BEFORE THE PUBLIC UTIITY COMMISSION

OF OREGON

AR 538/UM 1452

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<tr><td>In the Matter of

PUBLIC UTILITY COMMISSION
OF OREGON

Investigation into Pilot Programs to
Demonstrate the use and effectiveness of
Volumetric Incentive Rates for Solar
Photovoltaic Energy Systems.</td><td>)
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TESTIMONY OF
MARK PENGILLY;
OREGONIANS FOR
RENEWABLE ENERGY POLICY,</td></tr>
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The issue most critical to the success of a Feed-In Tariff program is setting the incentive rates. Oregonians for Renewable Energy Policy (OREP) appreciates the work done by the PUC staff on the range of issues presented in AR 538. Despite these efforts, and due in large part to the limited time allotted to consider the issues, OREP believes that further work is needed to fully consider the economics of solar PV projects and set appropriate incentive rates.

Volumetric Incentive Rates

Incentive rates should be set so that they adequately compensate generators of electricity, provide a balanced subsidy to solar PV projects of varying sizes and geographic locations and do not unfairly burden ratepayers. The Straw Proposal's proposed rates are inadequate to attract capital to solar PV projects and pose the risk to ratepayers of unbalanced subsidization for small and large solar PV projects.

The PUC staff and stakeholders need to be given more time to resolve these issues. We strongly urge that an additional workshop(s) be convened in to more thoroughly consider setting the volumetric incentive rates.

Other jurisdictions which have considered Feed-In Tariffs have produced detailed spreadsheets which set forth financing costs, geographical differences in solar radiation, differences in cost for various sizes of solar PV projects, tax considerations, operation and maintenance, inverter replacement and return on investment. See, for example, Vermont's efforts at http://psb.vermont.gov/docketsandprojects/electric/7523. Samples of cost spreadsheets for solar can be seen under "Submittal from Board's Independent Witness with Final Models Agreed Upon by the Cost Modelers (December 29, 2009)".

Oregon has not yet developed the ratesetting precision necessary to ensure that its rates will produce the results intended by HB 3039. OREP recommends the following resources as providing the expertise and experience that need to be considered by the PUC:

- "Paying for Renewable Energy: TLC at the Right Price", a Deutsche Bank Green Paper on FIT Policy design, December 2009 - available online at http://www.dbcca.com/research (copy attached)

This document was compiled in collaboration with FIT experts from around the world and reflects the latest data on FIT programs (such as costs and ROI paid in different countries). It spends considerable time explaining what is required to provide certainty for investors under a Feed-In Tariff. See especially Tables on pages 5, 18, and 24. Chapter V specifically addresses issues relevant to adopting Feed-In Tariffs in the U.S.

- "Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008", from Lawrence Berkeley National Laboratory, October 2009 (copy attached)

- "Advancing a Sustainable Solar Future - Policy Principles and Recommended Best Practices for Solar Reed-in Tariffs", a white paper by SEMI® PVGroup (copy attached)

- Powering the Green Economy: A Feed-In Tariff Handbook" by David Jacobs, published by Earth Scan Publications, November 2009,

- Ontario's Feed-In Tariff launched on December 16, 2009 with 700 projects comprising 1300 MW of solar enrolling on opening day. Enrollment In Ontario's microFIT program (<10kw) is done online at their website http://microfit.powerauthority.on.ca/ and shows how simply a FIT can be made to work for smaller projects

Important Oregon Issues

Return on Investment

The proposed rates do not provide for a return on investment and are inadequate to attract capital. Experience in Germany, Ontario and elsewhere demonstrates that incentive rates which do not return a profit for investors fail to stimulate deployment of solar PV projects. With the proposed incentive rates, there would be no return on an average-cost project investment for 15 years. No rational investor would invest money that would be tied up for 15 years with no return.

Risk of Unbalanced subsidization

There is a serious risk that the proposed incentive rate structure does not adequately address the potential variation in costs of systems of different scale. The proposed rates were calculated using cost estimates based primarily on ETO projects <= 10 kW in size. More data needs to be examined concerning the economies of scale of projects which will range from 2 kW up to 500 kW in size. The differences in cost must be considered closely to ensure that subsidies to systems of all sizes will be adequate, balanced and appropriate.

Transparency

The PUC's calculation of incentive rates is not transparent. An additional workshop(s) is needed to develop a spreadsheet that provides a more detailed, explicit picture of the costs of generation for all project sizes. For example, the workshop should identify costs for labor and benefits as set in the 2009 EEAST legislation, operation and maintenance, PV panel cost, permitting, insurance, taxes, depreciation, financing and return on investment. Without transparency and more precision, the incentive rates are unlikely to stimulate development of solar PV projects or adequately protect ratepayers.

Precision

More precision in rates is needed to avoid unbalanced subsidies. For example, the December 4, 2009 Straw Proposal (Table 2) proposes three categories of project size, while Table 1 of the Straw Proposal sets out two categories of rates by project size for four different geographic zones. The disparity should be resolved; appropriate rates should be set for all system sizes and locations.

We propose that variable incentive rates, or stepped tariffs, be set with at least four project size categories (<10 kW, 10-30 kW, 30-100kW and 100-500 kW) so that rates can be set with more precision. Alternatively, one rate could be set for the first10,000 kWh produced by a project, with a lower rate for energy produced above that amount, so that it is always beneficial for projects to produce as much energy as possible, yet the economies of scale for larger projects are taken into account.

Additionally, we propose the use of the ODOE Oregon Solar Climate Zone map set forth below at page 4, with three solar climate zones, as being simpler and perhaps more accurate than the four IOU Service Counties in Table 1 of the Straw Proposal.

Deployment of Pilot Program Capacity

HB 3039 establishes a goal that 75% of the energy generated in the pilot programs be generated by smaller-scale qualifying systems. The deployment of pilot program capacity by system size in Table 2 of the December 4th Straw Proposal proposes allocating 60% of pilot program capacity to systems <= 10 kW. While this does not achieve the 75% smaller-scale goal of HB 3039, we understand it to be an effort on the part of staff to accommodate the desire of larger-system solar developers for more capacity under the 25 MW pilot program cap. OREP considers this a reasonable compromise, but the capacity allocation should not deviate further from the 75% statutory goal of the pilot programs.

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are needed to see this picture.

Conclusion

It is critical that more consideration be given to solar PV project costs and to greater precision in ratesetting. Stakeholders and PUC staff need to examine this area further in another workshop, as it is critical to the success of the pilot programs.

Oregonians for Renewable Energy Policy (OREP)
/s/ Mark E. Pengilly
OREP Representative

SEMI® WHITE PAPER

Advancing a Sustainable Solar Future

SEMI PV Group Policy Principles and Recommended Best Practices for Solar Feed-in Tariffs

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PVGroup
an initiative of SEMI

DECEMBER 2009

Advancing a Sustainable Solar Future

SEMI PV Group Policy Principles and Recommended Best Practices for Solar Feed-in Tariffs

EXECUTIVE SUMMARY

This White Paper is intended to promote widespread awareness and understanding of public policy best practices in support of solar energy.

The PV Group is a SEMI special interest group dedicated to serving the global PV manufacturing supply chain. The PV Group's mission is to help lower costs for PV energy and foster the growth and profitability of SEMI members serving this essential industry. In pursuit of this goal, this White Paper was authorized by the SEMI Board of Directors, and produced under the guidance of members and Regional Advisory Groups from around the world.

The public policy principles that the PV Group hopes to advance with the White Paper include: stability and predictability to encourage private investment; transparent and streamlined policies to promote fair and honest outcomes; and open and accessible policies to enable distributed energy production. While other policy options are available that would meet these policy principles, this White Paper is focused on the best practices that would enable feed-in tariffs to be an effective approach to advance solar energy in most markets around the world.

The SEMI PV Group supports the development of feed-in tariffs as the most effective means to ensure sustained growth for the PV industry and rapidly realize the benefits of large-scale solar energy deployment. The PV Group believes that national feed-in tariffs are an optimum policy solution, and that feed-in tariffs should be tailored to the specific context and objectives of the country that is implementing them. Feed-in tariff design should take historical PV policy and market development experience into account and be benchmarked against both the policy principles and best practices described in this report. The continued spread of national feed-in tariffs that are stable, transparent, and substantial will fuel the rapid PV market growth the world requires and support new investment in the emerging solar economy.

Feed-in tariffs are also versatile in that they can be successfully integrated with existing polices such as rebates, renewable portfolio standards, tradable renewable energy credits, net metering, and tax credits. While there may be practical and pragmatic barriers to feed-in tariffs in some regions—and in these situations other policy options may be preferable to performance-based incentives—this set of characteristics has made feed-in tariffs an attractive policy solution for many national, state, and local governments.

The proliferation of feed-in tariffs is creating a common global policy language for the PV industry, and the PV Group is pleased to join other industry organizations that support feed-in tariffs, such as the International Solar Energy Society (2009), the European Photovoltaic Industries Association (2005), Solar Alliance (2009) and many others. Although there is an emerging consensus about the benefits of feed-in tariffs, it is important to note that feed-in tariff design varies widely from country to country. Today, no two feed-in tariff policies are exactly alike, and it is difficult to generalize about the structure and impact of feed-in tariff policies. However, this diversity of policy design and experience reveals a set of best practices against which future policy development can be benchmarked. The best practices encouraged by the White Paper include support for technology differentiation, generation cost-based rates, fair purchase and interconnection requirements, use of fixed price and long-term payments, and the use of predictable incentive declines.

INTRODUCTION

During the past decade, the global photovoltaics (PV) market has grown at rates typically associated with the personal computer and cellular phone industries, rather than the power sector. Over 5.5 gigawatts (GW) of PV were installed in 2008 alone, bringing the total global installed capacity to 14.7 GW—a fifteen-fold increase over the total amount installed a decade earlier (Fontaine, et al., 2009). Although the near-term growth path for PV is uncertain given the financial crisis and shifting market conditions, analysts have projected that 2012 installations could range anywhere from 11 GW to 53 GW (Jennings, 2008). The spread between these projections is attributable to a broad range of factors including manufacturing capability, raw material supply, conversion efficiency improvements, fossil fuel price trends, and government policy. The challenge for the global PV community as it navigates the recession will be to effectively coordinate the resources of industry, government, and the marketplace to enable the market to return to a strong, predictable, and sustainable growth trajectory.

As the PV market matures, the industry must mature alongside it. In the 2008 White Paper, *The Perfect Industry—the Race to Excellence in PV Manufacturing,* the SEMI PV Group (2008) laid out a set of principles to ensure and guide the growth of the PV industry in the near- and long-terms. These include:

- development of global manufacturing standards to ensure sustained profitability;
- adoption of corporate responsibility strategies to promote sustainable development;
- adherence to market and business practices that will enable a truly global industry; and
- creation of the market, workforce, and policy conditions necessary to support long-term growth.

At the core of the PV Group's vision is a recognition that the ultimate objective of the solar industry is to reduce "the world's dependence on fossil fuels and…the dangers of global warming." Given the principles set forth in the White Paper and the critical stakes involved with the success of the global PV industry, the PV Group concludes that "the overwhelming responsibility for the PV manufacturing supply chain is to deliver the lowest cost per kWh to the user." Unlike many electricity generation technologies, the cost per kWh of solar electricity is not driven by the price of fuel—sunlight is free. The key technical challenge to the solar economy of the future, therefore, is to reduce the costs associated with PV manufacturing and installation through improved process efficiency and automation, materials improvements, and cost reductions that result from economies of scale, while maintaining or enhancing lifetime energy yields from systems.

Manufacturing expansions and efficiency improvements require significant investments. New polysilicon manufacturing plants, for example, can cost from $500 million to well over $1 billion to build, and it has been estimated that the amount required to finance the growth projected through 2012 could range from $15 billion up to $67.9 billion (Jennings, 2008). In order to realize this level of investment, the global industry will need to work with financial and public sector partners to create stable and durable markets. Targeted and well-structured government policy incentives will be critical for accomplishing this goal. In this White Paper, the PV Group explores international PV incentives and identifies policy designs to create steady demand, support long-term industry growth, and ensure sustained profitability for the global PV industry.

DEFINING POLICY FOR THE PERFECT INDUSTRY

PV Policy Principles

At present, the vast majority of the global PV market is grid-connected. Since PV is not currently competitive with retail or wholesale electricity in most parts of the world, many governments provide market support through fiscal and regulatory instruments such as tax incentives, rebates and grants, loan programs, mandatory targets, premium prices for PV-generated electricity, and research and development funds. The regulatory landscape has evolved constantly during the last 30 years, and PV incentives have been implemented in a broad range of combinations and iterations. The most robust policy regimes, however, have demonstrated the same general set of characteristics, which provide a useful set of principles against which to evaluate PV incentive programs.[1] Generally speaking, successful incentives are:

Sufficient to Drive Predictable Demand. The incentives need to be substantial enough to affect fundamental market transformation, and drive PV technology costs down their experience curves. Historically, PV prices have dropped 20% for every doubling of installed power generating capacity (Poponi, 2003). Although module prices tracked upwards during the middle of this decade, primarily as a result of silicon shortages (Flynn & Bradford, 2006), shifting global market conditions have enabled supply to catch up with demand, resulting in a projected 43% decrease in PV module prices in 2009 (Greenwood, et al., 2009). In addition to sufficiency of demand, predictability of demand is also required to ensure that market growth to be within a range of growth rates viewed as desirable.

Stable and Predictable. Policy stability is critical to creating sustained PV market growth. Policies must be in place for a long enough period of time to attract investments in manufacturing and the development of a mature industry. Moreover, the "rules of the game" need to be clearly and believably established such that any changes or alterations in the policy can be understood and anticipated ahead of time. The prospect that the policy will be frequently revisited or subject to sudden change (or reversal) can deter strategic investments and create barriers to entry for developers and investors.

1 These principles are similar to those identified through efforts such as the International Energy Agency's *Deploying Renewables: Principles for Effective Policy* (Ölz, 2008), and through concepts such as Sustained Orderly Development and Commercialization of PV (Osborn, et al., 2005).

Transparent and Streamlined. Policies should be clearly defined and simple to understand. Transparent policies allow a broad range of market participants (including individuals) to easily assess risks and make investment decisions. Overly complex policies can increase project development timelines, decrease the pool of potential capital providers, and ultimately increase financing and policy costs unnecessarily. Closely related to this is the complexity and duration of the process required to access the incentive. Even if a policy is fairly straightforward to understand, the existence of unduly onerous applications, paperwork, approvals, etc. can create a barrier to market growth and a deterrent to investment (Lüthi & Wüstenhagen, 2009).

Accessible. The globalization of the PV industry has occurred at an extremely rapid rate during the past decade. Whereas component manufacturing was concentrated in a relatively few regional markets a few years ago, PV modules from around the world now trade freely on the open market. Consistent with the PV Group's commitment to support the development of a truly global industry, sound PV policy should be neither discriminatory nor protectionist. Policies that attempt to narrowly target outcomes such as domestic content or employment will undermine the primary objectives of fossil fuel replacement, solar power cost reduction, and solar power grid parity

Programmed to Sunset. PV incentives should be structured with a transition to grid parity in mind. Several of the leading global markets have attempted to achieve this[2] by building steady decreases into their PV incentive levels in order to both put continual downward pressure on PV prices, and to lower policy costs.

Finally, the recent financial crisis has brought another characteristic of successful policies into sharp focus: the ability to attract investment. The tightening of credit markets globally and the emergence of region-specific financial challenges, such as the contraction of tax equity in the United States, has inspired a re-evaluation of policies according to the ease with which they can be financed (Fritz-Morgenthal, et al., 2009; Schwabe, et al., 2009). Moving forward, incentives should be developed with the financial markets in mind—they should be designed to mitigate identifiable financial risks (thereby lowering financing costs), and structured to attract a diverse set of competitive capital providers.

Replicating Global Best Practices

When surveying global solar energy incentives, the policy that most closely matches the principles laid out in the section above is the feed-in tariff. Generally, feed-in tariffs are renewable electricity policies that typically guarantee renewable generators both a long-term, performance-based payment for electricity at a premium price, and interconnection to the grid (i.e. the right to "feed-in" electricity).

Feed-in tariffs have driven the majority of global PV installations to date as a result of their use in key European markets such as Germany and Spain. The impact of European feed-in tariffs has inspired the adoption of similar regulations by countries around the world, and feed-in tariffs are currently the most widespread national renewable energy policy. According to the REN21 Renewables Global Status Reports, there were 37 countries with feed-in tariff policies by the end of 2007 (Martinot, 2008). By 2008, the number of national feed-in tariff policies had grown to 45 (Martinot & Sawin, 2009). As will be discussed in Section 3, momentum for feed-in tariff policies has continued to grow in 2009, with India, South Africa, and the United Kingdom among the new countries that have announced feed-in tariffs for solar power.[3]

Feed-in tariffs have spread around the world not only because they have promoted rapid expansion of a broad portfolio of renewable resources, but because they have also been able to do so at a relatively low cost. Empirical studies in the European Union and elsewhere have demonstrated that feed-in tariffs, in the words of the Stern Review on the Economics of Change (2006), "achieve larger deployment at lower costs" than other policy types. As will be discussed in greater detail below, the stable, long-term revenues afforded by feed-in tariffs create a low-risk investment environment that reduces the cost of capital required to finance renewables, and reduces policy costs as a result. Moreover, feed-in tariffs are cash payments, rather than tax credits, and so they can be readily financed by a broader range of entities using debt, rather than tax equity (which is more expensive). Feed-in tariffs also minimize or eliminate transaction costs such as contract and interconnection negotiations and bid preparations that may prohibit smaller projects from moving forward. In other words, feed-in tariffs can provide an opportunity for diverse groups of investors, homeowners, and businesses to cost-effectively invest in, build, and reap the benefits of renewable energy installations. Feed-in tariffs are also versatile in that they can, and have been, successfully integrated with existing polices such as rebates, renewable portfolio standards, tradable renewable energy credits, net metering, and tax credits. This set of characteristics has made feed-in tariffs an attractive policy solution for many national, state, and local governments around the world.

The proliferation of feed-in tariffs is creating a common global policy language for the PV industry, and the SEMI PV Group is pleased to join other industry organizations that support feed-in tariffs, such as the International Solar Energy Society (2009), the European Photovoltaic Industries Association (2005), the Solar Alliance (2009), and many others. Although there is an emerging consensus about the benefits of feed-in tariffs, it is important to note that feed-in tariff design varies widely from country to country. During the 20 years since national feed-in tariffs were first enacted in Denmark and Germany, feed-in tariff design has steadily evolved as early adopters have revised

2 E.g. Germany, Japan, and California.

3 It is important to note that feed-in tariffs can, and have been, successfully implemented in developing countries. In crafting feed-in tariffs for the developing world, policy design must take into account both available grid infrastructure and national economic conditions. Developing countries may require additional support for national feed-in tariffs, such as feed-in tariffs coupled with the Clean Development Mechanism, the use of feed-in tariff caps that are tailored to specific resource and economic conditions, and the creation of funds supported by multi-lateral international donor organizations to help pay for feed-in tariff costs (Mendonça, et al., 2009).

their existing policies, and other countries have adapted feed-in tariffs to their own unique contexts. Today, no two feed-in tariff policies are exactly alike, and it is difficult to generalize about the structure and impact (and success or failure) of feed-in tariff policies. However, this diversity of policy design and experience reveals a set of best practices against which future policy development can be benchmarked.

There have been a number of recent efforts to catalogue and evaluate feed-in tariff design practices by organizations such as the International Feed-in Cooperation in Europe (Klein, et al., 2007), the National Renewable Energy Laboratory and the California Energy Commission in the U.S. (Couture & Cory, 2009; Grace, et al., 2008), the World Future Council and others (Mendonça, 2007; Mendonça, et al., 2009). Rather than restate the work of these reports, the sections below provides short overviews of the practices that are most important to enabling sustained solar energy industry growth.

Technology Differentiation

Climate stabilization will require that a full suite of renewable energy technologies be deployed in the coming decades. Recent studies have concluded that not only is it necessary to drive current renewable technologies down their cost-curves simultaneously, but that it will also be cheaper, in the long run, to do so (Huber, et al., 2004; Ölz, 2008). To achieve this goal, feed-in tariffs need to be tailored to target different technologies with specific rates. Policies that offer a single payment rate to all technologies—such as the current feed-in tariff in California—have not created diverse generation portfolios that include solar electricity.

Generation Cost-Based Rates

A clear best practice for feed-in tariff designs that are intended to support solar market growth is that the feed-in tariff rate should reflect the specific generation cost of PV, plus a reasonable profit. This ensures that the incentive level will be sufficient to drive demand. Accurately set, cost-based rates reduce price risk for developers, increase revenue certainty, reduce financing costs, and attract a broader base of investors. The majority of Europe's feed-in tariffs are, and have been, based on generation cost. A notable exception was Germany's early feed-in tariff, the *Stromeinspeisungsgesetz* (StrEG), which was in place from 1991 to 2000. The StrEG was technologically differentiated, but the payments were based on retail electricity rates,[4] which were insufficient to drive PV investment. While the national StrEG did not stimulate the PV market, German municipal utilities in cities such as Hammelburg and Aachen developed their own generation cost-based feed-in tariffs for solar power in 1993, which successfully drove local markets (Solarenergie-Förderverein, 1994). The practice spread rapidly among German municipal utilities and was eventually adopted at the national level with the passage of the revised feed-in tariff of 2000 (the *Erneuerbare-Energien-Gesetz* or EEG).

Basing PV incentive rates on generation cost also helps level the playing field with heavily-subsidized fossil fuel generation. The United Nations Environment Programme (United Nations Environment Programme, 2008) estimates that "worldwide, energy subsides…amount to $300 billion per year, or around 0.7 percent of world GDP, most of which go to fossil fuels." In the United States, a recent study found that fossil fuels received $72.5 billion in subsidies between 2002 and 2008, whereas non-ethanol renewables received just $12.2 billion during the same period (Environmental Law Institute, 2009). Generation-cost based rates avoid the need to index PV incentives to artificially low fossil fuel prices. As solar energy reaches grid parity, a generation-cost-based FIT may be lower than the retail price for electricity. In that case, feed-in tariffs should be programmed to sunset and polices to transition net metering should be in place.

Purchase and Interconnection Requirements

Feed-in tariffs are powerful policies not only because they guarantee a known price and mitigate revenue risk, but also because they typically require that solar electricity generators must be connected to the grid, and that any electricity fed onto the grid must be purchased. These "must-take" requirements limit the market power that individual stakeholders or interests might otherwise unduly exercise, and can significantly increase investor security by reducing market and operating risks.

Fixed Price Payments

Fixed price payments, especially when paired with long-term, generation cost-based payments can significantly lower investment risk and policy cost. According to recent analysis from the International Energy Agency (de Jager & Rathmann, 2008), the low risk profile of fixed price feed-in tariff policies can reduce financing costs by 10–30%. Specifically, the IEA states that "Countries with feed-in tariff schemes…are believed to have already realised a significant part of this reduction potential for…solar photovoltaic energy (e.g. more than 20%)." Premium payment feed-ins, under which generators receive a payment on top of the market price for power, have also been effective in driving PV markets, but provide less certainty to both investors and policy makers than fixed incentive levels (Couture & Gagnon, in press).

Long-Term Payments

Since PV systems have service lives of 25–30 years and beyond, long-term feed-in tariffs are advantageous for several reasons. First, longer-term payments allow the generation cost of PV systems to be amortized over a greater number years, enabling lower feed-in tariff rates and accelerating the timeline on which the hedge value of PV can be captured as electricity prices rise. Second, long-term payments more closely align with the service lives of PV systems, thereby reducing the risks associated with re-contracting after the feed-in tariff term ends.

Predictable Declines

There are many different approaches to adjusting and revising feed-in tariff rates over time. Some feed-in tariffs adjust automatically[5] after a certain period of time or after a certain capacity target is hit, some feed-in tariffs are adjusted only

4 Both wind and solar power were eligible for a payment set at 90% of the average retail rate of electricity.

5 It is important to note that adjustment in this case refers to the adjustment of the long-term rates available for a few installed systems from one year to the next. Once a generator is locked into a feed-in tariff rate, that rate should not significantly change.

after review by policy makers, and some combine automatic adjustments with periodic reviews. Of these options, adjustment schedules that occur after a certain period of time are preferable because they are more transparent and predictable than capacity-based declines or frequent review by policy makers. Although feed-in tariffs can be both adjusted upward and downward, the overall trend should be downward in order to place pressure on PV prices. The most notable example of downward tracking feed-in tariff rates for solar power is in Germany, where the German solar energy industry association (Bundesverband Solarwirtschaft) projects that the rate of decline, or "degression," embedded in the feed-in tariffs will bring PV to grid parity between 2012 and 2015 (see Figure 1).

From an investment perspective, declining incentives should not introduce undue risk if they are based on sound market and experience curve data. A recent survey of the banking industry, for example, determined that banks consider, "The principle of degression…a sound means to motivate increases in productivity and decreases in costs (Diekmann, et al., 2008)."

INVESTOR SECURITY:
Predictability, Stability, and Durability

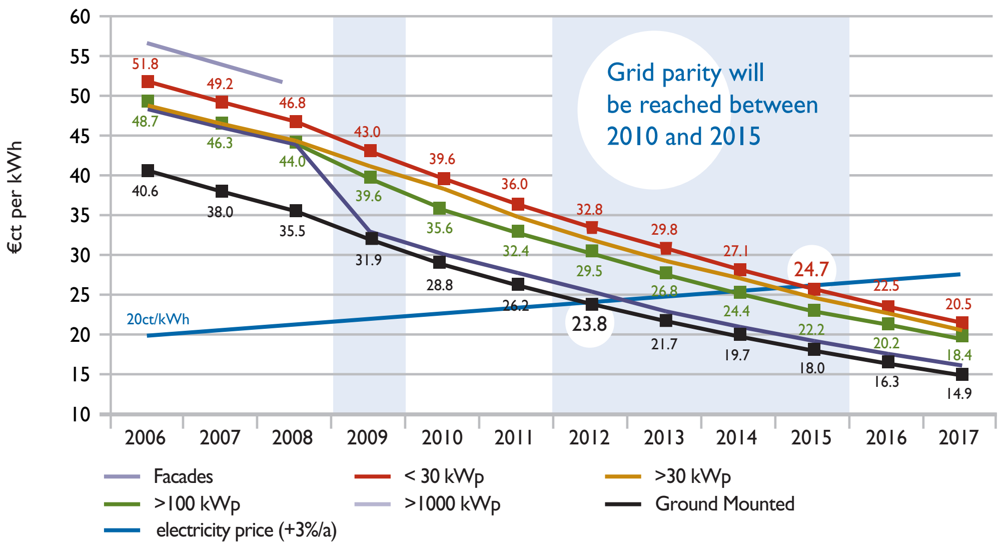
The set of feed-in tariff design characteristics described above conform closely to the policy principles outlined in Section 2.1, and their practical application around the world has generated impressive empirical results. There is now broad consensus among both the renewable energy policy making and the financing communities that feed-in tariffs are one of the most powerful solar energy policy tools available. In a comprehensive review of European Union renewable energy policies, the European Commission (2005) concluded that feed-in tariffs were not only the most effective policy for driving renewable markets, but were also the most cost-efficient because of their ability to minimize financial risk premiums, and therefore policy costs. These findings have been echoed in studies by the Stern Review (2006) and by the International Energy Agency (Ölz, 2008).

The ability of feed-in tariffs to attract low-cost capital from a broad range of different investor types has become even more important in the wake of the financial crisis. Renewable energy financing became more difficult (and more expensive) to source in nearly every PV market. The impacts have not been as severe in markets with feed-in tariffs, however, as they have been in markets that rely either on tax policy (and therefore a small base of tax equity investors) or on variable, high-risk incentives such as tradable credits (Guillet & Midden, 2009). A recent Deutsche Bank Group study found, for example, that countries with the lowest investment risk profiles for climate change and renewable energy investment are those that have strong incentives in place, and that "appropriately-designed and budgeted feed-in tariffs have demonstrated their ability to deliver renewable energy at scale" (DB Climate Change Advisors, 2009). The U.S., by contrast, was considered a moderate risk country due to its more unstable market, which has historically suffered from boom/bust cycles as a result of relying on policies such as short-term tax credits.

Another recent study by the United Nations Environment Programme's Sustainable Energy Finance Initiative (Fritz-Morgenthal, et al., 2009) reviewed the impacts of the financial crisis on the renewable energy industry found that "a clear majority" of the infrastructure providers, commercial bankers, and multilateral financial institution representatives viewed feed-in tariffs as the most effective for promoting renewable energy. A similar survey of private equity fund managers also returned the same results, with the majority of survey respondents ranking feed-in tariffs "higher than any other policy option provided" in terms their ability to inspire investment "in innovative clean energy technologies (Bürer & Wüstenhagen, in press)."

The simplicity, transparency, and certainty of feed-in tariffs can enable strong PV market growth. An important emerging issue, however, is the durability of feed-in tariff policies.

Figure 1 **Feed-in Tariffs for PV within the German Feed-in Tariff, Based on Degression Rates Decided on June 6th, 2008)**



Source: Gerhard Stryi-Hipp, Fraunhofer Institute for Solar Energy Systems ISE

Whereas revenue certainty enables low-risk investments at the project level, the perceived long-term viability of a given policy regime is what creates the conditions for larger-scale, strategic industry investments such as new market entry or expanded manufacturing. On the one hand, policy incentives are necessary to level the playing field with subsidized fossil fuels, and unlock the broad range of benefits of solar energy.[6] On the other hand, the creation of policy incentives inherently creates regulatory risk because whatever policy makers create, they can also take away.

In designing feed-in tariffs, it is not enough to create generous, long-term feed-in tariff payments—it is important to consider the stability and viability of the proposed policy. Recent research suggests that the perception of potential policy instability can outweigh the potential gain of higher feed-in tariff rates when industry investors are evaluating whether to enter a new solar market (Lüthi, 2008).

POLICY FLEXIBILITY

During the past decade, PV feed-in tariffs established a track record of being both stable and durable. After Germany revised its feed-in tariff in 2004, some analysts questioned the extent to which such a generous policy would be politically viable over the long-term (e.g., Rogol & Fisher, 2005), but most concluded that it would be difficult to significantly scale back the German feed-in tariff given strong public support and the political strength of the renewable energy industry. More recently, with the scaling back of the Spanish feed-in tariff and discussions in Germany about lower PV rate under the new government, some industry analysts have expressed anxiety about the durability of PV feed-in tariff regimes (Simonek & Chase, 2009). In general, such studies focus solely on the projected costs of feed-in tariff policies, and do not include an accounting of the significant wholesale electricity price savings generated by feed-in tariffs (Sensfuß, et al., 2008), or the significant environmental, societal, and economic development benefits that accompany rapid solar market growth. These benefits have been included in the calculus of the governments of both Germany and Spain,[7] and both countries appear committed to maintaining feed-in tariffs for photovoltaics.

Nevertheless, the shifting global market conditions and recent declines in PV module prices and installed costs have prompted evaluations of PV policy flexibility. There are a variety of approaches to feed-in tariff flexibility beyond the system of degression and periodic review employed by Germany's 2000 and 2004 feed-in tariffs. Both Germany and Spain are currently implementing more market-reactive adjustment mechanisms that accelerate or decelerate degression based on how much PV capacity was installed in a given year. For each increment that market growth exceeds expectation, the degression rate for the next year increases by a proportional amount. If market growth in Germany is higher than defined in a corridor, the digression rate might increase by 1% (from 8% to 9% for systems up to 100 kWp and 10% to 11% for systems above 100 kWp in the year 2010 if the market is bigger than 1,500 MWp and in the year 2011 if the market is bigger than 1,700 MWp). Spain has also implemented a form of flexible degression in the wake of its policy transition (Jacobs & Pfeiffer, 2009). Other jurisdictions have taken approaches, such as rates that decline automatically when a certain capacity amount is reach, or annual or overall caps.[8]

The issues of policy flexibility and durability will continue to evolve along with the solar market as policy makers seek to strike a balance between policy predictability and the ability of feed-in tariffs to react to changing market conditions. Ultimately, the approach to feed-in tariff flexibility will depend on the policy objectives in each individual country. In Spain, for example, the government has capped the market at 500 MW per year—still a significant amount of annual PV capacity. In Germany, meanwhile, it appears that the new government will continue to leave the PV market uncapped and will not lower the PV feed-in tariff dramatically. The experience in both countries can serve as important benchmarks as other countries evaluate how to build flexibility and durability into new generations of feed-in tariffs.

CONCLUSION

The SEMI PV Group supports the development of feed-in tariffs around the world as the most effective means to ensure sustained growth for the PV industry and rapidly realize the benefits of large-scale solar energy deployment. Although there have been recent calls for a global feed-in tariff regime,[9] SEMI PV Group believes that national feed-in tariffs are the optimum solution, and that feed-in tariffs should be tailored to the specific context and objectives of the country that is implementing them. Feed-in tariff design should take historical PV policy and market development experience into account and be benchmarked against both the policy principles and best practices described in this report. The continued spread of national feed-in tariffs that are stable, transparent, and substantial will fuel the rapid PV market growth that the world requires and support new investment in the emerging solar economy.

The PV Group understands there are practical and pragmatic limitations to feed-in tariffs in some regions and there are other policy options available to encourage solar power generation. In these cases, the PV Group supports policy options that conform to the principles that are sufficient to encourage predictable demand, encourage stability and predictability to encourage private investment; that are transparent and streamlined to promote fair and honest outcomes; and are open and accessible policies to enable distributed energy production.

6 For a discussion of the environmental and energy service benefits of photovoltaics, ***see e.g.*** (Contreras, et al., 2008; Letendre & Perez, 2006; Watt, 2001).

7 See, e.g. BMU (2009).

8 Caps and capacity declines must be carefully designed, however, in order to prevent "phantom" projects that may never be built from holding a place "in line." A discussion of feed-in tariff queue structure and management can be found in (Grace, et al., 2008).

9 The United Nations, for example, recently suggested a global feed-in tariff program that would be designed to "ensure a level playing field for all competing technologies and on-grid and off –grid operators and benefit targeted low-income consumers (Ahmad, et al., 2009)."

A SURVEY OF INTERNATIONAL SOLAR ENERGY FEED-IN TARIFF POLICIES

This section provides a high level review of current solar energy feed-in tariffs around the world. As discussed above, new feed-in tariffs are added, and existing feed-in tariff rates are adjusted, each year. This section is intended to be a snapshot, rather than a comprehensive review, of feed-in tariff policies. A brief overview of each continent or region is provided with the most current information available on solar feed-in tariff rates, including bulleted highlights of recent developments. It is important to note that this section focuses on feed-in tariffs for PV that are set within the range of generation cost in order to highlight those policies that are most likely to drive PV market development. Feed-in tariffs that are based on avoided cost, are applied only to net excess generation, or are not tailored specifically to PV are not discussed in detail.

Africa

PV development in Africa has historically been concentrated in off-grid applications, because of the limited grid infrastructure in many parts of the continent. To date, the number of national policies for grid-connected photovoltaics remains limited. Several countries have established feed-in tariffs for renewable energy,[10] but none of these have yet implemented specific PV feed-in tariffs.

- In October, 2009, South Africa announced that it would expand its existing feed-in tariff policy to include a rate for PV systems larger than 1 MW in size, set at 3.94 rand/kWh (€0.356/kWh) (van der Merwe, 2009).
- Several recent studies have also proposed feed-in tariffs for micro-grids in Africa and other parts of the developing world, but none have been implemented to date (Jacobs & Kiene, 2009; Moner-Girona, 2008).

Asia and Australia

During the past ten years, Asia has installed close to 20% of global PV capacity. The majority of these installations have been in Japan, which had installed 2 GW between 1999 and 2008, or approximately 15% of the global total. Recent feed-in tariff policy development activity in China, India, Japan and Taiwan has set the stage for significant possible PV market growth during the next few years.

- Although Japan relied on rebates to drive its PV market for many years, it introduced a net feed-in tariff for onsite PV generators in November, 2009, and the new government has announced its intent to develop a gross feed-in tariff.[11]
- In China, announcements of PV projects totaling 12.5 GW of development by 2020 have been made in recent months, but it remains unclear what type of policy will support this development (Hirshman & He, 2009). China recently established national wind feed-in tariffs, and the province of Jiangsu has established PV feed-in tariffs,[12] but no national PV feed-in tariff has been published to date.
- Taiwan's government passed feed-in tariff legislation on June 12, and the Bureau of Energy released proposed PV rates in September.[13] These rates have not been finalized as of the writing of this report, but the PV rates are scheduled to go into effect in January, 2010.
- In May 2009, India's Central Electricity Regulatory Commission (2009) initiated a regulatory process to develop feed-in tariffs for a range of renewable energy resources, including PV. The regulatory proceedings are ongoing, but it is clear that the PV rates will be based on generation cost over a 25-year contract term.
- Korea is thus far the only country in Asia to have instituted a gross PV feed-in tariff based on generation cost. In 2008, the PV feed-in tariff was set at 677 won/kWh (€0.39/kWh) for systems smaller than 30 kW and 711 won/kWh (€0.40/kWh) for systems larger than 30 kW, with an overall capacity cap of 500 MW by 2011, and an annual cap of 50 MW for 2009. The 2008 tariff supported the development of 276 MW of PV capacity. In 2009, the tariff has been revised to include five size categories, lower prices (428-589 won/kWh), and a choice between 15- and 20-year contract terms (Yoon & Kim, 2009). The annual caps for 2010 and 2011 will be 70 MW and 80 MW, respectively. In 2012, the feed-in tariff is scheduled to phase out in favor of a renewable portfolio standard (Hirshman, 2009c).

Australia has a national renewable electricity target of 20% by 2020, which it currently meets through a system of tradable renewable energy credits. Each of the Australian states and territories, however, is free to develop their own renewable energy policies and several have established feed-in tariff policies.

- Queensland, South Australia, and Victoria have each established net feed-in tariffs which only credit PV systems for excess generation above and beyond what is consumed onsite (Mendonça, et al., 2009).
- Australian Capital Territory (ACT) has established a 20-year gross feed-in tariff of AUS $0.5005/kWh for systems up to 10 kW and AUS $0.4004/kWh for systems up to 30 kW.
- In November, 2009, New South Wales became the second Australian government to establish a gross feed-in tariff for systems. The 7-year tariff of AUS $0.60/kWh for PV systems less than 10 kW can be combined with solar rebate program also available from the state (Hughes, 2009).

