of only 6%, MLPs have the potential to significantly reduce the cost of financing renewable energy projects.[79]

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[75] Reicher, Dan and Felix Mormann. "How to Make Renewable Energy Competitive." New York Times. http://www.nytimes.com/2012/06/02/opinion/how-to-make-renewable-energy-competitive.html?_r=1
[76] See: http://www.acore.org/wp-content/uploads/2012/06/2012-06-07-mlp-parity-act1.pdf
[77] Bullock, Bruce, Bernard Weinstein, Ben Johnson. Leveling the Playing Field: The Case for Master Limited Partnerships for Renewable Energy. May 2012. Pg 13
[78] Bullock, Bruce, Bernard Weinstein, Ben Johnson. Leveling the Playing Field: The Case for Master Limited Partnerships for Renewable Energy. May 2012. Pg 6
[79] Reicher, Dan and Felix Mormann. "How to Make Renewable Energy Competitive." New York Times. 6/2/12

The MLP Parity Act, as currently drafted, could help raise additional capital from institutional MLP investors against already operating projects, making available to renewable energy private investors and developers approximately 40% of the $404 billion MLP capital market. The benefits of the deep and liquid MLP investor base results in competitive costs of debt and equity compared to what is available to renewable energy projects today. Larger diversified generation entities (e.g. publicly traded Independent Power Providers), which have a mix of fossil and renewable energy generation assets, could form a renewable energy MLP and contribute their renewable assets. Further development could be financed through construction on balance sheet and then contributed to the MLP. Larger portfolios of renewable energy pure play companies that have sufficient critical mass could form an MLP and contribute operating assets that have already benefited from their tax attributes. Further development could be financed through the traditional combination of project debt financing with the ITC/PTC programs, and then be contributed when the projects start generating net cash flow (e.g., after the projects have benefited from their tax attributes). Once formed and established, renewable MLPs could serve as a monetization vehicle for smaller developers to sell their assets. Keeping in place the current policies needed to support project development is important to maintain development and a broad spectrum of capital investment.

Renewable energy sector access to MLP financing would not take the place of the existing ITC or PTC tax credits, as they actually complement each other and fulfill different market needs. The ITC and PTC tax credits help lower the up-front cost of capital-intensive new project development and construction. By comparison, MLP financing does not support non-operating assets during the construction period given the need for cash distributions, and instead would be raised against existing projects that provide cash distributions. However, funds raised from MLP financing would be an efficient vehicle to increase capital available for reinvestment in future renewable projects.

The use of MLP structures with current tax incentives is constrained by the passive loss rule and the at-risk rule. Under current law, allocated losses from an MLP can only be utilized to offset passive income (or active income from the same MLP).[80] MLPs must therefore have income from other, net-revenue generating activities in order to utilize the tax benefits of any new renewable project.[81] Further, the current at-risk rule prevents investors from fully utilizing the benefits of leverage in renewable projects.[82]

B. Real Estate Investment Trusts (REITs)

For more than 50 years, retail investors have been able to invest in real estate assets via real estate investment trusts (REITs). These entities participate in the financing of real estate assets in multiple ways, and provide returns to retail investors via tax-advantaged pass-through structures. There has recently been a breakthrough in the use of REITs for electric transmission and associated assets, as a result of a favorable IRS decision.[83] While applicability of the REIT framework for renewable energy assets has not been established, the potential for capital formation is considerable, and the approach appears consistent with

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[80] Master Limited Partnerships for U.S. renewables: panacea or pie in the sky?. Bloomberg New Energy Finance (BNEF). 1/5/12. Pg 9

[81] Bullock, Bruce, Bernard Weinstein, Ben Johnson. Leveling the Playing Field: The Case for Master Limited Partnerships for Renewable Energy. May 2012. Pg 18

[82] Master Limited Partnerships for US renewables: panacea or pie in the sky?. Bloomberg New Energy Finance (BNEF). 1/5/12. Pg 9

[83] See: http://www.pennenergy.com/index/power/display/0323139807/articles/pennenergy/power/transmission/2010/11/top-corporations_form.html

the legislative intent behind the creation of REITs.[84] Consequently, there is nascent entrepreneurial activity in applying REIT structures to renewable energy.

