CLIMATE
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Supporting Renewables while Saving Taxpayers Money

Climate Policy Initiative

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About CPI

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Executive Summary

Renewable energy deployment in the United States is booming. Renewable electricity generation has more than doubled since 2005,[1] bringing reductions in air pollution and greenhouse gas emissions. The doubling was financed largely through private investment mobilized by state and federal incentives and other policies, leading to substantial expansion of the renewable energy industry.

While solar and wind costs have fallen, rising deployment has increased the cost to government of providing the incentives. Key federal policy incentives are now beginning to expire, just as federal lawmakers are looking for opportunities to reduce the deficit. It is therefore important and timely to review the performance of federal renewable energy incentives.

In this paper, we address three specific questions:

1. How important are federal incentives for encouraging renewable energy deployment?
2. How cost-effective are these incentives as currently structured?
3. How could they be improved?

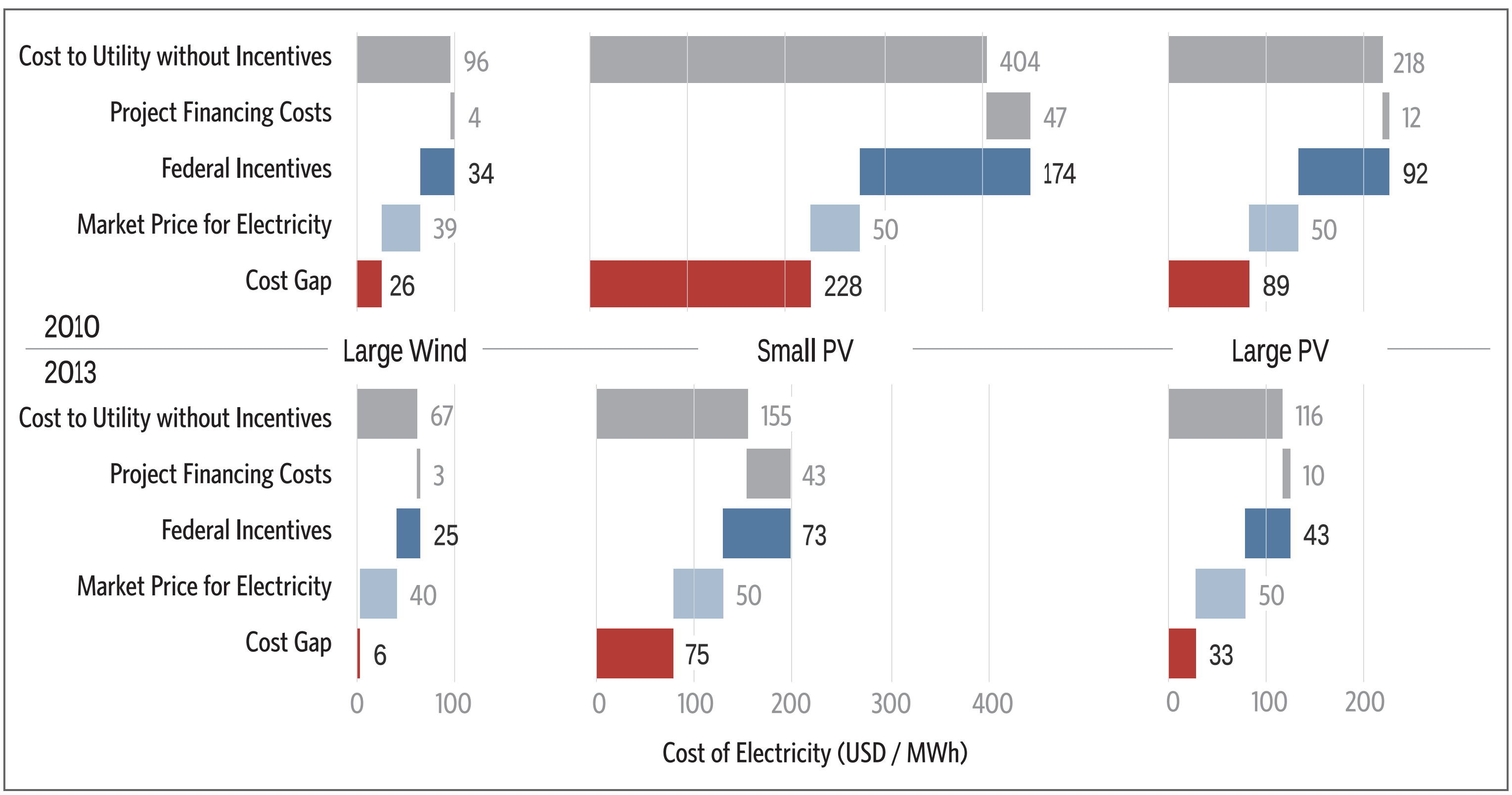
Incentive design influences how renewable energy projects are financed; project finance in turn affects the overall cost of electricity generation. Using detailed financial modeling, we have evaluated the impact of current federal incentives on the cost of three typical grid-connected utility-scale renewable energy projects—a large wind, a small solar photovoltaic (PV), and a large solar PV facility.

Under current law, a wind facility operating by the end of 2012 receives a production tax credit (PTC) of $22/MWh for electricity generated in its first 10 years while a solar PV facility operating by the end of 2016 receives an investment tax credit (ITC) equal to 30% of eligible project investment costs.

This analysis demonstrates how the federal government can modify these incentives to save money, while sustaining strong support for U.S. renewable energy deployment.

1 Net Generation by Energy Source: Total (All Sectors), June 27, 2012, Electric Power Monthly, Growth refers to non-hydro renewables.

Figure ES-1: Federal incentives are critical to the viability of wind and solar PV projects.

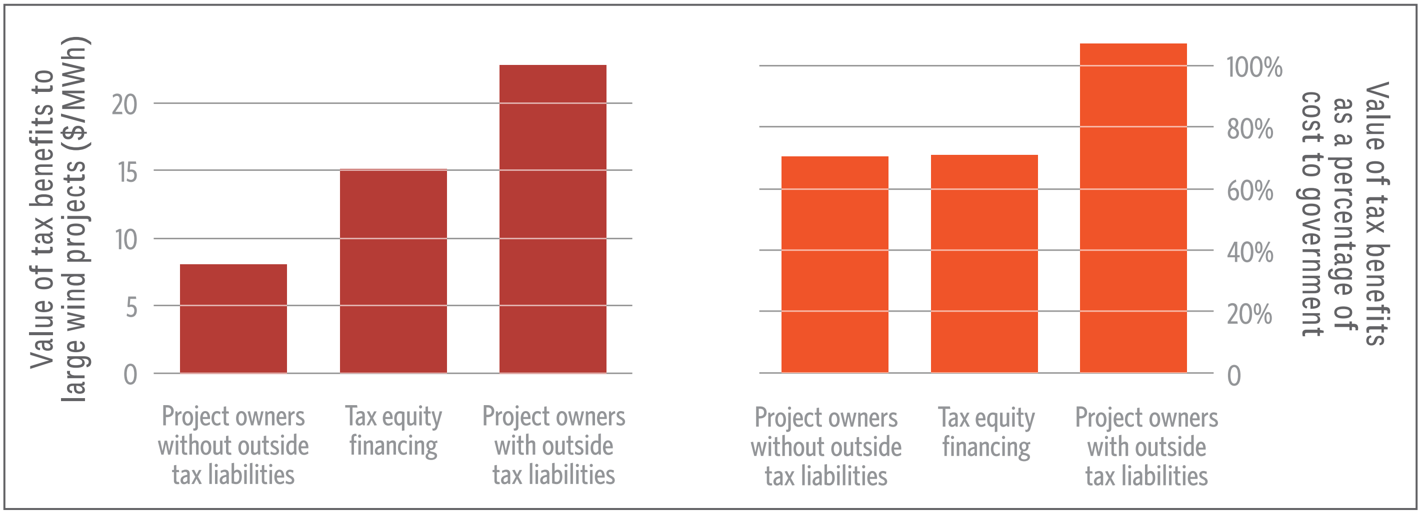


Key Findings

1. **Federal incentives have been critical to the viability of most renewable energy projects.**
   - The federal incentives available to projects financed in 2010[2] bridged roughly half the gap between the costs of renewable electricity generation and expected market prices for electricity.
   - To bridge the remaining gap, projects have largely been 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 mean that in the absence of federal incentives, it is unlikely that states and ratepayers alone would have filled the gap.
2. **Wind is now almost viable based on federal incentives alone. The gap for solar PV is narrowing.**
   - Recent cost reductions and performance improvements mean that if current federal incentives are sustained, a large wind project built in 2013 will be nearly cost-competitive.
   - Steep reductions in solar PV costs over the last two years mean solar PV projects will be more cost-competitive in 2013, but will still need some state or ratepayer support to be viable.
3. **Tax incentives leak money.**
   - A stand-alone large wind project has limited tax liabilities. As a result, project developers can only use tax benefits many years after they are received, and realize just one-third of their potential value (Figure ES-2).
   - Project developers therefore enter into financial arrangements with outside investors with tax liabilities—tax-equity financing—to use the tax incentives as they are received.
   - However, these arrangements are costly and only enable developers to realize two-thirds of the value of the incentive—an inefficient use of government money (Figure ES-2).
4. **Government can save money while providing the same support for projects by using taxable cash incentives rather than tax incentives.**
   - A 1603 Cash Grant half the size of the current investment tax credit could deliver the same benefit to a solar PV project in 2013 at half the cost to government (Figure ES-3).
   - Taxable cash incentives can be even more

2 These were the 30% 1603 Cash Grant, accelerated depreciation, and 50% bonus depreciation.

Figure ES-2: Tax incentives have less value to projects with limited tax liabilities.



cost-effective for governments than non-taxable cash incentives such as the 1603 Cash Grant.[3]

- If the wind production tax credit was delivered as a taxable cash incentive, it would almost halve the cost to government while delivering the same benefit to wind projects (Figure ES-3).

5. **But we must mindful of how different incentives impact the risks borne by government.**

- Investment-based incentives shift some project performance risks to the government, as the government pays a fixed fraction of the project's cost regardless of project performance.
- Production-based incentives reward performance equally across all projects, but carry greater price-setting risks. This is particularly acute when technology prices are hard to predict.

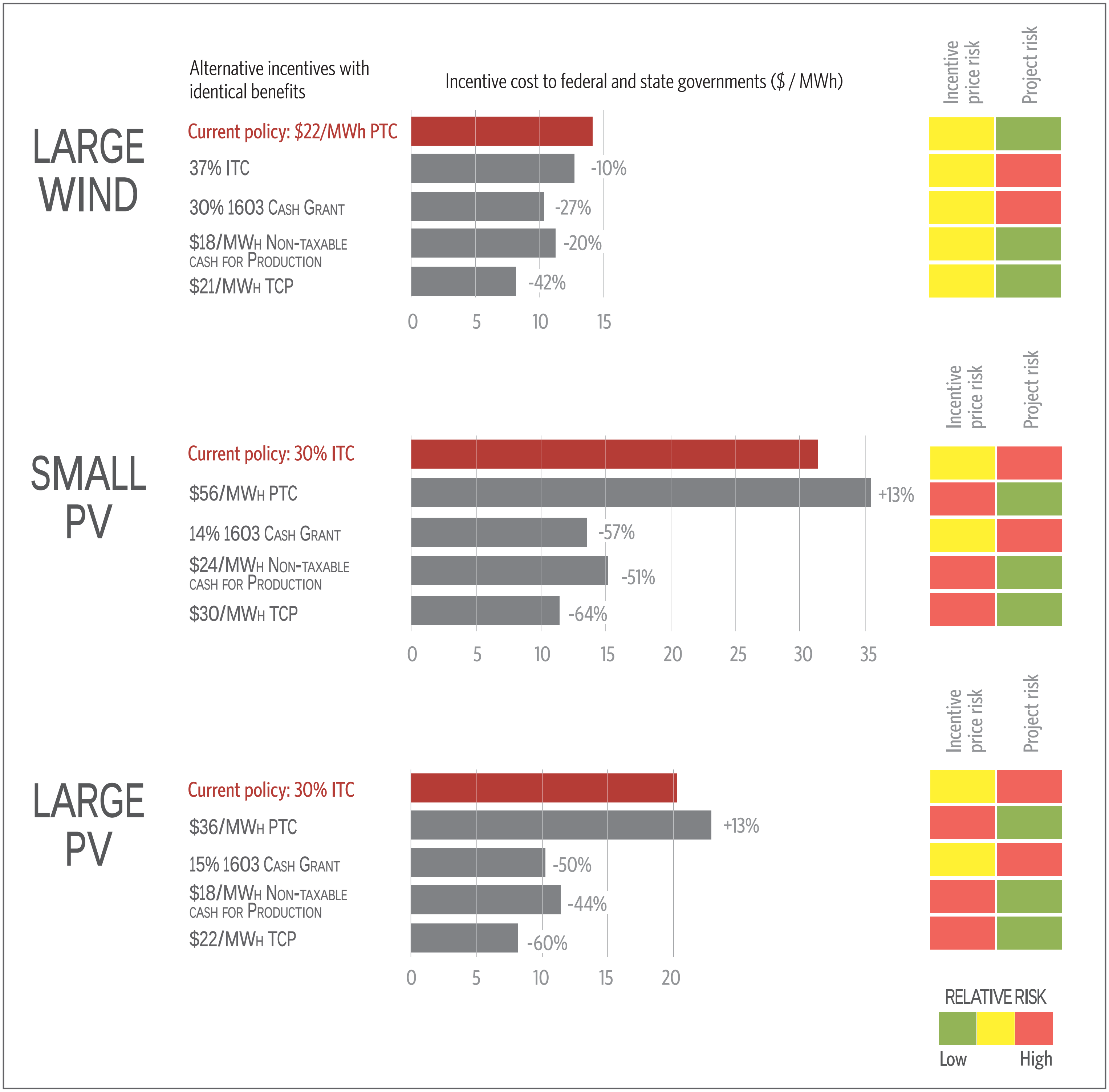
Policy Recommendations

Our work identifies two clear steps policymakers can take to improve the cost-effectiveness of federal renewable energy incentives:

1. **Extend the PTC as a taxable cash incentive for production (TCP) –** In the near term extend the $22/MWh PTC for wind, but deliver it as a $21/MWh TCP. This would:
   - Maintain the same effective level of support for wind projects.
   - Reduce the cost of the incentive to federal and state government by around 40% for every unit of clean electricity generated.
   - Avert a bust in the wind industry, and stimulate deployment even in states or regions with no local or state policy supports.
2. **Give solar PV projects the option to take a 20% 1603 Cash Grant in lieu of a 30% ITC –** This option could increase the value of the incentive to the project while reducing the cost to government of providing it.