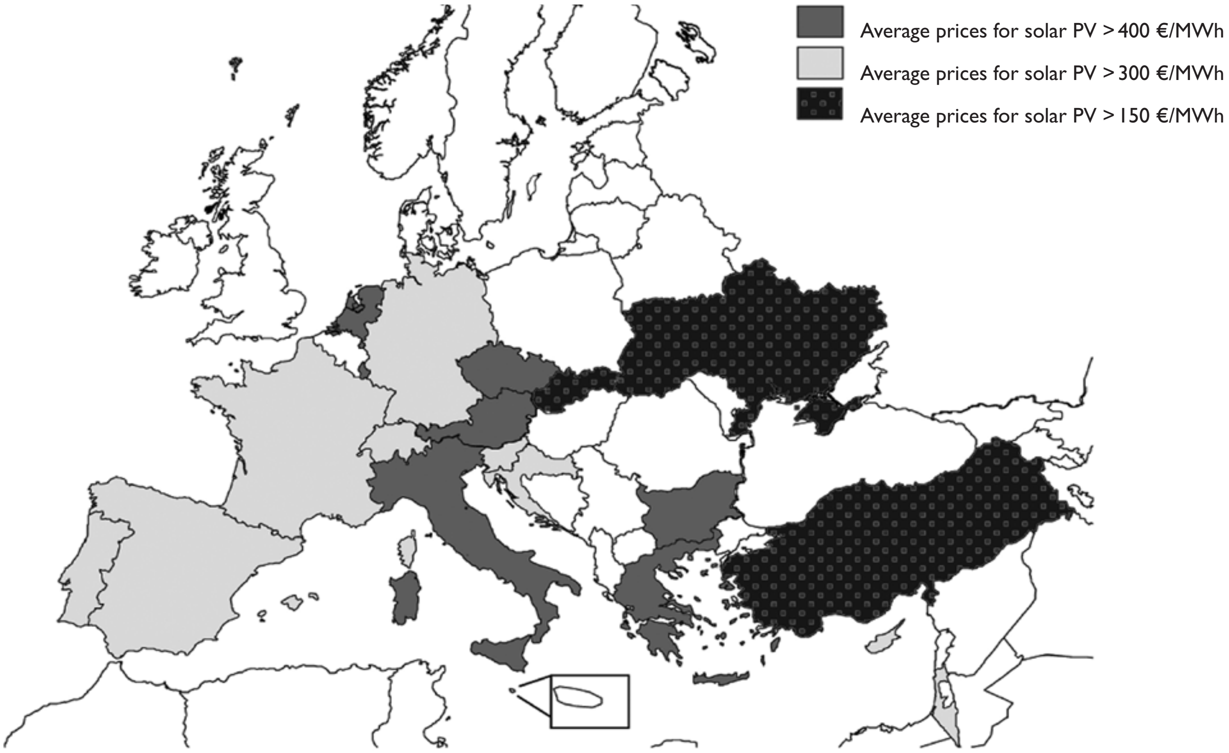
10 Algeria, Kenya, Mauritius, South Africa, and Uganda.

11 A net feed-in tariff provides a feed-in payment only for the generation that is not consumed on site, whereas a gross feed-in tariff provides a payment for all PV system output. Japan's 10-year net feed-in tariff is set at ¥0.48/kWh (€0.35/kWh) for residential systems, and ¥0.24/kWh (€0.175/kWh) for non-residential systems up to 500 kW (Hirshman, 2009a).

12 The Jiangsu feed-in tariff is set at 2.15 CNY/kWh (€0.21) for ground mounted systems and 3.70 CNY/kWh (€0.36) for rooftop systems, with a program target of 400 MW (Hirshman, 2009b).

13 The proposed PV rates are 8.12 TWD/kWh for 1–10 kW, 9.33 TWD/kWh for 10–500 kW, and 9.33 for projects larger than 500 kW.

Figure 2 **Average Prices for Solar PV in Europe**



Source: Fouquet et al. (2009)

Europe and the Middle East

Europe as been the epicenter of global photovoltaic market growth during the past ten years, installing 67% of the 13.7 GW installed globally between 1999 and 2008. This growth has been driven almost exclusively by feed-in tariff policies, which have rapidly diffused across the region. The map below provides an overview of current available feed-in tariffs, coded by the average PV feed-in tariff rate available in the country (Fouquet, 2009). In addition to the nineteen countries shown the map, the United Kingdom has also announced that it will implement feed-in tariffs for photovoltaic generators 5 MW and under in April 2010, with rates of between £0.26–£0.365/kWh (€0.287–€0.404/kWh) (Department of Energy and Climate Change, 2009).

North America

Although some areas of North America, such as California, were early global market leaders, North America's PV market has been slow to grow when compared to Europe. During the past ten years, North America only added 800 MW of PV capacity, or approximately 6% of the global total. Canada, Mexico, and the United States have not yet adopted federal PV policies that have driven rapid market growth nationwide to date. The U.S. Investment Tax Credit for Solar and tax related depreciation benefits provide as much as 50% of system costs in net present value to owners of commercial systems (Bolinger, 2009), but taking advantage of this credit requires a "tax appetite" by the owner and relatively complex ownership structures to fully extract the value. Most PV market growth has been driven primarily by targeted state or provincial policy. In both Canada and the U.S., subnational governments have begun to adopt feed-in tariffs.

- The first generation cost-based feed-in tariff for PV in North America was introduced in Ontario in 2006. The policy was revised in 2009 and now size differentiated in a manner similar to Germany's feed-in tariff, with rates that range from CAD 0.443/kWh (€0.28) to CAD 0.802/kWh (€0.51).[14]
- In the United States, the State of California passed a limited feed-in tariff in 2006 that offers the same feed-in tariff rate, based on avoided cost, to all renewable generators. This tariff has not yet supported the development of new PV generation.
- In 2009, the State of Vermont (PSB, 2009), and the cities of Gainesville, Florida and San Antonio, Texas each established limited PV feed-in tariffs based on generation cost. These were set at $0.30/kWh for 25 years, $0.32/kWh for 20 years, and $0.27/kWh for 20 years, respectively. Although these feed-in tariffs are capped, they have set a new national precedent for policy development.
- In 2009, the Hawaii Public Utilities Commission (2009) also announced preliminary rules for a forthcoming generation cost-based rate, and the State of Oregon passed solar feed-in tariff legislation, with rates to be determined.

South and Central America

Although some countries in Central and South America have implemented feed-in tariffs for renewable energy, none have implemented specific feed-in tariffs for PV to date.

14 Available online at: http://fit.powerauthority.on.ca/

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APPENDIX

Table A.1 **Current Solar Feed-in Tariff Rates by Region**

Region	Country/State/City	Rate (€/kWh)	Size	Length (years)	Notes
Asia	Republic of Korea	0.3405 0.3250 0.3095 0.2940 0.2476	< 30 kW < 200 kW < 1 MW < 3 MW > 3 MW	20	• 500 MW program cap • 15 year rates also available
	Jiangsu, China	0.3619 0.2103	Roof Mounted Ground Mounted	TBD	• 400 MW program target
	Taiwan (proposed)	0.1672 0.1920 0.1860	< 10 kW < 500 kW > 500 kW	TBD	
Australia	Australian Capital Territory	0.3105 0.2484	< 10 kW < 30 kW	20	
	New South Wales	0.3722	< 10 kW	7	• Can be claimed in tandem with rebate
North America	Ontario	0.5106 0.4540 0.4043 0.3432 0.2821	< 10 kW Any System Type > 10 < 250 kW Rooftop > 250 < 500 kW Rooftop > 500 kW Rooftop < 10 MW Ground Mounted	20	• Adders for aboriginal and community ownership
	Gainesville, Florida	0.2133 0.1866	Roof Mounted or Pavement Mounted, or Ground Mounted < 25 kW Ground Mounted > 25 kW	20	• 4 MW annual cap
	San Antonio, Texas	0.1800	50 kW Minimum 500 kW Maximum	20	• 10 MW program cap • 2 year program length
	Vermont	0.2000	< 2.2 MW	25	• 50 MW program cap

continued

Source: SEMI, November 2009

Table A.1 **Current Solar Feed-in Tariff Rates by Region** *continued*

Region	Country/State/City	Rate (€/kWh)	Size	Length (years)	Notes
European Union	Austria	0.4598 0.3998 0.2998	< 5 kW < 10 kW > 10 kW	12	
	Bulgaria	0.4208 0.3860	< 5 kW > 5 kW	25	
	Cyprus	0.36 0.34	< 20 kW < 150 kW	20	
	Czech Republic	0.4963 0.4925	< 30 kW > 30 kW	20	
	France	0.328 0.437 0.6018	Mainland Installations Overseas and Corsica BIPV	20	
	Germany	0.4301 0.4091 0.3958 0.33 0.3194	< 30 kW Rooftop <100 Rooftop < 1 MW > 1 MW Ground Mounted	20	
	Greece	0.45 0.4 0.5 0.45	< 100 kW Interconnected > 100 kW Interconnected < 100 kW Uninterconnected Islands > 100 kW Unitnerconnected Islands	20	
	Italy	0.48 0.431 0.392 0.451 0.412 0.372 0.431 0.392 0.353	1 kW–3 kW Full BIPV 1 kW–3 kW Partial BIPV 1 kW–3 kW Non-BIPV 3 kW–20 kW Full BIPV 3 kW–20 kW Partial BIPV 3 kW–20 kW Non BIPV > 20 kW Full BIPV > 20 kW Partial BIPV > 20 kW Non-BIPV	20	
	Luxembourg	0.42 0.37	< 30 kW 31–1000 kW	15	
	The Netherlands	383 353	0.6 kW–15 kW 15 kW–100 kW	15	
	Portugal	0.42 0.32	< 5 kW > 5 kW	15	
	Slovak Republic	0.2774		12	
	Slovenia	0.4154 0.38 0.315 0.4778 0.437 0.3626 0.3904 0.3597 0.2899	< 50 kW < 1 MW < 5 MW < 50 kW BIPV < 1 MW BIPV < 5 MW BIPV < 50 kW Ground Mounted < 1 MW Ground Mounted < 5 MW Ground Mounted	15	
	Spain	0.32–0.34 0.32	Rooftop Systems Ground Mounted	25	
	United Kingdom (proposed)	0.3457895 0.40713925 0.3457895 0.312326 0.290017 0.290017	< 4 kW (new construction) < 4 kW (retrofit) < 10 kW < 100 kW < 5 MW Stand Alone System	20	

continued

Source: SEMI, November 2009

Table A.1 **Current Solar Feed-in Tariff Rates by Region** *continued*

Region	Country/State/City	Rate (€/kWh)	Size	Length (years)	Notes
Non-European Union	Croatia	0.46 0.41 0.26	< 10 kW < 30 kW > 30 kW	12	
	Israel	0.36 0.29	< 30 kW 50 kW–5 MW	20	• 50 MW program cap
	Switzerland	0.49 0.43 0.41 0.39 0.43 0.35 0.33 0.32 0.59 0.48 0.44 0.41	< 10 kW Roof Mounted < 30 kW Roof Mounted < 100 kW Roof Mounted > 100 kW Roof Mounted < 10 kW Ground Mounted < 30 kW Ground Mounted < 100 kW Ground Mounted > 100 kW Ground Mounted < 10 kW BIPV < 30 kW BIPV < 100 kW BIPV > 100 kW BIPV	25	• Program capped at 0.006% of electricity sales, with solar capped at 5% of that
	Turkey	0.28 0.22	First 10 Years Second 10 Years	20	
	Ukraine	0.23695357 0.247724187	< 100 kW > 100 kW	Through 2030	• Floor price set in Euros • 1.8 multiplier in peak hours

Source: SEMI, November 2009

Paying for Renewable Energy: TLC at the Right Price

Achieving Scale through Efficient Policy Design

December 2009

Green policy paper available online: http://www.dbcca.com/research

Carbon Counter widget available for download at: www.Know-The-Number.com

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Editorial Letter

Kevin Parker
Member of the Group Executive Committee
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TLC: Transparency, Longevity and Certainty, drives investment. As investors, this has been our message to policy makers for much of 2009. In our Global Climate Policy Tracker report* we rated the risk of climate change policy regimes of countries around the world against TLC. A key factor in these ratings was our belief that Feed in Tariffs (FiTs) create a lower risk environment for investors.

This follow up paper focuses specifically on the mandates and incentives that can best complement the emerging carbon markets, which we believe hold the long term policy solution. With governments announcing more targets at Copenhagen, delivering on these through complementary policies on the ground right now is ever more important.

We then set out what we consider to be the most advanced features of FiTs that can stimulate investment on a large scale while containing costs and maintaining TLC. A critical feature of a successful FiT regime is periodic reviews, conducted in a transparent manner, of its progress and effectiveness. Such reviews are used to respond to changing market conditions in renewable technologies so that a fair return is established for investors. The recently announced review of solar tariffs by the German government is an example.

This policy green paper therefore sets out our view of the optimal features of an advanced FiT. Germany remains a leading example, and in North America the province on Ontario has emerged with a particularly strong policy. We regard these policies as applicable at a country, province, state or city level, anywhere in the world.

In the US, some States are already in the process of introducing or researching FiTs. There is even a national proposal in Congress. Although critics of FiTs argue that they are unacceptably expensive, our research shows that they are not only efficient but that the introduction of the key elements of FiTs in the US is a practical option. It would require certain adjustments to the existing electricity pricing structure rather than a wholesale replacement of the system.

Significantly, our research points out that the US Renewable Portfolio Standard (RPS) and Renewable Energy Credit (REC) markets already perform the same function as a FiT when bundled with a Power Purchasing Agreement (PPA). There is very little transparency or certainty in the existing pricing process which is essentially based on a contract by contract negotiation. However, as our research demonstrates, it is possible to adopt the advanced features into the PPA/REC framework.

**DBCCA, "Global Climate Change Policy Tracker: An Investor's Assessment," October 2009.*

Executive Summary

- The scale-up of renewable energy can satisfy a number of policy and economic goals including: emissions targets, energy security and job creation in the green sector.
- Renewable energy incentives can be integrated into carbon markets and play the role of a Research, Development and Demonstration (RD&D) incentive while proven technologies are in their "learning" phase.
- Investors want Transparency, Longevity and Certainty – "TLC" in order to deploy capital. There needs to be a transparent process that gives a reasonably certain rate of return over a long timeframe. This should reduce the cost of capital. However, public support is required for this to endure, so cost and price effectiveness are crucial.
- Building on our work on German feed-in tariffs (FiTs)[1] and our Global Climate Change Policy Tracker[2], we further look at how renewable energy policy regimes can achieve an optimal mix of TLC at the "right price." In the current economic environment, this could be seen as job creation with energy security and climate protection at the most efficient cost.
- In doing this, we examine five FiT regimes and set out what makes them advanced while still delivering enough TLC to achieve scale. Advanced features include cost/price discovery processes and the flexibility to respond to markets, while still operating within a transparent framework. Germany in particular stands out and is able to demonstrate many benefits that come with a strong volume response while being responsive to significant market developments. In a North American context, the province of Ontario has many features of a strong policy design.
- For contrast, we then analyze the US renewable policy framework in the context of US electricity markets. The structure is complex, fragmented and lacks many elements of TLC. It attempts to reach for a "pure market," lowest cost solution using Renewable Portfolio Standards (RPS) and Renewable Energy Certificates (RECs), interacting with Federal and other incentives. This can deliver results only if long term hedgeable REC markets emerge as Federal incentives also start expiring in 2010.
- Given the challenges of developing more stable and transparent REC markets, in our view, the best features of advanced FiTs can be integrated into the REC market via establishing a floor price which is also subject to advanced price discovery features. Standardizing the renewable energy contract then completes transparency. This can become the basis for constructing power purchase agreements (PPAs) in the US. PPAs should continue to reflect all other incentive features of the US policy scheme as they are set. This would add a crucial level of TLC for investors and enable renewable energy scale-up. Given the complexity of the US regulatory landscape, many believe this works best at the state level.
- Having said that, there is some cost to all incentive regimes, however well they are managed over time. That cost can be passed straight through to the consumer or spread across the tax base. However this is done, the public needs to see the benefits: job growth, secure energy and a positive environmental impact.

[1] *DBCCA, "Creating Jobs & Growth: The German Green Experience," September 2009.*
[2] *DBCCA, "Global Climate Change Policy Tracker: An Investor's Assessment," November 2009.*

Executive Summary

Key aspects of an advanced feed-in tariff (FiT) design

In many respects, at the core of our paper is the analysis of what we term "advanced" FiT policy design. This is set out in Chapter II. Below, we have extracted what we consider to be the key features we would recommend to be included in a FiT, tracked against the key regimes we have examined. It is these features that we believe can deliver TLC at the right price.

FIT Design Features	Key Factors	TLC at the Right Price	France	Germany	Netherlands	Ontario	Spain
Policy & Economic Framework	"Linkage" to mandates & targets	Yes	23% by 2020	30% by 2020	20% by 2020	Halt coal use by 2014	20% by 2020
Core Elements	Eligible technologies	All renewables eligible	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Biomass, Biogas, CHP	Wind, Solar, Hydro, Biomass, Biogas	Wind, Solar (PV & CSP), Geo, Small hydro, Biomass, Biogas
	Specified tariff by technology	Yes	Yes	Yes	Yes	Yes	Yes
	Standard offer/ guaranteed payment	Yes	Yes	Yes	Yes	Yes	Yes
	Interconnection	Yes	Yes	Yes	Yes	Yes	Yes
	Payment term	15-25yrs	15-20yrs	20yrs	15yrs	20yrs	15-25yrs
Supply & Demand	Must take	Yes	No	Yes	No	Yes	Yes
	Who operates (most common)	Open to all	IPPs; communities; utilities	IPPs; communities; utilities	IPPs; communities	IPPs; communities	IPPs, communities; utilities
Fixed Structure & Adjustment							
How to set price	Fixed vs. variable price	Fixed	Fixed	Fixed	Hybrid	Fixed	Both
	Generation cost vs. avoided cost	Generation	Generation	Generation	Generation	Generation	Generation
	IRR target	Yes	8%	5-7%	No	11%	7-10%
How to adjust price	Degression	Yes	Wind only	Yes	No	No	No
	Periodic review	Yes	No	Yes	Yes	Yes	Yes
	Grid parity target	Yes	No	Yes	No	No	No
Caps	Project size cap	Depends on context	Varies	No	Yes	PV only	Yes
Policy interactions	Eligible for other incentives	Yes - eligible to take choice	Yes	Yes	Yes	Yes	Yes
Streamlining	Transaction costs minimized	Yes	Yes	Yes	No	Yes	No

Source: DBCCA analysis, 2009.

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List of Exhibits & Boxes

I. Paying for Renewable Energy: Costs, Benefits And Jobs

Summary:

- *Governments need to support budget spending programs that create jobs and economic benefits.*
- *Even leaving aside any idea of offsetting the long term costs of failing to achieve climate goals, there are a significant number of measurable benefits that outweigh the costs in well-designed renewable energy policy regimes.*
- *The German government in particular, has done the analysis illustrating this point while being responsive to significant market developments.*
- *Ontario also expects the benefits of developing its energy policies will make it a competitor in a low-carbon economy.*
- *Further work needs to be done on the costs of subsidizing fossil fuels.*

In evaluating the costs and benefits of renewable energy payments to achieve scale, there are a number of obvious factors that need to be considered:

1. How much clean power is delivered from the policy (as a percentage of total generation)? Does the policy meet environmental goals?
2. How many jobs are created as a consequence?
3. What is the cost to either the electricity consumer (ratepayer) or the taxpayer of the incentives and spending programs?
4. What is the impact on the economy – to industry growth and exports?

However, there are other key economic implications:

1. What is the impact on energy security as measured by changes to the imports of fossil fuels?
2. What is the merit order effect in the electricity market and how much might it affect prices?
3. Is there a measurable impact on innovation and patents?

Evaluating costs and benefits in electricity markets is a complex economic calculation that does not lend itself to a simple net result. We believe this is an area that will require more research in the future for renewable energy markets.

In this paper, we have looked at feed-in tariff regimes in Europe and Ontario as well as discussed the US electricity market for renewables. Below is a high-level look at two of the key economic aggregates that are more readily available as a result of these policies and potential initiatives.

EX 1: Feed-in tariff policy outcomes

	France	Germany	Netherlands	Ontario	Spain
Job creation (gross)	7,000 (wind)	280,000	2000 (wind)	Est. 50,000	188,000
RE generation as a share of gross consumption (2007)	13.3%	15.1%	7.6%	N/A	20.0%

** Note: Figures represent annual renewable energy produced.*
Source: DBCCA Analysis, 2009; EWEA, "Wind Energy: The Facts", March 2009; BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p 52; Ontario's Independent Electricity System Operator (IESO), "Supply Overview", 2009; IESO, "IESO 2008 Electricity Figures Show Record Levels of Hydroelectric", January 12, 2009.

I. Paying for Renewable Energy: Costs, Benefits And Jobs

1.0 A more detailed cost-benefit analysis of the German FiT regime

The German government has done several in-depth studies to find a more comprehensive evaluation of costs and benefits of a feed-in tariff regime.

The strategic objective of the German government is to be a world environmental leader, to establish Germany as the "global environmental service provider" of the 21st Century, and to accelerate new growth and job creation. The "Ecological Industrial Policy" seeks to bring about "revolutionary technology advances" across the entire energy value chain.[3]
The three broad goals of the integrated policy are:

1. Improving energy security
2. Providing cost effective energy
3. Lowering the environmental impact of energy use

The success of German FiT policy in meeting its long term strategic objectives can be illustrated by analysis carried out primarily by the German Federal Environment Ministry (BMU).

Boxes 1.1 and 1.2 present an evaluation of the costs and benefits of Germany's FiT as well as a detailed view of the benefits. As already mentioned, the complex relationships between the figures below mean that they cannot be easily compared to derive a single, net result. However, in our view, the boxes below show substantial benefits in relation to the costs.

Box 1.1: Evaluating costs and benefits of the German feed-in tariff

2004-2006:

Electricity Sector Costs Incurred:

- Differential cost[1] (Premium above calculation cost): €8.6 billion[2]
- Balancing cost[3]
  (2006 estimate of €0.3 – €0.6 billion[2] x 3 years): €0.9 – €1.8 billion[4]
- Expansion of grid: €1 billion (estimate)[5]

Effect on Energy Security:*

- Electricity import savings: €2.2 billion[6]

Merit Order Effect:

- Avoided electricity generation of the most expensive fossil fuel plants: €9.4 billion[7]

** Note: Energy security is not specified as a cost or benefit because the import savings affect several parties differently (i.e. it causes distributional effects).*

1 The differentiated cost is the difference between fees paid by the grid operators to the renewable energy generators and the average electricity wholesale purchase costs. It includes costs borne by the ratepayer. The Renewable Energy Sources Act (EEG), which is the cornerstone FiT law, distributes the costs across the country and splits them among ratepayers. The average addition to the electricity bill has been €2-3 per month from 2004-2007. The EEG surcharge grew from 0.2 € cents/kWh in 2000 to 1.1 € cents in 2008.
Source: BMU, Renewable Energy Sources in Figures: National and International Development, June 2009, p. 33

2 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2008, p 33.

3 Represents the additional costs borne by grid operators balance the electricity supply, additional transaction costs.

4 Calculations built off of 2006 estimate from footnote #2.

5 Barbara Breitschopf, Fraunhofer, December 12, 2009. (Provisional figure)

6 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2008, p.28.

7 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2008, p. 35.

[3] *EEG Progress Report, 2007.*

I. Paying for Renewable Energy: Costs, Benefits And Jobs

Box 1.2: A closer examination of the benefits from the German FiT

Additional Benefits

Jobs:

- *Jobs Created:* According to the calculations of the German government, by June 2009 over 280,000 jobs in the renewable energy industry were created, of which the German government attributes about 66% occurring directly from the EEG.[8] The estimated net employment effect in 2006 was 67,000 to 78,000 new jobs created.[9]

Economy:

- *Net Impact on the Economy*: Annual renewable energy turnover (investment and operation) has increased from €10 billion in 2003 to €28.8 billion in 2008.[10]
- *Technology Sales*: As of 2008 Germany's renewable technology market share of global sales was 8%.[11] The national goal is to increase these global sales to 20-30% of market share by 2020.[11]
- *Domestic Electricity Share:* Renewable energy generation as a share of gross electricity consumption increased from 4.3% in 1997 to 15.1% in 2008.[12] Germany has met its 2010 target to obtain 12.5% of electricity from renewable energy and is on track to meet its 2020 goal of 30%.[13]
- *Investment Growth*: The annual investment Compounded Annual Growth Rate (CAGR) average is 55% and the cumulative investment CAGR is 93% for the years 2000-2008.[14] Investment into Germany's clean energy sector as a percent of its GDP is approximately 2-3 times greater than that of the US.[15]
- *Growth in Exports*: From 2004 to 2007, manufactured PV exports rose from 14% to 43% of total solar industry sales (€7 billion in 2007).[16] In 2007 German wind power companies had revenues of €11.7 billion, of which 70% of sales were exports.[17]
- *Patents Held & Innovation*: Germany currently ranks third (behind the US and Japan) in the number of solar patents held.[18] The high level of firm clustering creates research "hubs" for collaboration, learning and further innovations.[19]

Environmental Protection:

- *Avoided CO_2 Emissions*: The EEG has avoided 53 million tons of CO_2 in 2008 through the electricity sector.[20]
- *Avoided External Costs:* Expenditures of €2.9 billion in macroeconomic externalities, such as health and material damages and agricultural revenue losses, were avoided in 2008. [21]

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8 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p. 31.
9 BMU, "Background Report on the EEG Progress Report 2007", December 2007, p.6.
10 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p. 30.
11 Germany Trade & Invest, "Powerhouse Eastern Germany: The Prime Location for Cleantech Leaders", 2008, p.19.
12 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p. 11.
13 Economist, "German lessons: An Ambitious Cross-subsidy Scheme Has Given Rise to a New Industry". April 3, 2008.
14 New Energy Finance, includes PE/VC, AF, Public Markets. Note: Investment figures are based on New Energy Finance's PE/VC, Asset Financing and Public Markets database, which comprises of disclosed investment amounts. This may not accurately represent all investments made in the renewable energy sector during this time period. Market cap data is sourced from Bloomberg, 2009.
15 Investment data from New Energy Finance; GDP data from OECD Statistics; DBCCA analysis, 2009.
16 BSW. "Statistische Zahlen der deutschen Solarstrombranche (Photovoltaik)", März 2009.
17 Germany Trade & Invest, "Powerhouse Eastern Germany: The Prime Location for Cleantech Leaders", 2008, p. 26.
18 Cleantech Group. "Clean Energy Patent Growth Index", 3rd Quarter 2009.
19 Michael Storper, Lecture in GY 407: Globalization: Theory, Evidence and Policy, Lecture 3, London School of Economics, October 16, 2008.
20 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p.24.
21 BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p 36.

I. Paying for Renewable Energy: Costs, Benefits And Jobs

2.0 Ontario looking to create a competitive low-carbon growth economy

As another example from a robust tariff regime, the government of Ontario sees many opportunities and benefits stemming from their green energy policies, in particular the feed-in tariff law. In many senses, the Ontario government sees this as their entry into the new competitive low-carbon economy. Ontario, like some other FiT regimes, does have a local content requirement. As economists, we note that these sorts of policies can lead to distortions in trade.

Box 2: Ontario – Looking for significant economic benefits

Ontario's Green Energy Act (GEA), and related amendments to other legislation, received Royal Assent on May 14, 2009. The landmark Green Energy Act will boost investment in renewable energy projects and increase conservation, creating green jobs and economic growth to Ontario. This legislation is part of Ontario's plan to become a leading green economy in North America.

The GEA will:

- Spark growth in clean and renewable sources of energy such as wind, solar, hydro, biomass and biogas in Ontario attracting foreign direct investment;
- Create the potential for savings and better managed household energy expenditures through a series of conservation measures;
- Create 50,000 jobs for Ontarians in its first three years, particularly longer term manufacturing ones;
- Achieve the goal of phasing out coal-fired electricity generation by 2014.

"Our ambition is to increase the standard of living and quality of life for all Ontario's families. That is best achieved by creating the conditions for green economic growth." *-George Smitherman, Deputy Premier and Minister of Energy and Infrastructure.*

Source: Ontario Ministry of Energy and Infrastructure website: Green Energy Act.

I. Paying for Renewable Energy: Costs, Benefits And Jobs

3.0 Fossil fuel subsidy costs – Also a factor to consider

There are many historic reasons that countries have subsidized fossil fuels; however, we believe that in evaluating costs and benefits, an area that requires further research and inclusion is the role of fossil fuel subsidies. Below, we cite some work that has been done in this area.

Box 3: The role of subsidies: Fossil fuels much more heavily subsidized than renewable energy

On a global scale, energy is subsidized heavily to the tune of about $300 billion annually, according to the International Energy Administration (IEA). While this is a large number in the aggregate, on a ton of oil (TOE) or British Thermal Unit (Btu) equivalent basis fossil fuel subsidies are much lower than renewable energy, which reflects their dominance in the global energy mix. Approximately 75% of the subsidies are for fossil fuels and the balance is directed toward electricity, much of which is generated from them. The gross amount of energy subsidies varies substantially by country and industry. Energy subsidies can be direct or indirect and can be levied on either production or consumption. There are many historic reasons why countries have subsidies for fossil fuels, however when doing a cost/benefit analysis at a macro economic level, it is important to account for the impact of energy subsidies across all sectors of the economy.

The net effect is a distortion in the energy price to a below market reference level, which affects behaviour and impacts wealth transfers between producer, consumer and governments. On the production side, subsidies are generally bucked into tax breaks, cash grants or enshrined in regulation protecting producers. On the consumption side, which is more common in developing countries such as India and China, the government regulates fuel prices and sells them below market to consumers at a fixed price.

It has been argued that a more direct approach to dealing with the carbon externality in lieu of a tax or cap-and-trade in the short run is eliminating fuel subsidies. This appears to be the direction governments are going. At the G-20 meeting in September 2009, leaders of the world's largest economies agreed to end fossil-fuel subsidies, and committed to phasing out the subsidies "over the medium-term," blaming them for encouraging wasteful consumption and undermining efforts to combat climate change.

Citing studies by the Organization for Economic Cooperation and Development (OECD) and the IEA, the G-20 said that "eliminating fossil fuel subsidies by 2020 would reduce greenhouse gas emissions in 2050 by ten percent."

In the US, most of the largest subsidies to fossil fuels were written into the US Tax Code as permanent provisions. By comparison, many subsidies for renewable energy are time-limited initiatives implemented through energy bills, with expiration dates that limit TLC. The vast majority of subsidy dollars to fossil fuels can be attributed to just a handful of tax breaks, such as the Foreign Tax Credit ($15.3 billion) and the Credit for Production of Non-conventional Fuels ($14.1 billion). The largest of these, the Foreign Tax Credit, applies to the overseas production of oil through an obscure provision of the US Tax Code, which allows energy companies to claim a tax credit for payments that would normally receive less-beneficial tax treatment.

Fossil Fuels	$72.5bn
- Traditional Fossil Fuels	**$70.2bn**
- Tax Breaks	$53.9bn
- Direct Spending	$16.3bn
- Carbon Capture & Storage*	**$2.3bn**
Renewable Energy	**$29.0**
- Traditional Renewables	**$12.2**
- Corn Ethanol**	**$16.8**

*Sources: Internal Revenue Service, US Department of Energy (EIA), Congressional Joint Committee on Taxation, Office of Management and Budget, & US Department of Agriculture, via Environmental Law Institute. *CCS is a developing technology that would allow coal-burning utilities to capture and store their carbon dioxide emissions. Although this technology does not make coal a renewable fuel, if successful it would reduce GHG emissions compared to coal plants that do not use this technology. **Recognizing that the production and use of corn-based ethanol may generate significant GHG emissions, the data depict renewable subsidies both with and without ethanol subsidies.*

II. Renewable Energy Policies: Key Design Features

Summary:

- *In this chapter, we look at the key policy design elements used for renewable energy incentives, drawing on elements from the detailed sections that follow.*
- *Renewable energy policy sits within the framework of overall climate policy and energy security concerns.*
- *In order to achieve an adequate response, policy makers have to satisfy investor needs for Transparency, Certainty and Longevity (TLC) while seeking to minimize costs.*
- *Feed-in tariff regimes offer TLC and advanced features for price discovery and cost minimization.*
- *The US relies on RPS systems and supporting policies which are highly complex and lack elements of TLC.*
- *The best attributes of advanced FiTs can be adapted to the US renewable energy policy mix.*

As the world grapples with the aftermath of the economic recession, a continued build up of carbon in the atmosphere and long term questions about how to source secure, diverse and clean energy, government policy remains central to solutions to these issues. Encouraging the scale-up of renewable energy projects can address these issues. From the perspective of DB Climate Change Advisors (DBCCA), addressing the climate issue is crucial and the key driver for how we see renewable energy policy.

1.0 The climate policy framework for renewable energy

Climate Change Policy still remains a work in progress as the world gathers in Copenhagen (December 2009). Since we published Investing in Climate Change 2009 (October 2008), we have argued that there are three main ways that policy makers are engaged in pricing the carbon externality, which is an economic and market failure issue:

1. **Carbon Markets** – directly establishing a carbon price either through a tax or cap-and-trade programs;
2. **Mandates and Standards** – requiring a combination of renewables, energy efficiency, transport, and industrial sector targets and;
3. **Innovation Policy** – incentives designed to get specific technologies to deliver volume response if they are not already commercially viable and reduce their costs.

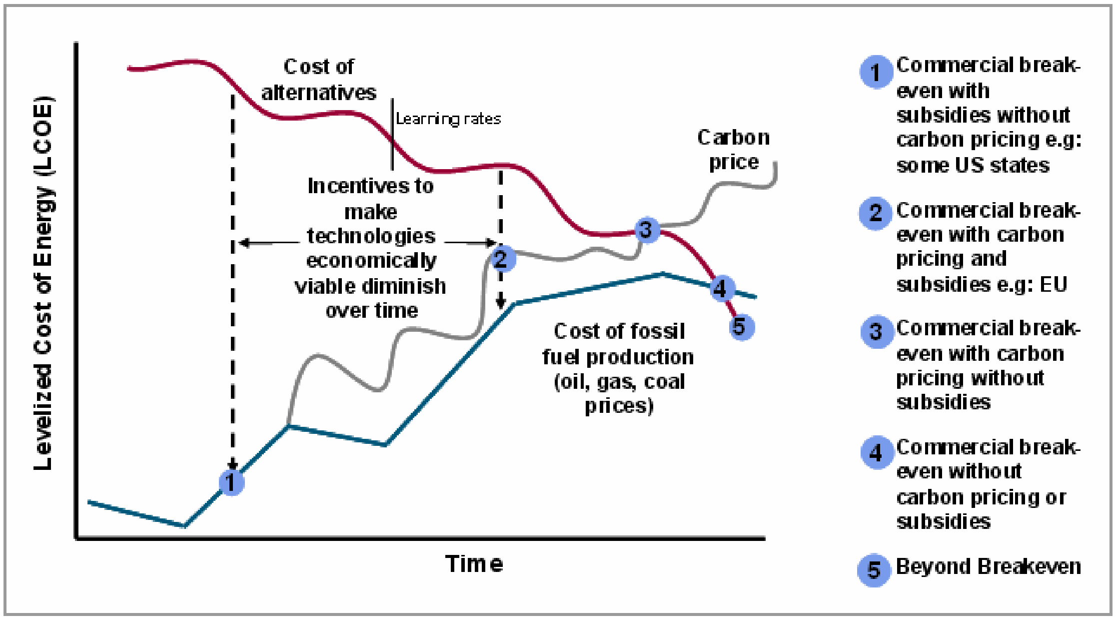
For economists and policy makers, the question is how can climate mitigation targets be met in the most time sensitive and cost efficient way, and in the current economic context, can they help create jobs? Many economists suggest a carbon price, most likely a straightforward tax, is the best way, leaving the market to select technologies. However, the political and market reality, particularly in an international context, means that an unconstrained approach to carbon pricing is not possible, particularly at an international level. A more likely approach is a slow buildup of cap-and-trade regimes to establish carbon prices that can lead to international linkages. However, it is hard to see a carbon price of sufficient magnitude in the next few years to cause major changes to the energy mix of the OECD.

Hence the need for “complementary policies,” often referred to as mandates, standards and incentives. Here policy makers need to make more proactive decisions about which technologies to encourage and importantly how to incentivize them. These complementary policies can further be designed to integrate with emerging carbon markets (for instance, by being incorporated into emission baselines) as they produce volume response and lower the cost of technologies as they scale-up. By incentivizing all available post demonstration proven renewable technologies at the appropriate cost level, policy makers can address criticisms of picking winners. Mandates and standards can be considered as a demand pull, whereas incentives can create supply push; these are complimentary with each other. Additionally, these policies can be designed to integrate into a carbon market. Furthermore, as with carbon markets, international cooperation to harmonize complementary policies to ensure level-playing fields, is considered highly beneficial.

II. Renewable Energy Policies: Key Design Features

The optimal approach would seem to be that complementary policies encourage technology cost reductions (i.e. which during the learning process are like a R&D subsidy) and fill the gap before a robust carbon market emerges and then fades, so long as persistent behavioral barriers are not found to be present, such as in areas like energy efficiency. That leaves a carbon price for any long-run incorporation of pricing the carbon externality into proven technologies. This is illustrated in Exhibit 2 below in terms of Levelized Cost of Energy (LCOE).

EX 2: Timeline and incentive structure to achieve commercial break-even (grid parity) for a technology



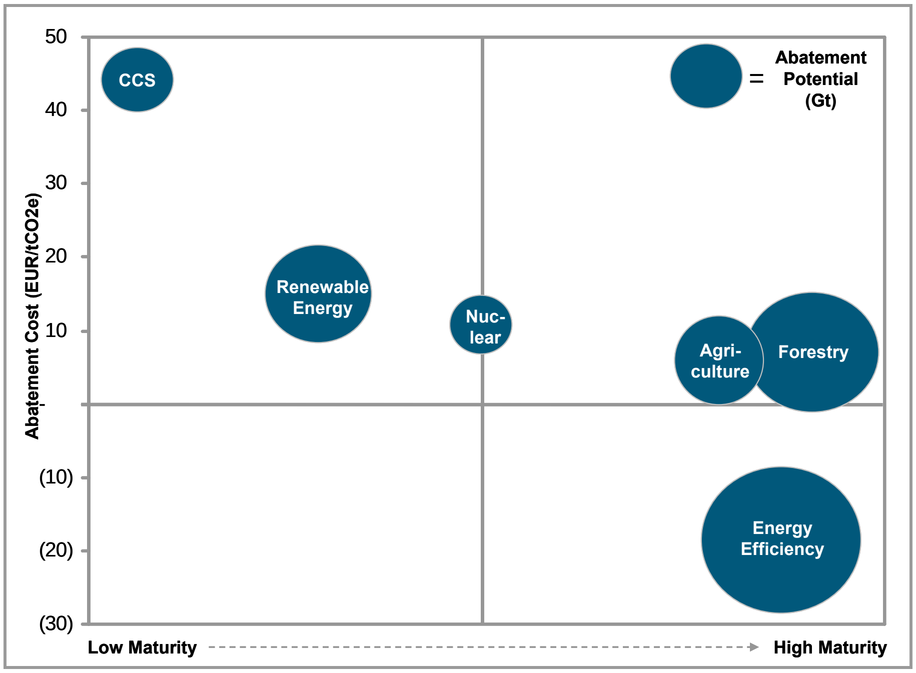
Source: DBCCA analysis, 2008.

Looking at the key areas that are expected to deliver a substantive amount of mitigation potential, we find that in Exhibit 3:

1. Energy efficiency technologies are the cheapest option and have the most mitigation potential however they are affected by behavioral barriers that require mandates and standards;
2. Forestry and Agriculture also have significant potential but behavioral issues are also evident in these sectors;
3. Renewable energy technologies might be able to reduce their costs to commercial break-even given historic learning rates, but most currently need mandates and incentives and;
4. The more expensive solutions, particularly Carbon Capture and Storage (CCS), will require a carbon price to equalize their cost against fossil fuels for the long run.

II. Renewable Energy Policies: Key Design Features

EX 3: 2030 Global GHG incremental abatement cost and technical potential vs. current technical maturity



Source: DBCCA analysis; McKinsey Climate Desk, 2009.

2.0 Investor response

Investors need to respond to renewable energy policy frameworks and they are looking for **TLC**:

Transparency – How easy is it to navigate through the policy structure and understand and execute?

Longevity – Does the policy match the investment horizon and create a stable environment for public policy support?

Certainty – Does the policy deliver measurable revenues to support a reasonable rate of return?

Failure to stimulate investor interest will lead to failure to achieve any target. Much of our recent work examines how investors respond to policy regimes. We have placed particular emphasis on the quality of incentives. Increased transparency and certainty can clearly reduce risk and allow developers to obtain a lower cost of capital. However, if achieved through overly generous fixed incentives, the cost could prove higher than a policy maker would want to pay, potentially leading to a withdrawal of the policy as public support wanes.