Here also, however, the structuring complexities that result from the presence of tax equity in renewable energy finance complicate the picture for REIT investment. Current law (TRA IRC section 46(e)(1)) imposes a limit on REITs' ability to use the ITC. The tax credit "master-tenant" pass-through structure (IRC section 48(d)(1)) says that the pass-through is not allowed for REITs and other entities under section 46(e)(1). Furthermore, section 38(c)(1) contains a general limitation on the ability of taxpayers to utilize their credits based on their tax liability. Specifically, section 38(c)(1) limits the amount of a credit that can be used by a taxpayer in a given year to the excess of the taxpayer's net income tax over the greater of its (A) tentative minimum tax, or (B) 25% of so much of the taxpayer's net regular tax liability, as exceeds $25,000. Section 38(c)(5)(C) modifies the above general limitation for REITs by requiring (by cross reference to Sections 46(e)(1) and (2) as in effect on the day before the date of the enactment of the Revenue Reconciliation Act of 1990) that a REIT reduce the $25,000 threshold of section 38(c)(1) by the relationship between its taxable income and its taxable income computed without regard to the dividend paid deduction.

Since most REITs distribute all of their taxable income and have no tax liability, the tax liability limitation of section 38(c)(1) would in practice deny most REITs the credit. Assuming the above technical changes were made, other changes would likely be further required so that individual investors in REITs would be able to immediately realize both tax credit and related depreciation deductions. In addition, other changes may also be necessary, including a redefinition of what constitutes real estate for REIT renewable energy projects, specific modifications to the income and asset tests that REITs must follow, or clarifications or improvements to the subsidiary services.

It appears likely that there are structuring solutions to cure the issues associated with tax equity in the REIT model. Perhaps the simplest would be to deploy the REIT investment framework as a project finance "exit" to original investors, allowing developers and their capital providers to monetize their returns after the tax equity period has expired.

C. Clean Energy Deployment Administration (CEDA) and State Clean Energy Banks

Proposals to create a CEDA and the development of state clean energy banks, can address many of the limitations faced by the DOE LGP and other market gaps in private sector renewable energy finance and investment. The mission of a CEDA, or state bank, would be to provide various types of credit supports to stimulate private sector investment in breakthrough or more established renewable energy technologies. Many breakthrough technologies fall into a "commercialization gap" commonly described as the "valley of death" as they are too capital intensive for venture capital, yet too risky for private equity, project or corporate debt financing. More established technology projects, such as wind farms, have been plagued by the high cost of capital caused by credit constraints in the debt and tax equity markets.

A CEDA or state bank focus on more established technologies, like commercial wind and solar technologies, would address the short-term challenges of the current credit limitation of the tax equity market, accelerate conventional renewables deployment in the near term, and help ensure sufficient depth to the renewable project finance market. Additionally, the lower credit risks for a portfolio of these technologies would allow CEDA to maximize leverage and private sector financing on an aggregate level. If successful, a CEDA focus on

[84] "The Technical Qualifications for Treating Photovoltaic Assets as Real Property by Real Estate Investment Trusts." NREL Technical Report, http://www.nrel.gov/docs/fy12osti/55396.pdf

more established generation could also create demand "downstream" in the renewable energy supply chain, thereby supporting a long-term market for breakthrough technologies.

A CEDA or state bank focus on breakthrough technologies would aid in the commercialization phase of clean energy, an investment stage which lacks sufficient financing in even a robust credit environment. This persistent financing challenge demonstrates a clear need for longer-term federal assistance and provides a justification for the creation of a new and permanent agency. Additionally, a focus on innovative technologies may accelerate the timeline on which renewables reach cost parity with conventional energy. Support for breakthrough technologies could strengthen U.S. clean technology leadership and lay the groundwork for a competitive U.S. export market.