3 Since the incentive is taxable, it results in additional project tax liabilities which can both help the project make better use of up-front tax benefits such as accelerated depreciation and increase tax revenues later in the life of the project to offset some of the cost of providing the incentive.

Figure ES-3: Policy alternatives and the costs and risks to federal and state governments.



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1 Why Look at Federal Tax Incentives?

Renewable electricity generation in the U.S. has grown rapidly over the last decade. According to the U.S. Energy Information Association (EIA), wind and solar PV accounted for over 30% of new generating capacity added to the grid in 2010.

This growth has been enabled, at least in part, by policy drivers at the state (Renewable Portfolio Standards (RPS) and related incentives), national (federal tax incentives and stimulus funding), and international levels (European renewable energy incentives and Chinese manufacturing have driven economies of scale and cost reductions in wind and solar PV).[4]

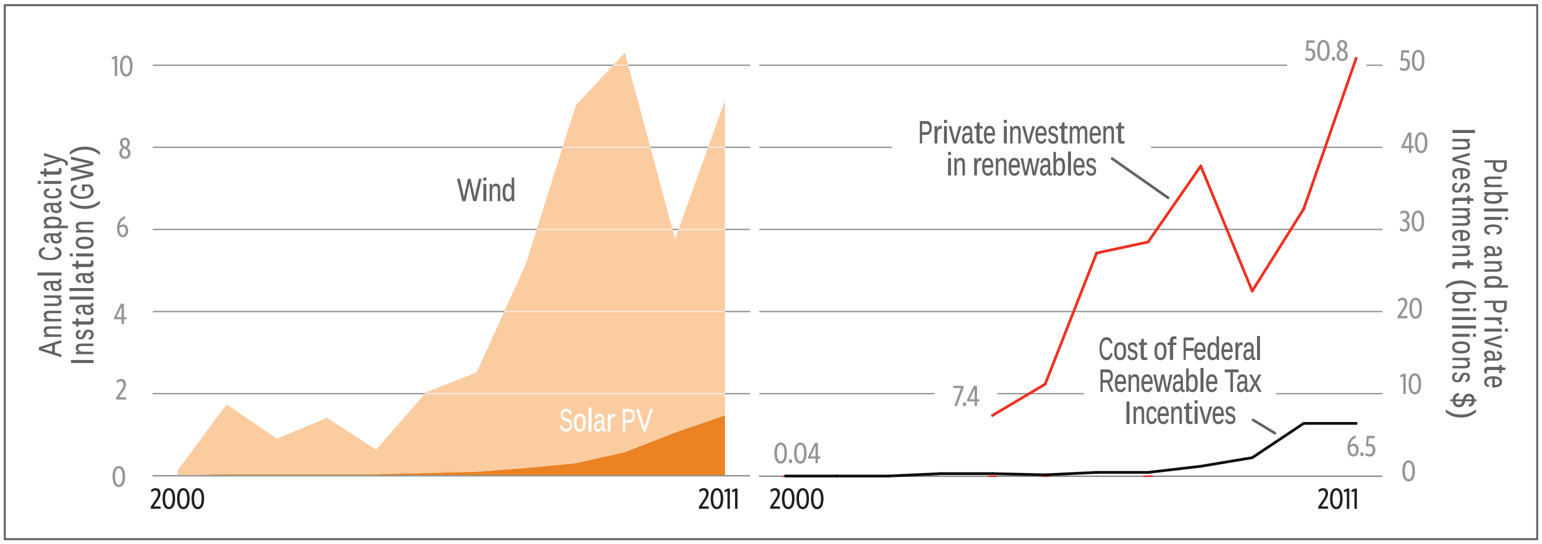
However, the continued growth of renewable energy deployment depends on overcoming a number of substantial policy, market, and budgetary challenges that are on the horizon.

4 This report is an expanded description of CPI analysis of federal renewable policies carried out to support collaborative work with the American Council on Renewable Energy (ACORE), the California Clean Energy Fund (CalCEF), and the Energy Foundation on the future of U.S. renewable energy policy.

Many federal incentives have expired or will do so shortly. Many key federal incentives require periodic re-authorization by Congress. Most were last extended as part of economic stimulus measures in late 2008 and early 2009 (the TARP and Recovery Act bills) and have recently, or will soon, expire. Table 1 summarizes the key incentives and their current status.

Extension of incentives is uncertain as rising deployment has brought rising incentive costs. Since federal incentives provide subsidies proportional to either investment in or production of renewable energy, their budgetary impact has risen with deployment. Large federal budget deficits, which arose as a result of the recession, have created substantial political pressure to reduce federal expenditures. Thus, the extension of these measures is now subject to substantially greater political risk. These risks have been exacerbated by the political fall-out from the failure of Solyndra (a solar manufacturer which was provided a Section 1705 direct loan). This has turned government support for renewable energy into a partisan political issue in an election year. 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, creating the potential for a countervailing political current.

Figure 1: Booming deployment and private investment has led to rising incentive costs to government



Sources: Annual grid connected solar PV and wind installations from EIA Annual Energy Outlook 2003-2012 including both the electric power sector and end-use generating capacity. Estimates of the budgetary impact of federal renewable electricity tax incentives (including the 1603 Cash Grant) are from CPI analysis based on OMB and JCT tax expenditure estimates. Estimate of new private investment in renewable energy projects leveraged in part by those incentives are from BNEF (2012) Global Trends in Renewable Investment 2012.

Table 1: Federal renewable energy incentives

Incentive	Origin	Expiration	Description	Risk to Government
Production Tax Credit (PTC) for Wind	Energy Policy Act of 1992	Placed in Service by **End of 2012**	$22/MWh tax credit for electricity generated	Incentive level may not be appropriate
Investment Tax Credit (ITC) for Solar	Energy Policy Act of 2005 (at 30%)	Placed in Service by **End of 2016**	Tax credit for 30% of eligible project costs	Project performance and cost risk
Investment Tax Credit (ITC) for Wind	Recovery Act of 2009	Placed in Service by **End of 2012**	Tax credit for 30% of eligible project costs in lieu of PTC	Project performance and cost risk
Section 1603 Cash Grant for Wind & Solar	Recovery Act of 2009	Start Construction by **End of 2011**	Option of a 30% cash grant in lieu of ITC or PTC	Project performance and cost risk
MACRS – Accelerated Depreciation	Economic Recovery Tax Act of 1981	-	5-Year depreciation for tax purposes	-
Bonus Depreciation	Economic Stimulus Act of 2008	100% by **End of 2011**, 50% by **End of 2012**	50% or 100% depreciation for tax purposes in first year	-
Section 1705 Loan Guarantee for Wind & Solar	Recovery Act of 2009	Closed Financing by **9/30/2011**	Government guarantee of up to 80% of project debt	Risk of project failure project performance and cost risk

State policy appears to be saturated. Contracts to meet state RPS requirements for the near future are already in place, leaving little room for additional growth. The U.S. Partnership for Renewable Energy Finance (US PREF, 2012) projects that RPS-driven demand can be met by deploying a little over 3 GW of new renewable electricity generation per year until 2030, significantly below recent annual deployment of around 10 GW per year.

Cheap natural gas and lower demand puts price pressure on renewable energy. The boom in domestic production of natural gas from shale formations has driven nominal gas prices down to levels last seen in the 1990s, transforming the outlook for the electricity sector. Gas generation now boasts lower marginal costs than coal generation in many states, and it delivers significant local air pollution reductions relative to coal.[5] Sustained lower electricity prices would diminish the economic viability of renewable technologies.

5 However, note that the long-term implications of shale gas are far from clear due to uncertain groundwater impacts, lifecycle CO_2 emissions, and long term production profiles.

Given these challenges, federal policymakers are looking to balance support for renewable energy with fiscal pressures. Improving the cost-effectiveness of federal renewable energy incentives could help.

In this work, we use project financial modeling and data on renewable energy project costs and performance to assess three aspects of the performance of current federal renewable energy incentives:

1. How important are federal incentives for encouraging renewable energy deployment?
2. How cost-effective are these incentives as currently structured?
3. How could they be improved?

For the first question, 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. We address the second question by comparing the cost to federal and state governments of providing the same level of benefit to a project using various currently employed incentives. Finally, we use insights gained from the first two analyses to propose an alternative incentive mechanism for wind—a Taxable Cash for Production (TCP) incentive—which can provide the same benefits as the current production tax credit (PTC), but at lower cost to federal and state governments.

In the next section, we discuss prior work on these topics. In section three, we provide an overview of the project data and financial modeling techniques used to address these questions, and discuss the strengths and weaknesses of our approach. In section four, we address the impact of federal incentives on the economic viability of renewable energy projects. In the fifth section, we discuss results regarding the relative cost-effectiveness of these incentives and a proposal for how the incentives might be modified to improve their cost-effectiveness. We conclude with recommendations to policymakers regarding near-term modifications to federal incentives which can improve their cost-effectiveness.

2 Prior Work on the Impact and Cost-Effectiveness of Federal Incentives

Our analysis builds upon a number of recent studies focused on the impact and cost-effectiveness of federal incentives. In this section we highlight some key findings from these studies in two important areas for our work—the nature and impact of the various financial structures used by renewable energy projects to monetize tax incentives, and the relative cost of various federal incentives.

2.1 Impact of Financial Structures

The Electricity Markets and Policy Group at Lawrence Berkeley National Labs (LBNL) have studied the financing structures used by the wind industry to utilize federal tax incentives since the mid-1990s. The key results from this work and related efforts relevant to this work are:

> The details of the financing arrangements made by a project developer to utilize tax incentives—tax equity financing—can impact the cost of electricity by as much as 30%.

The choice of tax equity financing structure can impact electricity costs by as much as 30% - Harper et al. (2007) and Bolinger et al. (2010) outlined in detail the rationale, structures, and terms for tax equity financing—the arrangements used by wind project developers without tax liabilities outside of the project to monetize tax incentives. They estimated that the variation in cost of electricity due to the choice of financing structure using the same tax incentive could be as high as 30%. This work significantly informed and motivated our focus on detailed modeling of tax equity financing structures.

The variation is tied to inefficiencies in tax equity capital markets - The choice of structure is often constrained by the specific risk and tax appetites of project stakeholders. In particular, the complexity of tax equity financing and the relatively small number of tax equity investors with significant, predictable, long-term tax liabilities and the capacity to structure these deals has resulted in a relatively thin market.

Recent evidence suggests that tax equity market conditions are improving - Some of these constraints should loosen as capital markets for renewable energy projects grow and become more efficient. More recent publications focused on current state of play in wind project financing—for example, Mintz Levin (2012) and Chadbourne & Parke (2012)—suggest that the pool of tax equity investors has widened (to over 20) and that recent transactions have largely utilized the more efficient structures such as institutional investor flips. As a result, we focus our work on some variants of the more efficient structures described in these reports.