II. Renewable Energy Policies: Key Design Features

3.0 Optimizing policy: TLC at the right price

Bringing together policy goals and investor needs, we examine what might be considered a best practice proposition for the scale-up of renewable energy.

We see the goals of policy makers in renewables in the next decade as carbon markets take time to mature, as follows:

1. Encourage early stage research, but concentrate on all available post demonstration and proven technologies that can grow to significant scale. This addresses criticisms about "picking winners."
2. Establish renewable energy targets consistent with climate change and energy security goals.
3. Use a mix of "on the ground" mandates, standards and incentives that will establish TLC for markets, and achieve a meaningful volume response.
4. Encourage cost reduction and a fair return in technologies to sustain public support for policy. Public support is important to ensure longevity of the policy for investors.

There is tension is between "certainty" to an investor and a pathway to commercial break-even that includes "**price discovery**", i.e., getting up-to-date input on actual market costs and investor returns. It is optimizing this that will produce the best set of policies.

Renewable energy policy should seek to achieve:

Volume response in support of an emissions target that creates investor TLC, and establishes a pathway (subject to transparent price discovery) to achieve commercial break-even (grid parity) for proven and demonstrated technologies.

3.1 Policy Levers – What's Available

When looking around the world at renewable energy policy, as set out in Climate Tracker, we can see a number of key policy levers that are being used to mandate and incentivize renewable energies:

- **Mandates:** Set volume targets (renewable portfolio standards (RPS) or renewable electricity standards) which can generate compliance certificates (RECs/ROCs)
- **Direct Incentives:** Such as production-based feed in tariffs (FiTs), and capacity-based grants and rebates
- **Tax Incentives:** Tax credits (PTC/ITC which can be converted into cash grants), tax exemptions
- **Financial programs:** Loan guarantee programs, low-interest loans, government guaranteed bonds

In this paper, we analyze FiT systems in Europe and Ontario, state RPS markets and federal tax incentives in the US. We also briefly look at the Loan Guarantees and "Green Banks".

In doing this, we take into account:
- The extent to which these policies satisfy the criteria for TLC
- Best practices in FiTs – we term these "Advanced FiTs"
- How costs/returns can be optimized for investors and policy makers

The question naturally arises as to how complementary these incentive policies are. How can a RPS market interact with FiT, tax credit, and Loan Guarantee programs? We set out how we believe these levers do and can interact.

II. Renewable Energy Policies: Key Design Features

4.0 Looking at feed-in tariffs – Standard offer renewable payments

As set out in our recent paper looking at the scale-up of renewable energy in Germany there is strong evidence that renewable energy targets can be met through a strong volume response incentivized by Feed in Tariffs (FiTs). We further expanded upon the effectiveness of the volume response in our Climate Tracker[4] and contrasted some of the key elements of a FiT with a more "market based" Renewable Energy Certificate (REC) approach.

In this paper we take the analysis further, especially in respect to the economics, pricing, and cost impact of deploying FiTs. In doing so we are looking for what could be termed "Advanced" features, particularly in relation to price discovery.
We examine FiTs in France, Germany, Netherlands, Ontario, and Spain. While not the focus of this paper, we are also interested in studying at the latest thinking in FiTs that are either in discussion or being proposed. As of publication, the UK, US, India and China all have proposals on the table, although we do not address these here.

The core elements of any FiT are:

1. Defined eligible technologies;
2. Tariff pricing differentiated by technology;
3. A standard offer (frequently expressed through a contract), for a guaranteed payment for renewable electricity generation;
4. A guaranteed interconnection for all renewable generators and;
5. Payments over a long timeframe.

A FiT can be designed to cover a wide range of project sizes, ownership, structures and technologies. In most markets, with the exception of Spain[5], independent power producers (IPPs) have tended to be the predominant owners and it is often the case that both large-scale and small-scale distributed technologies have benefited from FiTs. The two main tariff pricing structures, a fixed long term purchase price and a variable premiums added to the market price, can include a number of other more advanced design elements. In general, fixed pricing fosters a higher degree of revenue certainty, which is an important element for an investor.

In terms of volume targets, FiTs usually sit within a renewable energy goal or portfolio standard, but volume response is not necessarily limited to the target amount, as in the US REC approach (see below).

Chapter III shows the major features of FiTs as illustrated by five key regimes that we believe are useful to analyze their effectiveness in terms of TLC and how much price discovery they contain.

4.1 Looking for TLC with "price discovery"

Drawing on the existing FiT policy regimes as set out in 3.0 above and the optimal policy goals described above, we believe that a definition of an Advanced FiT building on the core features might include the following features.

Supporting a mandated renewable energy target by creating investor TLC with a pathway subject to transparent price discovery to grid parity.

Below, we highlight what we consider to be the key features that deliver TLC at the right price in a FiT tracked against the key regimes we have examined.

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[4] *DBCCA, "Global Climate Change Policy Tracker: An Investor's Assessment," October 2009.*
[5] *Stenzel and Frenzel,* "Regulating technological change – The strategic reaction of utility companies towards subsidy policies in the German, Spanish and UK electricity markets," *Energy Policy, 2008.*

II. Renewable Energy Policies: Key Design Features

EX 4: Key features for TLC at the right price

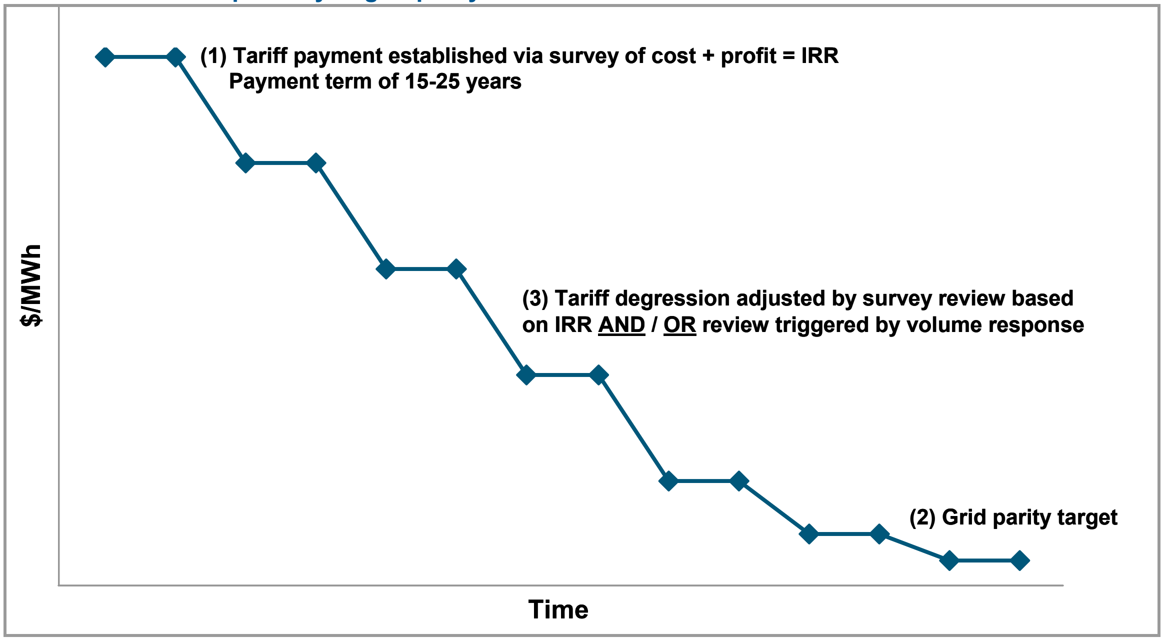
FIT Design Features	Key Factors	TLC at the Right Price	France	Germany	Netherlands	Ontario	Spain
Policy & Economic Framework	"Linkage" to mandates & targets	Yes	23% by 2020	30% by 2020	20% by 2020	Halt coal use by 2014	20% by 2020
Core Elements	Eligible technologies	All renewables eligible	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Biomass, Biogas, CHP	Wind, Solar, Hydro, Biomass, Biogas	Wind, Solar (PV & CSP), Geo, Small hydro, Biomass, Biogas
	Specified tariff by technology	Yes	Yes	Yes	Yes	Yes	Yes
	Standard offer/ guaranteed payment	Yes	Yes	Yes	Yes	Yes	Yes
	Interconnection	Yes	Yes	Yes	Yes	Yes	Yes
	Payment term	15-25yrs	15-20yrs	20yrs	15yrs	20yrs	15-25yrs
Supply & Demand	Must take	Yes	No	Yes	No	Yes	Yes
	Who operates (most common)	Open to all	IPPs; communities; utilities	IPPs; communities; utilities	IPPs; communities	IPPs; communities	IPPs, communities; utilities
Fixed Structure & Adjustment							
How to set price	Fixed vs. variable price	Fixed	Fixed	Fixed	Hybrid	Fixed	Both
	Generation cost vs. avoided cost	Generation	Generation	Generation	Generation	Generation	Generation
	IRR target	Yes	8%	5-7%	No	11%	7-10%
How to adjust price	Degression	Yes	Wind only	Yes	No	No	No
	Periodic review	Yes	No	Yes	Yes	Yes	Yes
	Grid parity target	Yes	No	Yes	No	No	No
Caps	Project size cap	Depends on context	Varies	No	Yes	PV only	Yes
Policy interactions	Eligible for other incentives	Yes - eligible to take choice	Yes	Yes	Yes	Yes	Yes
Streamlining	Transaction costs minimized	Yes	Yes	Yes	No	Yes	No

Source: DBCCA analysis, 2009.

1. A direct connection to RES/RPS policies could be made by integrating FiTs into existing frameworks.
2. Allowing all proven renewable technologies that are appropriate for a given context to be eligible prevents “picking winners” particularly when the tariff is differentiated by technology cost.
3. A standard offer / guaranteed payment over a long time horizon is a key core element of any FiT and are essential for complementing advanced features of FiTs.
4. Mandatory interconnection to the grid.
5. Must take provisions will allow for a broad range of generators to come online, including distributed and small scale projects. There may be limitations to must take requirements, depending on the policy objectives and infrastructure constraints (e.g. transmission) of a given country or state.
6. Any entity - utilities, communities and IPPs – should be eligible to participate in a FiT scheme. This creates a resilient investment environment.
7. Fixed pricing structures provide greater TLC than variable pricing.
8. Determining the tariff rate on a generation cost basis (which includes a reasonable return) rather than through avoided costs (the value of new generation to the utility) provides greater certainty for receiving a return on investment and is also more transparent.
9. An initial tariff or payment that reflects the IRR required to develop renewable energy projects.

10. A tariff degression schedule which steps down to a grid parity (i.e. commercial or LCOE break-even) target. The degression would not alter the payment terms of existing renewable installations but would decrease the tariff for facilities that come online in future years. These schedules could include:
    a) Straight line reduction from the starting tariff to grid parity, and
    b) DBCCA recommends adjustments to meet changing market developments and reflect technology learning curves.
11. The grid parity target projected for the particular electricity market that the advanced FiT is operating in. This could be adjusted for long term price trend estimates, and adjusted to meet changing electricity market environment.
12. The starting tariff, degression and grid parity points could all achieve price discovery by being based on:
    a) Surveys accompanied by market research, based on latest costs and IRR expectations of generators in particular technologies (not avoided costs). DBCCA recommends this approach (see below).
    b) Competitive benchmarking process, setting a price based on the outcomes of
        i. A competitive bidding (RFP), or
        ii. An auction process
13. Project size caps should depend on the policy objectives and contextual electricity infrastructure. Some policy makers, for example, argue that feed-in tariffs should be used to support smaller scale generators, whereas alternative mechanisms (e.g. competitive bidding) should be used to target larger scale projects. Feed-in tariff policy makers have taken different approaches to the issue of project caps. Spain, for example, has a project cap of 50 MW. In the US, several states (such as California, Hawaii, Illinois, Indiana, Michigan, Minnesota, New York, and Rhode Island) have introduced legislation adopting feed-in tariffs with a 20 MW cap for certain resources, and this same cap has been suggested as part of the proposed federal FiT.
14. Renewable energy producers should be eligible to choose if they want to take advantage of other incentives and in doing so, the FiT payment should be adjusted accordingly. The FiT tariff should not build in the assumption that all producers will qualify for and use every possible incentive.
15. Transaction costs should be minimized in order to set TLC and quicken the deployment rate of renewable technologies.

EX 5: Efficient tariff pathway to grid parity



Source: DBCCA analysis, 2009.

Many of the design features listed above try to bring in price discovery in some way.

The issue here is how it affects TLC. There needs to be transparent rules as to when and how a tariff review might happen, and the review cannot substantially reduce certainty over cash flow streams. Ideal rules would include:

1. Existing tariffs cannot be changed – this is essential. Price adjustments would only affect the tariffs paid to facilities that have yet to come online. Reviews would not alter the payments of installations already in existence.
2. There would not be less than two years between reviews. Reviews should occur on a transparent and predictable schedule, and be administered according to grid parity objectives.

An alternate approach is to trigger a review when a certain volume level has been reached. Germany has an element of this for solar PV.[6] A cap goes further and sets the limit specifically. Caps have the advantage of controlling overall costs but need to be designed carefully to prevent speculative queuing and gaming.

4.1.1 Survey vs. RFP / Auction for Price Discovery

1. A survey by a regulator would need to be wide and deep around the technologies. It would need to gauge the quality of respondent and ability to deliver volume. Track record would be important. Feedback loops whereby generators would be required to share actual cost and performance data would make the process more robust over time.
2. Competitive benchmarks, such as auctions, would be used to set the initial tariff price and adjust the payments for future facilities that become operational.. The issues here are “gaming,” the introduction of higher transaction costs and project development risks, and understanding if the bidders can really deliver the volume.
3. We favor a survey process.

4.1.2 Independent Power Producers (IPPs) and Utilities

As already mentioned, current FiTs have driven significant growth in smaller scale, distributed technology solutions such as residential rooftop solar PV, frequently owned by IPPs. In these cases, utilities’ primary roles are to pass through the tariff and make the interconnection.

A distributed IPP model is certainly a reasonable approach. However, in order to get to maximum impact it would be important to create incentives for a diverse range of renewable generation ownership structures. Both ownership cooperatives and utilities should have access to a FiT in the appropriate technologies—wind, solar CSP and large scale solar PV, for instance.

However, projects over 20MW are of such magnitude that many policy makers think that a more direct negotiation process would deliver a better outcome.

4.2 How Advanced Are Recent FiTs – Germany and Ontario?

As shown in Chapter IV Section 7.0, FiTs in leading markets have covered TLC—they are generally transparent, last up to 25 years and give high levels of certainty over cash flow payments for IRR calculation. Price discovery features are more common now. They sometimes make an IRR target an explicit part of the policy.

Two of the most advanced FiTs in our view at present are Germany and Ontario. Both systems initially set the tariffs through surveys in order to establish transparent, long term, fixed prices based upon different technologies’ generation costs, plus a small profit. Both Germany and Ontario then account for market changes and reductions in technology costs through systematic reviews based upon rigorous market research. These reviews do not change existing payments but change the payments for future facilities that come online. Germany has a responsive degression rate, which can change

[6] *German RES Act 2008*

marginally annually, but can be adjusted to accommodate more substantive changes every four years, while Ontario relies on having biannual pricing reviews. The incoming German government has announced an out of schedule review in 2010 to see if solar costs have substantially changed (See Box 4). These policy mechanisms allow for keeping current with cost reductions and minimizing implementation costs.

The FiTs in Germany and Ontario provide investor opportunities with certainty by including advanced features such as: must take clauses requiring purchase, setting few volume or project caps, providing incentives for a diverse range of capital providers and owners to participate, and streamlining administrative procedures. Despite the youth of Ontario's policy, evidence from Germany shows how these similar types of FiT policy design elements are being used to create a new industrial revolution in green technologies. Germany has become a world leader in installed renewable energy capacity, which has spurred low-carbon technologies to decline toward grid parity. We also anticipate significant growth in Ontario's renewable manufacturing industry because of domestic content requirements which have already caused a flood of companies to establish manufacturing facilities in the province.

5.0 Contrasting US renewable markets: RECs, Federal policy and PPAs

By comparison with a standard offer payment, such as a FiT, the US renewable policy framework is highly complex. It includes:

1. Federal level incentives—the investment tax credit (ITC) and production tax credit (PTC), which have been on/off in past years and rely on a tax equity market that is currently weak. The stimulus package allowed these to be converted into a cash grant equal to 30% of the value of the qualifying project. However, the cash grant expires in 2011. There are also Federal level loan guarantee programs included in the stimulus bill such as Section 1705 which expires in 2011.
2. State level RPS policies, which typically set renewable volume targets and generate RECs (i.e. "green tags") which certify the environmental attributes of power generation. The REC price depends on the supply and demand for renewables in a particular state or across states. Specific projects can be given RECs and bundled into the PPA (see below). RECs can also be traded; however, REC markets have not been liquid, deep, or hedgeable in general. Only if REC markets became such, which probably needs a meaningful penalty for non-compliance and even a price floor, could they even begin to deliver the type of volume response of a FiT.

These policies then have to interact with a complex set of electricity markets which reflect differing regulatory regimes and price practices. Indeed, the very complexity leads to the view by many commentators that most electricity market policy is best done at the state level. However, central to many of these power systems is a contract known as a power purchase agreement (PPA). In effect the PPA with a REC bundled in generally creates a long term contract with an established pricing schedule—in other words a structure very similar to a FiT (See discussion below in Section 7.0). The real difference is that this is not a standard offer contract—it lacks transparency in terms of TLC in particular and comes down to a project by project proposition. However, it could be argued that it provides price discovery as every contract is struck in a negotiation in a dynamic market environment.

The PPA also adjusts for other policy incentives in most cases so as to avoid double counting and excess returns. The current Federal cash grant has a lot of transparency and certainty but not much longevity due to its expiration in 2011. The ITC/PTC has established timeframes—currently set to expire by 2016—but not true longevity matched to the projects asset life. And the strength of the tax equity market is unsure and highly dependent on the strength of the economy. Loan guarantees are set to sunset in 2011 as well but the proposal to establish a Clean Energy Deployment Administration (CEDA) to take these into the future certainly would help long term access to debt markets.

II. Renewable Energy Policies: Key Design Features

In many senses, the US approach toward renewable energy policy socializes the incentives more through Federal subsidies. It is only when these are insufficient that the PPA needs to bundle a REC price (or other incentive) high enough to justify the renewable project. In this instance, it depends on the state regime as to whether this is funded by taxpayers or electricity ratepayers.

With gas prices below $6/mmBtu, there is no doubt that gas is highly competitive for renewables, and in many cases, this requires layering the RECs, or other state incentives, to make renewable projects viable even with Federal incentives. Alternatively, a FiT standardizes all this.

Overall, in our Climate Tracker we rated the US policy regime as medium risk due to its lack of many of the aspects of TLC.

6.0 Other incentives: Loan guarantees and infrastructure

Many countries and indeed states in the US have established banks or funds to promote renewable energy and energy efficiency programs, often in the context of overall infrastructure development. It was this idea that promoted DBCCA to issue its report "Economic Stimulus: The Case for 'Green' Infrastructure, Energy Security and 'Green' Jobs" in October 2008.[7] These institutions range from those that are specifically focused on renewable energy and energy efficiency, to those that can fund clean energy projects as part of a more general mission to support infrastructure.

In project finance terms, these banks and funds give access to debt markets at preferential rates as they mostly enhance private sector credit with a government guarantee, or lend government funds directly, sometimes raising capital through bond markets. In this way, a project receives a lower cost of capital, which reduces overall project LCOE and can help in boosting the IRR of a renewable energy project. In the US, this is taken into account in most cases when constructing a PPA, while in Europe there have been examples such as low-interest loans from the KfW in Germany, the country's national infrastructure bank.

Most importantly, these banks and funds give access to debt markets where there is not always the appetite in the private sector to provide the scale of capital needed. Given the recent credit crisis, this has become a crucial element of maintaining forward momentum in key markets. They also provide longer tenor, which is often hard to find. Financing estimates show the need for $3-500bn annually on a global basis for clean energy scale-up to meet the climate change challenge. Markets will benefit from a Public Private Partnership (PPP) approach in debt markets, given the required task.

7.0 Renewable energy payments - Reconciling policy regimes

It is evident that governments have many policy levers at their disposal when it comes to scaling-up renewable energy markets. The question is how well do they work? That can be answered in terms of how well they fulfill or support any volume mandate and at what cost. **Our thesis remains that policies need to have Transparency, Longevity, and Certainty (TLC) to deliver an investor-response that will yield the required volume, without inefficient cost to the consumer or taxpayer**, as this would not be financially sustainable.

In essence, a successful renewable energy project has at its core a long term price payment for whatever electricity is delivered. We believe standard offers are the most transparent and investor friendly to volume scale-up. They need to be responsive, through well-defined rules that incorporate price discovery, to market and technological developments. The contract can also be tied to a particular volume target or mandate. We have set out best practices in FiT markets that reflect these ideas, illustrated by Germany and Ontario in particular.

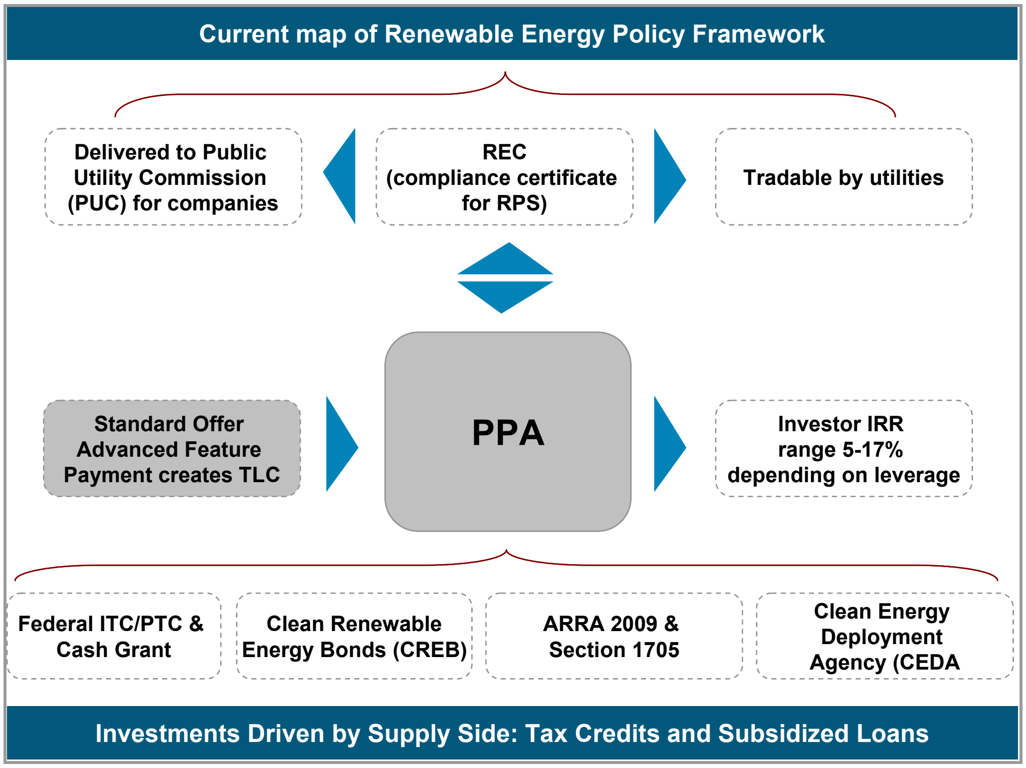
[7] *DBCCA, "Economic Stimulus: The Case for 'Green' Infrastructure, Energy Security and 'Green' Jobs," October 2008.*

II. Renewable Energy Policies: Key Design Features

It is interesting to note that the structure and terminology of the US RPS/REC market could be adapted to introduce the key design features of the advanced FiT. At a policy level, governments can simply adopt an advanced FiT based on the templates discussed above in order to capture TLC. However, introducing seemingly "foreign" policy structures or terminology often meets resistance.

1. The PPA in the US is a contract, but it is not a standard offer, and so it lacks transparency. Standard offer PPAs would change this.
2. The PPA sets a long term price for electricity, but this price may not be sufficient to drive renewable generation. The inclusion of RECs in PPAs (e.g. in response to RPS policies) can provide the basis for giving renewable generators the long term, premium rates they require for project development. In effect, the REC has the function of the premium price element of a FiT. Creating a standard offer PPA that bundles in RECs at prices set to deliver appropriate returns to investors would be analogous to a FiT from a financing perspective.
3. In states that rely on spot market REC trading, setting a minimum price floor for the REC in a standard offer and then applying other advanced features of FiT design (as set out in Chapter III) essentially brings the REC market closer to a design that would yield full TLC. RECs under this scenario could then still be traded.
4. The full range of other state and federal incentives could still be incorporated, subject to a reasonable IRR target, as discussed in Chapter V.

EX 6: Map of renewable energy policy framework



Source: DBCCA analysis, 2009.

Hence there is not necessarily a need to remove existing US policies when introducing FiT best practices. This works well at a state level and has even been proposed at a national level. In fact, a standard offer FiT design would substantially broaden the renewable energy market by increasing liquidity and lowering the barriers to entry for renewable suppliers. In turn this supply response would accelerate the technology learning rates and reduce the need for subsidies over the long run as renewable energy becomes competitive with fossil fuel generation.

III. DBCCA Feed-in Tariff Matrix

FIT Design Features	Key Factors	TLC at the Right Price	France	Germany	Netherlands	Ontario	Spain
Policy & Economic Framework	"Linkage" to mandates & targets	Yes	23% by 2020	30% by 2020	20% by 2020	Halt coal use by 2014	20% by 2020
	Electricity market structure	---	Regulated	Competitive	Competitive	Hybrid	Competitive
	In-state/country content requirements	---	No equip; Yes production	No equip; Yes production	No equip; Yes production	Yes	No
	Year current FIT established	---	2006	2009	2007	2009	2007
Core Elements	Eligible technologies	All renewables eligible	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Geothermal, Small hydro, Biomass, Biogas	Wind, Solar, Biomass, Biogas, CHP	Wind, Solar, Hydro, Biomass, Biogas	Wind, Solar (PV & CSP), Geo, Small hydro, Biomass, Biogas
	Specified tariff by technology	Yes	Yes	Yes	Yes	Yes	Yes
	Standard offer/ guaranteed payment	Yes	Yes	Yes	Yes	Yes	Yes
	Interconnection	Yes	Yes	Yes	Yes	Yes	Yes
	Payment term	15-25yrs	15-20yrs	20yrs	15yrs	20yrs	15-25yrs
Supply & Demand	Must take	Yes	No	Yes	No	Yes	Yes
	Who operates (most common)	Open to all	IPPs; communities; utilities	IPPs; communities; utilities	IPPs; communities	IPPs; communities	IPPs, communities; utilities
	Who buys	---	Transmission system operator	Transmission system operator	Transmission system operator	Transmission system operator	Transmission system operator
	Who pays	---	Ratepayer	Ratepayer	Taxpayer	Ratepayer	Ratepayer & taxpayer
Fixed Structure & Adjustment							
How to set price	Fixed vs. variable price	Fixed	Fixed	Fixed	Hybrid	Fixed	Both
	Generation cost vs. avoided cost	Generation	Generation	Generation	Generation	Generation	Generation
	IRR target	Yes	8%	5-7%	No	11%	7-10%
	Regional/resource differentiations	---	Yes	Yes	No	No	No
How to adjust price	Degression	Yes	Wind only	Yes	No	No	No
	Periodic review	Yes	No	Yes	Yes	Yes	Yes
	Inflation	---	60%	No	No	20%	100%
	Grid parity target	Yes	No	Yes	No	No	No
Caps	Volume cap	---	Yes	No	Yes	No	Yes
	Project size cap	Depends on context	Varies	No	Yes	PV only	Yes
Bonus options	Social "adder"	---	No	No	No	Yes	No
	Generation bonus	---	Yes	Yes	No	No	Yes
Policy interactions	Eligible for other incentives	Yes - eligible to take choice	Yes	Yes	Yes	Yes	Yes
Streamlining	Transaction costs minimized	Yes	Yes	Yes	No	Yes	No
Policy Outcomes	Investor IRRs	---	Usually 7%	Usually 7-9%	N/A	9-11%	Usually 7-10%
	Job creation	---	7,000 (wind)	280,000	2000 (wind)	Est. 50,000	188,000
	RE generation as a % of gross consumption (2008)	---	13.30%	15.1%	7.6%	NA	20.0%
	Wind & Solar Primary RE produced (2007)	---	4,069GWh	42,788GWh	3,474GWh	0.01GWh	28,010GWh
	Technology deployment by ownership	---	Utilities; IPPs	Community; IPPs; utilities	IPPs; utilities	Community; IPPs; utilities	IPPs; community; Utilities,

Source: DBCCA analysis, 2009.

IV. Feed-in Tariffs

Summary:

- *This paper and the case studies chosen are an outgrowth of a recent paper on the German renewable energy sector (entitled Creating Jobs and Growth[8]). As a German bank with a European perspective we have selected leading FiT schemes from France, Germany, the Netherlands, Spain and Ontario (Canada). The motivation for this paper is to provide an on the ground analysis of current implemented FiTs through an investors lens because a number of large jurisdictions and markets around the world are considering the adoption of FiTs.*
- *The above matrix in Chapter III analyzes these countries in light of 5 overarching feed-in tariff design features: policy and economic framework; core elements; interconnection standards; FiT structure and adjustment; and policy outcomes. These aspects were chosen with the intention of painting a fuller picture of the respective FiT policies as they are analyzed in light of their role in setting investor TLC.*
- *The FiT design features shape the structure of the following analysis. The matrix highlights that policy makers have many combinations of features to choose among when designing feed-in tariffs. DBCCA believes that 16 of these key factors play an especially crucial role in setting investor TLC expectations and/or facilitating price discovery. These are highlighted above in the "TLC at the right price" column.*
- *Key factors that are particularly important in setting TLC include: linking a FiT to mandates and targets; guaranteeing a payment; including must take provisions; and allowing a broad range of entities to own and operate renewable energy generation. Additionally, DBCCA recommends that to set investor TLC, FiTs should have an interconnection standard; support a full renewable energy technology mix; have a payment term of 15-25 years and set a fixed price structure that is determined by generation cost and an IRR target.*
- *We recommend a form of price adjustment through a degression and/or periodic review because we believe that this form of adjustment allows room for price discovery and can establish a pathway to commercial break-even. We also advocate allowing producers to choose if they would like to take advantage of incentives but would recommend an all-in package because too many layers to incentives reduces transparency. If transaction costs can be minimized it is advantageous to the producer because it is transparent and expedites the process of bringing facilities online.*

1.0 Core feed-in tariff principles

At a most basic level, five core principles characterize successful feed-in tariffs policies:

- **Eligible technologies:** Including all renewable technologies suitable for a given region encourages a diverse volume scale-up.
- **Specified tariff by technology:** Differentiating payments by technology supplies a granularity that can lead to more precise tariff pricing for a diverse range of resources.
- **Standard Offer / Guaranteed Payments:** Standard Offers and FiTs provide guaranteed payments to ensure renewable energy developers a minimum payment. It is important to set the minimum tariff at generation cost plus a small profit or a payment level designed to move the market. Advanced schemes have must take provisions that ensure the purchase of 100% of electricity generated.
- **Interconnection:** Most schemes include a mandate for grid operators to connect renewable electricity generators.
- **Payment term:** Renewable payments over a long timeframe, usually 20 years, provide certainty.

2.0 Policy and economic framework

2.1 Linkage to mandates and targets

Tying feed-in tariffs to broader renewable energy or climate change objectives tells the market that policy makers are committed to reaching their long term goals. DBCCA recommends using FiTs as a way to reach these targets and to set

[8] *DBCCA, "Creating Jobs and Growth: The German Green Experience," September 2009.*

investor expectations of how policy makers envision the future renewable energy landscape. All European countries are bound to Kyoto Protocol international greenhouse gas (GHG) reduction targets.[9] Low–carbon renewable energy plays a large role in decreasing CO_2 emissions. The EU has been more forward-looking than the US and has enacted long term national and supra-national targets.

The European case study countries have multiple commitments on the national and EU levels. The 20-20 by 2020 Directive[10] sets a EU goal to reduce GHGs by 20% (rising to 30% if there is a strong international agreement) and for renewable energy to contribute 20% of final energy consumption by 2020.[11] This directive is then articulated down into individual Member State commitments. For most EU member states, the final energy goal is split into national sub-targets for electricity and transport, and sometimes heat. Under the 20-20 Directive, France is committed to obtaining 23% of its electricity from renewable sources, Germany 18%, the Netherlands 14% and Spain 20%.[12] Germany and the Netherlands have voluntarily increased their national targets to 30% and 20% respectively, while Spain's 2005-2010 National Energy Plan states the goal of reaching a 2010 target of 30% gross electricity from renewable energy.[13] Exhibit 7 below contains each jurisdiction's highest renewable electricity target, as well as the corresponding policy mandate.

Similar to Europe, Canada has national greenhouse gas targets to lower total emissions by 20% from 2006 levels by 2020 and has agreed with the G-8 parties to reduce emissions by 80% by 2050.[14] On a provincial level, Ontario's driving force for renewable energy is the 2014 coal phase out, which currently represents 18% of the province's energy supply.[15] The low percentage of renewable power sources creates strong impetus to drive a rapid volume response through FiTs. Ontario does not have a percentage renewable electricity target but rather has the goal to add 10,000 MW of new installed renewable energy by 2015, and 25,000 MW by 2025.[16] Additionally, Ontario has a Climate Change Action Plan to reduce GHGs 6% 1990 levels by 2014 and 15% by 2020.[17]

EX 7: 2020 Renewable electricity goals

Country/Province	Highest Renewable Electricity Target	Commitment Made Under
France	23%	20-20 by 2020 Directive
Germany	30%	National Goal
Netherlands	20%	National Goal
Ontario	10,000 MW by 2015; 25,000 by 2025*	Ontario Target
Spain	30%	National Energy Plan 2005-2010

** Notes: Figures represent new installed renewable energy over and above 2003 levels.*
Source: EU 20-20 by 2020 Directive, 2007; Franzjoesf Schafhausen, "Renewable Energy in Germany", 2007. Ron van Erck, "New Dutch Feed-in Premium Scheme "SDE" Opened April 1st", 2007; Pablo del Rio Gonzalez, Ten Years of Renewable Electricity Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms, Energy Policy, 2008; Munoz et al, "Optimal Investment Portfolio in Renewable Energy: The Spanish Case," Energy Policy, 2008; Government of Ontario, "A Green Energy Act for Ontario: Executive Summary", Green Energy Act, January 2009.

[9] The US has not ratified the Kyoto Protocol and also lacks an integrated national final energy target.
[10] This directive is also nicknamed 20-20-20..
11 European Commission, "20 20 by 2020: Europe's climate change opportunity, Communication from the commission to the European parliament, the council, the European economic and social committee and the committee of the regions", January 2008.
[12] EU 20-20 by 2020 Directive, 2007.
[13] Franzjoesf Schafhausen, "Renewable Energy in Germany", 2007. Ron van Erck, "New Dutch Feed-in Premium Scheme "SDE" Opened April 1st", 2007; Pablo del Rio Gonzalez, Ten Years of Renewable Electricity Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms, Energy Policy, 2008; Munoz et al, "Optimal Investment Portfolio in Renewable Energy: The Spanish Case," Energy Policy, 2008.
[14] Government of Canada, "EcoACTION: Action on Climate Change and Air Pollution", 2007; Patrick Wintour and Larry Elliott; "G8 Agrees to Climate Targets Despite Differences with Developing Nations", The Guardian, July 8, 2009.
[15] Government of Ontario, "Go Green: Ontario's Action Plan on Climate Change", August 2007; Ben Block,,"North American Feed-in Tariff Policies Take Off", Worldwatch Institute, August 12, 2009.
[16] Green Energy Act, "A Green Energy Act for Ontario: Executive Summary", January 2009.
[17] Government of Ontario, "Go Green: Ontario's Action Plan on Climate Change", August 2007.

2.2 Electricity market structure

There are three types of electricity market structures: regulated, liberalized[18] (competitive) and hybrid. Regulated and hybrid markets are most common. This section summarizes the following for the EU and Ontario in Exhibit 8: the structure of the electricity market, the year the market became liberalized, the dominant electricity providers and their associated share of generating capacity. This is relevant because it highlights differences within the electricity market structures and shows that FiTs can be implemented under different market contexts.

All of the case study regimes have a form of a liberalized electricity market. The 1996 EU Electricity Directive (96/92/EC) has restructured European electricity markets by requiring utilities to unbundle (i.e. separate) their transmission, distribution, and generation assets. Since 1996, two successive EU liberalization packages have aided the transition to a competitive market. Compared to other EU electricity markets, France has been the slowest to implement its EU Directive. The Netherlands is considered ahead of the curve in terms of liberalization because of the high number of small players in the market.[19]

The government of Ontario introduced greater competition and deregulated its electricity market in 2002, but was then criticized for wide electricity price fluctuations. Six months later, price smoothing mechanisms were introduced, some of which are still in effect. Currently, the market is a hybrid between being liberalized and regulated. Some generators bid on the market and some have power purchase agreements with the Ontario Power Authority.

It is interesting to note the percentage of capacity (compared to total gigawatts installed) controlled by the dominant electricity providers. Providers in France and Ontario have relatively low competition because one entity controls the majority of installed capacity. The four dominant Dutch electricity providers share a comparatively low proportion of capacity.

EX 8: Comparison of case study electricity markets

FIT Scheme	Market Structure	Year of Liberalization	Dominant Electricity Providers	Provider(s) Share of Capacity (units in GW)*
France	Liberalized	2007	Electricité de France (EDF)	87%
Germany	Liberalized	1998	Vattenfall, E.ON, Energie Baden-Würtemburg and RWE	90%
* Netherlands	Liberalized	2004	Electrabel, E.ON, Benelux, Essent & Nuon	65%
Ontario	Hybrid	2002**	Ontario Power Generation	70%
Spain	Liberalized	2003	Iberdrola, Endesa	70%

*Note: *The provider share of capacity is compared to the total installed generation capacity in gigawatts **Ontario's market became fully open in 2002 then switched to a hybrid version six months later.*
Source: European Commission, Internal Market Fact Sheets for: France, Germany, Netherlands and Spain, 2007; Electricity Distributors Association, "Ontario Electricity Market Primer", 2007.

[18] *Note: Outside of the US the term "liberalized" is typically used to denote a competitive market structure. The government is still involved in some price setting and regulatory aspects.*
[19] *Eric van Damme; "Liberalizing the Dutch Electricity Market: 1998-2004", Tilburg University, March 2005.*

2.3 In-State/Country content requirements

France, Germany, the Netherlands and Spain do not have rules requiring renewable generation content to be produced nationally. To receive FiT payments, however, electricity must be generated within country borders.[20] Incorporating such requirements can strengthen the domestic political case for how FiTs and renewable energy policy can support the local economy, but can also raise concerns about distortions in trade. It does not pertain directly to price discovery (i.e. getting up-to-date input on actual market costs and investor returns) or setting investor TLC.

Although Spain does not have content requirements at the national level, some autonomous state governments such as Castile, Galicia, Leon and Valencia have provided development permission only if a percentage of manufacture and assembly is done locally.[21]

Ontario takes a strict stance on content requirements. To qualify for FiT payments, 40% to 50% of all solar projects must be manufactured within Ontario and 60% by Jan. 1, 2011.[22] For wind, the content requirement is currently 25% but it will rise to 50% on Jan. 1, 2012.[23] As economists, we recognize that such provisions can lead to trade distortions.