A CEDA or state clean energy bank, like in Connecticut and in development in New York, would have a variety of financial tools at its disposal, including equity or quasi-equity instruments, letters of credits, insurance products, and secondary market supports. In addition, they would have the ability to charge revenue-generating fees or take equity or convertible debt stakes in lieu of credit subsidy costs. This would greatly diversify the type of renewable energy projects CEDA or state banks could support and allow them to become a self-sustaining entity after the government's initial allocation. In addition, unlike the DOE LGP, CEDA and state banks would have authority to approve projects at a portfolio level as opposed to an individual level, which would allow it to better manage credit risk.

Clean Energy Deployment Administration proposals and state banks would be structured to mitigate a wide range of risks. In simple terms, this strategy involves the need to plan for both foreseen and unforeseen variables, balance near-term risks with medium to long-term benefits, and provide massive lines of financing quickly. This approach is similar to those employed by private capital providers throughout the economy. However, CEDA and state bank primary objectives are to keep a balanced risk profile in order to leverage the capability to provide additional financing for more risky projects, whereas the end goal of a typical private investor is to have invested in the lowest possible risk portfolio and received the highest return. A focused agency like a CEDA at the federal or state level can be most helpful in accelerating private sector investment in the clean energy sector.

D. Green Bonds

Climate or green bonds are increasingly in favor with long-term investors, but the market is presently dominated by large multilateral entities such as the World Bank, rather than domestically-oriented entities supporting renewable energy infrastructure. Much of this capital is therefore being directed to the developing world, supporting projects that, on their face, embody greater policy and market risk than would deployment within a well-structured RPS market in the U.S. Given the sensitivity of renewable energy project viability to the cost of debt, as well as the established affinity of both institutional and small retail investors for bond purchases, an acceleration of bonding activity for renewable energy infrastructure appears to be an attractive option for this project to pursue.

The major impediment that currently prevents bond issue from being utilized as a source of renewable energy finance is the terms and conditions that the bond issuer requires of the renewable energy project. Specifically, and typically in the case of tax-exempt bond issues, such as private activity bonds, there are legal and tax requirements that require the issuer to own the property being financed. In the case of renewable energy property, in particular ITC property, when governments or tax-exempt entities are present in the ownership of property, that ownership prevents the project from being eligible for the tax incentives. Therefore, the tax code for bonds would need to be amended to remove these provisions, or ownership by government and nonprofit entities would be curtailed.

E. Clean Renewable Energy Bonds (CREBs)

CREBs are a type of tax credit bond where the investor receives a tax credit from the Treasury Department instead of an interest payment from the bond issuer. Therefore, the federal government theoretically subsidizes municipal borrowing completely. Administered by the IRS, the CREB program received over $2.4 billion in Congressional appropriations as of February 2009, but has since not been extended. CREBs are different from traditional tax-exempt municipal bonds where the federal government tax exempts the issuer's cash interest payments.

F. Multi-Investor Tax Equity Models

With the expiration of the 1603 Grant program, more attention is being paid to increasing the number of tax equity investors active in the marketplace. A number of strategies are being explored to achieve this, including the formation of multi-investor funds akin to those used in affordable housing finance. Similarly, analysts have initially explored the possibility of expanding the Community Reinvestment Act (CRA) and the use of regulated investment companies (RICs) to include renewable energy investments as a qualifying category.

G. Business Development Corporations (BDCs)

Designed to provide mezzanine capital, mostly in the lower middle market in terms of deal sizes, the intent of BDCs is to provide financing for small, developing, and financially troubled companies that do not have ready access to public capital markets or other forms of conventional financing. Similarly, BDCs can allow smaller, non-accredited investors to invest in startup companies. BDCs are typically organized as limited partnerships to get pass-through tax treatment, but if organized as a partnership, a BDC cannot be traded on an exchange unless it qualifies as a publicly traded partnership (like a MLP). However, existing restrictions on the nature of BDC holdings may limit their applicability to renewable energy project finance.