2.2 Relative Cost-Effectiveness of Federal Incentives

The American Recovery and Reinvestment Act gave wind developers a choice between the ITC, PTC, and 1603 Cash Grant for projects which began construction by the end of 2010. This motivated a number of groups to study the relative cost-effectiveness of these federal incentives. Key conclusions from these studies relevant to our work are:

> Cost and performance dictates the choice between the PTC and the 1603 Cash Grant for any given wind project. However, overall, the 1603 Cash Grant has spurred greater deployment, reduced financial transaction costs, and halved the unit cost to government relative to the PTC.

Project cost and performance dictate the choice between the PTC and 1603 Cash Grant – Bolinger et al. (2009) found that the relative value of the PTC and the 1603 Cash Grant varied with costs and capacity factors across wind facilities. Lower cost, higher capacity factor facilities were likely to get more value from a PTC than the 1603 Cash Grant. This was confirmed by Bolinger et al. (2010) who noted that a quarter of all large wind projects in 2009 and early 2010 chose the PTC over the cash grant in spite of the poor tax equity market conditions.

The 1603 Cash Grant resulted in additional deployment relative to the PTC it replaced – Bolinger et al. (2010) also assessed the extent to which the choice of a 1603 Cash Grant enabled additional deployment relative to the

PTC alone. To assess if the project could have been built under a PTC, they analyzed the finances of wind projects deployed using the 1603 Cash Grant and found that roughly 2.4 GW out of the nearly 10 GW of wind projects built in 2009 would not have gone forward under a PTC.

High transaction costs for tax equity – The U.S. Partnership for Renewable Energy Finance's (US PREF) 2011 report on tax equity and tax credits estimated the difference in transaction costs between financing a solar project using the ITC and tax equity relative to a 1603 Cash Grant and debt financing. Their results are used as financial inputs to our models (see Table A.2 in Appendix A). Further, they noted that tax equity structures are difficult to leverage. This is because many tax equity investors are institutional investors with constrained risk profiles, so they are often loath to allow their tax equity investment to be subordinated to project-level senior-term debt.

The 1603 Cash Grant can cut government costs per MWh in half relative to the PTC – The Bipartisan Policy Center's (BPC) 2011 report cited analysis by Bloomberg New Energy Finance (BNEF) in 2010 that found the 1603 Cash Grant could have provided the same benefit to investors as a PTC for roughly half the total budgetary cost for projects deployed between 2004 and 2008.

The 1603 Cash Grant had much higher overall costs to government than initial expectations – The Majority Staff of the House Committee on Energy and Commerce, Subcommittee on Oversight and Investigations released a report assessing the impact of the 1603 Cash Grant. They note that the program is costing the government much more than initially anticipated. From the work of Bolinger et al., this appears to be the result of the 1603 Cash Grant leading to additional deployment relative to the PTC.

The ITC pays for itself and provides the government with a 10% return – US PREF (2012) teamed up with SolarCity and performed a tax analysis of a residential solar system and found that over the life of the project, the tax revenue from electricity sales significantly exceeds the cost to government of providing the ITC, in fact providing a 10% annual return above the amount provided.

Feed-in-Tariffs are more cost-effective than tax incentives – BNEF (2011) examined the relative cost-effectiveness of various types of incentives used globally. In particular, they compared the impact of a feed-in-tariff and a production tax incentive of the same level on the cost of electricity of a wind project. They found that feed-in-tariffs could deliver greater reductions to the cost of electricity for the same level of incentive.

We will discuss the implications of our work on these claims in the concluding section of this report.

3 How are We Assessing Federal Policy Impact and Cost-Effectiveness?

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 account for the largest share of recent deployment growth (large solar PV). Assumptions are based on the actual costs, financing, and operation of renewable energy projects financed over the last few years.

In this section, we begin by describing the project data that we analyzed, the model used for the analysis, and the outputs of the model relevant to addressing federal policy impact. We end the section with a discussion of some key strengths and limitations of using project financial modeling to address federal renewable energy policy impact and cost-effectiveness.

3.1 Getting Cases from Actual Project Statistics

To address the impact and cost-effectiveness of federal incentives, we began by collecting data on the timing, cost, performance, and financing structures and conditions of utility-scale renewable energy projects which were either financed or deployed in the U.S. between 2008 and mid-2012. The data is summarized in greater detail in Appendix A, but the key project data needed to faithfully capture the cost of electricity and the most important sources used to obtain them were:

- **Project costs and timelines** – We used cost and timelines from Bloomberg New Energy Finance's proprietary database of projects either financed or deployed from 2009-12.
- **Project performance** – We used the historical performance of most large renewable generators from the Energy Information Administration's project database operating from 2008-11, along with electricity market and time of use data from various sources.
- **Financial structures** – We used published ranges of expected after-tax returns to investors, debt conditions, and examples of financial structures and requirements from a number of sources (LBNL, US PREF, Mintz-Levin, S&P, Moody's).

We used the distribution of project sizes to identify clusters of projects which could be reasonably modeled by single representative cases. Based on the size and total generating capacity of those clusters, we chose three of particular importance. We used the median values for key technical characteristics of each of those three clusters to define generic project cases—a large wind farm, a small utility-scale solar PV facility, and a large solar PV facility. All cases were assumed to have been financed in mid-2010 for our policy impact analysis, roughly the mid-point of the range of project financing dates we studied.

Table 2 summarizes the basic characteristics of the three 2010 cases.

Looking forward to potential policy impacts and cost-effectiveness in 2013, we use modified assumptions based upon recent market conditions (Table 3).[6] The key changes relative to 2010 are: updated costs for wind and solar PV; improved performance for wind; increased size for large PV; slightly lower tax equity costs for solar PV; and revised policy settings (ITC for solar, and we assume the PTC for wind is extended to 2013).[7]

6 Key sources are US PREF (2012), Wiser et al. (2012) and Chadbourne & Parke (2012).

7 Our assumptions for cost and performance are based on work by LBNL and NREL on recent trends in wind turbine costs - http://eetd.lbl.gov/ea/ems/

Table 2: Basic details of the three representative 2010 cases

CASE	SIZE (MW)	CAPACITY FACTOR (%)	COST ($/W)	RATIONALE
Small Solar PV	1.2	18	6.0	Majority of deployed projects
Large Solar PV	15	24	4.2	Greatest deployment growth
Large Wind	131.5	31	2.1	Majority of deployed capacity

Table 3: Basic details of the three 2013 cases

CASE	SIZE (MW)	CAPACITY FACTOR (%)	COST ($/W)
Small Solar PV	1.2	18	2.2
Large Solar PV	60	24	2.2
Large Wind	131.5	39	1.8

Full technical and financial inputs for all 2010 and 2013 cases are provided in Appendix A.

3.2 From Case Data to Impact and Cost-Effectiveness

We developed a levelized cost of electricity (LCOE) calculator and financial model to take the available technical and financial characteristics of a case in a given policy scenario and calculate:[8]

1. The impact of federal incentives and financing costs on the cost of electricity to ratepayers
2. The total cost to state and federal government to achieve a given cost of electricity to ratepayers

Here, we will describe the methods used to arrive at the two metrics and discuss the interpretation of the results.

3.2.1 Determine the financing structure used for each case and policy scenario

For each case and policy scenario, we first used the LCOE calculator to determine the lowest cost of electricity that could be achieved while meeting all financing requirements. Specifically, we:

- **Determined possible financial structures** – We used published data and studies to manually define a list of potential financing structure scenarios (e.g. with or without debt, tax equity, construction financing), each accompanied by specific required investor returns. 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).[9]
- **Calculated the cost of electricity for each financial structure** - For each financing structure, we used the LCOE calculator to compute the additional revenue above market prices needed to simultaneously:
  - **Maximize debt volume** – This is determined by the requirement that the cash flow available to pay debt in each period exceeds the required payment by a certain Debt Service Coverage Ratio (DSCR).
  - **Meet all investor return requirements** – This is determined by the requirement that the cash flows for each equity or tax equity investor reach their required internal rate of return (IRR) at the appropriate time while optimizing the tax equity financing arrangement (within the constraints of IRS rules) to minimize the cost of electricity.[10] The financial model of the project is used to verify that the additional revenue for each financing structure does indeed allow the project to meet the relevant IRR and DSCR requirements.
- **Picked the financial structure with lowest final cost of electricity** – We manually selected the financial structure that resulted in the lowest final cost of electricity, and modeled the cash and tax flows assuming the use of that structure for further calculations.

3.2.2 Calculate the impact of federal incentives on the cost of electricity

We used the model of the cash and tax flows of the lowest cost structure to assess the impact of federal provisions on the cost of electricity in each case and policy scenario. Specifically, we:

- **Calculated a counterfactual cost of electricity without incentives** – We used the cash flow model to calculate levelized cost of electricity for each project, assuming that it was financed by a regulated utility as an investment on its balance sheet without any incentives—that is, using a discount rate equal to the utility cost of capital.[11]

reports/wind-energy-costs-2-2012.pdf. Specifically, we use the average of the projected 2013 capacity factors and costs of all technology options expected to be available for a wind regime corresponding to our 2010 large wind case (roughly 6.5 m/s – see Table A-2).

8 The cash flow model is based on a financial model previously developed by CPI; see Appendix A.1 of http://climatepolicyinitiative.org/publication/the-impacts-of-policy-on-the-financing-of-renewable-projects-a-case-study-analysis/. The additional capabilities of the LCOE calculator and cash-flow model used to perform this calculation are described in Appendix B.

9 We do not include leveraged tax equity structures in this analysis as very few projects have employed these structures to date, due to concerns with subordination of tax equity structures to project-level debt (see discussion in US PREF (2011)).

10 We do not, however, model capital adequacy requirements.

11 The regulated utility cost of capital is often used as a benchmark for appropriate capital costs for generation assets, due to the prevalence of rate of return regulation. In this case, we used the cost of capital calculated by the California

We believe that this provides a realistic baseline cost of electricity without policy support.

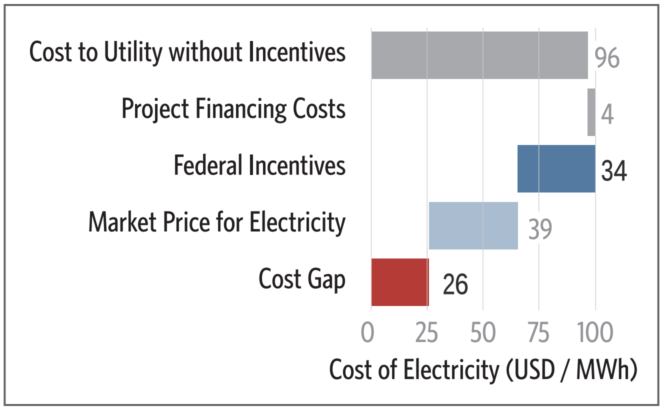
- **Compared the counterfactual and the actual cases to capture the impact of incentives** - We then calculated the contribution of incentive and financing cash and tax flows to the difference in levelized cost between the utility financed counterfactual case and the actual financing.

For example, consider the large wind case in 2010 assuming the use of a 1603 Cash Grant and debt. Figure 2 summarizes the results of our analysis where the terms are defined as follows:

- **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 34% of total costs for wind, including $24/MWh from the 1603 Cash Grant and $11/MWh from accelerated depreciation and 50% bonus depreciation).

Public Utilities Commission for the 2009 Market Price Referent, 8.25%.

Figure 2: The impact of federal incentives on the large wind case in 2010 with a 1603 Cash Grant



- **Market price for electricity** – The expected after-tax revenue from electricity sales at projected future national average wholesale market prices (taken from EIA's 2010 Annual Energy Outlook) adjusted for the time of use (about $39/MWh for wind).
- **Cost gap** – The difference between the final cost of electricity and expected market prices 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—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).

3.2.3 Calculate the cost of the federal incentive to all levels of government

We then calculated the cost to all levels of government (either in the form of direct payments or foregone tax revenues) of policy supports utilized by the project (such as grants, tax credits, accelerated depreciation, or deductions of interest expenses). This cost was calculated as the present value of all flows to government discounted using zero-coupon treasury security yields of the appropriate maturity.[12] That is, we are assuming that any impact on government cash flows is marginal and therefore must be financed through a government debt transaction (either the purchase or sale of a treasury security). Note that since we are computing costs to all levels of government, this is implicitly assuming that marginal shifts in state government finances are enabled by transfers from the federal government.[13]

The cost to government of an incentive isn't just captured by the direct cash flows associated with, for example,

12 These are bills, notes, or bonds depending on the maturity—we refer to them just as treasuries.

13 The focus on combined cost to all levels of government arises from a modeling limitation—our model currently uses a blended state and federal tax rate for calculations. Another consequence of this is that we cannot separately distinguish state and federal tax benefit carry-forward. This could, therefore, underestimate the cost to government of carrying forward federal tax credits (but not deductions). However, as all the financial structures we consider in policy scenarios with tax credits involve the use of tax equity, this issue does not affect our current analysis.

foregone tax revenues due to the tax incentive. The choice of incentive may affect the extent to which the project utilizes other federal tax provisions—such as accelerated depreciation or business interest deduction tax benefits. For example:

- The use of an investment tax credit reduces the depreciable basis of the facility by 50% of the value of the investment tax credit, thereby reducing the cost to government of the accelerated depreciation benefit.
- A production-based cash incentive in lieu of a PTC provides additional project cash flow that may allow the project to take on a larger loan than it would have without the incentive. As the interest on the larger loan is tax deductible, this increases the cost to government of the interest deduction.