2.4 Year current FiT established

Over 40 countries have adopted a FiT model since 1990, and legislators have taken many different regulatory and legislative approaches to establishing and refining their policies.[24] As demonstrated by the case studies, feed-in policy development is iterative and each of the policies analyzed in this report has been amended or adjusted several times. In this section, we confirm which version of the feed-in tariffs we are referring to in this report.

Germany's leading industrial environmental policy is a success story for renewables because of two key pieces of legislation. The Electricity Feed Law from 1990 (Stromeinspeisungsgesetz – StrEG) marked the beginning of Germany's formal support for renewable energy by establishing the first national feed-in tariff scheme.[25] The 2000 German Renewable Energy Sources Act (Erneuerbare Energien Gesetz – EEG) replaced the 1990 framework with a more advanced policy that addressed StrEG weaknesses.[26] The current EEG has catapulted Germany to become a world leader in renewable power.

All of the European countries have since updated their FiT schemes to include advanced features that support TLC yet provide a greater degree of market flexibility. Germany updated its FiT scheme in 2009, Spain in 2007 and 2008 (solar); the Netherlands in 2007 and France in 2006 with a PV update in 2009. In 2009, Ontario replaced its 2006 Standard Offer Program with a feed-in tariff modeled after European best practices.

3.0 Core elements

The following section highlights the design features that are core to any feed-in tariff as mentioned in Chapter II, Section 4.0. These elements are typical not only for the regimes focused upon in this section but also across most FiT policies.

[20] BMU, RES Legal Database, 2008.
[21] Joanna Lewis and Ryan Wiser, "Fostering a Renewable Energy Technology Industry: An International Comparison of Wind Industry Policy Support Mechanisms", Ernest Orlando Lawrence Berkeley National Laboratory, November 2005.
[19] Green Business, "Ontario Government Announces Details of Feed-in Tariff Program, Including Domestic Content Rules", September 25, 2009.
[20] Green Business, "Ontario Government Announces Details of Feed-in Tariff Program, Including Domestic Content Rules", September 25, 2009.
[24] REN21, "Renewables Global Status Report: 2009 Update," Paris: REN21 Secretaria, 2009.
[25] Before its national debut, the US state of California implemented the world's first feed-in tariff in 1984 under Standard Offer Contract No. 4, which set standards in response to the Public Utility Regulatory Policies Act.
[26] Pricing was variable and was tied to average retail electricity rates. The coal levy phase-out and market liberalization from 1996 onwards reduced electricity prices, causing renewable payments to decrease. These market price fluctuations deterred steady investment and made securing financing difficult.

IV. Feed-in Tariffs

3.1 Eligible technologies

Advanced tariff schemes encompass a wide range of post demonstration proven renewable energy technologies. France, Germany and Spain provide guaranteed payments for wind (on and offshore), solar (PV), geothermal, small hydropower, biomass and biogas facilities. The Netherlands gives payments for the above sources except geothermal but plus combined heat and power (CHP). Ontario has tariffs for wind (on and offshore), solar (PV), small hydropower, biomass and biogas facilities. Spain is the only regime studied which provides payments for solar thermal and concentrating solar power (CSP) facilities. DBCCA recommends including a wide breadth of eligible resources in FiT programs because it can rapidly diversify national generation portfolios and allow technologies to simultaneously advance down their learning curves.

3.2 Specified tariff by technology

Differentiation creates a level of granularity that accounts for the wide range in costs of developing and operating a given technology. Providing one payment rate for technologies with different project costs would result in incentives that over or underpay. Wind and solar, for example, have different costs. Providing a tariff that covers less expensive wind generation would not offer incentives to invest in solar as well. Alternatively, using only a higher tariff rate to cover solar installation expenses would lead to excess profits for those who invest in wind. Differentiated payments are typically determined based upon project costs, which provides an additional level of transparency for investors.

Each case study provides a different tariff range by technology as well as by the project size. For example, Ontario provides a large tariff payment range both within and across technologies. At one end of the spectrum, landfill gas projects range from 10.3¢/kWh for projects greater than 10MW to 11.1¢/kWh for those less than or equal to 10 MW.[27] On the other end lies solar PV projects which range from 80.2¢/kWh for installations 10 kW or smaller to 44.3¢/kWh for those larger than10MW.[28]

Typically, the amount paid to larger systems is smaller because of economies of scale - they cost less per power unit. Exhibit 9 highlights the specific tariff payment range within a given technology, in this case, solar power as under the German EEG.

EX 9: 2009 Solar PV installation payments under the German EEG

Installation Type	Installed Capacity (In kWpeak)	Tariff (Per kWh electricity produced)
Solar Plants	All	31.94 €Cents
Attached/ On top Buildings	< 30 kWpeak	43.01 €Cents
	30-100kWpeak	40.91 €Cents
	100kW – 1MWpeak	39.58 €Cents
	> 1MWpeak	33.00 €Cents

**Percentages can increase/decrease by 1.0% if installation capacity is above/below a certain threshold.*
Source: Adapted from German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008, Section 20 and Sections 32-33.

As investors, we favor tariff differentiation because choosing to ignore the diverse project costs which vary by technology and size and instead setting a flat rate across all technologies would result in coverage that over or underpays. This has nothing to do with "picking winners" as some analysts claim. Wind and solar, for example, have different costs because they

27 *OPA, "Feed-in Tariff Program", September 30, 2009.*
28 *OPA, "Feed-in Tariff Program", September 30, 2009.*

are at different stages of maturity. Differentiated payments are typically determined based upon project costs, which forms an additional level of transparency for investors.

3.3 Standard offer / Guaranteed payment

FiT design is characterized by promising a payment for sale of renewably produced electricity to the grid. Also called a standard offer[29] (e.g. Ontario's past FiT), this guaranteed payment feature is present in each FiT scheme we have analyzed. It is particularly vital in setting TLC for capital providers because it is a promise that investors will receive predictable revenue in order to recoup their investments. A guaranteed payment lowers the renewable energy project risk, which is particularly important with investors in the current economic climate.

3.4 Interconnection

Interconnection rules can be guaranteed through two avenues: on a statutory or a contractual basis. Germany, Spain and Ontario's interconnection rules set greater TLC because they were established through legislation guaranteeing access to the grid.

France and the Netherlands follow a contractual policy under which any party has the right to connect if it is agreed upon with the grid operator. French policy tries to streamline this by mandating that grid operators respond to applications within three months and allowing for government intervention should operators stall the interconnection process.[30] Dutch policy does not create a grid operator timeline. This provides less investor certainty because it allows room for grid operators to put up access roadblocks. Interconnection rules in all of the FiT systems apply to large and small projects though protocols for connection may differ by project size.

3.5 Payment term

Long term payments are a core principle of basic and advanced FiTs. The timeframe over which generators receive payments for electricity ranges from 15-40 years in the case study jurisdictions, with the majority of payments lasting for 20 years. Germany and Ontario authorize payments for 20 years for all sources except hydropower, which has a term of 15 years in Germany and 40 years in Ontario.[31] Spain provides between 15 and 25 years of payments if generators elect the fixed pricing payments (see Section 5.1.1 below).[32] If they choose a premium pricing scheme, the payments continue for the full project lifetime. France differentiates the most: geothermal, biogas, biomass and onshore wind have longevity of 15 years, PV, offshore wind and hydropower receive payments for 20 years.[33]

Renewable energy has a long lifetime. From an investor's perspective, a pre-determined contract length is a transparent way of satisfying longevity criteria. Matching the revenue stream with the length (or a substantial portion of the length) of the project life increases investor certainty.[34] Differentiating contract lengths by technology can account for the range in project costs and risks.

[29] The term "Standard Offer" derives from the principle that contract terms, payments and eligibility standards are the same for everyone.
[30] BMU, RES Legal Database, 2008.
[31] German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008; OPA, "Feed-in Tariff Program", September 30, 2009.
[29] Gonzalez, Pablo del Rio, "Ten Years of Renewable Energy Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms", Energy Policy, 2008.
[33] Doerte Fouquet, "Prices for Renewable Energies in Europe: Report 2009", EREF, 2009.
[34] David de Jager and Max Rathmann, "Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects", 2008..

IV. Feed-in Tariffs

4.0 Supply & demand

4.1 Must take

Germany and Ontario each have must take clauses.[35] Under such conditions, renewable energy receives priority purchase before fossil fuels on the grid. This guarantees that 100% of the clean power produced is purchased. Spain has two pricing regimes (See Section 5.1.1) and under its fixed first pricing structure, the must take provision is guaranteed. Spain's second pricing structure, variable pricing, does not include a must take clause because producers sell the power on the spot market.[36] France and the Netherlands have anti-discriminatory laws, which prevent preferential treatment to power providers.[37] Must take provisions provide a high level of TLC because investors and operators can closely predict their sales volumes and therefore their returns.

4.2 Who operates

All of the feed-in tariff mechanisms provide eligibility for independent power producers (IPPs), communities and large utilities to participate through ownership and investment. This is a trend in current policies whereas past FiTs made it more difficult for utilities to participate (e.g. the German 1990 FiT excluded the state municipalities/utilities if they owned more than 25% of the project).[38] While each case study regime allows anyone to participate in ownership and investment, tariff payment differentiation and bonuses (see Section 3.2 and Section 5.4) create distinctive incentives for certain players. By providing payments for small facilities, for example, size-differentiated feed-in tariffs provide greater ownership opportunities for communities, homeowners and farmers. A difficulty in the implementation of FiTs is getting utility companies' support because FiTs require them to share power generation with other players.

In Germany, homeowners commonly manage small installations, such as solar roof generators. Alternatively, larger installations such as wind are often owned and operated by community cooperatives, farmers or commercial IPPs. Germany's largest utility companies, RWE, E.ON, EnBW and Vattenfall have increasingly begun to take advantage of feed-in tariffs by leasing farmland and buying into cooperatives though they remain a small part of the market (<10%).[39] In Spain, renewable technologies are predominately owned and operated by utilities, however, many large scale PV farms have received community support through cooperatives. IPPs and utilities are heavily involved in Spanish projects as well. Since Ontario's legislation was recently enacted, the key players have not yet emerged.

Enabling and encouraging a diverse range of capital providers to participate in the renewable energy market can help build a larger, more competitive, and resilient investor pool.

4.3 Who buys

Grids are complex systems that are unique to a given location. How a specific generation unit dispatches its energy is a function of the technology type and the grid. Substations convert electricity into lower voltages to transmit electricity from a large power station to a private residence. Since power is produced at different voltage levels, connection also occurs at different points on the grid. For example, large hydropower is transmitted at the extra high or high voltage level while medium-sized wind farms may come online to a medium voltage network. A residential PV roof installation may be transmitted at the lowest voltage grade. Different types of entities are involved in each step of the process as renewable power joins the grid.

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[35] *German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008; OPA, "Feed-in Tariff Program", September 30, 2009.*
[36] *Gonzalez, Pablo del Rio, "Ten Years of Renewable Energy Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms", Energy Policy, 2008..*
[37] *BMU, RES Legal Database, 2008.*
[38] *StrEg 1990.*
[39] *Till Stenzel, "Regulating technological change – The strategic reaction of utility companies towards subsidy policies in the German, Spanish and UK electricity markets," Energy Policy, 2008.*

IV. Feed-in Tariffs

For each case study, transmission system operators are responsible for dispatching power sources sold. Grid operators serve as the responsible agents for balancing the grid system procuring the power and facilitating the transaction between the generator and the counterparty (utility). The operators typically purchase electricity and then pass the costs onto the utility. Electricity market liberalization in the EU and Ontario required utility companies to decouple transmission and distribution functions.[40] Now grid operation is run either by large utility companies that have created a separate legal entity, such as independent system operators (ISOs) or municipal agents.

The point at which the generator interacts with the grid varies by regime and is subject to the individual architecture of the system. For example, France obliges grid operators to complete interconnection transactions thus tying operators to paying the generator. French policy makers have determined that EDF and a specified list of private grid operators are responsible for the purchase.[41] Germany requires all grid operators to procure renewable power no matter the point of connection while Spanish eligibility rules excludes transmission system operators that connect generators at certain voltage levels.[42] While the transmission system operator procures the power, it is not responsible for the end payment because it passes the costs onto the utility.

4.4 Who pays

When governments intervene to accelerate the rate of renewable energy uptake, there is a cost no matter the type of policy. Policy makers must decide who should carry the added cost of a feed-in tariff: the ratepayer and/or the taxpayer. The FiT costs can be passed to the ratepayer, to the taxpayer (individual citizens and businesses), or to a combination of both as highlighted below:

This choice frequently results in an ideological discussion over which is the most efficient and transparent. Distributing costs among taxpayers is less transparent than ratepayer distribution because it relies on government budget appropriations, which may not actually be appropriated or may be redirected. When the ratepayer carries the FiT the costs, this can directly increase the price of electricity.[43]

- **Surcharge to ratepayer electricity bill (Germany, Ontario, France):** In Germany, large industrial ratepayers can apply for partial exemption with a €0.05/kWh cap on FiT payments and the burden is distributed to the rest of the rate paying population.[44] The added cost of purchasing more expensive electricity is passed onto the ratepayer by incorporating the payments into the electricity rate through an EEG surcharge on the monthly bill. The fee is determined by the National Equalization Scheme, which accounts for regions with larger renewable energy production capacity.[45] For example, Southern Germany has a greater number of installed solar collection facilities which receive the highest tariff rate. Transmission operators may buy more from local solar electricity generators than those in areas with less solar capacity. Grid operators who purchase beyond the national average receive compensation from other transmission system operators who paid a below-average proportion. These equalized prices are then passed to the ratepayer through the distribution companies.

  In Ontario, any increases in costs will be passed onto the ratepayer in the form of a higher electricity bill. The province takes individual electricity consumption level into consideration and has provisions to help disadvantaged population groups.

[40] *Luis Trevino, "Liberalization of the Electricity Market in Europe: An Overview of the Electricity Technology and the Market Place", MIR Working Paper, 2008; Blake, Cassels & Graydon LLP, "Overview of Electricity Regulation in Canada", February 2008.*
[41] *BMU, RES Legal Database, 2008.*
[42] *Ibid.*
[43] *Recent studies in Germany, Spain, and Denmark have found that wind power has helped put downward pressure on electricity spot market prices (see Sensfuss et al. 2008; de Miera et al. 2008; Munkgaard and Morthorst 2008, respectively).*
[44] *German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008.*
[43] *Ibid.*

In France, the ratepayer must pay into the Contribution au Service Public de l'Électricité (CSPE), which is raised through a quarterly ratepayer surcharge.[46] Payments are determined annually and help support the costs borne to large utilities for connecting renewables. Large industrial ratepayers are exempted from the surcharge if they produce a portion of their electricity onsite.

- **Charge through taxpayer revenues (Netherlands):** The Dutch Treasury pays for FiT costs directly from its budget (generated by tax revenues). The amount paid is determined by the target renewable energy capacity which the government establishes every 4 years.[47] The budget for 2009 for renewable energy FiT support is estimated at €2,585 million.[48] In this way, taxpayers pay for the FiT and the costs are shared equally without taking individual electricity consumption level into consideration.

- **Combine the charge to ratepayer and taxpayer (Spain):** The Spanish system distributes the cost to both ratepayers and taxpayers.[49] The grid operator initially pays for the FiT costs and passes it along to the ratepayers through an electricity bill surcharge. Taxpayers also contribute because the National Energy Committee (CNE) compensates grid operators should their extra expenses due to the FiT outweigh the revenues they derive from retail electricity sales.[50]

5.0 FiT Structure & adjustment

The following section breaks out the key features to consider when analyzing how FiTs aim to balance price discovery and TLC. It identifies 6 key factors: eligible technologies, how to set the price, how to adjust the price, caps, interaction with incentives and streamlining. It shows the many advanced options available to policy makers and which ones play a significant role in setting TLC.

5.1 How to set the price

5.1.1 Fixed Price vs. Variable Price

FiTs can use a fixed or variable pricing structure, both of which pose trade-offs. Using a fixed method is the most certain and predictable option because investors know their precise compensation level over a long time horizon. Variable pricing integrates more directly into electricity markets because it typically takes the form of a price premium paid on top of the electricity spot market price. Variable pricing is riskier for investors because the tariff payment fluctuates with electricity prices. Both options create the risk of excess profits for generators. Alternatively, legislators risk generating lower investment levels if investors believe that the market will not reliably cover project costs.

The following sub-section details three pricing structures as they pertain to each jurisdiction. Germany, France and Ontario use a fixed pricing structure. Spain provides renewable generators with the option to choose between fixed and variable pricing and the Netherlands uses a hybrid between the fixed and variable structure options.

Germany's fixed pricing structure creates a lower revenue risk because investors know exactly what they're getting for the duration of the first 20 years that their installation operates. The premium option, as in Spain, provides a potential for larger profits but with that comes a slightly higher risk. On one hand, this pricing structure integrates more into the electricity spot market but there is variability in the pricing. To limit price fluctuations and retain a level of TLC, the Spanish premium system has a price floor and ceiling. The Netherlands is the most integrated into the spot market but has the highest level of risk and uncertainty. Investors could reap greater profits because the variable base guarantee has no upper bound but the

[46] *BMU, RES Legal Database, 2008.*
[47] *Ron van Erck, "New Dutch feed in premium scheme "SDE" opened April 1st", 2007.*
[48] *BMU, RES Legal Database, 2008.*
[49] *Gonzalez, Pablo del Rio, "Ten Years of Renewable Energy Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms", Energy Policy, 2008.*
[50] *Ibid.*

lower bound (floor price) can decrease under certain economic conditions. This adds a level of risk that is not present in the fixed or premium models which is why DBCCA favors a fixed pricing model that fosters the highest level of TLC.

Fixed Pricing: Germany, France[51] and Ontario only use a fixed pricing mechanism under which a flat payment is established. As the pioneer of the fixed price method, Germany provides a strong case study. The German FiT uses technology project costs, type, overall cost-efficiency, installed capacity, location and the commissioning date to determine the specific payments. Prices are fully decoupled from the electricity market prices. Exhibit 10 shows the tariff range under the newest version of the German FiT policy.

EX 10: Overview of 2009 EEG renewables payments

Electricity Type	2009 Tariff Range (In €Cents/kWh or MWh output)
Hydropower	3.5 – 12.67
Landfill Gas	6.16 – 9.0
Sewage Treatment	6.16 – 7.11
Mine Gas	4.16 – 7.16
Biomass	7.79 – 11.67
Geothermal	10.5 – 16.0
Onshore Wind	5.02 – 9.2
Offshore Wind	3.5 – 13.0
Solar (PV)	31.94 – 43.01

Note: Tariffs do not include value-added tax. Tariff rates differ than those in the 2000 and 2004 EEG.
Source: Adapted from German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008, Section 20 and Sections 32-33.

Variable Pricing: The Spanish model is the prevailing example for variable tariff pricing.[52] Spain has two pricing options, which operators can revise at their discretion on an annual basis. The first option is a FiT and the second is a variable option (called a premium) in which a bonus is paid on top of the spot market electricity price. To curb against market volatility the premium price has floor and ceiling prices. If the electricity market price increases under the Spanish premium option, the developer receives the spot market price. The premium amount declines to zero as prices increase, but developers still retain the “upside risk” of electricity price volatility. Spain’s cap and floor system ultimately removes the “downside risk” by imposing a floor which thus reduces volatility to the middle range. The FiT system includes incentives to encourage producers to use the variable pricing mechanism. Electing the premium pricing structure enables generators to receive funding for the project lifetime whereas the fixed option payments end after a given technology’s specified payment term expires (15-25 years).

Dutch Hybrid Structure: The Dutch system shares characteristics with fixed price and premium approaches and is known as "spot-market gap" pricing.[53] Under this system the government guarantees a fixed base payment. If the spot market price is below the base payment, the generator receives the spot market price for electricity and then receives a feed-in tariff payment equal to the “gap” between the spot market price and the base payment. If the spot market price rises substantially above the base payment, the generator keeps the upside. Should the spot market price decrease significantly, the base payment can shift.[54]

[51] The French government uses a tendering system for projects exceeding 12 MW in size. After announcing the annual tender selection, developers bid and the winning bidder is bound to the price proposed.
[52] Following paragraph sourced from: Gonzalez, Pablo del Rio, “Ten Years of Renewable Energy Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms”, Energy Policy, 2008.
[53] Term according to NREL and sourced from: Karlynn Cory, Toby Couture, Claire Kreycik, “Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions”, NREL Technical Report, March 2009.
[54] The government subsidizes the difference between the retail and the guaranteed rates. The subsidy has a 2/3 cap tied to the anticipated long term electricity and gas prices. If the gap grows because of an electricity spot price drop then the amount the government pays will not exceed the 2/3 level. This would cause the FiT payment to decrease.

The advantage to this system, however, is that it allows for more flexibility as economic conditions change. If electricity prices rise beyond the minimum guaranteed payment level, the government does not have to contribute. This is because the difference between the electricity price and the minimum rate are positive. While this system can adjust to market changes, it is riskier than the fixed pricing schemes such as Germany's, France's and Ontario's models.

5.1.2 Generation Cost[55] vs. Avoided Cost

There are two fundamental ways to set a price: through generation cost and avoided cost. Most European-style FiTs and all of the case studies utilize the generation cost method under which the payment is determined by estimating the project cost plus a profit. The generation cost method typically sets a targeted internal rate of return (IRR) (Section 5.1.3) which decreases risk and provides investors with a high level of certainty.

The Dutch Ministry of Economic Affairs oversees FiT tariff level recommendations. The Energy Research Center of the Netherlands (ECN) (non-profit) and KEMA (consultancy, for profit) advise the Ministry by conducting a cash-flow analysis on prices and performance. The financial model is available to the public and stakeholders are asked to comment. The ECN and KEMA then issue a final recommendation, and the Ministry proposes tariff rates to the Parliament for consideration.

In Germany the Center for Solar Energy and Hydrogen Research (ZSW) analyzes prices through a technical review. Generators and developers must contribute costing information. Public participation is not like in the Netherlands but rather stakeholders have the opportunity to give comments on proposed rates. The ZSW submits the paper to the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) which evaluates and proposes a tariff to the Parliament. The Bundestag makes the final decision.

In Spain the National Energy Commission (CNE) uses input from key stakeholders to understand if pricing needs to be changed. It provides a recommendation to the Ministry of Industry, Tourism and Trade which then determines the final price.

The avoided cost method to determine FiT payments has been notably used in California, and typically represents the value of new generation to the utility. In California, this mechanism determines payments through a calculation of the value of electricity generated from natural gas and modified by a time-of-delivery factor that reflects whether the power is delivered during peak times.[56] Payments do not necessarily cover 100% of project costs.

When taking an investor's standpoint, if the value of the incentive does not match the generation cost then the project is not viable. This applies whether the pricing structure is fixed or variable. The avoided cost method will create a volume response only if the avoided costs approximately coincide with RE project costs, and allow for a reasonable return. It is most likely to over or underpay the electricity generator. If the policy goal is to drive volume response, determining pricing through generation cost is the best method because it guarantees coverage of project cost and a small profit. Generation cost-based payments also create greater opportunities for hedging and cost reduction over time so that renewables can be on a grid parity pathway.

5.1.3 IRR Target

The targeted internal rate of return per country or province ranges from 5% to over 10% for the programs that use fixed pricing. Ontario sets its IRR at 11% of after tax profits with a 70/30 debt equity leverage.[57] The 2006 French review officially establishes an 8% real project IRR before tax on profit. Dutch legislation does not explicitly state an IRR target but cost of

[55] Summaries on the Netherlands, Germany and Spain from: KEMA, "California Feed-in Tariff Design and Policy Options", Final Consultant Report Prepared for the California Energy Commission.
[56] California Public Utilities Commission (CPUC), "Energy Division Resolution E-4137", February 2008.
[57] OPA, "Proposed Feed-in Tariff Price Schedule, Stakeholder Engagement", April 7, 2009.

capital and equity return assumptions are built into the rate setting models that are posted online. For wind energy, for example, the return on equity is set at 15%.[58] Spain and Germany provide good examples of risk-based IRR targeting.

Spain has an advanced system that determines IRR based upon risk because certain projects ask more of their investors. Low-risk projects targets include PV (7%) and onshore wind (8%).[59] Targets are greater for high-risk projects, which include biomass (9-10%), offshore wind (>9%) and wave (>10%).[60] Additionally, Spain adjusts its IRR based upon how far the given technology is from reaching its national targets, as laid out in its National Energy Plan (PER 2005-2010). If the technology is falling short (as it was for Spain's biomass target as of 2007), it can adjust the FIT price and premium amounts upward, in order to target a higher rate of return, and drive a more rapid scale-up in that particular technology.

Germany sets a rough IRR target of 5-7%, which is low compared to other schemes, but aims to minimize excessive profits yet incentivize investment.[61] Germany also provides a strong example of risk-based IRR targeting for its offshore wind tariff. Developers generally acknowledge that the risk is high and the government already provides a bonus for projects developed before 2015. German policy makers argue that higher returns are needed to compensate for the added risk of an "emerging" technology and challenging project development conditions. The industry recognizes that the off-shore wind tariffs are generous and justifies these rates through the higher risk as well as the knowledge that if Germany can encourage greater offshore wind technical capabilities in, it opens up great export market opportunities for the sector, which is still in its infancy.

5.1.4 Regional / Resource Differentiations

France has different adjustments for solar and wind based upon region and resource intensity. Since the south is sunniest it receives lower payments for commercial rooftop solar PV within a range of a 20% reduction.[62] As for wind, all producers receive the same payment level for the first 10 years of onshore generation. The tariff amount is adjusted depending upon the average yield for those years. The adjusted price is paid out for the last 5 years of guaranteed payment. Payments for windier sites reduce a little more than for less windy sites.

In Germany, wind payments receive different treatment than from other renewable technologies. For the first 5 years, all wind producers receive a high tariff. FiT payments are subsequently reduced for the most productive (i.e. windiest) sites for the following 15 years to prevent excess profits.[63] The least windy sites continue to receive the base (i.e. highest tariff) payment level for a longer period of time.

5.2 How to adjust the price

The overarching objective of most feed-in tariff policies is to accelerate the process of making renewable technologies cost competitive with conventional fossil fuels. In aiming to reach the fine balance of setting strong TLC signals and allowing room for price discovery and market flexibility, FiT policies have introduced several forms of pricing adjustments, the main three types being degression, periodic review and inflation indexing. These adjustments do not change the payment terms of current facilities but affect the tariff rates of future renewable energy installations that have yet to come online. Based on the criteria for identifying a least cost path to grid parity, we feel that the opportunities to encourage future producers to reach grid parity are best achieved through using a degression and/or a periodic review.

These pricing adjustment mechanisms are transparent and provide a high level of investor certainty. A degression and a set review utilize current market fundamentals to set and adjust the generation cost, which we explain in below as the ideal way

[58] ECN, Hernieuwbare Energie – Projecten, http://www.ecn.nl/nl/units/ps/themas/hernieuwbare-energie/projecten/sde/sde-2010/
[59] Gonzalez, Pablo del Rio, "Ten Years of Renewable Energy Policies in Spain: An Analysis of Successive Feed-in Tariff Reforms", Energy Policy, 2008.
[60] Ibid.
[61] Hans-Josef Fell, "Feed-in Tariff for Renewable Energies: An Effective Stimulus Package without New Public Borrowing", April 2009.
[62] CLER, "Nouveaux tarifs d'achat PV : des avancées réelles mais des interrogations sur certains choix négatifs pour un développement optimal de la filière", October 12, 2009.
[63] German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008.

to reach grid parity. We recommend establishing a review that occurs at fixed intervals to set investor expectations. If the review is coupled with a degression then the timing between reviews could possibly be more spread out. An approach that could better integrate price developments is the use of a volume cap under which once a volume level is reached, it triggers a review. This system poses risks of speculative queuing and gaming. Transparent procedures regarding how operators get, and stay, in line are essential to minimize reducing TLC.

5.2.1 Degression

Germany is the only case study country that uses a degression rate for all of its eligible technologies. France uses a 2% degression rate for wind.[64] Under the German system, the 20-year fixed payment amount that generators can lock into adjusts annually. With a degression rate, the later plant operation begins, the lower the payment level the producer receives. Unlike other price adjustment mechanisms, this method is predictable and transparent for investors. Additionally, the degression eventually lowers the FiT payments so that it eliminates them completely. This is unique compared to other FiT schemes which do not have a projected sunset date. Germany uses a degression rate for payments to decrease as the technologies become less expensive to ensure that generators are not overpaid.

The goal of a degression is to track objective changes in technology costs. Historically, these have trended downward, so a degression attempts to mirror this decreasing trend to ensure that FiT payments continue to target grid parity, while avoiding overpayment. Ontario and Spain, for instance, choose to track objective changes in technology costs via biennial (every two years) and annual revisions, respectively, removing the need for degression. Germany opts for revisions every 4 years instead with incremental degression in between, thereby increasing TLC and providing a longer horizon for investors.

A degression level is difficult to set because it requires advance forecasting of future renewable energy costs. As the prices decrease and the payment level changes, the rate should still guarantee profitability and cover project costs. Additionally, it should decrease at the same rate that technology reaches grid parity. Exhibit 11 highlights the rates for PV, which receives the highest tariff and the steepest degression. This indicates how far away solar technology is from being competitive and that it also has the most to gain by advancing down its learning curve through economies of scale.

EX 11: 2009 Solar PV installation payments under the EEG

Installation Type	Installed Capacity (In kWpeak)	Tariff (Per kWh electricity produced)	Annual Tariff Degression (Dependant on installed capacity)
Solar Plants (Ground mounted/ Open field systems)	All	31.94 €Cents	10.0% in 2010 9.0% from 2011 onward
Attached/ On top Buildings	30 kWpeak 30-100kWpeak 100kW – 1MWpeak Over 1MWpeak	43.01 €Cents 40.91 €Cents 39.58 €Cents 33.00 €Cents	Up to 100kW: * 8.0% in 2010 9.0% from 2011 onward Over 100kWh: * 10% in 2010 9.0% from 2011 onward

*Tariffs do not include value-added tax. Tariff rates differ from those in the 2000 and 2004 EEG. Most technology degression rates are 1-1.5% excluding offshore wind, which is 5% after 2015 and PV solar, which is 8-10%. *Percentages can increase/decrease by 1.0% if installation capacity is above/below a certain threshold. Source: Adapted from German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008, Section 20 and Sections 32-33.*

The German FiT policy has evolved to incorporate a responsive degression scheme for solar PV which aims to account for significant market changes. While FiT law specifies the degression level, a 1% annual adjustment to the degression rate is

[64] *Arne Klein et al, Evaluation of Different Feed-in Tariff Design Options: Best Practice Paper for the International Feed-in Cooperation", October 2008.*

triggered when a specified volume is reached.[65] In theory, policy makers can account for large market changes should the annual installed capacity increase significantly. If the annual deployment of solar PV grows takes off, a more substantial degression can help better track objective changes in PV costs. With the change of government there has been a recent announcement to evaluate the pricing dynamics (See Box 4 below).

Two problems with the German responsive degression scheme exist. First, it only adjusts the rate of degression, rather than triggering a change directly in the tariff. Second, it is only designed to track downward price movements. If solar PV costs were to increase (due to supply bottlenecks, silicon shortages, etc.) then the FiT pricing would be out-of-step with the market. This could be overcome by basing adjustments on real-world cost experience, rather than the theory that all renewable energy costs with invariably trend downward. A second alternative would be to build in the degression and account for increases during the periodic revisions. Germany did this by revising upward for wind power tariffs in its newest FiT policy revision.

5.2.2 Periodic Review

Pricing reviews vary significantly: France as needed, Spain quarterly for some technologies and annually for others, Ontario biennially, Germany and the Netherlands every 4 years.

France conducts periodic pricing reviews as under "Material Adverse Conditions" (MACs). It does not have scheduled formal reviews but rather relies on market evaluations and the political desire to reevaluate pricing.[66] Wind is the only technology that has a formal review because pricing is potentially adjusted after the first 10 years of onshore generation.

Spain's quarterly reviews tie in with its advanced "responsive scheme" for solar PV price adjustment. The government sets out a series of 4 calls for renewable energy projects per year. Calls can vary – i.e. call 1 can be for 100MW PV and call 2 can be for 150 MW PV. Developers then submit applications. If the call is met by more than 75% then the tariff does not change. If the first 2 calls are not met by 50% then the tariff prices increase.[67] With this plan, prices change quarterly, leading to higher uncertainty and creating complications for developers and manufacturers. It causes a start-stop effect because they do not know when calls will occur or when demand has been met. The upside of this system is that pricing rates can be adjusted upwards or downwards unlike Germany's degression adjustment, which only decreases.

Ontario has replaced a need for a degression rate by mandating ongoing market research to check price development and formal biennial reviews.[68]

The Netherlands and Germany have the least frequent reviews: every 4 years. While the tariff prices in the Netherlands are variable, the government sets the cap payment levels every 4 years[69]. These reviews establish the range for the tariff payments. Germany can issue reviews more frequently as it is currently doing if sufficient political motivation is present.

[65] *Ibid; German Government, Gesetz für den Vorrang Erneuerbarer Energien, 2008.*
[66] *BMU, RES Legal, 2008.*
[67] *PV Magazine,"Combining Tariff Payment and Market Growth", May 2009.*
[68] *OPA, "Feed-in Tariff Program", September 30, 2009.*
[69] *Ron van Erck, "New Dutch Feed-in Premium Scheme "SDE" Opened April 1st", 2007.*

Box 4: Current review of the German FiT payments
The new German coalition between the CDU/CSU* and the FDP* parties has called for a re-evaluation of the solar tariff payments and degression rates in response to the substantial decrease in PV module costs over the past two years. If payments remain too high, producers will reap excessive profits. During its campaign, the minority party, the FDP, called for an immediate 30% annual reduction in PV tariffs. The solar industry is understandably worried that should the new government reduce rates too much it would exacerbate the over supply of solar modules. The coalition has announced plans to negotiate with the industry and it seems unlikely that 2010 rates will be reduced as dramatically as proposed. In relation to our view of advanced FiT features, while this is an out of schedule review, it represents a response to rapid changes in market conditions over the past two years. **The Christian Democrat Union of Germany and the Christina Social Union of Bavaria (CDU/CSU) are socially conservative sister parties. The Free Democratic Party (FDP) is the liberal pro-business party.*

5.2.3 Inflation

Adjustments for inflation vary across the regimes studied. The countries that do not adjust payment rates according to inflation are Germany and the Netherlands, which build an assumed inflation rate into their rate setting models. Pricing adjustments can occur internally, externally or through an internal/external combination.[70] An internal adjustment occurs to the specific tariff paid and changes its pricing, thus making it variable. Spain, for example adjusts its prices internally by accounting for 100% of inflation (minus a few basis points). This means that the price an on-line generator receives will fluctuate annually. Tying inflation to an internal adjustment can be used to account for operating costs as they change over time.

An external price adjustment does not change the rate of the current contracts that are already activated but rather it modifies the schedule of fixed payments available from one year to the next. Accounting for inflation through an external pricing adjustment takes changes in fixed costs that occur over time into consideration.

Assumed Inflation: Germany builds an inflation assumption into the model that it uses to calculate feed-in tariff rates. Should inflation be higher or lower than the built in 2%, the FiT tariff rate will not change.[71]

Internal Application of Inflation: In Spain, inflation is fully incorporated minus a few (typically 25) basis points. For resources dependent on a fuel (biomass, waste resources, refinery byproducts, coal, and natural gas) they are also indexed to the price of coal, and in some cases electricity).[72] This means that Spain almost fully accounts for its estimated 4%[73] annual inflation rate. Ontario adjusts 20% of the base tariff fully for non-solar technologies during contract life and 100% during construction.[74] This can be useful for renewable energy sources with high variable and operating and maintenance costs, such as those that must purchase fuel.

Internal / External Application of Inflation: France uses internal and external methods to adjust for inflation. The feed-in tariff rate available to generators from one year to the next is adjusted annually for inflation (i.e. an external adjustment). Once a generator locks into a feed-in tariff rate, the amount of payment that the generator receives annually is also adjusted for inflation (i.e. an internal adjustment). The inflation adjustment level is dependent upon the technology; for example, in France, wind and PV solar receive 60% and biogas 70%.[75]

[70] Concept adapted from: KEMA, “California Feed-in Tariff Design and Policy Options”, Final Consultant Report Prepared for the California Energy Commission, May 2009.
[71] BMU, “Progress Report”, 2007.
[72] Toby Couture and Yves Gagnon, “An Analysis of Feed-in Tariff Remuneration Models: Implications for Renewable Energy Investment”, Energy Policy, 2009.
[73] 2008 Estimate: Index Mundi.
[74] Ontario Green Energy Act, 2009.
[75] Toby Couture and Yves Gagnon, “An Analysis of Feed-in Tariff Remuneration Models: Implications for Renewable Energy Investment”, Energy Policy, 2009.

5.2.4 Grid Parity Target

The main outcome of most feed-in tariff policies is an acceleration of the process of making renewable energy technologies competitive with conventional fossil fuels. This is also known as reaching grid parity and is obtained through price adjustments. The FiT scheme that comes closest to emphasizing reaching grid parity is Germany. Its use of a degression rate so that FiT payments phase out once grid parity is reached. Each regime implicitly factors in technological progress towards grid parity because tariff payments are determined based upon project costs. Incorporating price adjustments allows policy makers to account for the price changes that come with future technological development. DBCCA encourages legislators to formalize their grid parity objective in their FiT policy as a way to emphasize their push to make renewables competitive.

5.3 Caps

Pricing limitations to the project size can occur in two ways: through a volume cap on the total amount of installed renewable energy facilitates and through a cap on a specific project size.

5.3.1 Volume Cap

Germany does not set a limit on total volume of renewable installations receiving payments because the core focus of their FiT is volume scale-up. They allow market forces to determine the total renewable energy deployment level. The Ontario FiT follows the same principle but sets a volume cap for solar PV. If a FiT scheme chooses to set limits on the volume receiving FiT payments, they can work in several ways as demonstrated by the case studies: firm volume caps (France), predetermined budgets to limit the amount of installed capacity (Netherlands); and goals that trigger cap reviews (Spain).

Firm volume caps: France sets firm volume caps by technology. For example, wind has a limit of 17,000 MW, biomass and hydropower at 2,000 MW each and PV at 500 MW.[76] From an investor's perspective, high caps, such as France's wind cap is a close equivalent to no cap for near-term market development.

Predetermined budgets to limit the number of payments: Every four years the Netherlands establishes a set amount that the Treasury will pay to subsidize renewables through a feed-in tariff payment. The amount determined is used to set the payments and volume per technology type.[77] The government determines these based upon current installed capacity and the estimated number of future installations. Upon announcement, developers submit applications. Once the cap is met no other projects receive tariff payments.

Goals that trigger cap reviews: The Spanish system issues 4 "calls" on a quarterly basis (e.g. call 1 may be for 100MW PV; call 2 for 150MW PV). Having re-vamped their policy in 2009, Spain now has an organized registry under which a cap is set and the number of projects is monitored.[78] The inability to track the number of applications and enforce the cap caused significant issues for the Spanish PV market this past summer (see Box 5 below). This system is less transparent because the calls are irregularly scheduled and the amounts vary. Transparency is further reduced because the tariff adjustment is contingent upon the extent to which the call is subscribed and the actual adjustment is unknown until after the call. The uncertainty is felt on both the project development side and even more acutely on the manufacturing side.