H. Crowd-Sourced Deployment Funds

Recent success by startup firms has raised the possibility of sourcing project finance directly from retail investors. A number of significant regulatory impediments are known to exist, principally including accredited investor, passive loss and at-risk rules, and issues of equity, transparency and fraud prevention must be addressed. But the potential of coupling local power initiatives with local finance strategies appears compelling.

I. Taxable Cash Incentive for Production (TCP) – or make the PTC Refundable and Taxable

Allowing an option to replace the PTC with a taxable cash incentive for production – or reforming the PTC to make it refundable, but slightly smaller and taxable – can deliver the same cost of electricity to ratepayers for wind generation at half the cost to the state and federal government.[85] Further, unlike the ITC or 1603 Grant Program, it does not shift project risks that can be managed by the private sector to the government.

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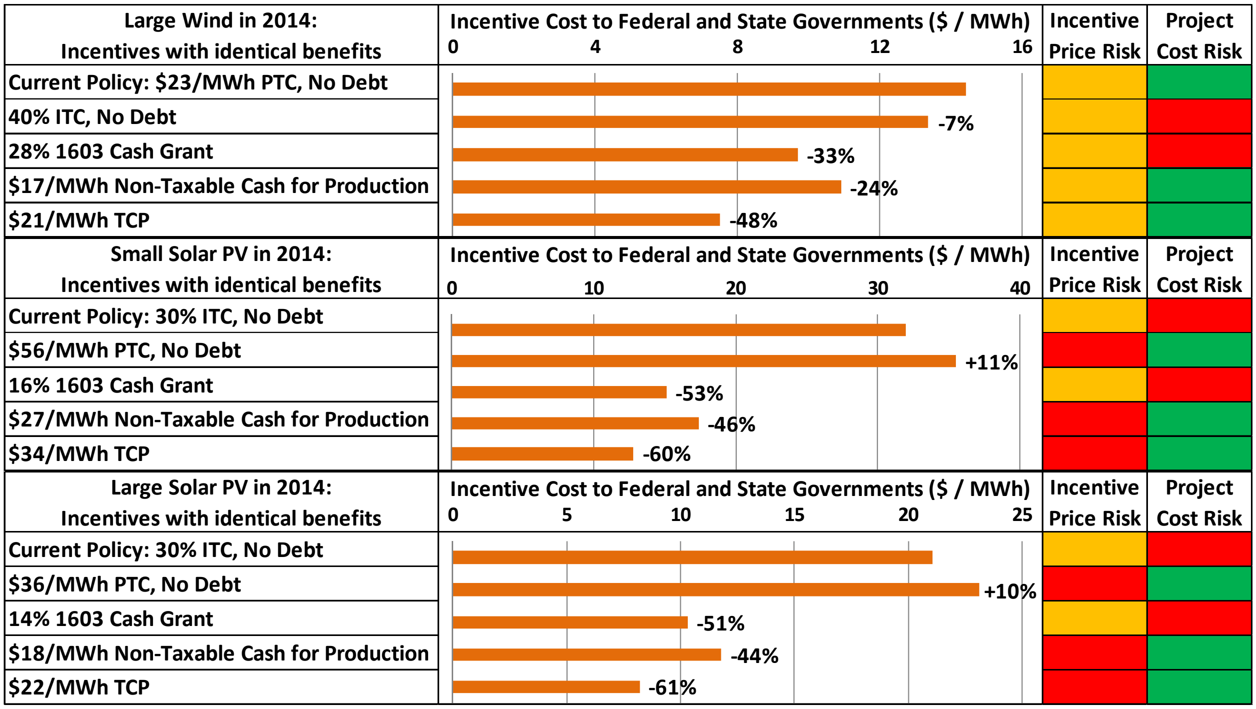
[85] This approach has been previously discussed by Climate Policy Initiative, see for example - http://climatepolicyinitiative.org/2012/12/18/supporting-wind-energy-and-saving-u-s-taxpayers-nearly-5-billion-in-three-easy-steps/. Note that such an incentive would be economically equivalent to a Feed-in-Premium (FiP), but paid directly by the federal government rather than through ratepayer funds.