However, accelerated depreciation and interest deduction tax benefits are broadly provided across industries in order to correct for the distortion of economic activity associated with corporate income taxation.[14] Further, when a legislative proposal for an incentive is scored (that is, assigned a cost either by the Congressional Budget Office or the White House Office of Management and Budget) interactions of this form are not included, as those broader investment tax provisions are treated at a macroeconomic level and scored using relations to expectations of investment growth. So, we separately report the **incentive cost**—the cost to state and federal government that results directly from the incentive alone and is relevant to scoring—and the change to the cost of accelerated depreciation and interest deduction tax expenditures resulting from the interaction. The sum of these two costs is the **total cost** to state and local governments of providing the incentive at a project level.

Take, for example, the large wind case. We calculate the cost of a 1603 Cash Grant to state and federal government by calculating cash flows to and from government associated with the provision of the cash grant alone, discounted at treasury rates. This yields an incentive cost of $18 / MWh. The loss in tax revenues associated with accelerated depreciation is $5 / MWh, and the loss in tax revenues associated with the provision that enables businesses to deduct interest payments on debt as expenses for tax purposes is $5 / MWh. This comes to a total cost to federal and state government of $28 / MWh.

14 See, for example Zee et al. (2002)

Even more broadly, you could consider how sales of power from the project impact tax revenue (e.g., see US PREF, 2012 undertaken in collaboration with SolarCity on the tax revenue impact of the ITC). However, such revenues are part of the base tax code; if the incentive had not redirected investment and consumption to the renewable energy facility, greater investment and consumption would likely have occurred elsewhere, with associated tax revenue. So, we exclude those tax collections from our analysis.[15]

3.3 Limitations and Opportunities

Project-level analysis like this can provide precise answers to questions regarding the costs and benefits of policies at a micro-level. However, it can leave out many critical costs or benefits which are often only visible when looking across project portfolios, at the broader economy, or over longer time periods. For example, this analysis doesn't capture policy impacts on innovation and technology costs. The analysis also does not address in detail how the impact and cost-effectiveness of federal policies may vary across the country due to the interaction of federal policies with the multitude of different state policies (such as Renewable Portfolio Standards). System-wide issues which can be affected by the nature of the incentive provided, such as grid reliability and stability, are also beyond the scope of this analysis.

We do not address macro-economic impacts of polices—on energy markets, prices, demand, and on the supply and cost of capital. So we cannot estimate the overall magnitude of the impact of policies on likely deployment rates, and therefore only provide estimates for the impact of policies per unit of electricity generated. However, our analysis of cost-effectiveness only compares policy scenarios which deliver the same benefits to the project as current policies. Therefore, we can (and do) reasonably assume that the scenarios would result in similar levels of deployment.

In spite of these limitations, careful accounting of costs and benefits at the project level can help evaluate policy impact and cost-effectiveness. This careful accounting captures the direct financial impacts of the incentives,

15 We note that this argument fails if such counterfactual private activity is significantly less likely—for example, in the case of a depressed economy, where fiscal policy may stimulate truly additional economic activity. However, in that case, the more appropriate question may be if the incentive has a higher economic multiplier than other forms of fiscal spending.

provides a reasonable first approximation to understanding their impacts, and can deliver insights robust and simple enough to help build consensus for policy change.

4 Importance of Federal Incentives

Absent incentives, the cost of electricity from wind and solar PV still exceeds current market prices in much of the U.S. Policy supports are employed to bridge the gap between the cost of renewable electricity and the price at which that electricity can be sold on wholesale electricity markets. These supports are provided for a number of reasons – for example, to correct for the fact that some of the benefits of renewable energy generation, such as avoided carbon emissions, are not yet reflected in market prices. These supports can also come from a number of sources: ratepayers (through requirements imposed by state or federal regulators), state and local governments, or federal incentives. To explore the relative importance of federal incentives, for each of the three project types, we:

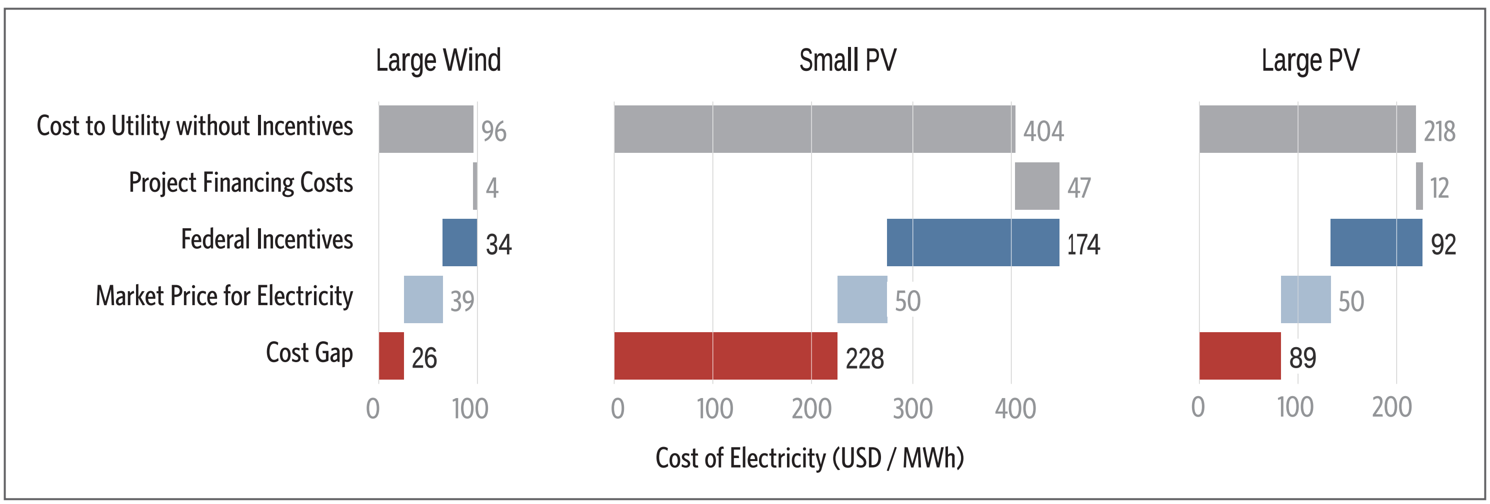
- Modeled the most widely used incentive and financial structures for projects financed in mid-2010 and those expected in 2013 assuming extension of current policy,
- Computed the impact of the incentive on the cost of electricity, and
- Compared it to the remaining gap to wholesale market prices.

4.1 Federal Incentives and Project Viability in 2010

> Federal incentives available to projects financed in 2010—specifically the 1603 Cash Grant and accelerated depreciation—bridged roughly half the gap between the costs of renewable electricity generation and expected market prices for electricity.

Project finance structures with project level debt and sponsor equity had the lowest cost for all cases. While project costs varied across technologies and sizes, federal incentives were not enough to bridge the gap between electricity generation costs and market prices for electricity for the vast majority of projects financed in 2010. Therefore, deployment of wind and solar has proceeded largely in areas where complementary state, local, or ratepayer policies apply (e.g. an RPS requirement), in regions with significantly higher than average wholesale electricity prices, and/or in places where conventional electricity generation development is constrained.

Figure 3: Impact of federal incentives on projects financed in 2010



4.2 Were Federal Incentives Necessary?

In theory, states or ratepayers could have increased their support to bridge the cost gap in the absence of federal support. In practice, the global recession and the resulting state fiscal constraints made such additional support unlikely.

Over the last decade, a number of states have implemented renewable energy policies such as binding targets for renewable energy generation or state tax concessions. These policies often include mechanisms to cover the gap between the cost of renewable electricity generation and market prices for electricity. These may involve explicit funding or subsidies such as tax concessions, rebates, or separate state funds for renewable energy. Others may involve implicit support—for example, regulators may be empowered to authorize increases in retail electricity prices to cover a utility's incremental costs for compliance with renewable energy targets.

In theory, states with such policies in place could have covered the cost gap in the absence of federal support through the increased use of such mechanisms. However:

- **State budget constraints from the recession made increasing support from states unlikely.** The global economic downturn, which began with the financial crisis of 2008, was particularly difficult on state budgets. Significant tax revenue losses associated with economic contraction along with increased mandatory spending to provide services to those impacted by the downturn (such as through Medicaid insurance) created significant fiscal pressures in nearly every state.[16] While the American Reinvestment and Recovery Act provided $145 billion to state and local governments to help them cope with the downturn, this covered only about 40% of state deficits and states were nevertheless forced to make severe cuts to essential services. The cuts were particularly severe in states with balanced budget requirements. These constraints made it unlikely that states would have increased spending if federal renewable energy incentives had been removed.
- **The recession's impact on electricity demand made additional ratepayer support unlikely.** The impact of the recession on ratepayers was similarly stark. Unemployment reached nearly 10%. According to FERC, electricity demand in the U.S. fell by 4.2% in 2009 due to decreased economic activity (the steepest drop in 60 years). As a result, utilities and the relevant regulators would have faced an exceptionally difficult business and political environment for making a case to increase retail rates to cover additional costs of new renewable electricity generation.
- **European states facing fiscal constraints pulled back renewable energy policies but U.S. states did not.** Nevertheless, renewable energy deployment in the U.S. continued to grow during the recession, and most state renewable energy targets prior to the recession were either maintained or strengthened. This is in marked contrast, for example, to the impact of the downturn on renewable energy deployment in Europe. E.U. Member States facing significant fiscal constraints—such as Spain and Italy—abruptly curtailed their renewable energy policy ambitions in the absence of E.U.-wide fiscal support analogous to the support provided by federal incentives to U.S. states.

Thus, we believe that additional state or ratepayer support was not likely and that federal policies were critical to the recent growth in renewable energy deployment. Due to the continued weakness of the global economy, it does not appear that the budget and demand constraints noted above are likely to ease in the near term. Further, as we noted in the introduction, current state policies alone do not appear to be strong enough to sustain the level of growth in renewable energy deployment seen over the last four years. The PTC was allowed to expire at the end of 2001 and 2003 when wind faced similar market conditions, leading to booms just prior to expiration followed by substantially lower deployment in the year after. As a result, it is likely that the expiration of federal incentives, in particular, the PTC for wind, could lead to significantly reduced levels of annual renewable energy deployment in the near future, another boom and bust cycle for renewables.

16 See for example - http://www.brookings.edu/research/reports/2011/10/27-state-budgets-gordon

4.3 Federal Incentives and Project Viability in 2013

Rapid reductions in generation costs for both solar PV and wind over the past two years have substantially narrowed the cost gap. If these trends continue and the PTC is sustained, wind could be almost viable in 2013 based on federal incentives alone, leading to wind deployment in states without other support policies.

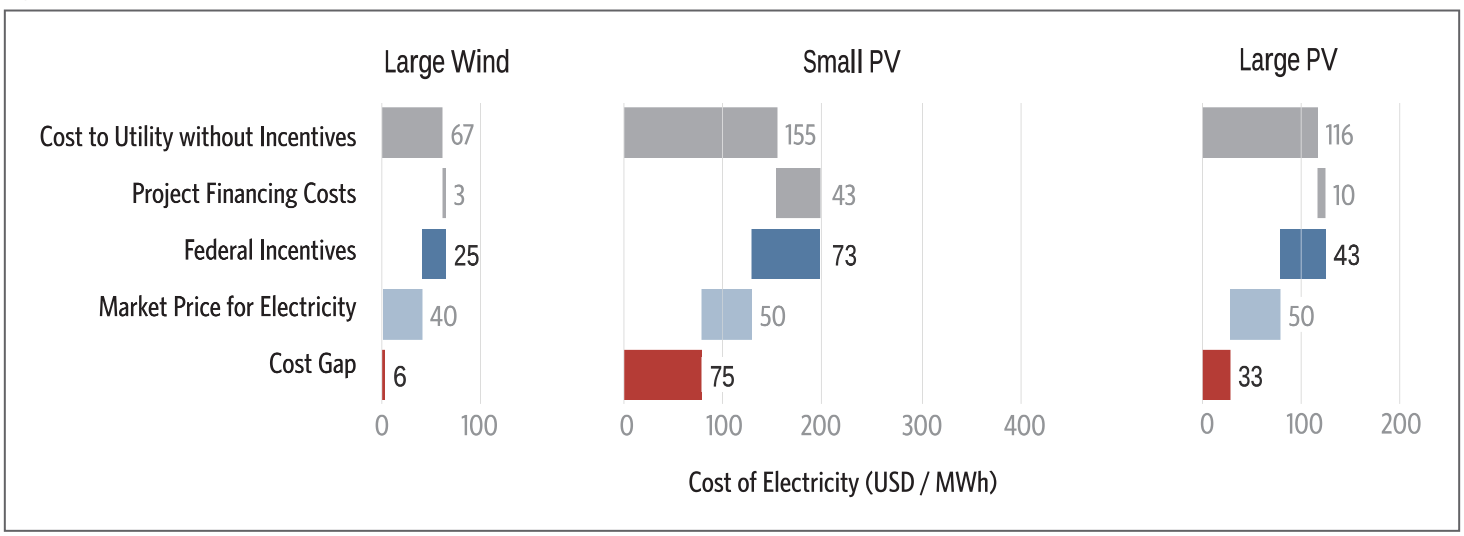
Unlevered tax equity financing leads to the lowest cost of electricity for all three cases in 2013.