[76] *BMU, RES Legal, 2008.*
[77] *Caps for the next four years include onshore wind: 2000MW; offshore wind: 450 MW; biomass: 200-250MW; biogas: 15MW; solar: 70-90MW. Source: Ron van Erck, "New Dutch Feed-in Premium Scheme "SDE" Opened April 1st", 2007.*
[78] *PV Magazine,"Combining Tariff Payment and Market Growth", May 2009.*

IV. Feed-in Tariffs

Box 5: Lessons learned from the Spanish FiT

The Spanish FiT has been an example of a massive solar scale up followed by a tremendous crash. In its National Energy Plan (PER) for 2005-2010, Spain set a PV solar target of 400 MW by 2010. Under the policy in place at the time, the RD 436/2004, the FiT prices were defined as fixed percentages of the prevailing electricity price. This link to the electricity price did not provide reliable TLC for investors, and led to little development in solar PV. In response to a number of shortcomings of this policy framework, Spain adopted its RD 661/2007 in May of 2007, introducing many landmark modifications to its renewable energy policy. Among other changes, this policy provided for stable, fixed pricecontracts for electricity generated from solar PV projects up to 50 MW in size for 25 years.

Combined with its high quality solar resource, this made Spain a highly attractive investment environment for solar power at the time, guaranteeing higher rates of return than Germany's policy, in a market with more available land, and less oversight. This combination of conditions led to a remarkable growth in solar PV deployment, with Spain installing over 47% of new global PV capacity additions in 2008.[79]

As a result, Spain surpassed its 400 MW target for solar PV in September 2007, which triggered an automatic revision to its solar policy, due to come into effect one year later. This gave investors a one-year window to capitalize on the generous policy framework created by the RD 661/2007. This led to a rush of project development, creating a total deployment of over 2600 MW in 2008 alone, and to a dramatic revision of its policy in September 2008.

The rush of development put unexpected pressure on government budgets. In Spain, the government regulates retail rates and fixes the amount that retail rates can increase each year. The government then uses taxpayer funds to cover any costs that are above the fixed retail electricity rate. The sharp increase in solar installation led to rate impacts above the fixed maximum, increased the taxpayer burden, and further encouraged policy makers to re-evaluate the policy. A further problem that emerged is project developers were able to string together large numbers of 100 kW projects in order to take advantage of higher rates for smaller systems. This led to costlier PV development, as developers gamed the system to their advantage.[80]

Among other controversial provisions, Spain's new revision (the RD 1578/2008, applicable only to solar PV) imposed a 500 MW cap on annual solar development. This sudden introduction of a hard cap on solar caused the market to contract and led employers to cut over 20,000 jobs in Spain.[81]

The impacts of such sudden and abrupt adjustments to a FiT policy highlight the importance of sound and flexible policy design. Despite the rise and fall of its solar market, Spain is committed to improving its FiT. Its amended policy seeks to learn lessons from its mistakes, which are applicable to policy makers considering FiT regimes.

1) **Get the prices right:** Offering aggressive tariff levels in a region with a high quality resource is likely to stimulate substantial investment. Accurate price discovery is essential to designing a successful FiT, and control over the targeted rate of return can be used as an adjustment mechanism to prevent the market from over-heating.

2) **Electricity Consumers Should Pay for the FiT:** Rather than funding FiTs partially or fully through government budgets, FiTs should be financed through electricity prices.

[79] *REN21, "Renewables Global Status Report: 2009 Update", 2009.*
[80] *Paul Voosen, "Spain's Solar Market Crash Offers a Cautionary Tale About Feed-in Tariffs", New York Times, August 18, 2009.*
[81] *The Economist, "Good Policy, and Bad", December 5, 2009.*

Box 5: Lessons learned from the Spanish FiT (continued)
3) **Design Caps Carefully:** First, Spain designed its cap as a target, rather than a fixed ceiling. Furthermore, surpassing that 400 MW target was only designed to trigger a revision, rather than an automatic adjustment. To compound this, the revision was only meant to come into effect only one year later. This delay in implementing changes, and the failure of policy makers to anticipate and monitor the rapid rate of market growth, exacerbated the problem. Spain has now added an enforceable ceiling to the amount of installed solar that receive payments. While discussions in the summer of 2009 favored 300 MW annual caps, the industry was able to negotiate a 500 MW[82] cap for 2009. The government cut tariff levels from about €0.44 per kWh to €0.32-0.34 per kWh of for roof-mounted systems and €0.32 for ground-based systems.[83] It has also created a registry that tracks the amount of new renewables installed. 4) **Avoid Loopholes Favoring the Highest Tariff Rate:** Spain's policy design enabled large projects to be broken into smaller pieces to exploit the higher tariff rate. This increased the policy's overall cost, and led to a number of challenges for policy makers. Applications should be monitored more closely and provisions imposed to prohibit project clustering. 5) **Make Feed-in Tariffs Market-Responsive:** Before its recent amendment, Spain's FiT did not include a built-in price adjustment mechanism. The policy did not include a degression rate or a form of stepped reductions as in Germany.[84] To make its FiT more adaptable, Spain now uses a series of calls which through which the government readjusts prices on a quarterly basis (See Section 5.2.2). The Spanish example demonstrates that FiTs can be powerful tools to drive investment in renewable energy, but that like all tools, they must be used carefully. Greater foresight and a quicker reaction may have blunted or prevented Spain's solar market crash. In order to be successful, feed-in tariffs need to ensure that the balance between market flexibility and TLC is frequently evaluated and adjusted.

5.3.2 Project Size Cap

Policy makers have taken different perspectives to adopting caps. Germany and Ontario do not have total volume caps and generally they also do not have size requirements for projects to be eligible for tariffs. Ontario's exception is a 10MW cap for ground-mounted PV. Spain has a project cap of 50 MW for solar[85], while France caps FiT payments at 12 MW except for on and off-shore wind.[86] French projects exceeding 12 MW go into a tendering system. The Netherlands set limits for some technologies. For example, combustion biomass project payments are capped at 50MW and caps PV collectors at 100kW.[87]

In the US, several states have introduced legislation that would adopt FiTs with a 20 MW cap for select resources. Deciding to implement a cap is very dependent upon contextual constraints such as infrastructure (e.g. transmission) and policy objectives. Using a 20 MW cap with must take provisions will allow for distributed and small-scale utility projects and favors alternative procurement mechanisms for much larger projects.

[82] *The official cap is 400 MW of which 2/3 goes toward roof-mounted installations and the remainder for ground-based collectors. A supplementary100 MW is added to help the transition.*
[83] *Martin Roberts, "Spain Ratifies New 500 MW Solar Subsidy Cap", Reuters, September 26, 2009.*
[84] *Paul Voosen, "Spain's Solar Market Crash Offers a Cautionary Tale About Feed-in Tariffs", New York Times, August 18, 2009.*
[85] *Edwin Koot, "Incredible Growth in Spanish Solar Energy Market Spells Good and Bad News for PV Industry", AltEnergyMag, February 2009.*
[86] *EREF, "Renewable Energy Policy Review: France", March 2009.*
[87] *Ibid.*

5.4 Bonus options

Feed-in tariff policies often include different types of bonus payments, or "adders" which supplement the guaranteed payment. These can be in the form of *social adders* to encourage local ownership or investment; *generation premiums* to reward the use of innovative technologies; or *regional/resource differentiations* to account for ranging productivity levels.

5.4.1 Social "Adder"

The only policy to utilize a social "adder" or bonus is Ontario. Its FiT mission emphasizes decentralizing power production and enabling the local community become owners and investors. Eligibility occurs with a minimum of 10% participation.[88] A payment bonus is also provided to generation owned by aboriginal communities.

Bonuses are as follows:

	Maximum Aboriginal Bonus	Maximum Community Bonus
Wind and PV (Ground Mounted)	1.5 cents/kWh	1.0 cents/kWh
Hydropower	0.9 cents/kWh	0.6 cents/kWh
Biogas, Biomass and Landfill Gas	0.6 cents/kWh	0.4 cents/kWh

Source: Ontario Green Energy Act, 2009; Paul Gipe, "GEAA Analysis of Ontario's Feed-in Tariff Program", May 22, 2009.

5.4.2 Generation Bonus

The case study regimes have two key types of generation bonuses. The first is for the use of innovative technologies. France and Germany boost payments for geothermal, biomass and biogas sources that combine heat and power (CHP) production.[89] These jurisdictions also encourage participation in the agriculture sector for creative uses of agricultural waste. Germany also gives bonuses if old wind turbines (from the 1970s to the early 1990s) are updated or re-powered.

The second type of generation bonus is for contributing electricity during peak hours of use. Spain, for example gives generators the option to select a rate that awards a bonus for power generated (104.62% of the payment) during peak hours and assesses a slight penalty for off-peak generation (96.70% of the payment).[90] Ontario also offers an adder for dispatchable resources that operate on peak.

5.5 Policy interactions

5.5.1 Eligible for Other Incentives

Incentives can interact with FiTs in several ways so that renewable energy operators are eligible or ineligible for forms of incentives. First, other incentives can be additive to feed-in tariffs and increase generators' profit. Second, policy makers can offer generators the choice between a FiT and other incentives, but prevent them from claiming both. Third, generators can be given the option to choose to take advantage of both a FiT and another incentive, such that the FiT rate is reduced by the value of the other incentives claimed. This is what happens in the Netherlands under the Energy Investment Deduction scheme (EIA).[91] Finally, the government sets tariffs based upon what other incentives it expects producers to be eligible for. This option has the lowest amount of transparency because the more that different incentives are layered into

[88] OPA, "Feed-in Tariff Program", September 30, 2009.
[89] Germany provides bonuses for the use of Stirling engines and organic Rankine cycles.
Source: Klein et al, "Evaluation of different feed-in tariff design options – Best practice paper for the International Feed-in Cooperation", 2008.
[90] Kema Inc, "California Feed-in Tariff Design and Policy Options, Final Consultant Report", May 2009.
[91] Ibid.

the payment scheme the more complex the FiT payment becomes. Additionally, there is a risk that the assumed incentives will not be available at certain times or to certain subsets of generators[92].

The renewable energy policy framework is dynamic and always changing. Generally, each regime studied allows interactions with other incentives. Examples of available incentives can be found in the Appendix. DBCCA encourages policy makers to allow incentives to interact with FiTs. We recommend the third choice, under which generators are allowed to choose either a FiT or an incentive with a reduced FiT rate, because it allows for greater flexibility while preventing excess profit.

5.6 Streamlining

5.6.2 Transaction Costs Minimized

Ontario and Germany stand out through their streamlined administrative processes. This can lower hurdles to development, increase transparency and reduce costs to the government and investors. For example, the average length of a German FIT contract is 2 pages verses the near 100 page PPA that is common in the US.[93] Ontario has introduced a new Renewable Energy Facilitation Office, which is a one-stop shop to help renewable energy projects get off the ground faster.[94] As investors, we favor minimizing transaction costs because it expedites the process of making renewable projects operational and provides greater transparency.

6.0 Outcomes

6.1 Investor IRRs

For France, Germany and Spain, investor IRRs tend to be in the 7%-10% range (See Section 5.1.3). Ontario's policy estimates a target return on equity of 11% based on a debt/equity ratio of 30/70.[95]

6.2 Job creation

Job creation has been most dramatic in Spain and Germany so far. The German FiT regime has established a strong TLC environment supported by domestic policies and investment incentives. This has enabled the German renewable sector to expand 75% since 2000. Cumulative investment in renewables grew to €30 billion in 2008, installed renewable energy capacity has tripled[96] and employment has doubled to over 300,000.[97] Solar has been particularly successful. As of 2008 an estimated 42,000 Germans work in photovoltaics.[98] This is a dramatic increase from the combined 5,500 in 1998.[99]

The Spanish renewable industry has grown rapidly since FiT implementation. As of 2007, 188,000 work directly and indirectly Spain's renewable energy sector with the majority of employees working in wind and solar.[100] While the number of direct employees in the French wind sector may seem low (7,000) as shown in Exhibit 12, this is a dramatic increase from less than 100 in 1993, 1,000 in 2000, 5,000 in 2007 and a goal of reaching over 180,000 by 2010.[101]

[92] Changes in available incentives and subsidies in the US, for example makes it harder for developers to predict the level of government support. See: Stephen Lacy, "Beyond Rebates: State Solar Market Transitions", Renewable Energy World, January 27, 2009.
[93] Craig Lewis, "Wholesale DG Feed-In Tariffs: Financing the Renewables Revolution", September 29, 2009.
[94] OPA, "Feed-in Tariff Program", September 30, 2009.
[95] OPA, "Feed-in Tariff Program", September 30, 2009.
[96] BMU, "Renewable Energy Sources Act (EEG) Progress Report," 2007.
[97] BMU, "Renewable Energies Create Jobs and Economic Growth. Press Release," 2009.
[98] Lothar Wissing, "National Survey Report of PV Power Applications in Germany 2007", 2008.
[99] Bundesverband Solarwirtschaft (BSW), "Statistische Zahlen der deutschen Solarwärmebranche (Solarthermie)", Februar 2009.
[100] UNEP, "Green Jobs: Towards Decent Work in a Sustainable, Low-Carbon World", September 2008.
[101] Chabot, Bernard, "France's Advanced Renewable Tariffs", 2008.

IV. Feed-in Tariffs

Exhibit 12 below shows the gross quantity of jobs in the wind sector. At the end of the day, it is truly the net jobs created from a policy that are most important. These figures are difficult to measure and reliably calculate across regimes.

EX 12: Estimated employees in wind sector in 2009

	Direct Employees in Wind Sector
France	7,000
Germany	38,000
Netherlands	2,000
Spain	20,500

Source: EWEA, "Wind Energy: The Facts", March 2009.

Local content requirements and Ontario's overall FiT policy have already encouraged companies to relocate. Atlantic Wind and Solar and ATS Automation Tooling Systems have decided to establish their headquarters in Ontario. Samsung Group is considering opening a new plant. GE Canada is considering retrofitting an existing plant for solar and Canadian Solar plans to open a manufacturing plant in Ontario for solar modules although cells will still be built in China.[102] It is estimated that more than 50,000 direct and indirect jobs will be created under the Act.[103] Investments in new renewable energy projects, those already in place or under construction in Ontario since 2003, exceed $4 billion.[104] Despite the expected growth in jobs, it is difficult to ignore that such local content requirements can cause distortions in trade.

6.3 Total primary renewable energy produced (GWh)

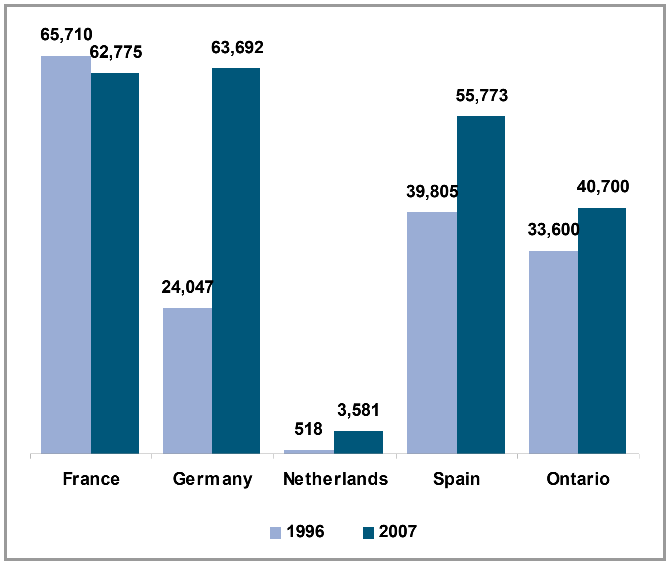
Growth in total renewable electricity supply has been most significant in Germany, which grew from a 4.3% share in 1997 to 15.1% in 2008. Germany is the only EU country in this report to have already met its EU 2010 renewable electricity supply target. In terms of the share of gross electricity consumption provided by renewables, France has 13.3%, the Netherlands 7.6%, and Spain 20.0%.[105]

Germany and Spain not only stand out among the case studies, but they also lead in worldwide annual production of primary renewable energy produced. Exhibit 13 presents a comparison of primary renewable energy produced from hydropower, wind and solar energy. France's production levels decreased due to a major phase out of hydropower plants that were replaced by renewable energy sources. Exhibit 14 displays renewable energy only from wind and solar technologies. It emphasizes the magnitude of Spanish and German growth in these renewable technologies. Notice the large difference in electricity produced for France between Exhibits 13 and 14 highlights its dependence on hydropower. In Ontario, the majority of renewable electricity comes from hydropower and only 2,400GWh of electricity from wind and solar was produced in 2008. This is bound to change, however, as Ontario has the ambitious goal of adding 10,000 MW of new installed renewable energy by 2015 and 25,000 by 2025.[106]

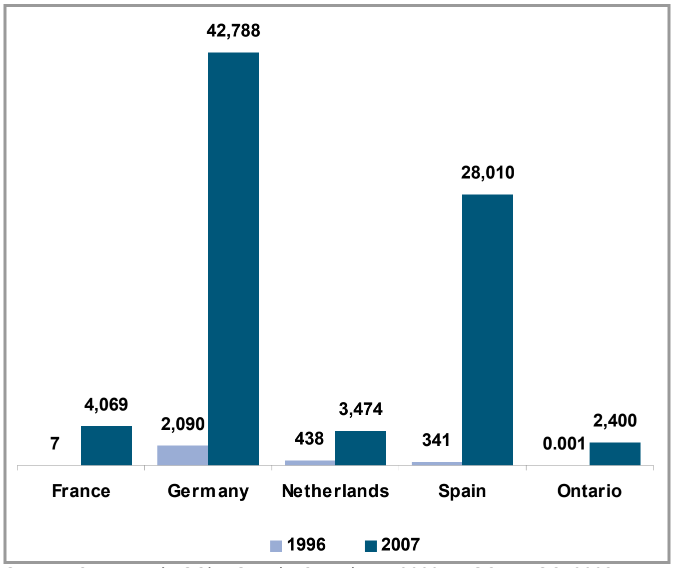
[102] *Richard Blackwell,"Canadian Solar to Build Ontario Facility", Globe and Mail, December 4, 2009.*
[103] *Green Business, "Ontario Government Announces Details of Feed-in Tariff Program, Including Domestic Content Rules", September 25, 2009.*
[104] *Ibid.*
[105] *Above paragraph sourced from: BMU, "Renewable Energy Sources in Figures: National and International Development", June 2009, p 52.*
[106] *Green Energy Act, "A Green Energy Act for Ontario: Executive Summary", January 2009.*

IV. Feed-in Tariffs

EX 13: Comparison of primary renewable electricity produced – Hydro, Solar & Wind (Annual GWh)



EX 14: Comparison of primary renewable electricity produced – Solar & Wind (Annual GWh)



Source: DBCCA Analysis, 2009; Eurostat 2009; Ontario's Independent Electricity System Operator (IESO), "Supply Overview", 2009; IESO, "IESO 2008 Electricity Figures Show Record Levels of Hydroelectric", January 12, 2009.

This past November, Spanish wind generators broke records. Over several days, wind power met 53% of nationwide electricity demand. Spain's wind industry alliance, La Asociacion Empresarial Eolica (AEE) says that 10,170 MW wind energy supported demand ranging from 19,700 MW to 21,700 MW.[107] Wind contributed 11.5% of Spanish electricity needs in 2008.[108]

6.4 Technology deployment by ownership

As discussed in Section 4.2, all of the feed-in tariff mechanisms provide eligibility for independent power producers (IPPs), communities and large utilities to participate through ownership and investment. This has led to diverse ownership in each regime studied.

Ontario has local content rules that focus on encouraging IPPs and communities to own and operate renewable energy facilities. Germany also began initially with strong local content rules under its 1990 StrEG by providing payments only to installations that were less than 25% owned by the state, and did not extend eligibility to utilities.[109] From the inception of FiT policy in Germany and during the first few years of the EEG, technology deployment occurred primarily on a local and community level. Regional and community banks have become stronger supporters of small-scale projects because they benefit the local community. German utilities are beginning to join the game and invest in larger-scale renewable power sources.

The trend of first spurring technology deployment through communities and IPPs and then later by utilities has been common among the feed-in tariff schemes studied. France is the exception; the majority of technology deployed is through EDF, the natural monopoly generator.. Spain deploys a considerable volume of renewables through utilities but also through large community-owned generation facilities, most notably for PV.

[107] *SustainableBusiness.com, "Spanish Wind Power Tops 50% of Electricity Demand", November 11, 2009.*
[108] *Ibid.*
[109] *StrEG 1990 Legislation.*

6.5 Critiques of feed-in tariffs[110]

In effect, our paper has set out what we believe to be the answers in terms of how to achieve cost control and integrate FiTs with other policies. Opponents to FiTs criticize them as too expensive, inflexible, ineffective and incompatible with other policies, burdensome and that they create a job effect bias.

Too expensive: A common complaint is that FiTs cost too much to the economy. *Answer (A): Our paper sets out our view about making costs efficient. An evaluation of costs and benefits of a FiT policy is the best approach.* Many critics argue that FiTs only benefit the wealthy by saddling low-income groups with higher electricity bills. *A: The low-income bracket does typically bear a larger proportional burden of an increase in electricity costs—e.g. regressive tax. They do, however, also face greater negative environmental pollution and health externalities, which are not included in the price for using fossil fuels as a power source. The use of cleaner power would reduce the costs of these negative externalities. Distributing the costs of a FiT based upon energy consumption (greatest for industries and high income groups) rather than as a flat payment to all ratepayers would reduce the negative side effects. This occurs in Ontario and Germany and is discussed in Section 4.3. Unlike other renewable energy policies, FiTs qualify communities and individuals to invest in renewable energy. Combining FiTs with low-interest loans, as in Germany, enables certain income groups that would otherwise be excluded to profit from renewable technology scale-up.*

Inflexible Pricing: Setting a fixed rate for electricity payments rather than a market price creates inflexibility and an inability to adapt to changes in market conditions. *A: Advanced features attempt to incorporate price discovery such as through a responsive degression rate as discussed in Section 5.2.*

Ineffective & Incompatible with Other Policies: FiT opponents argue that they pick technology winners and losers.
A: Rather than choosing winners, FiTs support a range of demonstrated technologies when rates are calculated on a generation-cost basis (Section 5.1.2). Additionally, FiTs can drive innovation which allows room for other technologies to become eligible once they reach a post-demonstration stage. FiTs encourage the development of projects that may not be suitable for a given local environment. *A: We assume a rational approach from governments to achieve a volume response that is relative to what makes sense in their jurisdiction.* Some opponents also believe that FiTs are incompatible with other renewable energy policies such as RPS and the REC/ROC markets. *Answer: We believe FiTs are valuable instruments that are compatible with climate change and renewable energy objectives, and can integrate well into RPS as discussed in Chapter VI Section 1.0. In fact, we consider RPS to be a demand pull and FiTs to be a supply push (See "Global Climate Change Policy Tracker: An Investor's Assessment").*

Burdensome: FiTs are burdensome to transmission system operators and utilities because they have to connect many small providers. *A: This is a cost for distributed renewable scale-up.* FiTs also create an extra administrative burden for the government and results in complications once the payment term concludes. *A: We believe that FiTs have lower administrative and transaction costs than other renewable energy incentives particularly because of their transparency.* FiTs decentralize electricity generation and take away from the utilities market share if policy is not catered to allow them to participate. *A: If the policy goal is volume scale-up, then encouraging a broad range of investors and including utilities makes the market more resilient (Section 4.2).*

Job Effect Bias: Studies such as the 2009 draft paper from King Juan Carlos University, claim that FiTs result in net job losses. *A: The Spanish government and the National Renewable Energy Laboratory in the US have challenged the data and methodology used, citing that when analyzing net job loss then the net effects of using investment alternatives should be specified.* A 2009 RWI study has argued that jobs will disappear as soon as FiT payments end. *A: The German government has challenged the findings by citing how FiTs have empirically created long term jobs and will continue to do so as the global market for renewable energy expands.*

[110] This section draws from research conducted by the World Future Council and Meister Consultants Group, Inc.

7.0 Conclusion

As the following chapter highlights, there are many ways to design feed-in tariffs so that they can adapt to given renewable targets and electricity markets. The greatest difficulty is finding the balance between setting investor TLC and allowing market flexibility for price discovery. Although no FiT is perfect, two regimes are most able to balance these objectives: Germany and Ontario. Both schemes support the 5 factors we highlight as being crucial in setting TLC: guaranteed payments, must take rules, long payment terms, determine pricing through generation cost and provide ways to benefit from complementary incentives. Germany and Ontario are able to strike the fine balance because they utilize a potent combination of advanced features and are actively proving their commitment to scale-up renewables:

Strong Commitment: Adoption of the FiT has committed Germany to advancing an industrial environmental policy. While the Ontario FiT is a new policy, there are strong indicators that in a few years it will become a renewable energy leader. Its current FiT sets strong signals that Ontario is committed to meeting its 2014 coal phase out target and will support its local economy in the meantime through aggressive state content requirements. Establishing long term payment contracts under FiTs proves that these regimes plan to look beyond short political cycles and plan for the future.

Advanced features: Germany and Ontario have implemented must take provisions, interconnection rules and determined payments based upon project costs plus a profit. This sets expectations and reduces the investment risk because the financiers can closely predict their returns. Applying payments based upon generation costs that match the specific technology creates tariffs that are more precise and allows the free market to determine the outcomes. Refraining from using project or volume caps also sets TLC yet allows space to modify pricing should price discovery occur. Germany and Ontario's FiTs integrate complementary incentives that support the local community (e.g. social adders and bonuses) and utilities (e.g. waiving property taxes for hydropower). Both regimes use pricing mechanisms that provide degrees of certainty and flexibility. Germany's use of a flexible degression mechanism and Ontario's 2-year review creates room to factor in price discovery while reductions and minimizing implementation costs.

We see great potential for these advanced features to improve current and future FiT schemes. Using feed-in tariffs to support renewable energy accelerates the process of technological development. It enables these clean, low-carbon technologies to reach grid parity and provides a part of the solution to climate change mitigation.

V. US Renewable Payments Market

Summary:

- *This chapter looks at the complexity of the US electricity system and lack of TLC in power purchase agreements (PPAs)—the key instruments for pricing electricity and complying with state renewable portfolio standards (RPS) and renewable energy credit (REC) markets—and examines how RPS and RECs interact with CO_2 policies.*
- *We then map the structure and interaction of Federal incentives underpinning the renewable energy markets, exploring the production tax credit (PTC), investment tax credit (ITC), convertible investment tax credit and low interest loan guarantee facilities and review the diminished tax equity market.*
- *We pull everything together to show how all the different elements interact to finance renewable energy projects.*

1.0 Introduction: The US - A complex electricity system collides with a complex renewables structure

Every country tackles renewable energy policy in a slightly different and nuanced fashion from command and control at one end of the spectrum to market mechanisms at the other. The US policy tool kit has trended toward the latter approach, driven by the fact that it is extremely hard to have a solution at a national level because of Federalism, state rights, and the political infeasibility of funding renewable energy scale-up through increased electricity rates in many parts of the country. US electricity markets were developed at a state level and have only in the last decade been integrated into regional power systems. There is no equivalent of a national railroad, interstate highway or natural gas pipeline infrastructure for electricity transmission. So in comparison to Europe, where there were a limited number of national operators in the electricity sector, the US experience has been much more disaggregated which complicates the integration of renewables.

The industry is fragmented into literally hundreds of players from small municipal cooperatives and community supported wind farms to investor owned utility holding companies operating in multiple jurisdictions with $billions of revenues. Divergent regulatory structure, interconnect capabilities, and natural resource abundance or limits is each highly state specific, and has resulted in a wide range of electricity prices. In the US, the average electricity price in 2009 has been about $0.12 /kWh but varies substantially from state-to-state, with ratepayers in New York paying as much as $0.192 kWh and ratepayers in West Virginia paying $0.0792 k/Wh.[111] A one size fits all approach is therefore fundamentally difficult.

Moreover, the US experience has also been colored by poor policy design in the past stemming from state implementation of the Public Utilities Regulatory Policy Act (PURPA), which was the first attempt to stimulate a renewable energy supply response in the 1980s and whose legacy lives on today in the minds of many regulators and industry players. Consequently, by comparison to the advanced FiT policies in the case study countries, the US renewable policy framework and payment system is highly complex and disaggregated at the state and local levels. US electricity markets include regulated and deregulated states and some of which are hybrids and include features of both models. Electricity pricing runs the gamut from bundled into rate cases (regulated), wholesale market pricing on an exchange (de-regulated), and bi-lateral power purchase agreements (PPAs), which can take place in both regulatory structures.

At the core of the US renewable energy policy structure are the renewable portfolio standards (RPS), which are found in 35 states and have been proposed at a national level in the American Clean Energy and Security Act of 2009 (Waxman-Markey HR-2454). This establishes a target level for renewables, often by technology. In order to track compliance with a RPS, renewable energy certificates (RECs) are generated when a qualifying renewable energy source delivers power to a grid operator. RECs are essentially the environmental attributes of the power and can be transferred from generators to utilities or traded among utilities within and across grid operator borders. In effect, they provide the same function as the premium aspect of a tariff. Their intrinsic value reflects the supply and demand relative to the RPS and hence they can be volatile and not particularly deep markets.

[111] US Energy Administration Agency

V. US Renewable Payments Market

Although some US RPS program participants rely primarily on spot purchases of tradable renewable energy credits, the majority of renewable energy credit procurement occurs through bilateral contracts, with RECs typically bundled with electricity into PPAs between electricity retailers and renewable generators. PPAs share similar elements of a FiT in that they define the revenue requirements and payment term for the project between the electricity supplier and renewable producer. The goal for independent power developers is to maximize incentive capture while minimizing risk. The motivation for the electricity supplier is to achieve its mandated target as cost effectively as possible.

However, in contrast to a FiT, PPAs are not prescribed by statute and so are not standard offers; there are no mandatory interconnect and must take provisions. In this respect, PPAs generally lack TLC since they are bi-lateral agreements between buyer and seller negotiated on a case-by-case basis. Consequently, although PPAs allow the market to determine the renewable energy revenue requirement for any given project based on supply and demand, administrative and transaction costs are higher than they optimally ought to be. There is very little transparency or certainty going into the negotiation.

PPAs also capture the value of incentives which rely on a mix of Federal (PTC/ITC), state and local tax credits, loan guarantees and the tax equity market to counter renewable energy's cost premium to fossil fuel generation. Historically, this approach has proven inherently more volatile due to these incentives frequently expiring or being subject to repeated amendment. Right now the ITC/PTC can be converted into a cash grant but this is set to expire in 2011.

2.0 Pricing electricity: The role of PPAs

US electricity markets are highly complex, encompassing different regulatory structures with different layers of government oversight, reflecting state and federal jurisdiction. We do not attempt a detailed review of this. However, certain features are critical for understanding how renewable energy policy does and can fit into this system.

1. In regulated markets, electricity is priced through a rate case based on a bundled cost of service. It is negotiated between a state regulatory body and the utilities involved on a periodic basis.
2. In de-regulated markets, there can be a spot and forward wholesale market price for electricity. Generation, transmission and distribution can all be separated.
3. In both markets, a longer-term contract called a Power Purchase Agreement (PPA) can be negotiated where needed.

A PPA has the following as its core elements:

- **Energy volume:** projected plant availability, capacity and energy production (MWh),
- **Duration:** length of contract,
- **Pricing:** There is no standard offer payment schedule as with a FiT. Each contract is negotiated specifically, although guidelines from a RFP are often made available. In effect, these individualized contracts can be made to conform to any design schedule.

Fundamental to a de-regulated market and to an independent power producer operating in a regulated or hybrid market is the PPA. In our view, spot and forward markets have frequently been too volatile or not effective in providing enough certainty even for fossil fuel generators selling power on a merchant basis. Consequently, most electricity generators operating in a deregulated context sell forward their power on a hedged basis utilizing a variety of market products and services including PPAs to ensure more stable cash flows.

V. US Renewable Payments Market

The key point for investors looking for TLC is the lack of Transparency in particular when entering into a price negotiation. Simply put, there is no standard offer. This model immediately favors large generators with the ability and budget to engage in such a process. Even for large generators, this increases transaction costs.

Electricity service providers in the US certainly look for least cost solutions in terms of ratepayer impact and to the extent they are required to by regulation. However, renewable energy policy introduces another element into electricity markets – a required volume for a particular grouping of supply. This means that at the margin the cost of supply is generally rising in the short run in order to achieve a RPS volume target.

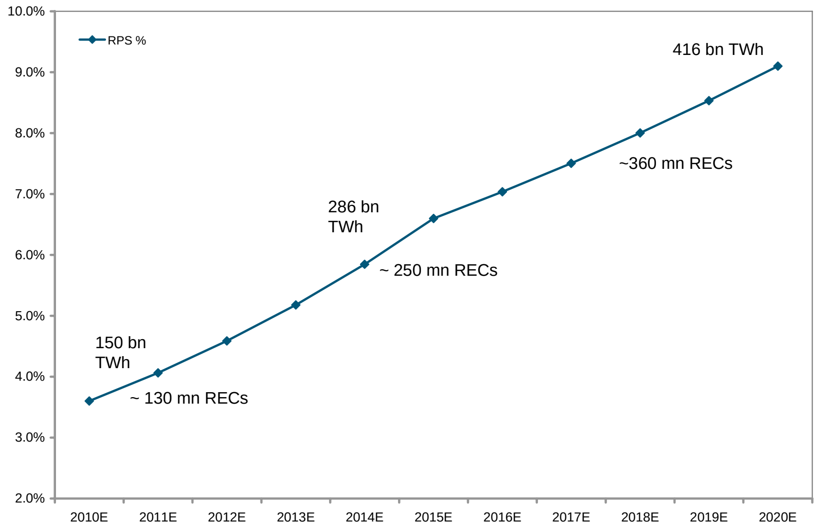
In many competitive electricity markets the fuel at the margin that sets electricity prices is natural gas. Recently gas prices have tumbled due to the recession and new shale gas supplies. This obviously is an issue for the relative size of incentives required to deploy renewables over natural gas generation.

3.0 Renewable Portfolio Standards (RPS): Volume approach to achieving environmental goals with energy security

The majority of US states have favored either voluntary or mandated target systems (collectively referred to here as Renewable Portfolio Standards (RPS)) as a policy mechanism for achieving renewable energy volumes over short and medium term timeframes — e.g. up to 15 years. These create environmental attributes which are enshrined in renewable energy certificates (RECs) — see next section. Many RPS programs include requirements for specific technology mixes, which is similar in intent to FiT rates differentiated by technology. However, RPS policy designs vary widely among states and uniform design elements have not yet emerged. Although the potential impact of state RPS targets could lead to a more than doubling of US REC markets (see Exhibit 15) with most states calling for a 20% renewable energy mix by 2020, achieving the necessary investment to reach this level of penetration may require a more robust policy framework, such as our proposed advanced payment system. For many state programs, the absence of binding penalties means that the consequences to utilities of failing to achieve RPS targets are of questionable strength. Under the current policy framework it is not uncommon for there to be a sizable number of “trophy PPAs” in the RPS queue, some of which stand little chance of ever being completed.

EX 15: State RPS mandates: Driving force behind renewable deployment in the US

Renewable energy % US demand (TWh) based on state RPS mandates



Source: EIA, DOE, MJ Beck Consultants, DBCCA.

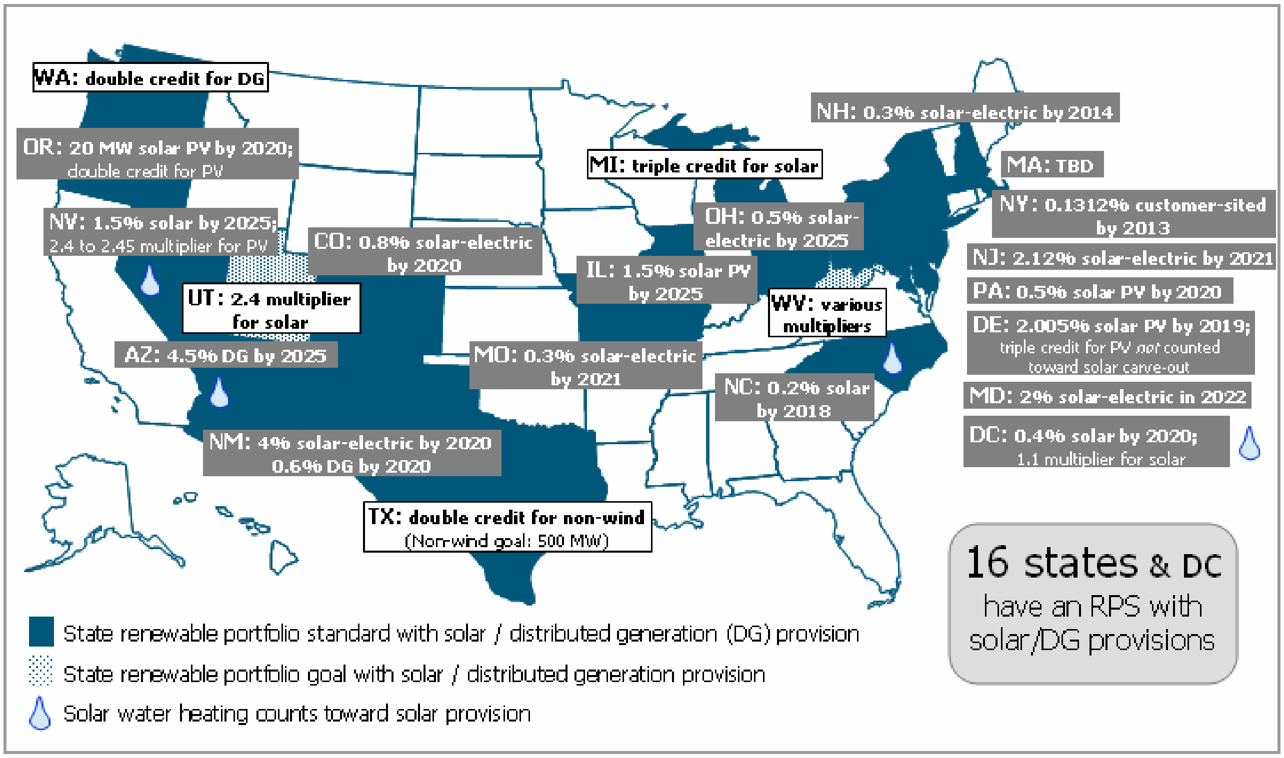
V. US Renewable Payments Market

Questions have been raised over whether a RPS target will be met. There are no uniform penalties for non-compliance.

States may choose to set penalty values or determine penalty amounts when utilities fail to meet the renewable target. Some penalties are assessed per each kilowatt-hour that utilities are "short" for a given compliance year. These penalties range from as low as $0.01 kWh (Montana) to $0.05 and over in states such as Texas and Washington. In some states, penalty payments cannot be passed on to ratepayers. REC markets are also frequently defined by alternative compliance payments (ACPs). ACPs, like some penalties, are also structured as $/kWh payments that utilities can pay in lieu of purchasing RECs. The cost of alternative compliance payments can typically be passed on to ratepayers. ACPs effectively set a price ceiling for REC markets and have a similar range as those states with $/kWh penalties. Where specific technologies have volume provisions, the penalties or alternative compliance payments for missing these targets are typically separate and higher.[112] In general state regulators have been sensitive to the impact that the RPS targets may have on electricity rates and some states have clauses that explicitly exempt the utility from compliance if the rate impact reaches a certain threshold. In this sense the penalty is not truly binding.

EX 16: State RPS mandates: Driving force behind renewable deployment in the US

US RPS Policies with Multipliers and/or Carve-outs for Solar and Distributed Generation



Source: www.dsireusa.org / November 2009

4.0 Renewable Energy Certificates (RECs)

A critical component of many RPS programs is the creation of an underlying market for Renewable Energy Credits (RECs). RECs represent the environmental attributes of renewable electricity expressed in a unit of electricity (MWh). As a general rule of thumb, most renewable energy programs allocate 1 REC for every MWh of energy production. However, certain REC polices allow for bonus RECs to encourage investment in renewable technologies that are not least cost, such as solar PV. RECs are handled administratively through an electronic certification system that is in most cases aligned with the

[112] *MJ Beck Consulting: "The RPS Edge"*

regional transmission organization (RTO). Electricity providers deliver their RECs as needed to achieve their RPS targets by their compliance date.