In addition to the elimination of the risks and costs associated with monetizing tax benefits, the lower cost of the taxable cash grant can also be traced to the following factors:

Greater cash available for debt service enables higher leverage: While an up-front incentive can reduce the requirement for expensive tax equity, the additional cash flow available for debt-service provided by a cash production incentive can support greater project-level debt.

Greater debt increases interest tax benefits: As the interest on debt is tax deductible, the production cash incentive can leverage this additional tax incentive.

Incentives delivered as taxable revenues can monetize accelerated depreciation benefits: Further, as the cash incentive is taxable, it provides the project with additional tax liability early in the project life, which can be used to monetize accelerated depreciation tax benefits without the use of tax equity, thereby further lowering financing costs.

VIII. Conclusions and Next Steps

Renewable energy generation is an important part of our nation's energy strategy. The federal government and states have enacted complementary policies to encourage private investment. This has resulted in significant growth in renewable energy capacity, technology cost reduction, private capital formation and investment, economic development and job creation. To support continued scale-up, federal and state financial incentives are still needed. In addition, regulatory reforms to the tax code as well as the electricity market are also necessary. At a time of fiscal constraint, these policies need to optimize private investment as well as broaden and open new sources of private capital. Continued access to the current tax credits and the ability to monetize them is critical as a bridge to new policies.

As for next steps, the 2013 time frame represents an important juncture. The 1603 Grant Program expired at the end of 2011 and the PTC is set to expire at the end of 2013. This threatens impressive market progress. States also face fiscal and other challenges at a time when RPSs and other state policies need reinvigoration to maintain policy support for continued renewable energy market growth.

The Congress and President agree that a major policy focus in 2013 will be tax reform to simplify the tax code, promote economic growth, and reduce the nation's massive debt. Within this context, the role of federal incentives and regulatory structures as tools of energy policy will be addressed. At the state-level, governors, legislatures and regulators have an opportunity to enhance, expand or enact state RPS policies to increase renewable energy investment and production.

This year is about engaging in the discussion to ensure, as important policy decisions are made on the future of renewable energy policy, that the President, members of Congress, governors, and others make informed decisions on the continuing value of the existing tax credits, RPS policies and the value of new strategies, such as MLPs and REITs, to drive greater levels of capital formation and investment in renewable energy.

This paper serves as the basis of an important policy discussion with recommendations on the most viable options to support private capital formation and investment to drive the scale-up of the U.S. renewable energy market. In 2013 and beyond, ACORE intends to pursue discussions with key policy makers, industry leaders, and other audiences to advance these recommendations, which include: extending the successful PTC and ITC policies; enabling renewable energy access to the highest-value new private finance techniques, MLP and REIT investment; optimization of incentive structures; expanding and reinvigorating state-level RPS programs; and implementing power market regulatory reforms and promote integration of RPS and RTO/ISO policy. These recommendations build on the success of current policies, provide a level playing field for renewable technologies, improve and enhance the effectiveness and cost-effectiveness of policies to drive low-cost investment, and reform regulatory and market design to encourage renewable investment.

ACORE will also pursue a coordinated advocacy strategy around these best practices, targeted at the relevant points of intervention – federal, state and regulatory policy and within the financial community.

The objective is to develop a broad consensus on a policy framework that would support greater levels of capital formation and investment in renewable energy, economic growth, deficit reduction, and a more efficient and effective tax system.