Turbine performance improvements and lower turbine contract prices mean the unsubsidized cost of wind electricity coming on-line could drop by nearly 30% from $96 in 2010 to $67/MWh in 2013. If the PTC were extended through 2013, federal incentives alone (the PTC and accelerated depreciation, with tax equity financing at current costs) could cover nearly the entire gap for an average wind project, leading to a final cost of electricity of $46/MWh, within $6 of expected average market prices for the electricity generated. At these prices, wind could be viable in some regions without complementary state policies. As existing state policies can only drive limited growth, this could encourage significant additional deployment and avert a significant contraction of the renewable energy industry.

Solar PV has seen even steeper cost reductions but still requires some support beyond federal incentives. Nevertheless, the cost gap is closing. If U.S. utility-scale installations in 2013 can match Germany's average installed costs for small ground-mounted solar PV installations in mid-2012 (about $2.20/W—a conservative assumption, given smaller installations are generally more expensive than larger ones) large solar PV would face a market price gap after federal subsidies of about $33/MWh, about a third of the gap seen in 2010. This suggests that solar PV could soon be cost-competitive in states with particularly good solar resources, higher than average electricity prices, or even modest complementary policies.

Despite these gains, a number of challenges could significantly diminish the competitiveness of renewable technologies in the near term. These include a significant fall in expected electricity prices due to falling natural gas prices and softer economic growth, the risk of curtailment, and international renewable technology trade disputes.

Figure 4: Impact of federal incentives on projects built in 2013



5 Cost-Effectiveness of Federal Incentives

The form of the incentive provided can significantly impact the cost of financing a project. This issue is particularly acute with tax incentives:

> Cash incentives are a more cost-effective way to support projects than tax incentives.

Project stakeholders must have significant, predictable tax liabilities to make use of federal tax incentives. In principle, this promotes renewable energy business models which are more profitable and more likely to be sustainable. Unfortunately, project owners do not typically have sufficient tax liabilities—whether from the project itself or other business activities—to use the tax benefits as they are generated.

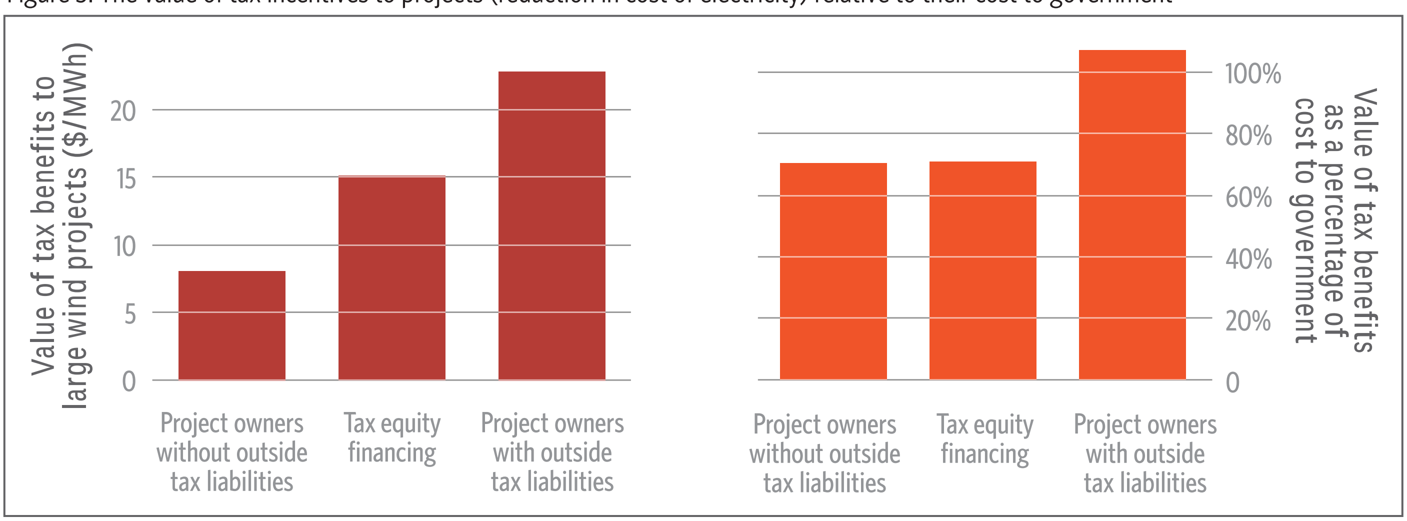
For a large wind project with debt in 2010, the PTC and accelerated depreciation benefits reduce the cost of electricity by $24/MWh (at a cost to governments of $21/MWh) if the investor has enough tax liabilities from other business activities to use all the tax benefits as they are generated by the project. However, the value of these incentives is just $8/MWh (at a cost to governments of $11/MWh) if the investor does not have tax liabilities from other business activities. So, without outside tax liabilities, the tax benefits have only a third of their potential value to the project.

This motivates project developers to bring in an outside investor with such tax liabilities—a tax equity investor—to monetize the tax incentive and finance the project. However, the high cost of tax equity financing only allows project developers to realize two-thirds of the full value of the tax benefits ($15/MWh, at a cost to governments of $21/MWh). Thus, the costs associated with tax equity finance substantially reduce the impact and cost-effectiveness of the incentive.

To quantify how these issues impact the relative cost-effectiveness of current federal policies, we:

- **Calculated the cost of electricity for each 2013 case assuming current policy, the use of project-level debt, and project owners without outside tax liabilities.** Assuming current policy (ITC for solar PV, PTC for wind), we calculated the cost of electricity in the lowest-cost project finance structure. We assumed that project owners and investors did not have any tax liabilities from other businesses they expected to use to offset the tax benefits generated by the project.
- **Determined the level of alternative incentives which achieve the same cost of electricity.** For each alternative policy (a 1603 Cash Grant, PTC, ITC, non-taxable cash incentive for production, or a taxable cash incentive for production) we used the levelized cost of electricity (LCOE) calculator

Figure 5: The value of tax incentives to projects (reduction in cost of electricity) relative to their cost to government



to determine the level of incentive required to achieve the same cost of electricity. 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 \$11/MWh or \$22/MWh—however, it is necessary to make a meaningful comparison of their relative cost-effectiveness. We choose the project finance structure which leads to the lowest level of incentive for each policy scenario (unlevered tax equity for the ITC and PTC; debt and equity for the other three), again, assuming that project owners do not have outside tax liabilities.

- **Calculated the cost to the state and federal government.** We then determined the total cost to state and federal government for providing the incentive for each case and policy scenario.

5.1 Small Solar PV in 2013 and 1603 Cash Grant

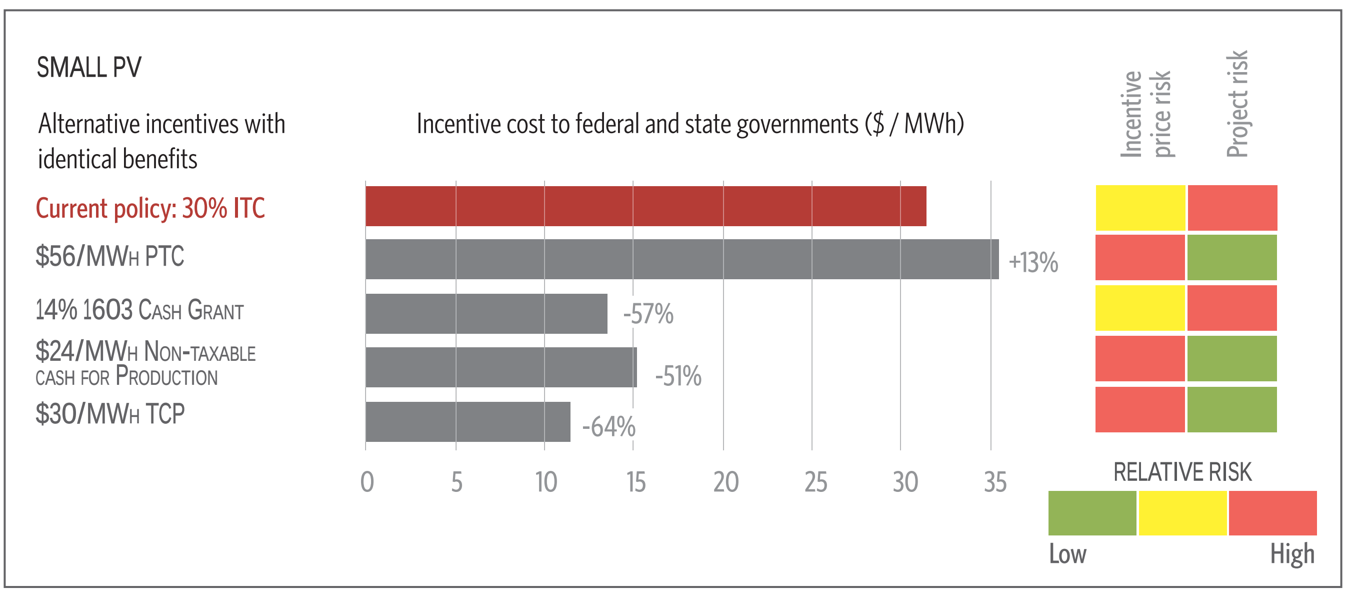
For small solar PV in 2013, a 14% 1603 Cash Grant could provide the same benefit to the project as the current ITC at half the cost to state and federal governments.

The current 30% investment tax credit (ITC) for an average small PV project in 2013 would cost federal and state governments \$31/MWh. A 14% 1603 Cash Grant would provide the same benefit to the project and its investors for a 57% lower cost to government. It would take a \$56/MWh production tax credit (PTC) to get the same benefit; this would cost governments 13% more than the ITC. Thus, the federal government could provide greater benefits to small solar PV projects at lower unit cost by offering a 1603 Cash Grant for between 14 and 30% of eligible project costs, in lieu of the ITC (Figure 6). As shown in Figure 9 below, the same would be true for large solar PV.

The differences in cost to government reflect the impact of differing levels of risks associated with the timing and nature of the benefits delivered to project stakeholders:

- **The timing of the incentive** – Up-front investment incentives reduce the overall need for and cost of financing. Thus they deliver greater benefits to the project for every dollar of government spending.
- **The ability of investors to use the tax benefits** – Cash incentives can be used by any investor, whereas tax benefits require tax liabilities. Tax equity investors take the risk that they may not have enough tax liabilities to use the tax credits, so they demand a higher return. This accounts for the difference between the cost to government of the ITC and the 1603 Cash Grant. The PTC is further impacted by the timing and variability

Figure 6: Small PV policy options – costs and risks to federal and state governments



of the tax benefits, which are tied to 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.

While the ITC and the 1603 Cash Grant are less expensive than the PTC for the average project, they allocate some project cost risks to the government.

The PTC fixes the cost to the federal government for every MWh of renewable electricity produced. In contrast, investment-based incentives (ITC or 1603 Cash Grant) provide the same subsidy for any given investment independent of the quality of the renewable resource or the performance of the project: This leads to variable rewards per MWh. Our analysis suggests that this variation is significant across existing solar PV power plants; comparable investment-based incentives translate to a nearly 70% variation in the per MWh cost of the subsidy to government.

Investment-based support enables government to share the burden of technology cost risks with investors. This makes sense for the scale-up of innovative technologies. However, it 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. While it is too early to conclusively judge the effect on U.S. solar PV development, we can see some hints of this weakness in the variation in capacity factors observed in EIA solar PV power plant operations data.

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

Cash incentives for production could reduce costs to government and, at the same time, allocate project cost risks to developers and investors (Figure 6). However, these increase the incentive price risk to government, as discussed in section 5.3 below.

For the small solar PV facilities, a 1603 Cash Grant led to a cost of electricity at least $15/MWh lower than any financing structure with a tax credit. This is largely due to the fixed financial fees associated with obtaining tax equity financing for small projects, equivalent to $29-38/MWh generated. On the other hand, the large solar PV case yielded essentially equivalent cost of electricity with the ITC and 1603 Cash Grant (see Figure 9 and the subsequent discussion).