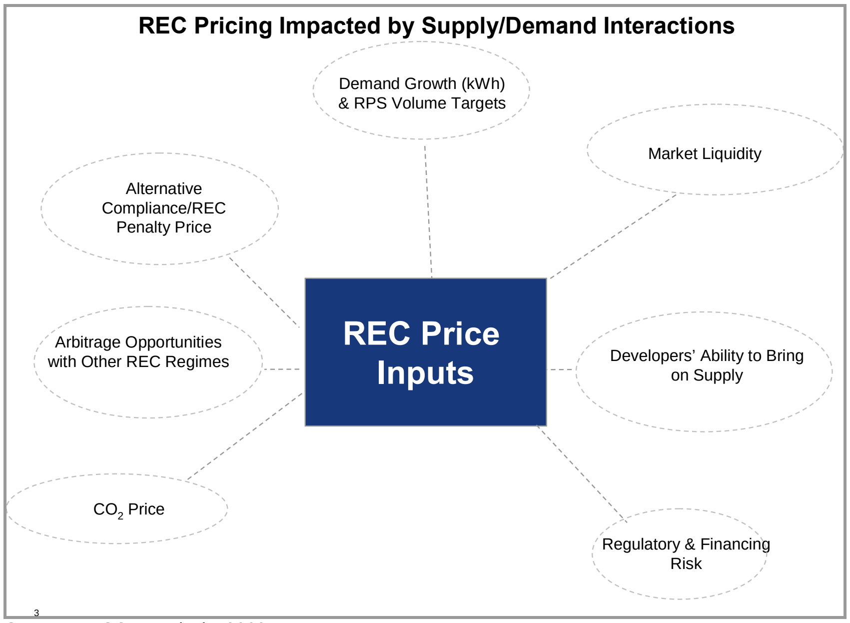
RECs obviously have to then interact with their regulatory framework. In regulated markets, there is the desire to include these in the rate base, although PPAs can also be used, and in the unregulated markets, the RECs interact with the PPA. RECs also enable contractual partners to unbundle the environmental attributes of power generation from the energy volume of the project. If a utility, for example, has an abundance of renewable power in its portfolio, it could sell its excess RECs to another utility that is short. REC volumes are explicitly linked to the volume of electricity generated from the project. This also allows RECs to be traded in-state and potentially out-of-state.

Until recently, most utilities in regulated states were restricted from taking full advantage of federal tax incentives such as the production tax credit (discussed in Section 5.1) or were prohibited from building renewable generation and putting it into rate base because of statutes that expressly limit incremental capacity additions to least cost sources. Consequently, for RPS compliance purposes regulated utilities have tended to procure renewable power through PPAs to achieve compliance. This is, however, beginning to change and rate based renewable generation is becoming a larger share of the mix. Where regulated utilities earn an allowed return on equity (ROE) on their renewable investments, they must deliver all the associated REC volumes from the project and not sell the RECs separately.

Unregulated electricity service providers, on the other hand, tend to look for where they can acquire the RECs the cheapest and may acquire the RECs separately from the power itself. All but three states with RPS programs allow unbundled RECs to count toward RPS compliance. In a so-called “pure” de-regulated REC market for renewable energy, generators receive the spot price for their electricity. In the absence of other incentives, the REC price would have to replace the required incremental incentive to supply renewables above the fossil fuel price. In effect, the REC plays the equivalent role of the premium price in a FiT. If other incentives exist, these will reduce the REC price. This is a pure market based approach looking for the lowest cost solutions from any renewable power source. However, these would only work efficiently if the RPS was driving the buyers on literally a day-by-day basis in a smooth and efficient way. Since this is not the case, the REC price can be volatile, and returns can potentially not meet the needs of a renewable energy generator. The lack of TLC is overwhelming and early REC markets, and indeed the UK ROC markets, failed to deliver much volume as a result. This is because such programs were designed in the 1990s at a time when the electricity industry was restructuring globally and there was the belief that electricity and its underlying attributes could be unbundled and traded as a commodity just like other natural resources. However, the fact that electricity volumes can not be stored means that a supply response from price signals can only come from new supply (not storage). Given the capital intensive and heavily regulated nature of the industry, lead times to bring on new supply can take anywhere from one to five years depending on the technology and regulatory environment, which makes dynamic commodity like trading in the spot market for both RECs and the underlying electricity volatile and often illiquid.

V. US Renewable Payments Market

EX 17: Components of REC pricing



Source: DBCCA Analysis, 2009.

RECs have therefore tended to be blended into the PPA process, where a longer-term timeframe is suited for purchasing power. This reduces their value and role significantly as a pricing signal. In fact REC pricing in the short term tends to barbell toward extremes: trending toward zero or close to the compliance penalty cap which puts a ceiling on pricing. They become more of a compliance record. However, trading can still take place around either in-state or out-of-state requirements between utilities with excess RECs and those short of their RPS requirements after their PPA process clears.

Over the next few years, there may be increased tension in terms of how much of a REC premium utilities are willing to reflect in PPAs for financial reasons. In the US, most regulators impose a required capital structure on utilities, 55% equity and 45% debt is a general rule of thumb. In addition, rating agencies such as Moody's, Standard & Poor's and Fitch base their ratings in part according to a utility's leverage and perceived credit quality. Rating agencies are beginning to treat PPAs – including those for electricity bundled with REC payments – as imputed debt since they are long term liabilities and capitalize the value of the PPA if it is higher than the market price for electricity.[113] Such treatment may potentially affect a company's balance sheet structure and raise the financing costs for utilities if above market price RECs bundled into PPAs become a larger component of power procurement.

The American Clean Energy and Security Act (ACES, "Waxman-Markey") also contains provisions for a national RPS with an alternative compliance penalty price of $25/MWh, which we believe is too low to impact behavior and raises the same concern as what is currently playing out at the state level where many RPS targets may not be met.

At the national level, it is also important to note that since the cost of renewable energy varies substantially by region and is generally lowest far from the load center in areas like the windy Dakotas, a liquid REC market that adds transmission delivery cost into the price discovery would also be needed to encourage renewable deployment where it is most cost effective while also allowing electricity marketers to achieve a least cost volume target by responding dynamically to national price signals.

[113] *Richard W. Cortright, Jr., Managing Director, U.S. Utilities and Infrastructure Ratings, Standard & Poor's, "Debt By Any Other Name: Are Ratings Reality? Does the Accounting Make It So?", Harvard Energy Policy Group, May 30, 2008*

V. US Renewable Payments Market

4.1 RPS, REC and Advanced FiT Interaction with CO_2 Prices

CO_2 emission permits, RPS volume targets and tradable RECs are fundamentally different instruments and policies. They are however interconnected. The introduction of carbon prices in the US will raise the marginal cost of electricity generation, which will raise the average around-the-clock (ATC) electricity price proportionately to the generation fuel on the margin—either natural gas or coal. If there is a robust enough carbon price the pricing of the emissions externality will narrow the cost gap between fossil and renewable generation. Right now, RECs are both a “proxy” for a CO_2 tax and also represent the LCOE premium of renewable to conventional generation. Therefore, as renewable generation becomes more cost competitive to fossil generation provided there is a robust enough CO_2 price signal, the value of RECs will decrease. This lack of certainty is a contributing factor to why there is such little liquidity in unbundled RECs beyond 2015. It is not known how a carbon cap-and-trade policy in the US will interact with REC markets.

In Spain and Germany where there are both FiTs and CO_2 sector level emissions caps for the electricity sector. The FiT is netted against the carbon cap but there is no CO_2 volume allocation from the renewable generation to avoid a double payment. However, to the degree that a renewable producer has exceeded its cap, it can unbundled the environmental attributes of the renewable generation and sell the equivalent MWh value in the REC market to anyone who is short in meeting their EU Emissions Trading Scheme (ETS) compliance target.

In general, the development of renewable energy sources from a FiT will imply a lower price of CO_2-permits in the EU emission trading system, independent of support system. But by how much will depend on design and implementation of the considered support policy and the level of cross border trading and commodity linkages including fuel switching from coal to gas.[114]

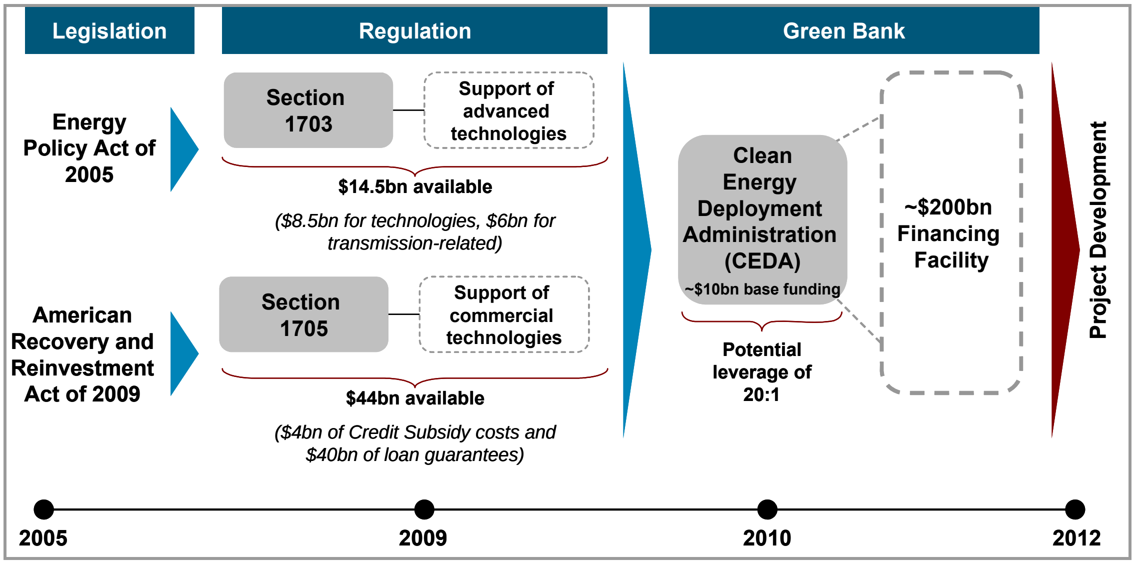
5.0 Other Incentives: Federal

Renewable energy projects can also include and generally require incentives over and above the demand pull from RPS and REC markets. In the US, the primary incentives have been structured at the Federal level through a combination of tax benefits, and loan guarantees. Under the stimulus act that expires in 2011, the section 1703 and 1705 loan guarantee programs provide government guaranteed debt financing for qualifying projects. he Clean Energy Deployment Administration (CEDA) has the potential to extend low cost government guaranteed debt financing, which could be potentially scaled even further with the creation of an even larger national green infrastructure bank (discussed in Chapter VI).

[114] Mario Ragwitz, Anne Held, Frank Sensfuss, Fraunhofer – ISI, “OPTRES: Assessment and optimization of renewable support schemes in the European electricity market,” January 2006

V. US Renewable Payments Market

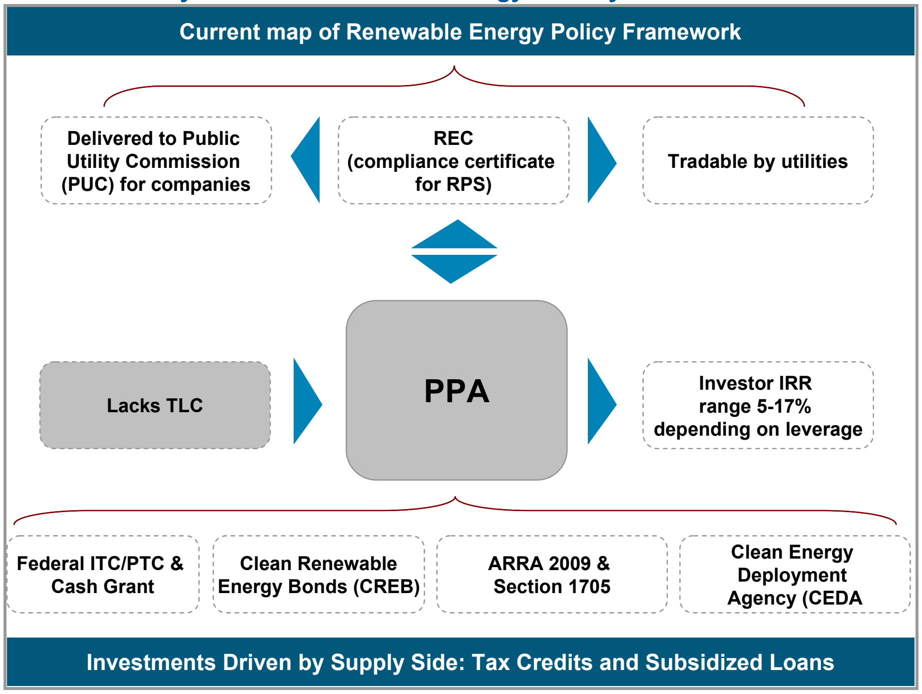
EX 18: Summary of various renewable energy subsidy mechanisms



Source: DBCCA analysis, 2009.

A limited number of variables drive project economics for renewable energy. Equipment cost, financing cost, and plant availability are the two largest constraints affecting returns and define the minimum delivered power price that a developer can tender in an RFP bid to a utility. The US renewable market is muddled and there is not an explicit interaction between incentives and PPAs. Consequently, as a generality, developers selling into RPS and REC markets attempt to maximize incentive capture in structuring their projects in order to bid competitively on projects and also earn an acceptable investment return. By definition this requires bundling any and all local and state incentives on top of federal loan guarantees and tax incentives in structuring the project and engaging in a bi-lateral PPA negotiation (see Exhibit 19 below).

EX 19: Summary of various renewable energy subsidy mechanisms



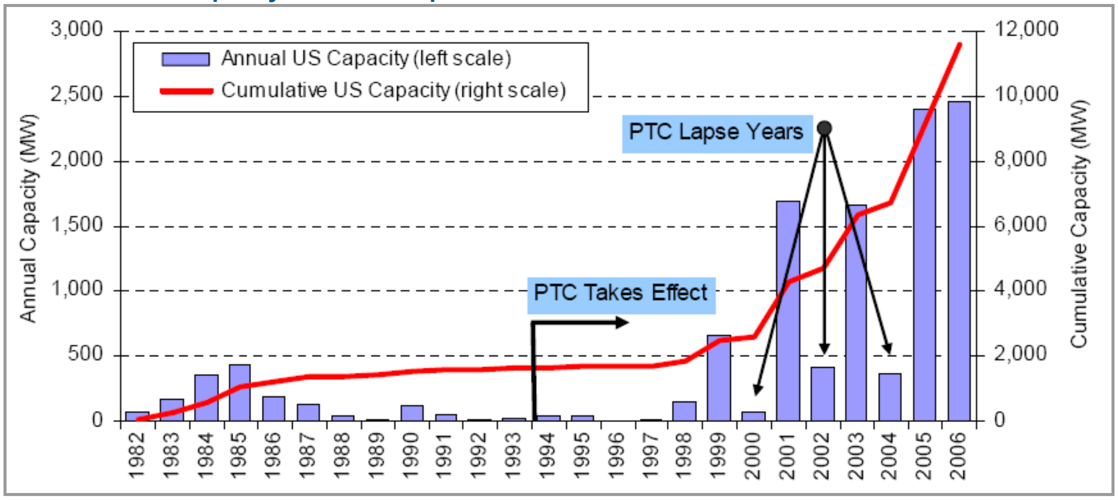
Source: DBCCA analysis, 2009.

V. US Renewable Payments Market

5.1 ITC & PTC

In contrast to state reliance on RPS, the US federal approach toward subsidizing renewable energy and energy efficiency has to date been primarily through the tax code under the theory that lowering marginal tax rates stimulates a supply side response. Since 1992, the Production Tax Credit (PTC) has been the subsidy mechanism of choice by Congress and has been allowed to lapse in three different years: 1999, 2001 and 2003. Consequently investment in renewable energy has waxed and waned with the policy.

EX 20: US wind capacity additions dependent on PTC



Source: LBNL

Currently, renewable project developers can elect to receive an investment tax credit (ITC) in lieu of the PTC. The ITC reduces federal income taxes for qualified tax-paying owners based on capital investment in renewable energy projects. Both the PTC and the ITC can be applied to Federal tax liabilities from the prior year and carried forward up to 20 years. In February 2009, Congress included several provisions in *The American Recovery and Reinvestment Act of 2009 (ARRA)* designed to make federal incentives for renewable energy more useful in an economy with shrinking appetite for tax shields.

The incentives and appropriations in ARRA provide a three-year extension of the PTC through the end of 2012 and allows PTC-eligible projects to also elect a 30% ITC; so for a short while at least wind projects can benefit from subsidized capital cost, a tax shield and accelerated depreciation—modified accelerated cost recovery system (MACRS), which writes down the capital cost of renewable projects over five years, providing substantial front-loaded cash flows.

5.2 Tax Equity Market

The tax equity market provided a source of renewable energy financial support until the recession. Entities with tax appetite entered into highly structured flip partnerships in which they received the PTC tax benefits for a defined period of time with the equity ownership ultimately reversing back to the project developer after the PTC value had been harvested from the project. However, given the downward cyclical change in the economy and abundance of net operating loss (NOL) carry forwards, the US tax equity market has effectively dried up since the cost of capital to finance such structures has increased substantially. The ITC cash grant was designed by policy makers to fill the cyclical gap through 2011 under the presumption that the tax equity market will open up again as the economy recovers and companies once again become interested in tax shields.

V. US Renewable Payments Market

5.3 Convertible Investment Tax Credit (ITC) Cash Grant

ARRA provides the option for a cash grant, or convertible ITC, of up to 30% of the capital cost of a qualifying renewable energy projects that commence construction in 2009 and 2010 and are placed into service prior to 2014 for wind and prior to 2017 for solar.[115] The convertible ITC is paid when the capital investment is deployed and reduces the required equity contribution from project developers. The value of the cash grant is substantial and can add as much as 400 basis points to the internal rate of return (IRR) of a wind project with a 75%/25% debt to equity ratio. The grant program is expected to provide an estimated $3 billion in grants supporting $10-14 billion in investment and largely makes up for the lack of tax equity investors in the market place. It also has the effect of attracting investment from European renewable energy producers with no US taxable income as incentive to keep them investing in the US. Eligible programs apply directly to Treasury and must be operational in either 2009 or 2010. Funds will not be disbursed until the project is complete.

The choice of whether to choose the ITC, convertible ITC or PTC is largely project specific and depends on a combination of quantitative and qualitative factors including: the renewable technology being deployed, the capital structure of the project, the firm's cost of capital, the expected availability and capacity factor of the project and the developer's overall tax position among others. From an earnings and cash flow perspective, the subsidies are similar over the long run. However, for project developers there is a higher internal rate of return (IRR) utilizing the ITC cash grant because of the reduced equity contribution and higher cash flows in the early years of the project that can make an equity payback in as few as five years depending on the project's leverage.

We estimate that the value of the ITC grant is substantial for projects that are debt funded, adding as much as 400 to 500 basis points to the equity IRR over a 25 year period for a project capitalized 50% debt and 50% equity. However, the IRR impact on an all equity unlevered project would be comparable to the PTC.

EX 21: Timeline comparison of US tax credit options

Tax Credit options	Technology	2009	2010	2011	2012	2013	2014	2015	2016
Convertible ITC	Wind	●	●	❍	❍				
	Solar	●	●	❍	❍	❍	❍	❍	❍
ITC	Wind	●	●	●	●				
	Solar	●	●	●	●	●	●	●	●
	Biomass	●	●	●	●	●			
PTC	Wind	●	●	●	●				
	Geothermal	●	●	●	●	●			
ITC Cash Grant		●	●	●					

● Available if placed in service by this date

❍ Available if construction beings by 12/31/10, and is completed by this date

Source: FPL Group, NREL, DBCCA analysis, 2009.

[115] *Mark Bolinger and Ryan Wiser, Lawrence Berkeley National Laboratory, "PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States," March 2009*

V. US Renewable Payments Market

EX 22: Comparison of tax credit options and choices from ARRA

Generation Technology	PTC	ITC	ITC Cash Grant	Comments
Solar			√	High capital cost favors ITC cash grant
Wind	√	√	√	Choice project specific; ITC cash grant increases levered returns; PTCs are more liquid
Open-loop Biomass		√		Open-loop biomass only eligible for ~half PTC value versus wind; ITC more favorable
Geothermal	√			High capacity factor favors PTC

Source: NREL, DBCCA analysis, 2009

Given the sunset provision in the convertible ITC, which his set to expire in 2011, we expect most project developers will elect for the cash grant in 2009 and 2010. Indeed, FPL Group, the largest US wind developer, has stated that it plans to use the cash grant to finance 800 MW of its planned 1000 MW of wind capacity additions in 2009.

But standing on its own, the question for US policy makers is what is next after 2011 when these incentives sunset.

5.4 US DoE Loan Guarantees

The American Recovery and Reinvestment Act of 2009 (ARRA) is intended to address the severe financing challenges facing the US economy. ARRA has amended Department of Energy's (DOE) Section 1703 loan guarantees of the Energy Policy Act of 2005 by creating $40 billion worth of Section 1705 loan guarantees. The stated goal is to spur manufacturing and construction in the short term, thereby creating jobs, and increase the amount of renewable energy generated in the US in order to address climate change and energy independence concerns. These loan guarantees are limited to commercially proven technologies in the renewable energy, transmission, and "leading edge" bio fuels sectors to be scaled up. July of 2009 added alternative fuel vehicles, hydrogen & fuel cells, efficient buildings technologies (originally covered under Section 1703) to the approved list of 1705 projects and an additional $8.5 billion of available guarantees were made available. $6 billion was originally appropriated by Congress to cover the application costs of the 1705 loan guarantees; however, $2 billion of that amount was diverted to the "Cash for Clunkers" program in the fall of 2009 dropping the credit subsidy funds available to $4 billion. All in, $48.5 billion of loan guarantees and $4 billion of credit subsidy costs bring this program to a whopping $52.5 billion "clean energy" program.

The DOE has established two forms of solicitations thus far under the Section 1705 program – the Financial Institution Partnership Program (FIPP) and a direct DOE application process. The latter is just as it sounds; projects will submit applications directly to the DOE for funding consideration. The FIPP program is an evolving partnership with various global financiers to provide products that meet the needs of the aforementioned projects. One of the latest unofficial products is to create an "OPIC-style" fund that uses mezzanine debt to invest as equity capital into projects.

Specific characteristics of the 1705 program include:

- DOE require that financiers (via FIPP) have "skin in the game" by funding 20% of the 80% DOE funded debt. This "unguaranteed portion" (16% of project costs), would require the financial community to hold an estimated $10-15 billion on their balance sheets over the next few years – this is not popular and is being debated within the market.
- No CMBS to be paid – very good for smaller projects when 15% of cost.
- Projects must be under construction by September 30th, 2011.

V. US Renewable Payments Market

"These investments will be used to create jobs, spur the development of innovative clean energy technologies, and help ensure a smart, strong and secure grid that will deliver renewable power more effectively and reliably. "This administration has set a goal of doubling renewable electricity generation over the next three years. To achieve that goal, we need to accelerate renewable project development by ensuring access to capital for advanced technology projects. We also need a grid that can move clean energy from the places it can be produced to the places where it can be used and that can integrate variable sources of power, like wind and solar." - Stephen Chu, Secretary, US Department of Energy, July 29, 2009

5.5 Clean Energy Deployment Agency (CEDA)

Legislation in both the Senate and the House of Representative empowers the DOE to create a Clean Energy Deployment Administration (CEDA), which will combine its own mandated programs with those of the existing DOE Loan Guarantee Program (LGP), authorized under the Energy Policy Act of 2005. The LGP's mission has been to provide guarantee-based financing for high-potential projects intended to decrease air pollutants or man-made greenhouse gases; employ new or significantly improved technologies; and have a reasonable prospect of repayment. CEDA is expected to be funded with $10 billion as base capital. Assuming that these funds are leveraged 20:1 would expand the low interest rate-funding base to $200 billion to encourage the private sector to invest in low-carbon technologies. Such projects would be more expansive that the current tax based renewable energy subsidy schemes and could in addition to renewable energy systems also include advanced nuclear or fossil energy technologies, and production facilities for fuel-efficient vehicles (although this latter initiative has now been separated out from CEDA). CEDA's goal is to decarbonize the US economy as much as possible and at the lowest possible cost, while catalyzing as much private sector financing for this purpose as possible. At this time in the legislation the emphasis is more on early stage technologies.

5.6 Clean Energy Renewable Bond (CREB)

Non taxable entities such as municipalities may not be able to directly benefit from tax incentives, but may instead reap differentially higher cash incentives at the state level, and also may have access to attractive tax-exempt municipal debt or even "zero interest" Clean Renewable Energy Bond (CREB) financing at the federal level. With the passage of the Energy Policy Act of 2005, certain tax-exempt entities now also have access to CREBs, which provide the bondholder with a tax credit in lieu of an interest payment. As such, CREBs offer the promise of a 0% interest rate to the borrower over a 10- to 15-year term; in practice, however, transaction costs have reportedly eroded much of this promise (Cory et al., 2008). As with municipal bonds, CREBs are not available to (non-governmental) non-profit entities; only projects sponsored by governmental entities, electric cooperatives, and public power providers are eligible for CREB financing. Furthermore, the typical maturity of a CREB – 10 to 15 years – is shorter than the 20- to 30-year maturity often seen for municipal bonds.[116]

5.7 US Feed-in Tariffs

A number of US states and municipalities are implementing or considering FiT programs. These include Wisconsin, California, Washington State, Oregon, Arkansas, Florida, Hawaii, Illinois, Indiana[117], Michigan, Minnesota, New York, Rhode Island, Vermont and Gainesville, Florida. In addition, Representative Jay Inslee (D-Washington) and Representative Bill Delahunt (D-Massachusetts) plan to reintroduce a national FiT bill to complement the proposed cap-and-trade program and national RPS targets that are part of the Waxman-Markey legislation. Many of these FiTs have technology specific caps and are designed to complement state RPS programs.

[116] *Mark Bolinger, Lawrence Berkeley National Laboratory, "Financing Non-Residential Photovoltaic Projects: Options and Implications," January 2009*
[117] *Interview with Paul Gipe, Wind-Works.org, December 7, 2009*

V. US Renewable Payments Market

6.0 Financing a renewable energy project

Bringing this all together, we can see how all the different elements interact to finance and establish a renewable energy project. The PPA is central for de-regulated markets. It can reflect all these elements. However, we re-iterate that this is a highly complex equation, lacking TLC and favoring larger generators.

In regulated markets, if the regulated utility does the renewable project itself, this requires PUC approval and gets directly incorporated into the rate base. If an IPP responds to an RFP from a regulated utility, then a PPA will be put in place.

Box 6: PURPA: The first attempt at a standard offer in the US
In the US, the discussion of standard offers and FiTs defaults to PURPA as point of reference. The 1978 Public Utilities Regulatory Policy Act (PURPA) was the largest experiment the US has had with fixed payment policies interconnecting renewable energy into the grid. PURPA is considered to be the grandfather of feed-in tariff schemes and is often criticized for the rigidness in which PPAs were constructed based on inflexible cost calculations . Passed as part of the National Energy Act, PURPA was a federal law meant to create greater use of renewable energy and decentralized power production. Under Title II of PURPA, utilities were required to interconnect power from independent power producers (IPPs) and issue a standard offer—e.g. fixed price—contract for energy from qualifying facilities (QFs). PURPA in effect gave birth to the PPA concept and independent power market in the US. These so called “QFs” were defined as plants 80 MW or less that used renewable energy such as geothermal, wind, hydro biomass or waste. Co-generation combined heat and power (CHP) facilities also qualified. PURPA left it up to states to determine how best to apply the Federal law and was intentionally vague. Most states did very little, however California and New York State regulators enthusiastically embraced PURPA creating a market for “PURPA Machines”—developers who benefited from the legislation. These independent power producers sold above market rate electricity by taking advantage of generous payments streams and definitional nuances enabled by “avoided cost” —the pricing mechanism used to determine the standard offer contract. Since utilities were required to interconnect QFs whether or not they needed the power, stranded power was often the result. New York had what became known as the “Six Cent Law” setting a minimum rate of $0.06/kWh for utility purchases from QFs even if avoided costs fell below that rate. The generous fixed price concession put financial stress on certain utilities unable to gain rate relief and incorporate the above market PPAs into their rate base. PURPA highlights the complexity of the US electricity system and the unintended consequences that can arise when there are no flexibility provisions for cost containment. Nevertheless, two important features in PURPA have been canonized in advanced FiTs: the standard offer and the must connect provision.

VI. Reconciling Policies: The Standard Offer Payment

Summary:

- *In this chapter we show how advanced FiT policy design practices can be reconciled with the current US market structure using RECs to create TLC.*
- *We indicate how standard offer PPAs would provide transparent renewable energy incentives.*
- *In turn, these standard offer PPAs could be aggregated and financed with the creation of a Green Bank, which could catalyze renewable energy scale-up by reducing transaction costs and mitigating project risk.*

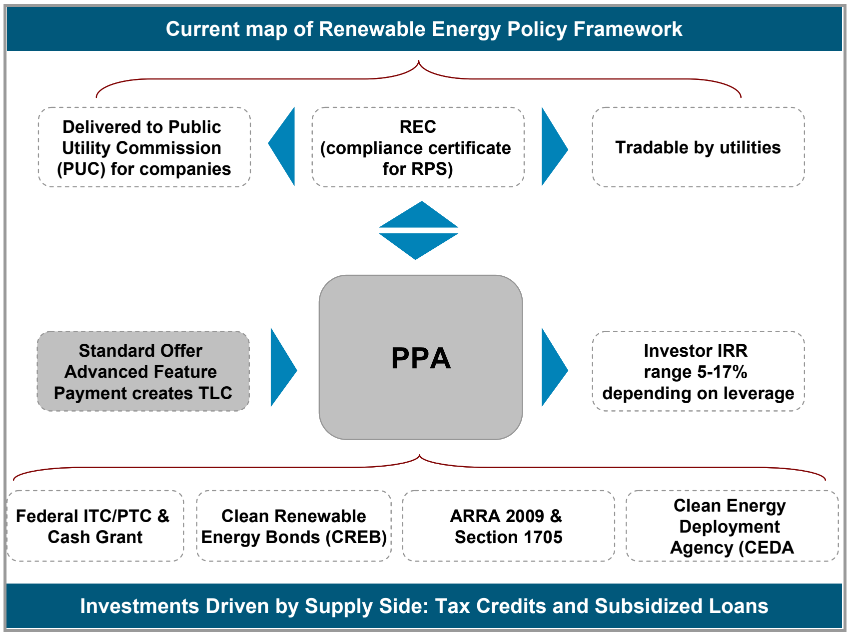
1.0 Interaction and reconciliation of advanced renewable payments with current policy

At a policy level, governments can simply adopt an advanced FiT based on the templates discussed above in order to capture TLC. However, introducing seemingly "foreign" policy structures or terminology often meets resistance.

While it looks at face value that the US RPS/REC policy regime is very different from FiTs, we believe that it would be possible to reconcile FiT design best practices and different US renewable energy policy frameworks.

1. The PPA in the US is a contract, but it is not a standard offer, and so it lacks transparency. Standard offer PPAs would change this.
2. The PPA sets a long term price for electricity, but this price may not be sufficient to drive renewable generation. The inclusion of RECs in PPAs (e.g. in response to RPS policies) can provide the basis for giving renewable generators the long term, premium rates they require for project development. In effect, the REC has this function of the premium price element of a FiT. Creating a standard offer PPA that bundles in RECs at prices set to deliver appropriate returns to investors would be analogous to a FiT from a financing perspective.
3. In states that rely on spot market REC trading, setting a minimum price floor for the REC in a standard offer and then applying other advanced features of FiT design (as set out in Exhibit 23) essentially brings the REC market closer to a design that would yield full TLC. RECs under this scenario could then still be traded.
4. The full range of other state and federal incentives could still be reflected, subject to a reasonable IRR target, as discussed in Chapter IV.

EX 23: Map of renewable energy policy framework



Source: DBCCA analysis, 2009.

VI. Reconciling Policies: The Standard Offer Payment

Hence there is not necessarily a need to remove existing US policies when introducing FiT best practices. This works well at a state level and has even been proposed at a national level. In fact, a standard offer FiT design would substantially broaden the renewable energy market by increasing liquidity and lowering the barriers to entry for renewable suppliers. In turn, this supply response would accelerate the technology learning rates and reduce the need for subsidies over the long run as renewable energy becomes competitive with fossil fuel generation.

2.0 A "Green Bank"

A national infrastructure bank modeled on the Overseas Private Investment Corporation (OPIC) could mobilize and facilitate capital deployment in renewable energy in scale with the goal of fostering energy security, new industries, job creation and achieving carbon emission targets. As a public benefit corporation, the bank would be structured as an independent, wholly owned US government subsidiary with tax exempt status and an independent board with relevant industry and finance domain expertise. The "Green Bank" would subsume the current Clean Energy Deployment Agency (CEDA) and operate in parallel with the existing federal and state renewable energy policy framework.

The creation of the new Green Bank could help in US energy policy, which at present lacks an integrated planning and support framework and has historically relied on tax subsides versus enhanced credit. Investors and project developers crave certainty in making capital allocation decisions. Reducing risk is important since risk has a price, expressed as the risk premium. Since clean energy deployment is at its core a scale challenge, lowering the cost of capital is certainly an important element. But cheap debt issuance alone even if backed up by the full faith and credit of the US government is unlikely to mobilize large sums of investment. Rather, it is the *availability* and flexibility of debt capital across a variety of tenures that conform to project specific elements and long term certainty of the capital availability that are key. The majority of the debt should conform to the technical life of the project. Providing these financing products would fill a large void in the US energy sector, providing highly rated hedgable instruments that could enable producers and financiers to dynamically adjust their capital at risk and market exposures by timeframe based on changes in fundamentals.

In order to strike a fair balance between the private and public sector, the Green Bank would require at least 20% equity participation from project developers and would have indoctrinated in its mandate a targeted after tax equity return of 15% for participants inclusive of all available state, local, and federal incentives. This would eliminate incentive double-dipping and complement existing policies by adding much needed longevity to the financing mosaic.

The Green Bank could therefore act as a clearinghouse for structuring and backstopping the standard offer PPAs with advanced features in the energy market that we are suggesting, complementing private sector investments and leveraging the existing tax credit structure. The Green Bank would develop a set of national best practices for clean energy financing, such as a standard loan application, consistent lending and verification standards and would apply the same robust credit analysis to loans as a private banking institution. With the Green Bank integrating and enshrining the core features of our advanced renewable payment market structure into its operations would lower administrative and transaction costs. This would bring much needed transparency and more effective risk management to the renewable energy market driving primary and secondary investments in energy projects. The Green Bank's scale and government charter status would provide the certainty and liquidity needed to enable the capital markets to purchase, pool and securitize renewable energy projects along different durations. The long-dated and consistent cash flows generated by standard offer PPAs underpinning the bank's lending would have strong demand appeal as securitized products to institutional investors such as pension funds and insurance companies looking to optimize asset and liability matching over specific time periods. In this respect, the Green Bank could truly be transformational in scope and reestablish the US position as a renewable energy leader while also creating a liquid secondary market in government bonds.

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Appendix

Examples of renewable energy incentives by country

Chapter IV, Section 5.5.1 presents different ways that incentives can interact with FiTs. This appendix provides a few examples of incentives that are available in each of the policy regimes we have examined.

Many German states, particularly in the East, provide renewable subsidies and low-interest loans. Due to the lack of market liquidity, smaller projects are currently easier to finance. Regional and community banks provide good incentives and have become stronger supporters of small-scale projects because they benefit the local community.[118] Germany's national infrastructure bank, the KfW also provides low-interest loans.

France provides low-interest loans, a PV tax credit covering 4%-50% of installed costs through 2010 and EuroFideme[119] provides loans to large projects.

The Netherlands provides tax exemptions through an Energy Investment Deduction scheme (EIA).[120] The program gives tax relief to Dutch companies that invest in sustainable energy and/or energy efficient equipment. The EIA subtracts up to 44% of the purchase and production costs of the annual investment from yearly profits. A maximum of €111 million can be deducted; this leaves a lower corporate profit tax that companies must pay. Other Dutch direct incentives include exempting generators from the eco-tax levied on electricity consumption[121] and providing low-interest rates from Green Funds. [122]

Ontario has a wide range of incentives such as the creation of Community Power Fund for community-based renewable energy projects through a grant of $3 million to the Ontario Sustainable Energy Association; sales tax rebates for residential systems; and waiving property taxes in lieu of taxes on gross revenues for operators of hydropower facilities. Additionally, the ecoENERGY for Renewable Power program provides an incentive of one cent per kWh for up to 10 years to eligible low-impact, renewable electricity projects constructed from April 1, 2007 to March 31, 2011.

[118] *Conversation with Johannes Lackmann, former President of the Federal Renewable Energy Association (BEE).*
[119] *Eurofideme is an investment fund that specialized in renewable energy finance.*
[120] *The ensuing EIA scheme is sourced from: Kema Inc. California Feed-in Tariff Design and Policy Options, Final Consultant Report. May 2009.*
[121] *EWEA, Support Schemes for Renewable Energy A Comparative Analysis of Payment Mechanisms in the EU, est. 2005.*
[122] *David de Jager, Financing the deployment of renewable energy, Ecofys, IEA Workshop, 2007, http://www.iea-retd.org/files/15_Mar_07_David_De_Jager_Financing_deployment_of_RE.pdf*

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Tracking the Sun II

The Installed Cost of Photovoltaics in the U.S. from 1998-2008

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October 2009

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Lawrence Berkeley National Laboratory

LBNL-2674E

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The Installed Cost of Photovoltaics in the U.S. from 1998-2008

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Contents

Executive Summary

As the deployment of grid-connected solar photovoltaic (PV) systems has increased, so too has the desire to track the installed cost of these systems over time and by location, customer type, system characteristics, and component. This report helps to fill this need by summarizing trends in the installed cost of grid-connected PV systems in the United States from 1998 through 2008 (updating a previous report with data through 2007).[1] The analysis is based on installed cost data from more than 52,000 residential and non-residential PV systems, totaling 566 MW and representing 71% of all grid-connected PV capacity installed in the U.S. through 2008.[2]

Key findings of the analysis are as follows:[3]

- The capacity-weighted average installed cost of systems completed in 2008 – in terms of real 2008 dollars per installed watt (DC-STC)[4] and prior to receipt of any direct financial incentives or tax credits – was \$7.5/Watt, a decline from \$7.8/W in 2007 following several years (2005-2007) during which installed costs remained relatively flat. From 1998 to 2008, installed costs declined by about 3.6% (or \$0.3/W) per year, on average, starting from \$10.8/W in 1998.
- Preliminary cost data indicates that the average cost of projects installed through the California Solar Initiative program during the first 8½ months of 2009 rose by \$0.4/W relative to 2008, while average costs in New Jersey declined by \$0.2/W over the same period.
- The decline in installed costs from 2007 to 2008 appears to be attributable largely to a reduction in module costs, as suggested by Navigant Consulting's Global Module Price Index, which fell by approximately \$0.5/W from 2007 to 2008.[5] In contrast, the decline in total installed costs from 1998 to 2005 is associated primarily with a reduction in non-module costs (which may include items such as inverters, other balance of systems hardware, labor, and overhead).
- Long-term reductions in installed cost are most evident for systems ≤100 kW, with systems ≤5 kW exhibiting the largest absolute reduction, from \$12.3/W in 1998 to \$8.5/W in 2008.