5.2 Large Wind in 2013 and a Taxable Cash Incentive for Production (TCP)

A $21/MWh TCP in lieu of the $22/MWh PTC could provide the same support to wind projects at about half the cost federal and state governments, without shifting project risks to government.

As we saw in the last section, a good federal incentive for renewable energy:

1. Delivers benefits efficiently to the investor by minimizing timing and liquidity risks, and
2. Allocates project risks to the parties best able to manage the risks (i.e., for emerging technologies, risks are shared between the private sector and government; for mature technologies, risks are managed by the private sector).

Unfortunately, none of the current federal incentives can do both of these things, at least for wind. Here, we explore a new option—a taxable cash incentive for production (TCP)—which could fulfill both these requirements. Under a TCP, the federal government would provide projects with periodic cash payments based upon actual renewable production. These cash payments would be treated as taxable income.

Replacing the $22/MWh PTC for a wind project in 2013 with a TCP of $21/MWh can provide the same benefits to the project (the same cost of electricity while meeting all financing requirements) but at just above half the cost to state and federal government. It provides many of the benefits of the 1603 Cash Grant, without shifting project risks which can be better managed by the private sector to the government (Figure 7).

As we noted in the last section, extension of the PTC could see accelerated deployment as wind becomes viable in some states without complementary policies. A move to a TCP could substantially reduce the associated impact on federal budgets or enable a longer-term extension at similar total cost.

The TCP incentive is essentially equivalent to a Feed-in-Premium (FiP), but is paid directly by the federal government rather than through ratepayer funds. The greater cost-effectiveness of a Feed-in-Premium relative to tax incentives was noted in BNEF (2011), and is consistent with our results. Hudson Clean Energy Partners proposed a similar—but not taxable—cash production incentive in 2009 (see BPC (2011)). The non-taxable cash production incentive is less expensive than the PTC because it eliminates the risks and costs associated with monetizing tax benefits. The taxable cash incentive saves even more for the following reasons:

- **Greater cash available for debt service enables higher leverage, reducing financing costs** - While an up-front subsidy can reduce the requirement for expensive tax equity, the additional cash flow available for debt-service provided by a TCP can support greater project-level debt. As debt is generally significantly less expensive than equity, this reduces financing costs.
- **Greater debt increases interest tax benefits** - As the interest on debt is tax deductible, the TCP allows developers to take advantage of this existing tax benefit.
- **Greater taxable revenue monetizes accelerated depreciation benefits** - Further, as the cash incentive is taxable, it provides the project with additional tax liability early in the project life. This allows developers to monetize accelerated depreciation tax benefits without the use of tax equity, thereby further lowering financing costs.

As a result, reductions in total cost to government are not quite as large as reductions in incentive costs. Specifically, the cost to government of the interest tax deduction provided to the project for a TCP is roughly $1/MWh higher than that of the non-taxable cash production incentive due to the greater use of debt. Further, as the ITC and 1603 Cash Grant reduce the depreciable basis of a facility, while production-based incentives do not, the cost of depreciation benefits using a production-based incentive are about $2/MWh higher. Thus, the reduced cost to government of the TCP is in part offset by the increased use of existing investment tax benefits. For large wind, the total cost to federal and state governments of a $21/MWh TCP including accelerated depreciation and interest tax benefits is 21% lower than the total cost of the $22/MWh PTC (Figure 8).

Figure 7: Large wind policy options – costs and risks to federal and state governments

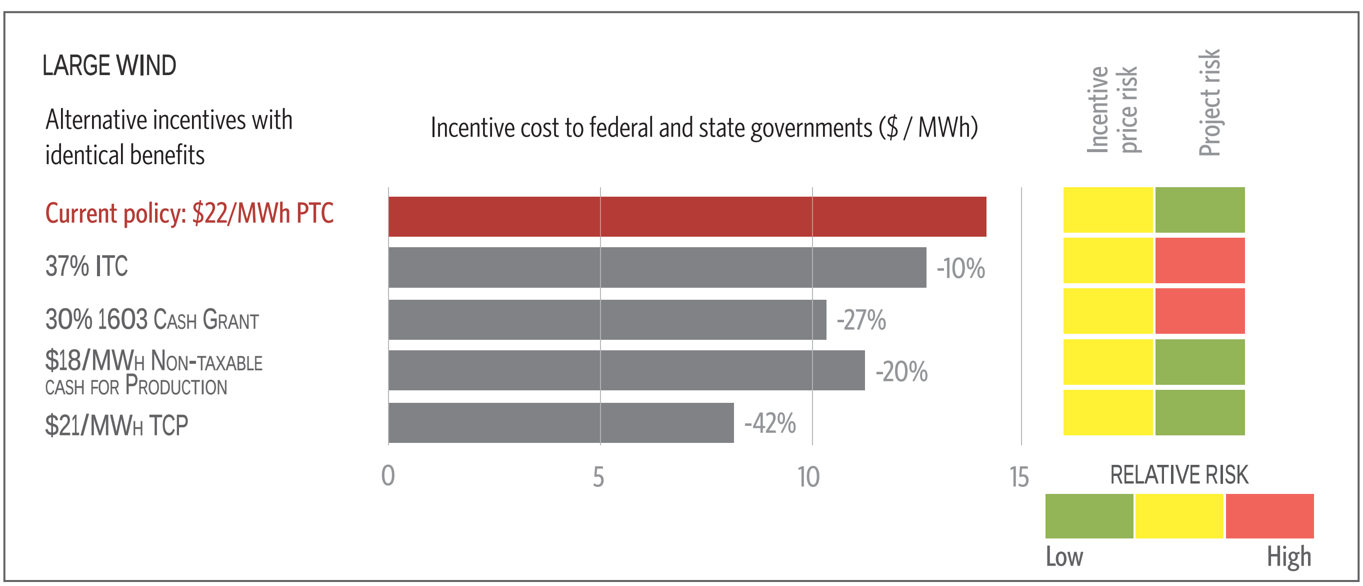
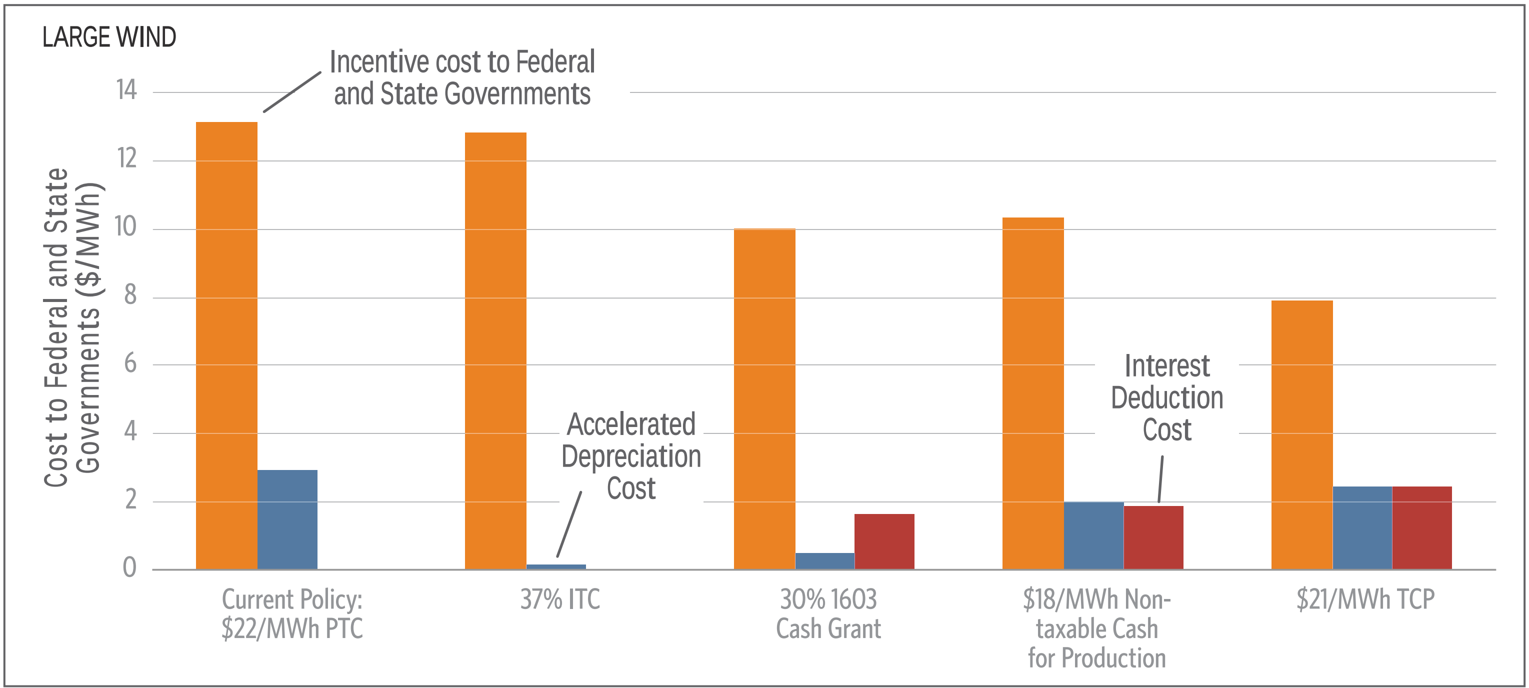


Figure 8: Cost of accelerated depreciation and interest deduction benefits to federal and state governments: Large wind facility in 2013. All scenarios deliver equal benefits to the large wind facility.



Note: The ITC and PTC case do not include project level debt and therefore have no government cost associated with the interest tax deduction at the project level.

Like BPC (2011) and BNEF (2010), we also found that the 1603 Cash Grant could be significantly more cost-effective than the PTC. Our estimated reduction in cost to government is roughly 25%, lower than BNEF's estimate of 50% per project. We believe that this difference is likely explained by:

- Our use of discounting by treasury interest rates to calculate costs to government rather than an undiscounted sum of nominal costs over multiple years.
- The difference in tax equity spreads from 2009-2011 relative to BNEF's calculation which considered tax equity market conditions for projects from 2004-2008.

5.3 Large Solar PV in 2013 and Incentive Price Risk

A TCP incentive could reduce government costs by 60% for a large solar PV facility, but the move to a fixed-price production incentive brings new risks to government.

The current 30% investment tax credit (ITC) for a large solar PV project in 2013 would cost federal and state governments $20/MWh. It would take a $36/MWh production tax credit (PTC) to deliver the same benefit; this would cost governments 13% more than the ITC. A 15% 1603 Cash Grant could provide the same benefit to the project and its investors for half the cost to governments of the ITC.

Cash incentives for production could reduce costs to government and, at the same time, allocate project cost risks to developers and investors. The TCP reduces costs to government across the range of projects analyzed, although the price level that provides equivalent benefits to the existing ITC varies depending on the project size and other characteristics. For example, a $22/MWh taxable cash incentive for production (TCP) could provide the same benefit to a large solar PV project in 2013 as the ITC, at 60% lower costs to government; while a $30/MWh TCP could provide the same benefit to a small solar PV project as the ITC, at 64% lower costs to government. Thus, the federal government could provide the same benefits to solar PV projects as the current 30% ITC, at lower unit cost, by offering a TCP in lieu of the ITC. The government would also benefit by shifting project performance risks back to the private sector.

However, this move would increase the incentive price risk borne by government. In general, when government sets the level of an incentive, it bears the risk that the level it sets may not be appropriate. This is particularly acute for production-based incentives, where government directly sets a price level. It is less problematic for the investment-based incentives because they scale with costs (though not directly with prices).

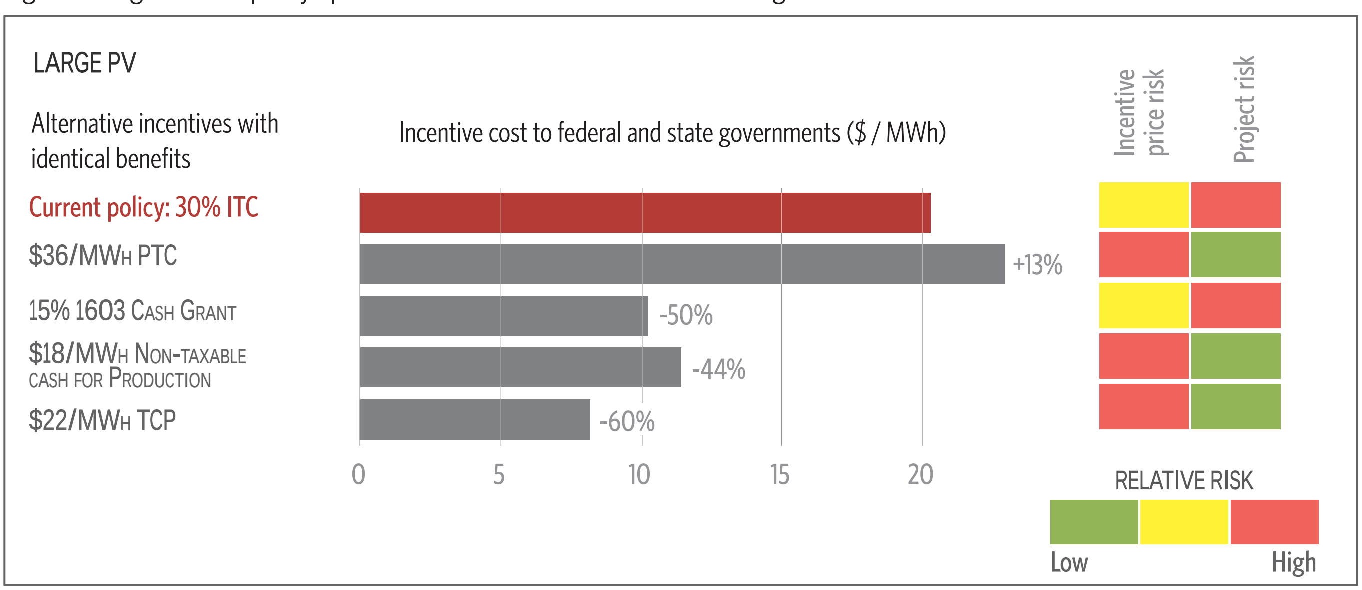
In both cases, if the government sets the incentive too low, it may not be enough to drive significant deployment. To the extent that state and ratepayer funds are able to make up the difference, this risk is somewhat mitigated in the U.S. However, as discussed in section 4, additional support for renewables from states and ratepayers is not likely in the near future.

If the incentive level is set too high, deployment may boom very quickly. This would result in ballooning costs that may be difficult to predict or control. This risk has been particularly problematic in the case of production-based incentives for solar PV due to rapidly evolving technology costs and performance (as well as the small lead times for deployment). This has been borne out by experience in Europe: Costs for solar PV feed-in-tariffs (FiT) and feed-in-premia (FiP) in Spain and Italy exploded due to much-higher-than-expected deployment driven by plummeting solar PV costs over the last few years, resulting in unexpected policy shifts which created subsequent industry busts. Solar PV costs have now fallen far below any historical nominal benchmarks. There is great uncertainty about the future cost trajectory and even significant variation in solar PV costs across geographies.

This risk is mitigated with current U.S. policy: a stable ITC in place until the end of 2016. Additional analysis would be needed to determine whether the savings associated with the TCP are sufficient to outweigh the increased risk associated with setting an appropriate price level. Absent this analysis, we cannot be sure the TCP would deliver net benefits to the government, relative to a 1603 Cash Grant.

For wind projects, the federal government already bears incentive price risks through the current PTC. Thus, a switch to the TCP involves no additional risk to government. Further, the price risk is less intense for wind than solar. While wind costs have come down substantially in the last two years, on balance, they have been relatively stable over the last decade. This has been borne out by recent experience: FiTs and FiPs for onshore wind in Europe have led to steady, cost-effective deployment over the last decade (see BNEF (2011) and Ragwitz et al. (2012)), and the PTC itself has supported steady deployment of wind in the U.S. since 2008. Note, however, that the European incentives all include mechanisms to reduce the subsidy level over time to account for and to incentivize cost reductions. Similar mechanisms could be applied to address this risk with a TCP.

Figure 9: Large solar PV policy options – costs and risks to federal and state governments



6 Conclusion and Recommendations

We used financial modeling of three representative project cases based upon cost, performance, and financing data for projects financed or deployed over the last three years to assess the impact and cost-effectiveness of federal policies. We found that:

Impact – Federal policies have played a crucial role in helping enable the recent boom in the deployment of wind and solar. They covered about half the gap between renewable energy costs and electricity market prices, enabling a six-fold increase in wind and solar generation in spite of a deep global recession. Recent reductions in the cost of electricity from wind and solar mean that the PTC alone (if extended) could fully bridge that gap for new large wind projects, and that the gap for solar has been significantly narrowed.

Cost-Effectiveness – Tax incentives are not the most cost-effective way to support renewable energy projects. Projects can only realize their full value if they can offset them with tax liabilities external to the project—a risk for investors which increases financing costs. Investment incentives can provide the same benefits to projects as production incentives at a lower cost to government. However, investment incentives shift some project risks to government. With both types of incentives, government bears some risk in setting the right level for the incentive. This risk is greater for technologies with rapidly shifting costs but can be better managed by investment-based incentives because they adjust with changing costs.

Potential Improvements – We find that a taxable cash incentive for production (TCP) would be more cost-effective than the PTC. Cash sidesteps the illiquid tax equity market. The production-based incentive allocates project cost and performance risks to private sector actors who are willing and able to bear them. In the event that the PTC is extended into 2013, our analysis suggests that the government could save more than 40% on incentive costs per MWh by delivering it as a TCP of $21/MWh over 10 years rather than a tax credit of $22/MWh.

Our work identifies two clear steps policymakers can take to improve the cost-effectiveness of federal renewable energy incentives:

1. **Extend the PTC as a taxable cash incentive for production (TCP)** – In the near term extend the $22 / MWh PTC for wind but deliver it as a $21 / MWh TCP. This would:
    - » Maintain the same effective level of support for wind projects.
    - » Reduce the cost of the incentive to federal and state government by around 40% for every unit of clean electricity generated.
    - » Avert a bust in the wind industry, and stimulate deployment even in states or regions with no local or state policy supports.
2. **Give solar PV projects the option to take a 20% 1603 Cash Grant in lieu of a 30% ITC** – This option could increase the value of the incentive to the project while reducing the cost to government of providing it.

This analysis has important limitations which we hope to address in future work. We have not considered policy measures such as national renewable portfolio standards, reverse auctions, or cap and trade systems which rely on market mechanisms to set price levels. These mechanisms could be much more cost-effective in the long term if the gains in the economic efficiency of using markets to determine price levels are not offset by expense of incentive price volatility. As our previous work (CPI, 2011) suggested that incentive price volatility could lead to higher financing costs, it is an open question as to which policy option would be most cost-effective. We have also not considered options to eliminate the stop/start problems of temporary tax provisions (BPC, 2011).

Finally, a number of policy options have been proposed as alternatives or complements to current policy, such as the use of Master Limited Partnership or generalizations of Real-Estate Investment Trusts for renewable energy. The comparative cost-effectiveness of these proposals, and their interaction with the federal policy alternatives considered here, is another area for potential future work.

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Appendix A - Summary of Project Input Data, Assumptions, and Results

To address the importance and cost-effectiveness of federal incentives, we began by collecting data on the utility-scale renewable energy projects either financed or deployed in the U.S. over the last few years. We were able to obtain the following information for utility-scale, grid-connected solar PV and wind projects:

Technical details, costs, and timelines for a large sample of renewable energy projects - We used the median costs, timelines, and size of the large U.S. wind, small solar PV, and large solar PV projects financed or commissioned between 2009 and mid-2012 contained in Bloomberg New Energy Finance's (BNEF) proprietary renewable energy project database.

Historical performance of most large renewable energy generators - We based expected project performance on the monthly electricity generation reported by producers to the EIA for projects in operation for at least one full year between 2008 and 2011. We also used this data to estimate annual performance variation as well as variation in average capacity factor across facilities. We corrected the expected revenues based on time of use factors which we estimated using: the Eastern and Western Renewable Integration Studies for hourly resource variability, NREL's System Advisor Model to model varying generation, Bloomberg Terminal data and data from ERCOT, MISO, and FERC on hourly electricity pricing.[17]

Published ranges or examples of financial structures and requirements - We used a mix of academic work and publications by law and financial firms to compile prevailing financial structures, costs, fees, required equity returns, terms and conditions for renewable energy project financings.[18]

We were not able to obtain systematic, detailed information about the financing structure, revenues, or federal and state incentives used by specific projects. So we could not use statistical methods to assess differences across projects which may be attributable to policy.

Instead, we used the project cost and performance datasets to determine median characteristics of renewable energy projects (summary statistics are provided in Table A-1 below), and compiled them into three representative, generic project cases with median values for key technical characteristics – a large 130 MW wind farm (which comprised the majority of installed capacity), a small utility-scale 1 MW solar PV facility (majority of the installed projects), and a large 15 MW solar PV facility (the bulk of deployment growth). All projects were assumed to have achieved financial closure in mid-2010, roughly the midpoint of the range of project financing dates we studied. Key modeling assumptions for the three generic 2010 project cases are listed in Table A-2 below.

We assessed the impact of federal policy on these three cases in 2010 using financial modeling based on prevailing practice (as discussed in greater detail in Section 3), and present the results of that analysis in sections 4.1 and 4.2.

For the analysis of potential impact and cost-effectiveness in 2013 presented in section 4.3 and section 5, we modified the price, performance, size, and financial assumptions based upon reports on recent market conditions such as in US PREF (2012), Wiser et al. (2012), and Chadbourne & Parke (2012). The changes relative to the 2010 cases are:

- **Updated costs and performance for wind –** 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. Specifically, we use the average of the projected 2013 capacity factors and costs of all technology options expected to be available for a wind regime corresponding to our 2010 large wind case (roughly 6.5 m/s).
- **Updated size for large PV, and costs for small and large PV –** Large solar PV projects are getting even larger. We assumed a 60MW project size based on BNEF project data trends. We assume that U.S. utility-scale installations in 2013 can match Germany's average installed costs for

17 Note that we could not systematically link the majority of projects in the BNEF database to their EIA performance data.

18 Key data sources for information regarding prevailing terms for renewable project financing include: Mintz-Levin (2012) - http://www.mintz.com/publications/3055/, and NREL's REFTI survey - https://financere.nrel.gov/finance/REFTI on investor return requirements, US PREF - http://uspref.org/white-papers on tax equity transaction costs and current market conditions, LBNL (Bolinger et al.) - http://eetd.lbl.gov/ea/ems/reports/lbnl-2909e.pdf on tax equity structures.

small ground-mounted solar PV installations in mid-2012, about $2.20/W.

- **Lower tax equity costs for solar PV –** Due to reports of increasing volumes of solar PV tax equity financings (nearly $2.5 billion in 2011 according to Chadbourne & Parke, 2012), we have assumed that tax equity IRRs for solar PV will fall to roughly 50bp above those for wind by 2013.
- **Revised policy settings –** As the 1603 Cash Grant has expired, we assume that the ITC is the only option for solar PV in 2013. We assume the PTC for wind is extended at least to 2013.
- **Updated market price assumptions –** We use EIA projections for average wholesale market prices from EIA's Annual Energy Outlook 2012 reference case scenario.

The modified assumptions for the 2013 cases are also noted in Table A-2. Detailed results of the comparative cost-effectiveness analysis for 2013 scenarios discussed in section 5 are provided in Table A-3.

Table A-1: Summary Statistics of U.S. Renewable Project Data

Key Project Features	PV	Small PV	Large PV	Wind	Small Wind	Medium Wind	Large Wind
Project Size, Cost, and Timeline (BNEF)[1]							
Number of Projects in BNEF Data	332	267	65	326	54	116	156
Total Capacity in BNEF Data	1,774 MW	455 MW	1,318 MW	28,916 MW	288 MW	4,922 MW	23,706 MW
Size of Projects							
Low (P90)	0.8 MW	0.7 MW	6.0 MW	5.0 MW	1.5 MW	19.7 MW	99.0 MW
Mid (Median)	1.5 MW	1.2 MW	15.0 MW	78.2 MW	3.3 MW	42.0 MW	131.5 MW
High (P10)	14.9 MW	3.5 MW	38.8 MW	198.8 MW	10.5 MW	71.0 MW	207.8 MW
Overnight Costs							
Low (P10)	$3.6 / W	$4.3 / W	$3.2 / W	$1.5 / W	$1.5 / W	$1.8 / W	$1.6 / W
Mid (Median)	$5.7 / W	$6.0 / W	$4.2 / W	$2.2 / W	$2.1 / W	$2.3 / W	$2.1 / W
High (P90)	$8.3 / W	$8.5 / W	$5.4 / W	$3.0 / W	$3.1 / W	$3.5 / W	$2.6 / W
Duration of Construction (Median)	2Q	1Q	3Q	3Q	2Q	3Q	3Q
Duration of Development (Median)	2Q	2Q	3Q	6Q	6Q	4Q	7Q
Project Performance (EIA)[2]							
Number of Projects in EIA Data	53	43	10	548	173	183	192
Size of Projects							
Min	0.1 MW	0.1 MW	8.2 MW	0.8 MW	0.8 MW	13.0 MW	87.5 MW
Max	48.0 MW	5.0 MW	48.0 MW	735.5 MW	12.5 MW	85.5 MW	735.5 MW
Percentile Cutoff for Category		85%	100%		33%	67%	100%
Total Capacity in EIA Data	244 MW	60 MW	185 MW	39,265 MW	806 MW	8,026 MW	30,434 MW
Median Capacity Factor							
Low (P90 Median CF)	10.4%	10.8%	14.7%	19.7%	16.7%	19.2%	23.5%
Mid (P50 Median CF)	18.8%	18.0%	23.8%	30.0%	29.6%	29.1%	31.0%
High (P10 Median CF)	25.1%	24.6%	25.1%	37.8%	34.7%	39.8%	38.3%
P90/P50 Factor							
Low (P90 P90/P50 Factor)	75.2%	73.3%	93.2%	76.5%	74.0%	79.8%	76.9%
Mid (Median P90/P50 Factor)	95.0%	95.3%	94.8%	90.8%	90.4%	91.6%	90.6%
High (P10 P90/P50 Factor)	97.4%	97.4%	97.1%	96.0%	96.0%	96.5%	94.8%
P90 Capacity Factor							
Low	7.9%	7.9%	13.7%	15.1%	12.4%	15.3%	18.0%
Mid	17.9%	17.2%	22.6%	27.2%	26.7%	26.7%	28.1%
High	24.4%	23.9%	24.3%	36.3%	33.3%	38.5%	36.3%
TOU Adjustment[3]	121%	121%	121%	95%	95%	95%	95%

[1] BNEF data are summary statistics of estimates for overnight costs and project development and construction durations based on projects financed or commissioned from 2009 to mid-2012 where data was available. As BNEF data depend on publicly available information sources (such as regulatory filings, press releases, etc.), these estimates may be biased due to selection effects. We have not attempted to correct for such biases.