[1] Although the report is intended to portray national trends, with 16 states represented within the dataset, the overall sample is heavily skewed towards systems in California and New Jersey, where the vast majority of PV systems in the U.S. have been installed.
[2] Grid-connected PV represented approximately 88% of the U.S. PV market in 2008, with off-grid systems constituting the remainder. See: Sherwood, L. 2009. *U.S. Solar Market Trends 2008*. Interstate Renewable Energy Council. http://www.irecusa.org.
[3] Unless otherwise noted, the results reflect all system types represented within the sample (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, thin-film, etc.).
[4] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs is the nameplate capacity of the PV modules, which is reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout the present report. Alternatively, module ratings may be specified in terms of DC watts under PVUSA test conditions (PTC), which are lower than STC ratings, as they account for the effect of normal operating temperature on module output. Finally, PV system ratings may be specified in terms of alternating current (AC) watts, to account for inverter losses (as well as potentially losses within other system components). AC system ratings may be specified as either STC or PTC. As one example, the California Public Utilities Commission has historically used an AC-PTC rating, which is equal to roughly 85% of DC-STC capacity.
[5] It should be noted, however, that there is likely a lag between movements in the wholesale price of PV modules and the average installed cost of PV projects, as module costs for installed projects may reflect prevailing wholesale prices at the time that contracts for system installation were signed. Thus, the decline in the Global Module Price Index from 2007 to 2008 is likely to be larger than the reduction in module costs for projects installed over the same time period.

Long-term cost reductions for systems >100 kW are less apparent, given the limited number of data points for the early years of the study period.

- The distribution of installed costs within a given system size range narrowed significantly from 1998 to 2005, with high-cost outliers becoming increasingly infrequent, indicative of a maturing market. However, little if any further narrowing of the cost distribution occurred from 2005 through 2008.
- PV installed costs exhibit significant economies of scale, with systems ≤2 kW completed in 2008 averaging $9.2/W, while 500-750 kW systems averaged $6.5/W (i.e., about 30% less than the smallest systems).
- Component-level cost data indicates that, among systems installed in 2008, module costs averaged $0.7/W less for systems >100 kW than for systems ≤10 kW, while non-module costs differed by less than $0.1/W.
- International experience suggests that greater near-term cost reductions may be possible in the U.S., as the average cost of small residential PV installations in 2008 (excluding sales/value-added tax) in both Japan ($6.9/W) and Germany ($6.1/W) was significantly below that in the U.S. ($7.9/W).
- Average installed costs vary widely across states; among ≤10 kW systems completed in 2008, average costs range from a low of $7.3/W in Arizona (followed by California, which had average installed costs of $8.2/W) to a high of $9.9/W in Pennsylvania and Ohio. This variation in average installed cost across states, as well as comparisons with Japan and Germany, suggest that markets with large PV deployment programs tend to have lower average installed costs for residential PV, though exceptions exist.
- The average installed cost of residential systems in 2008 was less than for *similarly sized* commercial systems, with the average cost of residential systems lower by approximately $0.6/W for systems within the 5-10 kW size range and by $0.3/W within the 10-100 kW range.
- The new construction market offers cost advantages for residential PV; among 1-3 kW residential systems funded through three California programs (the Emerging Renewables Program, the New Home Solar Partnership Program, and the California Solar Initiative) and installed in 2008, PV systems installed in residential new construction cost $0.8/W less than comparably-sized residential retrofit systems (or $1.2/W less if focused exclusively on rack-mounted systems).
- Among PV systems installed in residential new construction in 2008, building-integrated PV systems cost $0.9/W more, on average, than rack-mounted systems ($8.3/W vs. $7.4/W).
- Although there were relatively few thin-film systems within the sample, PV systems with thin-film modules generally had lower average installed costs in 2008 than comparably-sized crystalline systems ($1.5/W less among 10-100 kW systems and $0.6/W less among >100 kW systems).
- Among 10-100 kW systems installed in 2008, systems with tracking had average installed costs $0.5/W (or 6%) higher than fixed-axis systems.
- The average cash incentive provided by the state/utility PV incentive programs in the sample ranged from $2.1-$2.4/W for systems installed in 2008, depending on system size, representing about a 50% decline from its peak in 2002.
- In 2008, the average combined *after-tax* value of state/utility cash incentives *plus* state and Federal ITCs (but excluding revenue from the sale of renewable energy certificates or the

value of accelerated depreciation) was $2.8/W for residential PV (its lowest level since prior to 1998 and down $0.3/W from 2007) and $4.0/W for commercial PV (just below its all-time peak of $4.3/W in 2002 and down $0.2/W from 2007). The differing trajectories of after-tax incentives for residential and commercial PV is associated with the more lucrative Federal ITC adopted for commercial PV systems in 2006. However, incentive levels will converge to some extent in 2009, with the lifting of the dollar cap on the Federal residential ITC.

- In 2008, the average *net installed cost* faced by PV system owners – that is, installed cost minus after-tax incentives – stood at $5.4/W for residential PV and $4.2/W for commercial PV. For both residential and commercial PV, average net installed costs rose slightly from 2007 to 2008 (by 1% and 5%, respectively), as the annual decline in incentives outpaced the drop in installed costs.
- Financial incentives and net installed costs diverge widely across states. Among residential PV systems completed in 2008, the combined after-tax incentive ranged from an average of $2.5/W in California to $5.1/W in New York, and net installed costs ranged from an average of $3.5/W in New York to $6.9/W in Vermont. Incentives and net installed costs for commercial systems varied similarly across states.

1. Introduction

Installations of solar photovoltaic (PV) systems have been growing at a rapid pace in recent years. In 2008, 5,948 MW of PV was installed globally, up from 2,826 MW in 2007, and was dominated by grid-connected applications.[6] The United States was the world's third largest PV market in terms of annual capacity additions in 2008, behind Spain and Germany; 335 MW of PV was added in the U.S. in 2008, 293 MW of which came in the form of grid-connected installations.[7] Despite the significant year-on-year growth, however, the share of global and U.S. electricity supply met with PV remains small, and annual PV additions are currently modest in the context of the overall electric system.

The market for PV in the U.S. is driven by national, state, and local government incentives, including up-front cash rebates, production-based incentives, requirements that electricity suppliers purchase a certain amount of solar energy, and Federal and state tax benefits. These programs are, in part, motivated by the popular appeal of solar energy, and by the positive attributes of PV – modest environmental impacts, avoidance of fuel price risks, coincidence with peak electrical demand, and the typical location of PV at the point of use. Given the relatively high cost of PV, however, a key goal of these policies is to encourage cost reductions over time. Therefore, as policy incentives have become more significant and as PV deployment has accelerated, so too has the desire to track the installed cost of PV systems over time, by system characteristics, by system location, and by component.

To address this need, Lawrence Berkeley National Laboratory initiated a report series focused on describing trends in the installed cost of grid-connected PV systems in the U.S. The present report, the second in the series, describes installed cost trends from 1998 through 2008.[8] The analysis is based on project-level cost data from more than 52,000 residential and non-residential PV systems in the U.S., all of which are installed at end-use customer facilities (herein referred to as "customer-sited" systems). The combined capacity of systems in the data sample totals 566 MW, equal to 71% of all grid-connected PV capacity installed in the U.S. through 2008 and representing the most comprehensive source of installed PV cost data for the U.S.[9] The report also briefly compares recent PV installed costs in the U.S. to those in Germany and Japan. Finally, it should be noted that the analysis presented here focuses on descriptive trends in the underlying data, serving primarily to summarize the data in tabular and graphical form; later analysis may explore some of these trends with more-sophisticated statistical techniques.

The report begins with a summary of the data collection methodology and resultant dataset (Section 2). The primary findings of the analysis are presented in Section 3, which describes trends

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[6] SolarBuzz. 2009. *MarketBuzz 2009*. http://www.solarbuzz.com/Marketbuzz2009-intro.htm.

[7] Sherwood, L. 2009. *U.S. Solar Market Trends 2008*. Interstate Renewable Energy Council. http://www.irecusa.org.

[8] To be clear, the report focuses on installed costs *as paid by the system owner*, rather than the costs born by manufacturers or installers. It is possible, especially over the past several years, that cost trends may have diverged between manufacturers and installers, or between installers and system owners. Note also that, in focusing on installed costs, the report ignores improvements in the performance of PV systems, which will tend to reduce the levelized cost of energy of PV even absent changes in installed costs.

[9] In addition to the primary dataset, which is limited to data provided directly by PV incentive program administrators and only includes customer-sited systems, the report also summarizes installed cost data obtained through public data sources for nine multi-MW grid-connected PV systems in the U.S. (several of which are installed on the utility-side of the meter). These additional large systems represent a combined 52 MW, bringing the total dataset to 619 MW, or 78% of all grid-connected PV capacity installed in the U.S. through 2008.

in installed costs prior to receipt of any financial incentives: over time and by system size, component, state, customer segment (residential vs. commercial vs. public-sector vs. non-profit), application (new construction vs. retrofit), and technology type (building-integrated vs. rack-mounted, crystalline silicon vs. thin-film, and tracking vs. rack-mounted). Section 4 presents additional findings related to trends in PV incentive levels over time and among states (focusing specifically on state and utility incentive programs as well as state and Federal tax credits), and trends in the net installed cost paid by system owners after receipt of such incentives. Brief conclusions are offered in the final section, and several appendices provide additional details on the analysis methodology and additional tabular summaries of the data.

2. Data Summary

This section briefly describes the procedures used to collect, standardize, and clean the data provided by individual PV incentive programs, and summarizes the basic characteristics of the resulting dataset, including: the number of systems and installed capacity by PV incentive program; the sample size relative to all grid-connected PV capacity installed in the U.S.; and the sample distribution by year, state, and project size.

Data Collection, Conventions, and Data Cleaning

Requests for project-level installed cost data were sent to state and utility PV incentive program administrators from around the country, with some focus (though not exclusively so) on relatively large programs. Ultimately, 27 PV incentive programs provided project-level installed cost data from 16 states. To the extent possible, this report presents the data as provided directly by these PV incentive program administrators. That said, several steps were taken to standardize and clean the data, as briefly summarized here and described in greater detail in Appendix A.

In particular, two key conventions used throughout this report deserve specific mention:

1. All cost and incentive data are presented in real 2008 dollars (2008$), which required inflation adjustments to the nominal-dollar data provided by PV programs.
2. All capacity and dollars-per-watt ($/W) data are presented in terms of rated module power output under Standard Test Conditions (DC-STC), which required that capacity data provided by several programs that use a different capacity rating be translated to DC-STC. [10]

The data were cleaned by eliminating projects with clearly erroneous cost or incentive data, by correcting text fields with obvious errors, and by standardizing identifiers for module and inverter models. To the extent possible, each PV system in the dataset was classified as either building-integrated PV or rack-mounted, and as using either crystalline or thin-film modules, based on a combination of information sources. Finally, data on market sector (e.g., residential, commercial, government, non-profit) were not provided for many systems, in which case systems ≤10 kW were assumed to be residential, and those >10 kW were assumed to be commercial, when calculating the value of state and federal investment tax credits and net installed costs.[11]

[10] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs is the nameplate capacity of the PV modules, which is reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout the present report. Alternatively, module ratings may be specified in terms of DC watts under PVUSA test conditions (PTC), which are lower than STC ratings, as they account for the effect of normal operating temperature on module output. Finally, PV system ratings may be specified in terms of alternating current (AC) watts, to account for inverter losses (as well as potentially losses within other system components). AC system ratings may be specified as either STC or PTC. As one example, the California Public Utilities Commission has historically used an AC-PTC rating, which is equal to roughly 85% of DC-STC capacity.

[11] 10 kW is a common, albeit imperfect, cut-off between residential and commercial PV systems. Among the approximately 23,000 systems in the dataset for which market sector data were provided, 94% of systems (and 93% of capacity) ≤10 kW are residential, while 41% of systems (and 80% of capacity) >10 kW are commercial. If the same distribution applies to the entire dataset, a total of 7% of all systems in the sample (and 8% of the total capacity) would be misclassified by using a 10 kW cut-off between residential and commercial systems.

Sample Description

The final dataset, after all data cleaning was completed, consists of more than 52,000 grid-connected, residential and non-residential PV systems, totaling 566 MW (see Table 1).[12] This represents approximately 71% of all grid-connected PV capacity installed in the U.S. through 2008, and about 67% of the 2008 capacity additions (see Figure 1). The largest state markets missing from the primary data sample, in terms of cumulative installed PV capacity through 2008, are: Hawaii (representing 1.7% of total U.S. grid-connected PV capacity), Texas (0.6%), and North Carolina (0.6%). In addition, although one Colorado program did provide data, this program constitutes a small fraction of the state's PV market. Thus, Colorado – which represents 4.5% of total U.S. grid-connected PV capacity through 2008 – is significantly under-represented within the data set.

Table 1. Data Summary by PV Incentive Program

State	PV Incentive Program	No. of Systems	Total MW_{DC}	% of Total MW_{DC}	Size Range (kW_{DC})	Year Range
AZ	APS Solar & Renewables Incentive Program	912	6.2	1.1%	0.4 - 255	2002 - 2008
	SRP EarthWise Solar Energy Program	346	1.7	0.3%	0.7 - 36	2005 - 2008
CA	Anaheim Solar Advantage Program	69	0.3	0.1%	1.4 - 18	2001 - 2008
	CEC Emerging Renewables Program	27,947	146.4	25.9%	0.1 - 670	1998 - 2008
	CEC New Home Solar Partnership	539	1.6	0.3%	1.3 - 92	2007 - 2008
	CPUC California Solar Initiative	11,533	146.7	25.9%	1.2 - 1,308	2007 - 2008
	CPUC Self-Generation Incentive Program	796	144.9	25.6%	33 - 1,239	2002 - 2008
	LADWP Solar Incentive Program	1,463	17.6	3.1%	0.6 - 1,200	1999 - 2008
	Lompoc PV Rebate Program	5	0.02	0.0%	3.0 - 5.3	2008 - 2008
	SMUD Residential Retrofit and Commercial PV Programs	170	1.0	0.2%	1.3 - 97	2005 - 2008
CO	Governor's Energy Office Solar Rebate Program	16	0.1	0.0%	2.0 - 5.4	2008 - 2008
CT	CCEF Onsite Renewable DG Program*	66	5.6	1.0%	1.6 - 480	2003 - 2008
	CCEF Solar PV Program	557	3.1	0.5%	0.8 - 17	2005 - 2008
MA	MRET Commonwealth Solar Program	1,091	8.1	1.4%	0.2 - 460	2002 - 2008
MD	MEA Solar Energy Grant Program	230	0.8	0.1%	0.5 - 45	2005 - 2008
MN	MSEO Solar Electric Rebate Program	145	0.5	0.1%	0.5 - 40	2002 - 2008
NJ	NJCEP Customer Onsite Renewable Energy Program	3,167	54.2	9.6%	0.8 - 702	2003 - 2008
	NJCEP Solar Renewable Energy Credit Program	58	8.4	1.5%	1.0 - 1,588	2007 - 2008
NV	NPC/SPPC RenewableGenerations Rebate Program	393	2.0	0.3%	0.5 - 31	2004 - 2008
NY	NYSERDA PV Incentive Program	1,158	7.2	1.3%	0.7 - 51	2003 - 2008
OH	ODOD Advanced Energy Fund Grants	35	0.3	0.0%	1.0 - 122	2005 - 2008
OR	ETO Solar Electric Program	878	6.6	1.2%	0.8 - 859	2003 - 2008
PA	SDF Solar PV Grant Program	164	0.7	0.1%	1.2 - 12	2002 - 2008
VT	RERC Small Scale Renewable Energy Incentive Program	225	0.8	0.1%	0.6 - 38	2004 - 2008
WA	Klickitat PUD Solar PV Rebate Program	5	0.01	0.0%	0.3 - 3.0	2008 - 2008
	Port Angeles Solar Energy System Rebate	2	0.004	0.0%	1.4 - 2.7	2007 - 2008
WI	Focus on Energy Renewable Energy Cash-Back Rewards	386	1.7	0.3%	0.2 - 38	2002 - 2008
	Total	***52,356***	***566.3***	***100%***	***0.1 - 1,588***	***1998 - 2008***

* This report includes within CCEF's Onsite Renewable DG Program, which was launched in 2005, systems that were funded by CCEF prior to inception of any formal PV incentive program.

[12] There may be a modest level of double-counting of systems between programs, as some systems funded by LADWP and SMUD may have also received incentive funding through the CEC's Emerging Renewables Program. Some other large systems funded by LADWP and SMUD also received funding through the CPUC SGIP; however, those systems were removed from the SGIP dataset, in order to eliminate double counting.

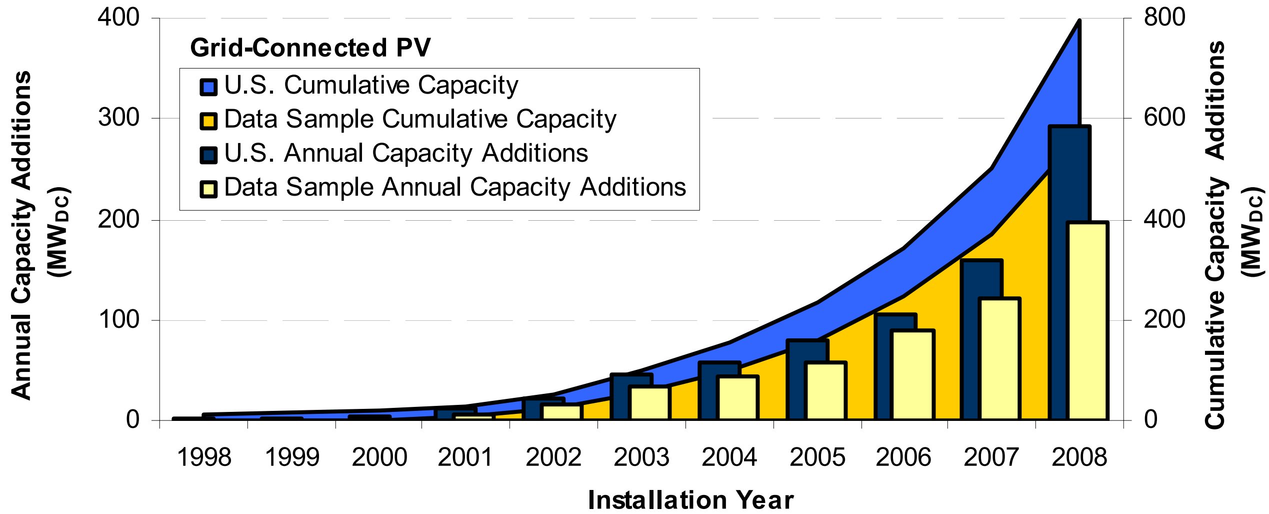


Figure 1. Data Sample Compared to Total U.S. Grid-Connected PV Capacity

Table 2. Data Sample by Installation Year

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
No. of Systems	39	180	217	1,308	2,489	3,526	5,527	5,193	8,677	12,103	13,097	***52,356***
% of Total	*<1%*	*<1%*	*<1%*	*2%*	*5%*	*7%*	*11%*	*10%*	*17%*	*23%*	*25%*	***100%***
Capacity (MW$_{DC}$)	0.2	0.8	0.9	5.4	15	34	44	57	90	122	197	***566***
% of Total	*<1%*	*<1%*	*<1%*	*1%*	*3%*	*6%*	*8%*	*10%*	*16%*	*22%*	*35%*	***100%***

The primary sample consists only of data provided by PV incentive program administrators, all of which are for customer-sited systems. The report separately describes the installed cost of nine multi-MW grid-connected PV systems not included in the primary dataset, including the three largest PV systems installed in the U.S. through 2008.[13] Cost data for these projects were compiled from press releases and other publicly available sources. The data for these nine projects bring the total PV capacity for which cost data are presented to 619 MW, equal to 78% of all grid-connected PV capacity installed in the U.S. through 2008.

The PV systems in the primary dataset were installed over an eleven-year period, from 1998 through 2008. As to be expected, though – given the dramatic expansion of the U.S. solar market in recent years – the sample is skewed towards projects completed during the latter years of this period, with approximately half of the PV systems and half of the total capacity in the sample installed in 2007 and 2008 (see Table 2). See Appendix B for annual installation data (number of systems and capacity) disaggregated by PV incentive program and by system size range.

Among the 27 PV incentive programs that provided data for this report, the lion's share of the sample is associated with the four largest PV incentive programs in the country to-date: California's Emerging Renewables Program (ERP); California's Self-Generation Incentive Program (SGIP); the California Solar Initiative (CSI) Program; and New Jersey's Customer Onsite Renewable Energy (CORE) Program. As such, the sample is heavily weighted towards systems installed in California and New Jersey, as shown in Figure 2. In terms of installed capacity, these two states represent

[13] These three PV systems are the 8.2 MW$_{DC}$ system installed in 2007 in Alamosa, CO, the 12.2 MW$_{DC}$ system installed in 2008 in El Dorado, NV, and the 14.2 MW$_{DC}$ system installed in 2007 at Nellis Air Force base in Nevada.

83% and 12% of the total data sample, respectively. Connecticut, Massachusetts, Arizona, New York, and Oregon each represent 1.2-1.5% of the sample, with the remaining nine states (Colorado, Nevada, Maryland, Minnesota, Ohio, Pennsylvania, Washington, Wisconsin, and Vermont) comprising 1.2%, in total.

The size of the PV systems in the primary dataset span a wide range, from as small as 100 W to as large as 1.6 MW, but almost 90% of the projects in the sample are ≤10 kW (see Figure 3). In terms of installed capacity, however, the sample is considerably more evenly distributed across system size ranges, with systems >100 kW comprising 45% of the total installed capacity, and systems ≤10 kW comprising 36%.

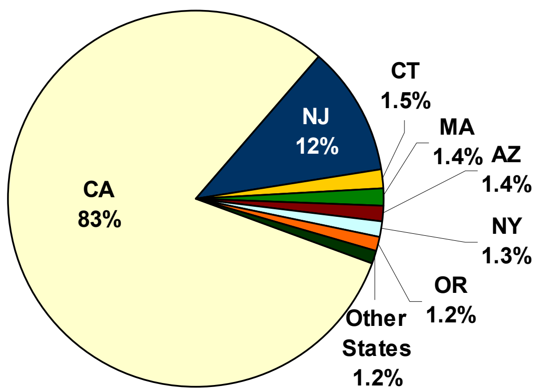


Figure 2. Data Sample Distribution among States (by Cumulative MW)

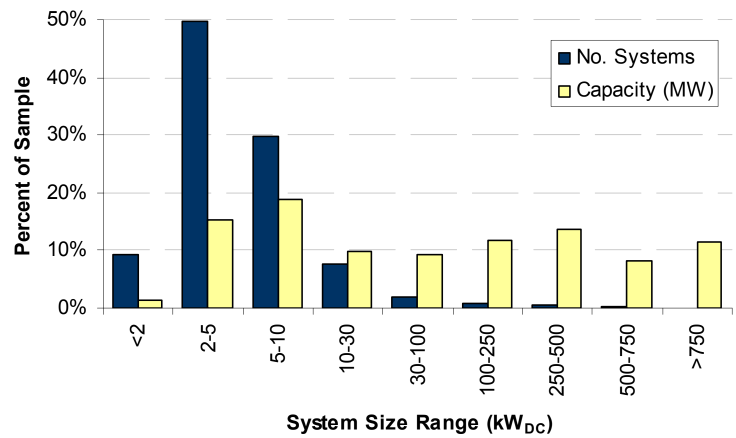


Figure 3. Data Sample Distribution by PV System Size

3. PV Installed Cost Trends

This section presents the primary findings of the report, describing trends in the average installed cost of grid-connected PV, based on the dataset described in Section 2. It begins by presenting the trends in installed costs over time; by system size; by component, between the U.S., Germany, and Japan; among individual states; and among customer types (residential, commercial, public sector, and non-profit).[14] It then compares installed costs among several specific types of applications and technologies – specifically, residential new construction vs. residential retrofit, BIPV vs. rack-mounted systems, systems with thin-film modules vs. those with crystalline modules, and tracking vs. fixed-axis systems. To be clear, the focus of this section is on installed costs, as paid by the system owner, prior to receipt of any financial incentives (e.g., rebates, tax credits, etc.).

Installed Costs Declined from 2007 to 2008, Following Several Years of Stagnation

Figure 4 presents the average installed cost of all projects in the primary sample completed each year from 1998-2008.[15] As shown, capacity-weighted average costs declined from $7.8/W in 2007 to $7.5/W in 2008 – a 4.6% year-on-year reduction. This decline is somewhat greater than the average rate of cost reductions from 1998-2008, wherein installed costs declined by $0.3/W (3.6%) per year, on average, starting from $10.8/W in 1998.

The reduction in installed costs from 2007 to 2008 marks an important departure from the trend of the preceding three years, during which costs remained flat, as rapidly expanding U.S. and global PV markets put upward pressure on both module prices and non-module costs. This dynamic began to shift in 2008, as expansions on the supply-side coupled with the global financial crisis led to a decline in wholesale module prices. The initial effect of this trend on retail installed costs is evident in the drop in installed costs from 2007 to 2008 shown in Figure 4, though it is important to note that the cost of many projects installed in 2008 may be based on contracts signed (and inventory stocked) prior to the global decline in wholesale module prices that began in 2008.

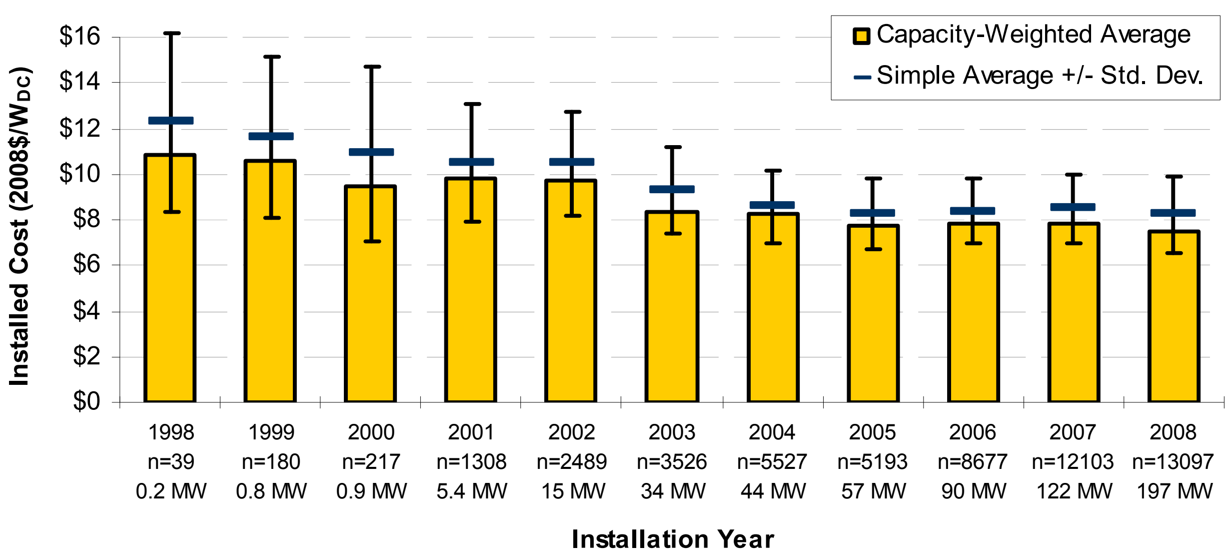


Figure 4. Installed Cost Trends over Time

[14] Unless otherwise noted, the reported results are based on all system types in the data sample (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, non-crystalline, etc.).
[15] See Appendix B for average annual cost data for each of the 27 PV incentive programs, individually.

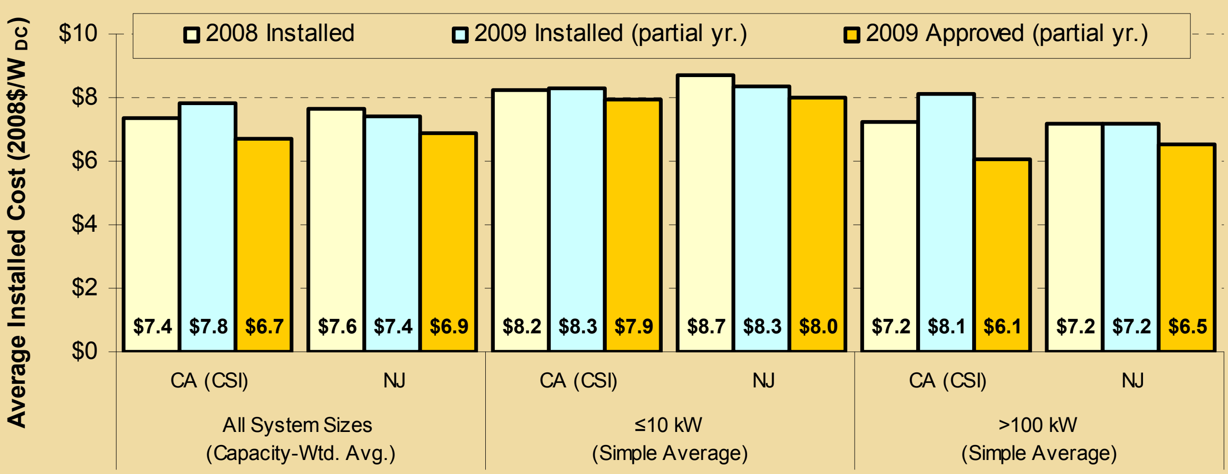
Text Box 1. Preliminary Installed Cost Trends for 2009

The dramatic and widely reported decline in wholesale module prices that began in 2008 and continued through 2009 suggests that retail installed costs should decline from 2008 to 2009. However, preliminary cost data for projects installed or approved for incentive payment in 2009 paints a more-complex picture.

Figure 5 compares the average cost of projects installed in 2008 to the cost of projects installed during approximately the first 8 months of 2009, with results presented separately for California (based on data from the CSI program through September 15, 2009) and New Jersey (based on data from all statewide incentive programs through August 31, 2009). Within California, the capacity-weighted average cost of CSI projects installed from January 1 – September 15, 2009 actually rose by \$0.4/W relative to the average in 2008. The cost increase in California was particularly significant for >100 kW projects, rising by \$0.9/W (from \$7.2/W to \$8.1/W), while ≤10 kW projects registered a smaller cost increase of \$0.1/W (from \$8.2/W to \$8.3/W).

In contrast, capacity-weighted average installed costs in New Jersey fell by approximately \$0.2/W, from \$7.6/W in 2008 to \$7.4/W during the first 8 months of 2009. The reduction in average installed costs in New Jersey occurred primarily among small systems, with the average installed cost of projects ≤10 kW in New Jersey falling by \$0.4/W (from \$8.7/W to \$8.3/W), while >100 kW systems registered no discernable change in average installed costs.

Figure 5 also presents the average reported cost of projects with incentive applications approved in 2009 but that had not yet been installed as of the aforementioned dates. Although these data are *highly provisional*, as costs may change once a project is installed, they suggest that further cost reductions are on the horizon. In California, the capacity-weighted average reported cost of 2009 approved projects is \$6.7/W, or \$0.7/W below the average for projects installed in 2008 and \$1.1/W less than for projects installed in the first 8½ months of 2009. In New Jersey, the capacity-weighted average reported cost of 2009 approved projects is \$6.9/W, compared to \$7.6/W for projects installed in 2008 and \$7.4/W for projects installed in the first 8 months of 2009. In both states, the decline is evident across system sizes, but is larger for >100 kW systems than for ≤10 kW systems.



Notes: CA data are from the CSI program (through September 15, 2009), while NJ data are from the CORE Program, SREC-Only Pilot, Renewable Energy Incentive Program, and SREC Registration Program (through August 31, 2009). Cost data for "2009 Installed (partial yr)" are based on systems installed by the aforementioned dates, while data for "2009 Approved (partial yr)" are based on systems with an approved incentive application on file (or that have registered within the NJ SREC program), but that were not yet installed by the aforementioned dates.

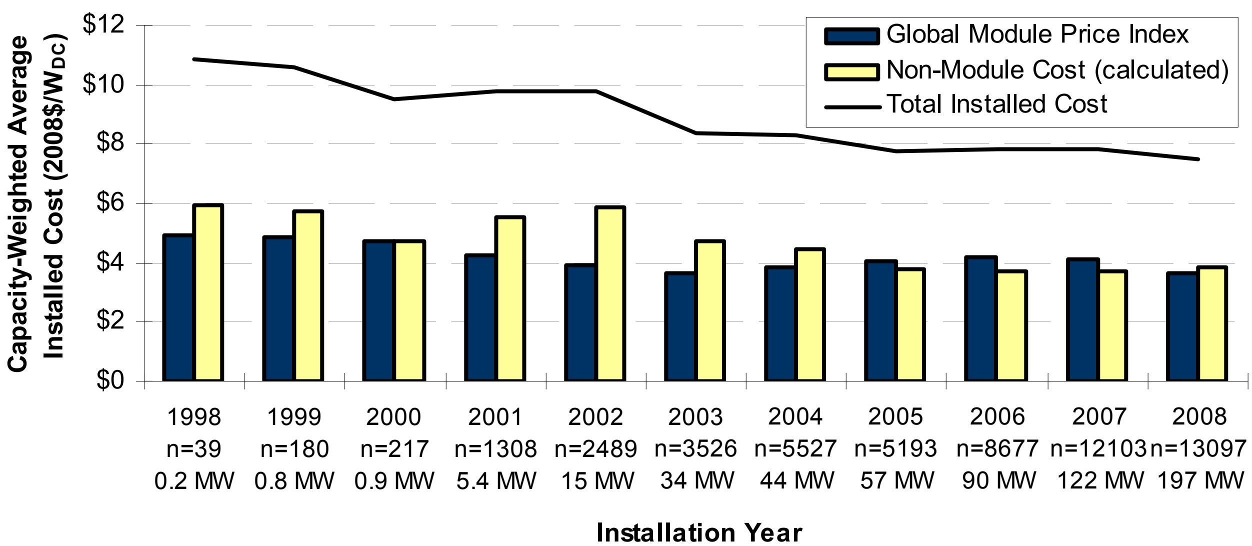
Figure 5. 2008 and Preliminary 2009 Installed Costs for California and New Jersey

Installed Cost Reductions from 2007 to 2008 Are Primarily Associated with a Decline in Module Costs

Figure 6 disaggregates average annual installed costs into average module and non-module costs. As many programs did not provide component-level cost data, Figure 5 presents Navigant Consulting's Global Power Module Price Index as a proxy for module costs. Average non-module costs (which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and profit) shown in Figure 5 were calculated as the difference between the average total installed cost and the module price index in each year.

Based on this method, the decline in installed costs from 2007 to 2008 appears to be primarily attributable to a drop in *module* costs, which fell by approximately $0.5/W over this period.[16] This contrasts with the longer-term historical trend, in which installed cost reductions have been associated mostly with a decline in *non-module* costs. Specifically, from 1998 to 2008, non-module costs fell by $2.1/W, from approximately $5.9/W in 1998 to $3.8/W in 2008, representing 62% of the overall $3.4/W drop in total installed costs over this period. In comparison, the module index price dropped by $1.3/W from 1998 to 2008.

Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV programs. Unlike module prices, which are primarily established through national (and even global) markets, non-module costs consist of a variety of cost components that may be more readily affected by local programs – including both deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. Thus, the fact that non-module costs have fallen over time, at least until 2005, suggests (though does not prove) that state and local PV programs have had some success in driving down the installed cost of PV.



Note: Non-module costs are calculated as the reported total installed costs minus the global module price index.

Figure 6. Module and Non-Module Cost Trends over Time

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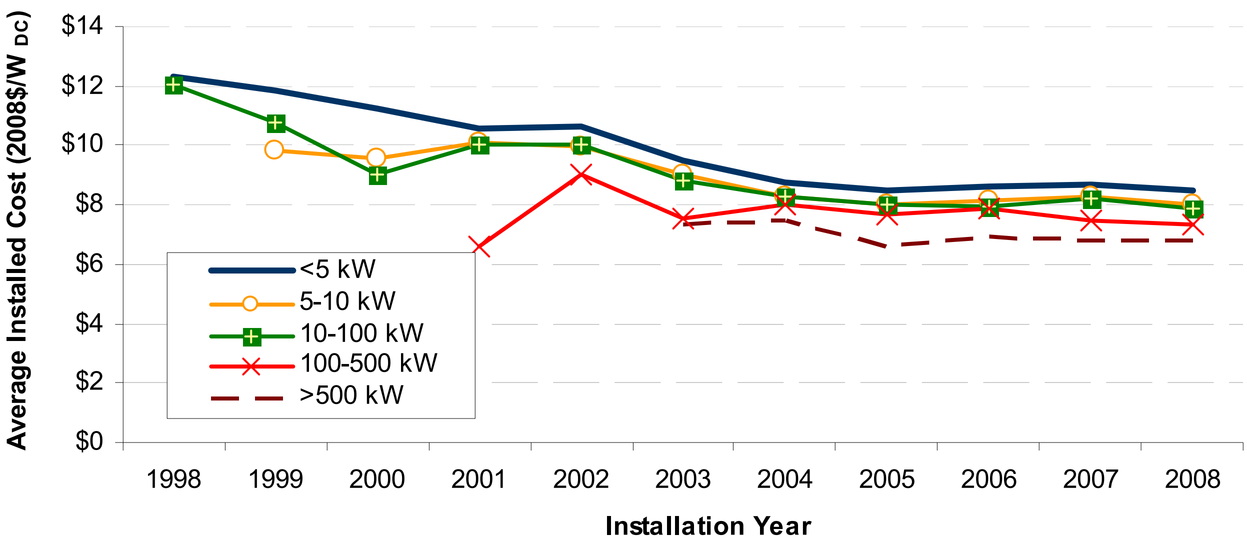
[16] It should be noted, however, that there is likely a lag between movements in the wholesale price of PV modules and the average installed cost of PV projects, as module costs for installed projects may reflect prevailing wholesale prices at the time that contracts for system installation were signed. Thus, the decline in the Global Module Price Index from 2007 to 2008 is likely to be larger than the reduction in module costs for projects installed over the same time period.

Historical Cost Reductions Are Most Evident for Systems Smaller than 100 kW

As shown in Figure 7, long-term historical cost reductions are most evident for smaller system sizes. For example, the average installed cost of systems ≤5 kW dropped from \$12.3/W in 1998 to \$8.5/W in 2008, equivalent to an average annual reduction of \$0.4/W per year. Similar cost reductions occurred for 10-100 kW systems, and somewhat lower cost reductions occurred for 5-10 kW systems. It is less apparent whether, and to what extent, larger systems (i.e., 100-500 kW and >500 kW) have experienced long-term cost reductions, due to the limited availability of data for the early years of the analysis period. Based on the data available, systems >500 kW experienced a modest cost decline from 2003 to 2008, while the average installed cost of 100-500 kW systems actually rose from 2001 to 2008 (although this latter trend may simply be an artifact of small sample size).[17]



Note: Averages shown only if five or more observations were available for a given size category in a given year.

Figure 7. Installed Cost Trends over Time, by PV System Size

The Distribution of Installed Costs Narrowed from 1998 to 2005, But No Further Narrowing Occurred through 2008

As indicated by the standard deviation bars in Figure 4, the distribution of installed costs has narrowed considerably over time. This trend can be seen with greater precision in Figure 8 and Figure 9, which present frequency distributions of installed costs for systems less than and greater than 10 kW, respectively, installed in different time periods. Both figures show a marked narrowing of the cost distributions occurring from 1998 through 2005, although this trend largely subsided from 2005 through 2008. This convergence of prices, with high-cost outliers becoming increasingly infrequent, is consistent with a maturing market characterized by increased competition among installers and module manufacturers and by better-informed consumers. The two figures also show a *shifting* of the cost distributions to the left, as would be expected based on the previous finding that average installed costs have declined over time.