[2] EIA data are based on monthly generator data collected in EIA forms 923 and 860 and include only PV and wind projects which were operating for at least one year between 2008 and 2011.

[3] We estimated Time of Use (TOU) factors using: the Eastern and Western Renewable Integration Studies for hourly resource variability, NREL's System Advisor Model to model varying generation, Bloomberg Terminal data and data from ERCOT, MISO, and FERC on hourly electricity pricing.

Table A-2: Final Modeling Assumptions

	Small PV	Large PV	Large Wind
Project Cost & Performance			
Project Size (2010)	1.2 MW	15.0 MW	131.5 MW
Project Size (2013)[1]	1.2 MW	60.0 MW	131.5 MW
Project Cost (2010)	$6.0m / MW	$4.2m / MW	$2.1m / MW
Project Cost (2013)	$2.2m / MW	$2.2m / MW	$1.8m / MW
Construction Duration	1Q	3Q	3Q
Development Duration	2Q	3Q	7Q
Fixed Operations & Maintenance (O&M)	$26 / kW-Year	$17 / kW-Year	$60 / kW-Year
Median Capacity Factor (2010)	18.0%	23.8%	31.0%
P90 Capacity Factor (2010)[2]	17.2%	22.6%	28.1%
Median Capacity Factor (2013)	18.0%	23.8%	38.7%
P90 Capacity Factor (2013)[2]	17.2%	22.6%	35.0%
First-Year Market Price Corrected for Time of Use (2010)[3]	$68/ MWh	$68 / MWh	$53 / MWh
First-Year Market Price Corrected for Time of Use (2013)[4]	$75 / MWh	$75 / MWh	$58 / MWh
Project Life	20 Years	20 Years	20 Years
Accelerated Depreciation	5-Year MACRS	5-Year MACRS	5-Year MACRS
Bonus Depreciation (2010 - none in 2013)	50%	50%	50%
Utility Discount Rate	8.25%	8.25%	8.25%

[1] Due to increasing PV project size for large solar PV projects expected to be built in 2013 observed in BNEF project data, we have chosen to consider a significantly larger project size for large PV in 2013.
[2] The P90 Capacity Factor is a more conservative estimate of capacity factor used by debt providers. The project should exceed it in nine out of 10 years it operates.
[3] Our expected wholesale electricity market prices for the 2010 cases are taken from EIA's Annual Energy Outlook 2010 reference case market price projections. Assuming 2% baseline inflation, these projections are consistent with 0.99% real market price escalation over the life of the project. Further, based on historical annual market price volatility, we assume that the P90 market prices used by debt providers are roughly 32% lower than expected market prices for both the 2010 and 2013 cases.
[4] EIA Annual Energy Outlook 2012 reference case market price projections are used for 2013 cases, corresponding to -0.14% real escalation relative to 2% baseline inflation.

	Small PV	Large PV	Large Wind
Financing Assumptions[4]			
Required Min Debt-Service Coverage Ratio (DSCR)	1.4x	1.4x	1.3x
Debt Term	10 Years	15 Years	15 Years
Term Debt Interest Rate	7.5%	7.0%	6.5%
Term Debt Closing Costs	2.4%	2.0%	2.0%
Construction Debt Closing Costs	$0.1m	$0.1m	$0.1m
Tax Equity Closing Costs	$0.5m	$0.5m	$0.5m
Tax Equity Syndication Fee	0.5%	0.5%	0.5%
Tax Equity Contribution (Unlevered)	60%	60%	60%
Tax Equity Contribution (Levered)	95%	95%	95%
Tax Equity Internal Rate of Return (IRR, 2010)	9.8%	9.8%	8.5%
Tax Equity IRR (2013)	9.0%	9.0%	8.5%
Sponsor IRR	10%	10%	9.3%
Lowest Cost Financing Structure (2010, Cash Grant)	Sponsor, Debt	Sponsor, Debt	Sponsor, Debt
Lowest Cost Financing Structure (2013, ITC for PV, PTC for Wind)	Unlevered Tax Equity	Unlevered Tax Equity	Unlevered Tax Equity

[4] Financing assumptions were drawn from Mintz-Levin (2012), NREL's REFTI Survey, US PREF (2011), Harper et al. (2007), Bolinger (2010), Moody's (2010), S&P (2009). Note that due to reports of increasing volumes of solar PV tax equity financings (nearly $2.5 billion in 2011 according to Chadbourne & Parke, 2012), we have assumed that tax equity IRRs for solar PV will have fallen to roughly 50bp above those for wind by 2013.

Table A-3: Results of analysis of costs to federal and state governments: Current policy, and alternatives that deliver the same benefit to renewable projects

Large Wind	Debt	Equity	Tax Equity	Equity IRR	Tax Equity IRR	Flip Year	Final LCOE ($/MWh)	Incentive Level	Incentive Cost ($/MWh)	Change	Accelerated Depreciation Cost ($/MWh)	Interest Deduction Cost ($/MWh)	Total Costs ($/MWh)	Change in Total Costs
Current Policy: $22/MWh PTC, No Debt		40%	60%	9.3%	8.5%	11	46	$22/MWh	13.6	**0%**	2.5	0.0	16.2	0%
37% ITC, No Debt		40%	60%	9.3%	8.5%	11	46	37%	12.3	**-10%**	0.1	0.0	12.3	-24%
30% 1603 Cash Grant	31%	69%		9.3%			46	30%	10.0	**-27%**	0.5	1.3	11.7	-27%
$18/MWh Non-Taxable Cash for Production	48%	52%		9.3%			46	$18/MWh	10.9	**-20%**	2.0	1.9	14.8	-8%
$21/MWh TCP	52%	48%		9.3%			46	$21/MWh	7.9	**-42%**	2.5	2.5	12.8	-21%

Small PV	Debt	Equity	Tax Equity	Equity IRR	Tax Equity IRR	Flip Year	Final LCOE ($/MWh)	Incentive Level	Incentive Cost ($/MWh)	Change	Accelerated Depreciation Cost ($/MWh)	Interest Deduction Cost ($/MWh)	Total Costs ($/MWh)	Change in Total Costs
Current Policy: 30% ITC, No Debt		40%	60%	10.0%	9.0%	11	125	30%	31.3	**0%**	6.5	0.0	37.8	0%
$56/MWh PTC, No Debt		40%	60%	10.0%	9.0%	11	125	$56/MWh	35.4	**+13%**	12.7	0.0	48.1	+27%
14% 1603 Cash Grant	45%	55%		10.0%			125	14%	13.6	**-57%**	4.8	5.3	23.7	-37%
$24/MWh Non-Taxable Cash for Production	53%	47%		10.0%			125	$24/MWh	15.2	**-51%**	7.2	6.3	28.7	-24%
$30/MWh TCP	55%	45%		10.0%			125	$30/MWh	11.4	**-64%**	7.7	6.9	26.0	-31%

Large PV	Debt	Equity	Tax Equity	Equity IRR	Tax Equity IRR	Flip Year	Final LCOE ($/MWh)	Incentive Level	Incentive Cost ($/MWh)	Change	Accelerated Depreciation Cost ($/MWh)	Interest Deduction Cost ($/MWh)	Total Costs ($/MWh)	Change in Total Costs
Current Policy: 30% ITC, No Debt		40%	60%	10.0%	9.0%	11	83	30%	20.3	**0%**	1.1	0.0	21.3	0%
$36/MWh PTC, No Debt		40%	60%	10.0%	9.0%	11	83	$36/MWh	22.9	**+13%**	5.2	0.0	28.1	+32%
15% 1603 Cash Grant	50%	50%		10.0%			83	15%	10.2	**-50%**	3.0	5.5	18.7	-12%
$18/MWh Non-Taxable Cash for Production	58%	42%		10.0%			83	$18/MWh	11.4	**-44%**	4.7	6.1	22.2	+4%
$22/MWh TCP	60%	40%		10.0%			83	$22/MWh	8.2	**-60%**	5.1	6.7	20.0	-6%

Appendix B - Modifications to CPI Financial Model for this analysis

The model used in this this analysis is a modified version of the financial model previously developed by CPI to support case study analysis of the impact of policy on the financing of renewable energy projects.[19] That model took as input the technical, financial, and policy characteristics of a project and calculated all cash and tax flows to and from the project over its useful life. The model was used to address two questions closely related to those we are considering here:

How did policy contribute to the actual costs and returns of a specific project? Given a specific project, the relevant policy supports, details of the actual financing structure used, and estimates of the revenues expected, the modeled cash flows were used to calculate financial metrics such as the project's internal rate of return (IRR), debt service coverage ratio, the returns to equity investors, and the contribution of policies to the cost of electricity.

How would project costs vary under different policy scenarios? For a specific project in a given policy environment, the cash flow model could also be used to numerically calculate the revenue required to meet the combined return requirements for all equity investors while simultaneously maximizing the leverage (the level of project debt) – a slight variant of the usual levelized cost of electricity for the project. By varying only the policy environment and computing the change in levelized costs, we can assess the impact of policy on the cost of financing the project.

The previous model did not have the tax equity financing detail needed to perform comparative analysis of U.S. federal incentives, nor did it have the capacity to address the cost of government of providing financial support to projects. We modified the model in several ways to address these issues:

Direct calculation of a variant of the usual levelized cost of electricity. The levelized cost of electricity is usually defined as the revenue per unit of electricity generated needed to achieve a project IRR equal to the weighted average cost of capital for the project. The weighted average cost of capital is generally provided as an input and depends on the required equity return and the leverage (along with the cost of debt). For this analysis, we have data on required after-tax returns for various investors, but rather than leverage, we have general information about the terms, conditions, and costs of debt and tax equity financing. We built a levelized cost calculator that determines the minimum revenue needed to meet the equity return requirements of both the developer and a potential tax equity investor. However, it does so while adjusting certain tax equity financing parameters and optimizing the leverage to meet a required minimum debt service coverage ratio. So our levelized cost is a function of required equity return, debt-service coverage ratio, and certain tax equity and debt costs and fees rather than equity return and leverage.

Added tax equity details. We added options to model the tax equity project financing structures used by project developers to bring in outside tax investors to help them monetize the tax benefits provided by federal incentives. These options are the parameters and conditions describing the allocation of tax and cash benefits among tax equity investors and sponsors over the life of the project, and are constrained by IRS rules as well as industry practice.[20]

Optimized tax equity structure for levelized cost calculation. We modified the levelized cost calculation to adjust the tax equity structure to minimize the revenue required to simultaneously meet the return requirements of both tax equity investors and sponsors while maximizing the leverage.

Added calculation of cost to government of various policy supports. We added the capacity to calculate the cost to government (either in the form of direct payments or foregone tax revenues) of policy supports utilized by the project (such as grants, tax credits, accelerated depreciation, or deductions of interest expenses). Specifically, this cost is calculated as the present value of all flows to government discounted using zero-coupon treasury yields of the appropriate tenor. That is, we are assuming that any impact on government cash flows

19 Described in Appendix A.1 of http://climatepolicyinitiative.org/publication/the-impacts-of-policy-on-the-financing-of-renewable-projects-a-case-study-analysis/.

20 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).

is marginal and therefore must be financed through a government debt transaction (either the purchase or sale of a treasury). Note that since we are computing costs to all levels of government, this is implicitly assuming that marginal shifts in state government finances are enabled by transfers from the federal government.

Generalized levelized cost to allow variation of policy supports. In order to compare the cost to government of different federal incentives which deliver the same cost of electricity to ratepayers, we modified levelized cost calculation to allow the revenues needed to meet financial requirements to arise (at least in part) from specific policy sources such as investment or production tax credits.