[17] Within our data set, there are five systems in the 100-500 kW size range that were installed in 2001 – the minimum sample size required for a data point to be included in Figure 7.

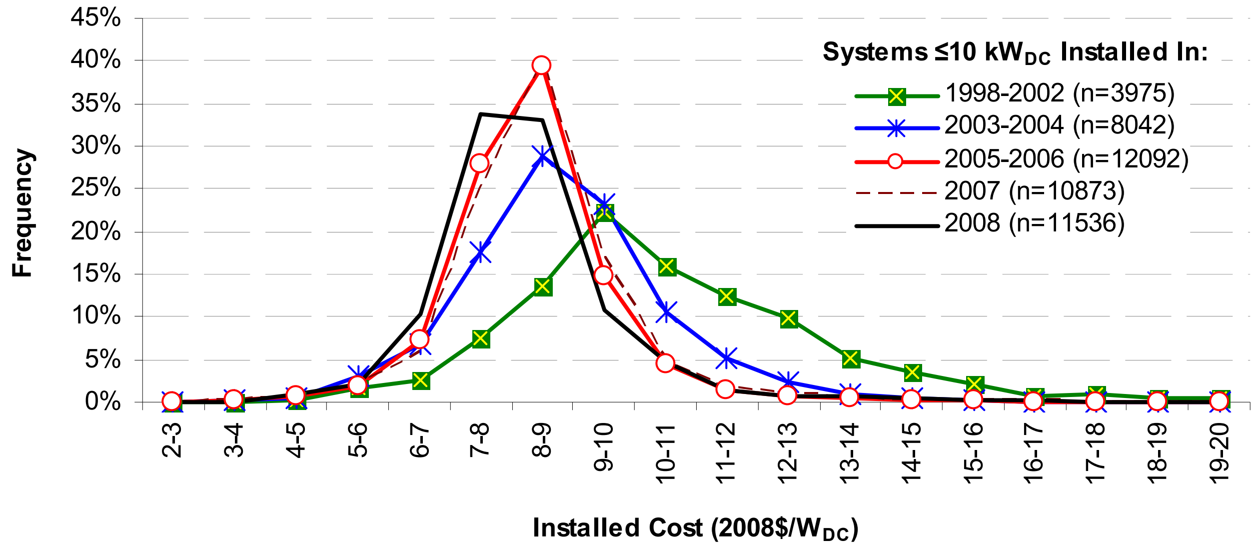


Figure 8. Distribution of Installed Costs for Systems ≤10 kW

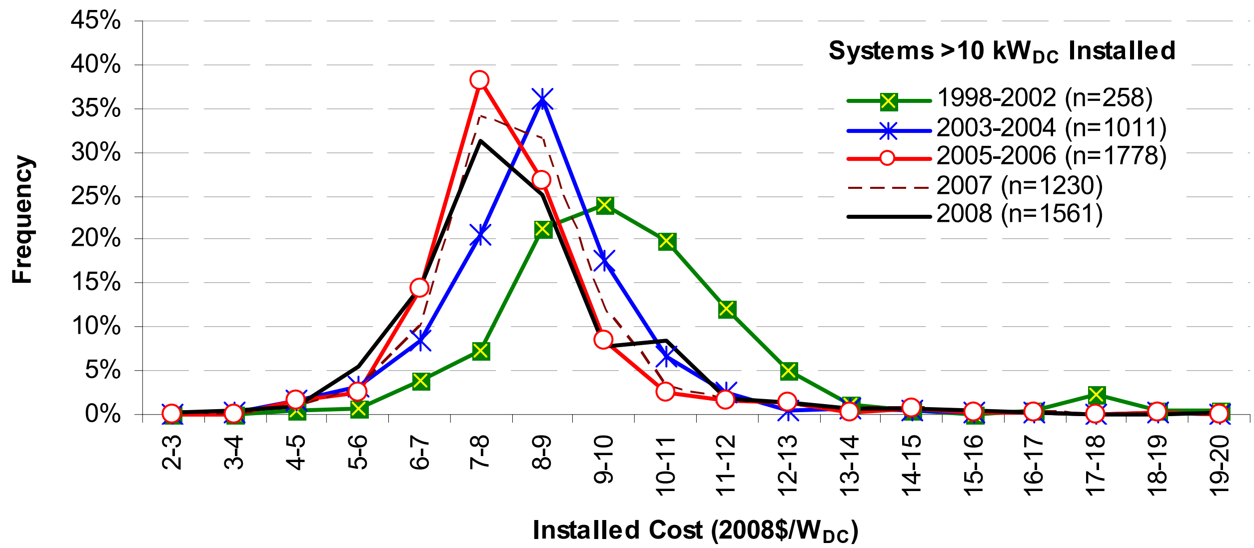


Figure 9. Distribution of Installed Costs for Systems >10 kW

Installed Costs Exhibit Economies of Scale

Large PV installations may benefit from economies of scale, through price reductions on volume purchases of materials and through the ability to spread fixed costs and transaction costs over a larger number of installed watts. This expectation has generally been borne out in experience, as indicated by Figure 10, which shows the average installed cost according to system size, for PV systems completed in 2008. The smallest systems (≤2 kW) exhibit the highest average installed costs ($9.2/W), while the 500-750 kW systems have the lowest average cost ($6.5/W, or about 30% below the average cost of the smallest systems). Interestingly, the economies of scale do not appear to be continuous with system size, but rather, most strongly accompany increases in system size up to 5 kW, and increases in system size in the 100-750 kW range. In contrast, the data do not show evidence of significant economies of scale within the 5-100 kW size range. Somewhat counterintuitively, the average installed cost of systems >750 kW is higher than for 500-750 kW systems ($6.8/W vs. $6.5/W, respectively), potentially reflecting a higher incidence of tracking systems among the >750 kW systems.

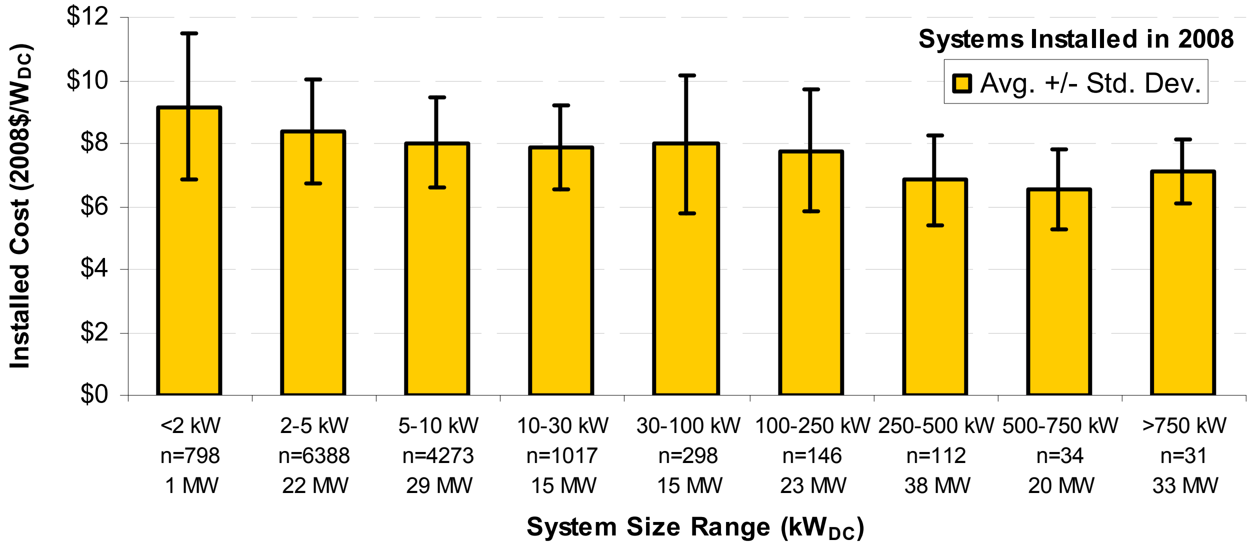


Figure 10. Variation in Installed Cost According to PV System Size

The primary dataset underlying the results shown in Figure 10 consists only of data provided by the 27 PV program administrators in our sample. Not included in this dataset are a number of large, multi-MW PV systems, several of which are installed on the utility-side of the meter. Installed cost data for nine of these projects have been reported in press releases and other public sources, and are summarized in Table 3.[18] As shown, the installed costs of these projects vary considerably. Of the four projects completed in 2008, two projects (in Boulder City, NV and Fontana, CA) have reported installed costs that are *significantly* below the average for the >750 kW systems shown in Figure 10. Also note that a number of the systems in Table 3 installed prior to 2008 have tracking systems, and are therefore likely to attain higher performance (and thus lower *levelized* costs on a $/MWh basis, even if the up-front installed costs are higher) than the large projects in the primary dataset, which are mostly fixed-axis systems.

To the extent that the economies of scale described above have persisted over time, they may partially explain the temporal decline in average installed costs, as the average size of PV systems has grown over time. As shown in Figure 11, which describes the average size of systems for which customer type (i.e., residential vs. non-residential) was explicitly provided by PV incentive programs, the average size of residential systems grew from 2.7 kW in 1998 to 5.2 kW in 2008, while the average size of non-residential systems rose from 25 kW to 88 kW over the same time period.

[18] Table 3 only includes systems >2 MW that are not in the primary dataset and for which installed cost data could be found. Note, though, that the sources of these cost data vary in quality, and therefore these data are less certain than the data in the primary sample.

Table 3. Installed Cost of Large (≥ 2 MW) Out-of-Sample PV Systems

Location	Year of Installation	Plant Size (kW_{DC})	Installed Cost ($2008\$/W_{DC}$)	Actual or Expected Capacity Factor	Tracking System Design
Boulder City, NV	2008	12,600	3.2	21%	none (fixed-axis)
Fairless Hills, PA	2008	3,000	6.7	14%	none (fixed-axis)
Fontana, CA	2008	2,400	4.3	no data	none (fixed-axis)
Riverside, CA	2008	2,000	6.5	15%	none (fixed-axis)
Nellis, NV	2007	14,200	7.3	24%	single axis
Alamosa, CO	2007	8,220	7.6	24%	none, single axis, and double axis
Fort Carson, CO	2007	2,000	6.5	18%	none (fixed-axis)
Springerville, AZ	2001-2004	4,590	6.2	19%	none (fixed-axis)
Prescott Airport, AZ	2002-2006	3,388	5.6	21%	single axis and double axis

Notes: Cost for Springerville is for capacity added in 2004. Cost for Prescott is for single-axis capacity additions in 2004.

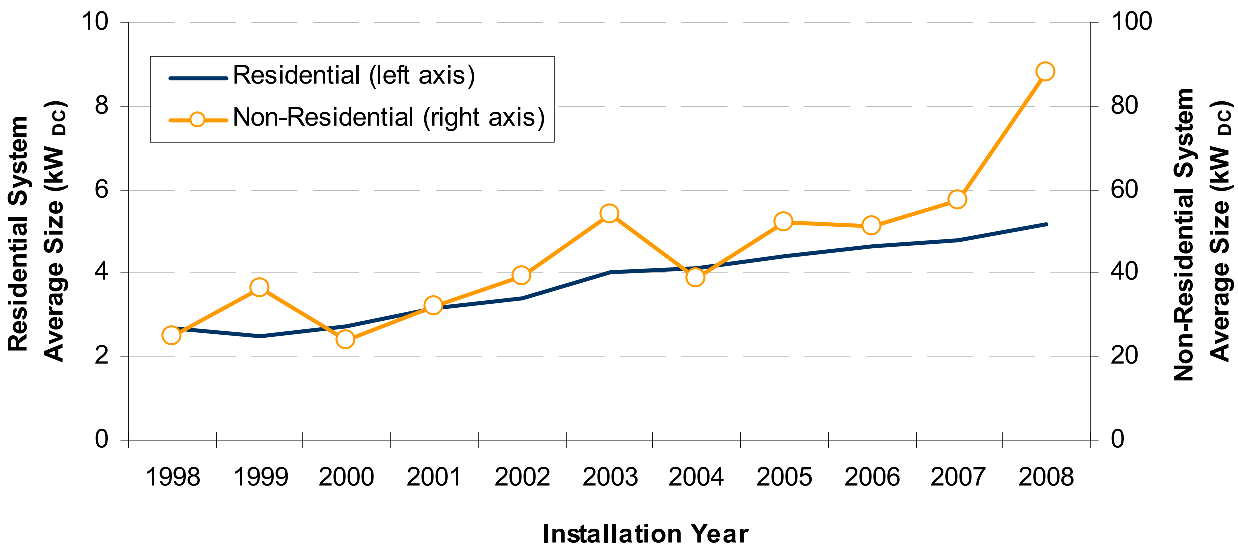


Figure 11. PV System Size Trends over Time

Module Costs Were Lower for Large Systems than for Small Systems in 2008, While Non-Module Costs Were Relatively Constant Across System Sizes

The average module and non-module costs presented in Figure 6 were estimated based on a module price index. This approach was necessitated by the fact that many of the PV incentive programs in our data sample did not provide component-level cost data. However, a number of programs did provide component-level cost data (even if at a fairly coarse level of detail), and these data lend some validation to the break-down between module and non-module costs implied in Figure 6, and also provide a moderate level of additional detail on the composition of non-module costs and the variation in component-level costs across system sizes. [19]

Figure 12 summarizes the component-level cost data provided by the PV incentive programs in our data sample, for systems installed in 2008. As shown, modules represented between 56% and 58% of total installed costs, depending on the particular size range – which is slightly higher,

[19] Component-level cost data were provided for 64% of the systems in the dataset installed in 2008. Component-level cost data are more limited for earlier year, precluding presentation of time series data on component-level costs.

though not dramatically inconsistent, with the imputed breakdown between module and non-module costs indicated in Figure 6. On average, inverter costs comprise 6-9% of the total cost, while other costs (e.g., mounting hardware, labor, overhead, profit, etc.) make up the relatively substantial remaining 34-39%.[20]

Comparing across the size ranges, Figure 12 indicates that module costs were $0.6-$0.7/W lower for systems >100 kW than for systems in the two smaller size groupings, perhaps indicative of the bulk purchasing power that larger systems may enable. The "Other" (non-module/non-inverter) costs, however, did not vary appreciably by system size (ranging from $2.6/W to $2.9/W), which is somewhat contrary to conventional wisdom, as certain non-hardware costs (e.g., labor, regulatory compliance, and overhead) are generally assumed to benefit from economies of scale.

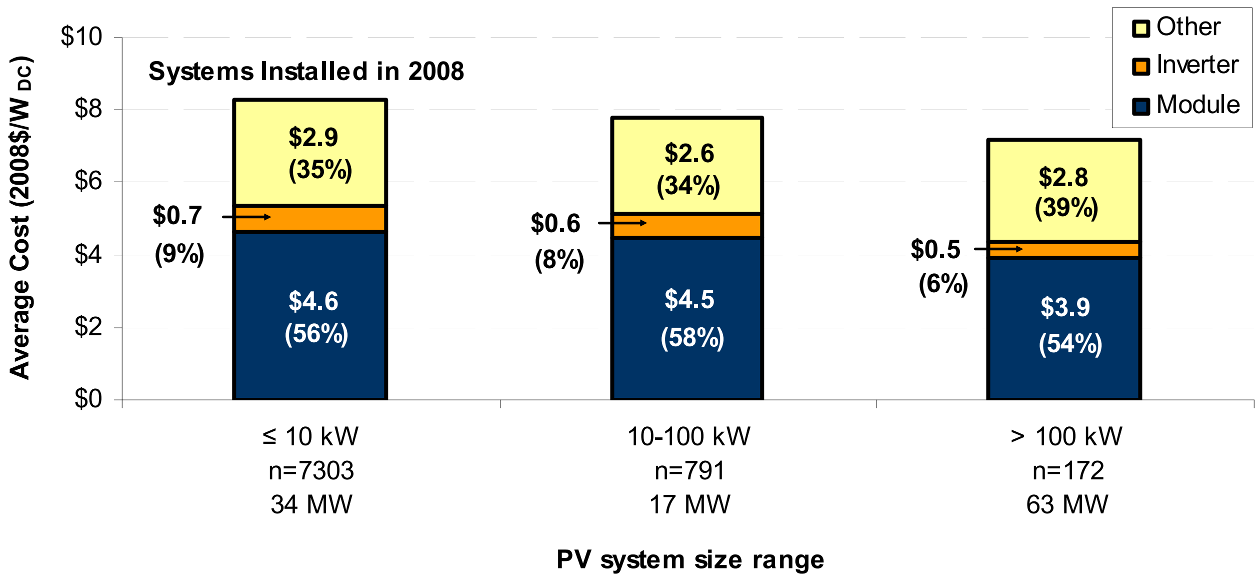


Figure 12. Module, Inverter, and Other Costs

Average Installed Costs for Residential Systems Are Lower in Germany and Japan than in the U.S.

Notwithstanding the significant cost reductions that have already occurred in the U.S., international experience suggests that greater near-term cost reductions may be possible. Figure 13 compares average installed costs in Germany, Japan, and the United States, focusing specifically on small residential systems installed in 2008 (and excluding sales or value-added tax). Among this class of systems, average installed costs were substantially lower in Germany and Japan ($6.1/W and $6.9/W, respectively) than in the U.S. ($7.9/W). These differences may be partly attributable to the much greater cumulative grid-connected PV capacity in Germany and Japan (about 5,300 MW and 2,000 MW, respectively, at the end of 2008), compared to just 800 MW in the U.S. That said, larger market size, alone, is unlikely to account for all of the variation.[21]

[20] Some additional detail on individual component costs, although not based directly on project data, can be gleaned from the results of a survey of PV installers conducted by Berkeley Lab in 2008 and reported in Wiser, R., G. Barbose, and C. Peterman. 2009. *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[21] Installed costs may differ among countries as a result of a wide variety of factors, including differences in: module prices, technical standards for grid-connected PV systems, installation labor costs, procedures for receiving incentives

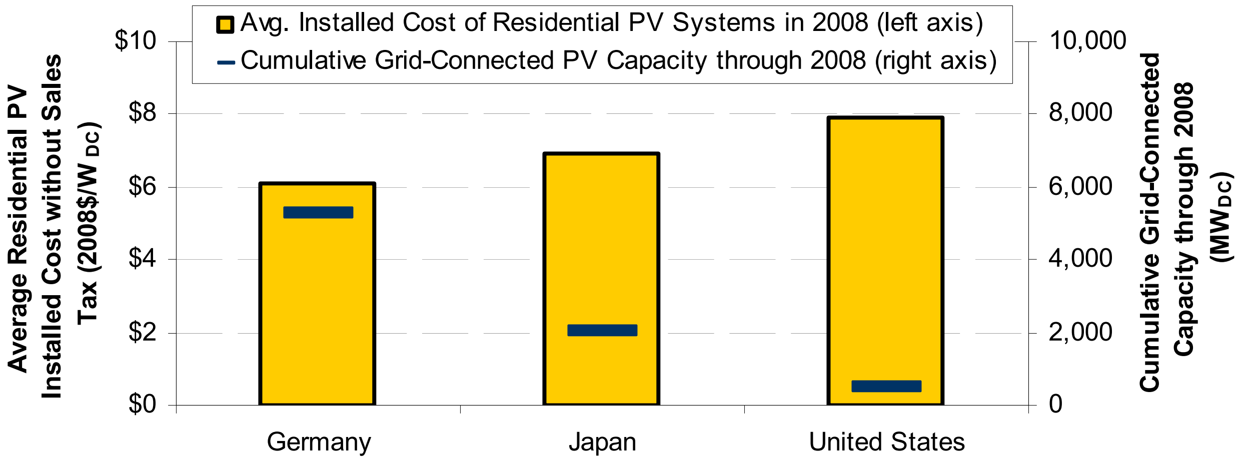


Figure 13. Comparison of Average Installed Costs in Germany, Japan, and the U.S. (Small Residential Systems Completed in 2008)[22]

Installed Costs Vary Widely Across States

The U.S. is clearly not a homogenous PV market, as evidenced by Figure 14, which compares the average installed cost of systems ≤10 kW completed in 2008, across 14 of the 16 states in our dataset.[23] Among systems in this size class, average costs range from a low of $7.3/W in Arizona to a high of $9.9/W in Pennsylvania and Ohio. Table 4 presents the same data in tabular form, along with comparative data for other system size ranges and groupings.

The variation in average installed costs across states may partially be a consequence of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and hence greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. It therefore is perhaps not surprising that California, the largest PV market in the U.S., has among the lowest average costs, lending some credence to the premise behind state policies and programs that seek to reduce the cost of PV by accelerating deployment.[24]

However, as with the preceding international comparison, other factors also drive differences in installed costs among individual states. Incentive application procedures and regulatory compliance costs, for example, vary substantially. Installed costs also vary across states as a result of differing sales tax treatment; 7 of the 14 states shown in Figure 14 exempted residential PV systems from state sales tax throughout 2008, and Oregon has no state sales tax. If PV hardware costs represent

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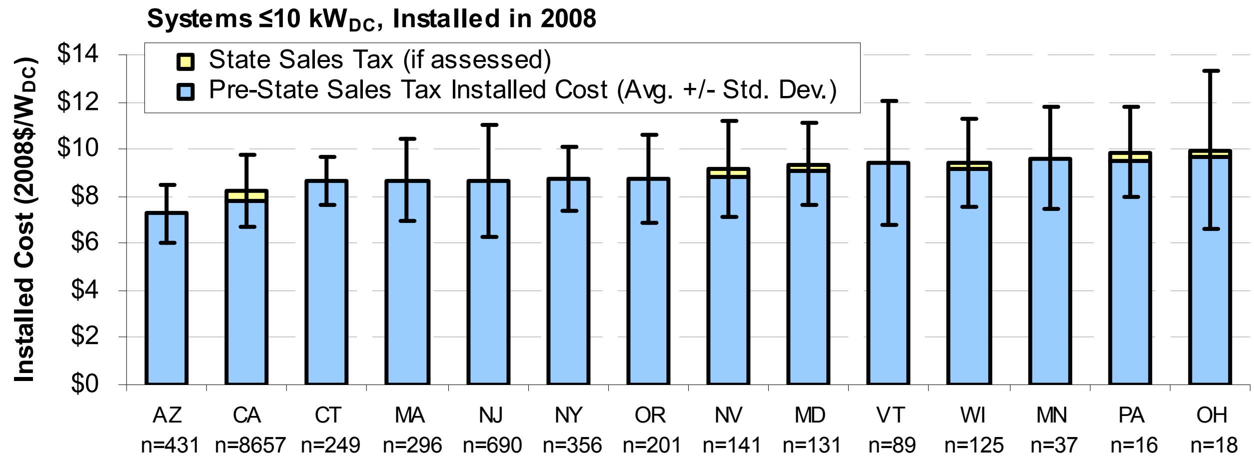
and permitting/interconnection approvals (i.e., "paperwork burden"), foreign exchange rates, and the degree to which components are manufactured locally. The lower costs of residential PV in Japan relative to the U.S. may also be partly explained by the fact that Japan's PV support policies have focused largely on the residential sector, and that a sizable amount of this market consists of pre-fabricated new homes that incorporate PV systems as a standard feature.

[22] The Japanese and U.S. cost data shown in Figure 13 are for 2-5 kW systems, while the German cost data are for 3-5 kW systems. Additionally, note that the U.S. data presented in this figure exclude sales tax, and therefore are not directly comparable to data presented elsewhere in this report. Source for Japanese price and cumulative installed capacity data: Yamamoto, M. and O. Ikki. 2009. *National survey report of PV Power Applications in Japan 2008.* Paris, France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems. Source for German price and cumulative installed capacity data: Wissing, L. 2009. *National Survey Report of PV Power Applications in Germany 2008.* Paris: France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems.

[23] We exclude Colorado and Washington from the figure, as the data sample includes only a very small fraction of the 2008 capacity additions in both states, and therefore may not be indicative of average installed costs in these two states.

[24] The reason for the low average cost in Arizona – itself a relatively small PV market – is unknown.

approximately 65% of the total installed cost of residential PV systems (an assumption supported by component-level cost data presented previously), state sales tax exemptions effectively reduce the post-sales-tax installed cost by \$0.2-0.4/W, depending on the specific state sales tax rate that would otherwise be levied.



Notes: State Sales Tax and Pre-State Sales Tax Installed Costs were calculated from 2008 sales tax rates in each state (local sales taxes were not considered). Sales tax was assumed to have been assessed only on hardware costs, which, in turn, were assumed to constitute 65% of the total pre-sales-tax installed cost. CO and WA are excluded from the figure due to insufficient sample size.

Figure 14. Variation in Installed Costs among U.S. States

Table 4. Average Installed Cost (\$/W_{DC}) by State and PV System Size Range

State	All Reported Yrs. Capacity-Weighted Average Cost (all sizes)		2008 Systems									
			Capacity-Weighted Average Cost (all sizes)		Simple Average Cost							
					0 - 10 kW_{DC}		10 - 100 kW_{DC}		100 - 500 kW_{DC}		>500 kW_{DC}	
AZ	\$7.4	(n=1258)	\$6.8	(n=477)	\$7.3	(n=431)	\$6.8	(n=42)	*	(n=4)	*	(n=0)
CA	\$7.8	(n=42522)	\$7.4	(n=9845)	\$8.2	(n=8657)	\$7.7	(n=934)	\$7.3	(n=199)	\$6.8	(n=55)
CO	\$8.3	(n=16)	\$8.3	(n=16)	\$8.3	(n=16)	*	(n=0)	*	(n=0)	*	(n=0)
CT	\$8.1	(n=623)	\$7.9	(n=310)	\$8.6	(n=249)	\$8.3	(n=49)	\$7.6	(n=12)	*	(n=0)
MA	\$9.1	(n=1091)	\$8.0	(n=336)	\$8.7	(n=296)	\$8.7	(n=34)	\$7.4	(n=6)	*	(n=0)
MD	\$9.4	(n=230)	\$9.0	(n=135)	\$9.3	(n=131)	*	(n=4)	*	(n=0)	*	(n=0)
MN	\$8.9	(n=145)	\$9.8	(n=38)	\$9.6	(n=37)	*	(n=1)	*	(n=0)	*	(n=0)
NJ	\$7.9	(n=3225)	\$7.6	(n=860)	\$8.7	(n=690)	\$8.3	(n=132)	\$7.2	(n=29)	\$6.9	(n=9)
NV	\$9.1	(n=393)	\$8.8	(n=145)	\$9.2	(n=141)	*	(n=4)	*	(n=0)	*	(n=0)
NY	\$8.9	(n=1158)	\$8.6	(n=401)	\$8.7	(n=356)	\$8.8	(n=45)	*	(n=0)	*	(n=0)
OH	\$9.6	(n=35)	\$9.5	(n=23)	\$9.9	(n=18)	*	(n=4)	*	(n=1)	*	(n=0)
OR	\$8.3	(n=878)	\$8.4	(n=248)	\$8.7	(n=201)	\$9.4	(n=39)	\$8.2	(n=7)	*	(n=1)
PA	\$9.3	(n=164)	\$9.5	(n=18)	\$9.9	(n=16)	*	(n=2)	*	(n=0)	*	(n=0)
VT	\$8.7	(n=225)	\$9.1	(n=94)	\$9.4	(n=89)	\$8.8	(n=5)	*	(n=0)	*	(n=0)
WA	\$7.7	(n=7)	\$7.7	(n=6)	\$8.9	(n=6)	*	(n=0)	*	(n=0)	*	(n=0)
WI	\$8.9	(n=386)	\$9.0	(n=145)	\$9.4	(n=125)	\$8.6	(n=20)	*	(n=0)	*	(n=0)

* Cost data is omitted if the sample size (n) is less than five.

Installed Costs are Generally Lower for Residential Systems than for Similarly Sized Commercial and Public-Sector Systems

Figure 15 compares average installed costs across four customer segments: residential, commercial, public sector (i.e., government and schools), and non-profit. We focus on systems installed in 2008 for which customer segment data was provided, splitting those data into two size categories: 5-10 kW and 10-100 kW.[25] As shown, the differences in average costs among customer segments are generally modest, and the rank ordering of customer segments is somewhat inconsistent between the two size groups (suggesting that some of the variation may be more idiosyncratic than systematic). That said, Figure 15 does indicate that installed costs tend to be relatively low for residential systems compared to similarly sized commercial or public sector systems. Specifically, within the 5-10 kW size range, systems installed for residential customers have an average installed cost ($8.0/W) that is $0.4/W less than for public sector and non-profit customers ($8.4/W), and $0.6/W less than commercial customers ($8.6/W). Within the 10-100 kW size range, average costs are lowest for the non-profit segment ($7.5/W), followed by residential customers ($7.8/W), which is $0.3/W below the average for commercial customers ($8.1/W) and $0.8/W below the average for public sector customers ($8.6/W).

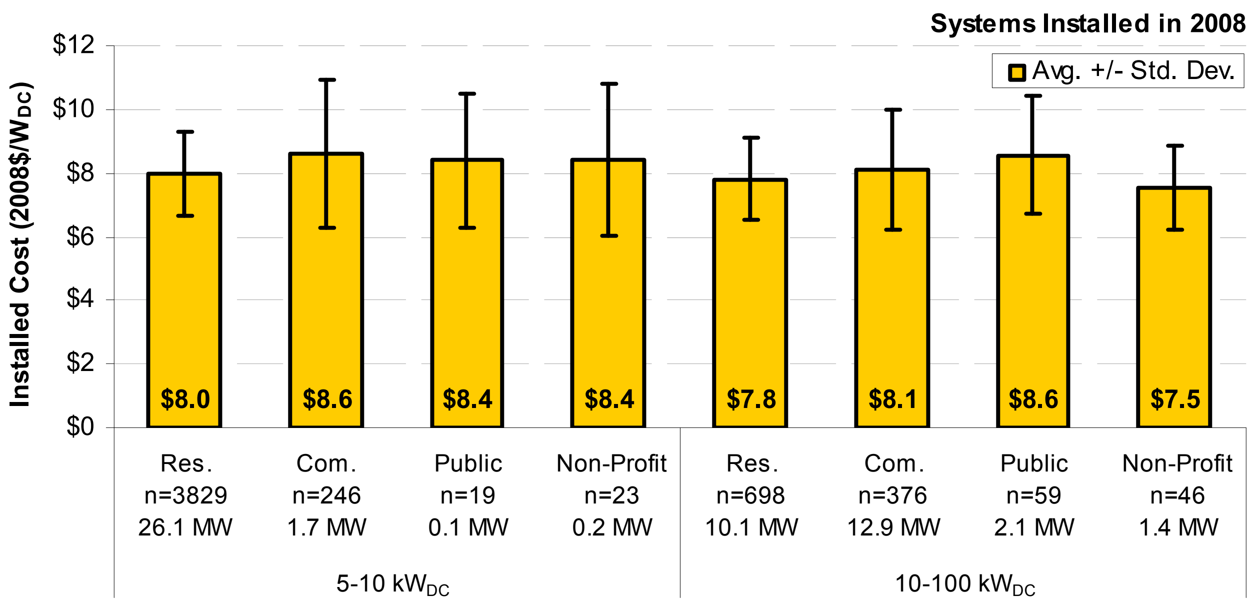


Figure 15. Variation in Installed Costs among Customer Sectors

The New Construction Market Offers Cost Advantages for Residential PV, Despite the Higher Cost of BIPV Relative to Rack-Mounted Systems

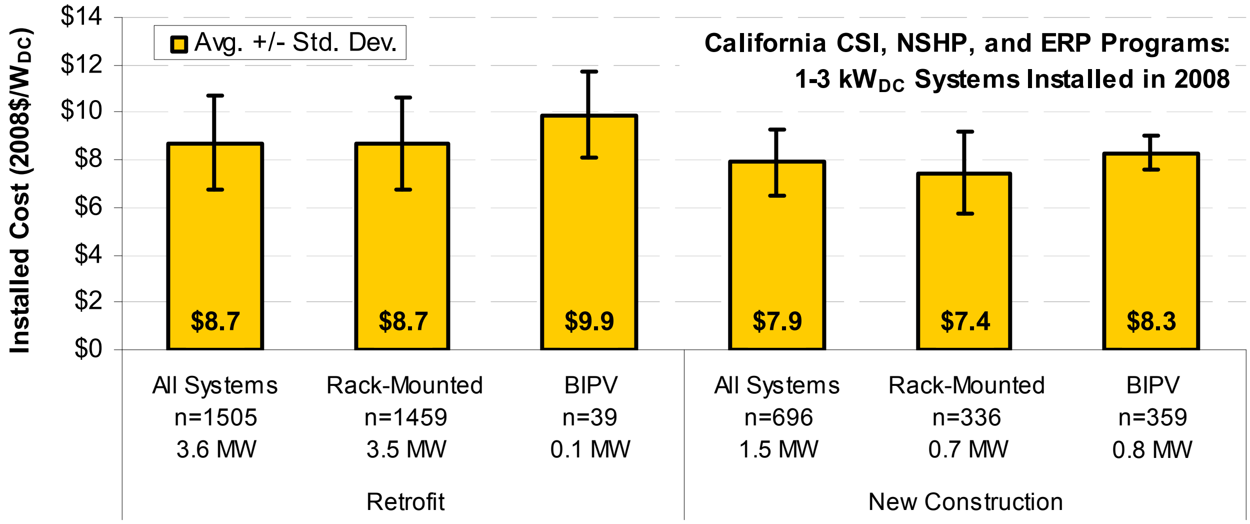
Three California incentive programs provided data on systems that could be readily identified as either residential new construction or residential retrofit: the Emerging Renewables Program (ERP), the California Solar Initiative Program (CSI), and the New Solar Homes Partnership (NSHP) program. Figure 16 compares the average installed cost of residential new construction and residential retrofit projects funded through these three California programs, focusing in particular on 1-3 kW projects (the size range typical of residential new construction[26]) completed in 2008. Among this group of PV systems, those installed in residential new construction cost $0.8/W less,

[25] Customer segment identifiers were provided by PV incentive programs for approximately 86% of all 2008 installations within the dataset. We focus on the 5-10 kW and 10-100 kW size ranges, as both are ranges within which there are limited economies of scale and for which the sample size in each customer segment is sufficiently large.
[26] Of the 820 systems within the dataset identifiable as having been installed in residential new construction in 2008, 85% are within the 1-3 kW size range.

on average, than comparably-sized residential retrofit systems ($7.9/W compared to $8.7/W), a price advantage of approximately 10%.

However, simply comparing the overall average cost of all residential new construction and all residential retrofit systems masks the fact that a much larger proportion of new construction systems are building-integrated PV (BIPV), which tend to have somewhat higher costs than rack-mounted systems, though the higher installed costs may be partially offset by avoided roofing material costs. Systems within the data sample were identified as BIPV or rack-mounted based on module manufacturer and model data provided by the incentive program administrators. As shown in Figure 16, BIPV systems in the three California programs cost $0.9/W more, on average, than rack-mounted systems installed in residential new construction (i.e., $8.3/W vs. $7.4/W).

To make an apples-to-apples comparison between residential new construction and residential retrofit applications, one can compare the average cost of rack-mounted systems installed in the two applications, which is broken out in Figure 16 from the larger sub-samples. This comparison suggest a somewhat greater cost advantage for new construction than implied by the overall averages, with rack-mounted systems installed in residential new construction averaging $1.2/W less than residential retrofit systems ($7.4/W compared to $8.7/W).[27]



Note : The number of rack-mounted systems plus BIPV systems may not sum to the total number of systems, as some systems could not be identified as either rack-mounted or BIPV.

Figure 16. Comparison of Installed Costs for Residential Retrofit vs. New Construction

Systems >10 kW with Thin-Film Modules Had Lower Installed Costs than Those with Crystalline Modules

Individual systems were identified as employing either thin-film or crystalline modules based on module manufacturer and model data provided by the PV incentive programs.[28] Figure 17

[27] Similarly, BIPV systems installed in new construction averaged $1.6/W less than BIPV systems installed in residential retrofits ($8.3/W compared to $9.9/W). However, some caution is warranted in interpreting the cost comparison for BIPV systems, as some modules made for BIPV applications may be installed as rack-mounted systems. It is therefore possible (if not likely) that some of the systems identified as residential retrofit BIPV systems may be misclassified and may, in fact, be rack-mounted installations.

[28] Thin-film systems include both amorphous silicon and non-silicon modules.

compares the average installed cost of crystalline and thin-film systems, focusing specifically on rack-mounted (i.e., not BIPV) systems installed in 2008. As shown, thin-film systems in both the 10-100 kW and >100 kW size ranges had average installed costs lower than comparably-sized crystalline systems (by \$1.5/W and \$0.6/W, respectively), while thin-film systems ≤10 kW were somewhat more costly than their crystalline counterparts.[29] Notwithstanding the fact that the number of thin-film systems within the sample is quite small, the results for the 10-100 kW and >100 kW size ranges are consistent with expectations, as thin-film modules are widely considered to be lower cost than crystalline, and the greater uncertainty in the long-term performance of thin-film modules on the part of consumers would tend to drive down the price of thin-film systems relative to crystalline systems. The differing result for the ≤10 kW size range, where thin-film systems exhibit higher average costs than crystalline systems, may be attributable to the lower efficiency of thin-film modules, leading to higher balance of system costs (which may be proportionally more significant for small systems) that offset the reduced module costs.[30]

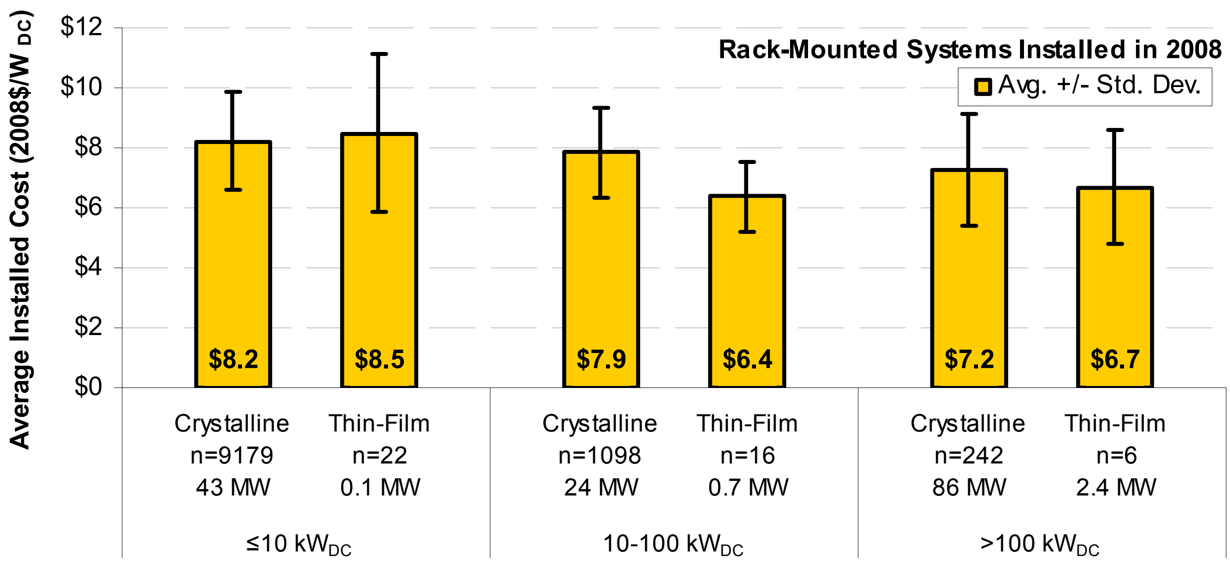


Figure 17. Comparison of Installed Costs for Crystalline vs. Thin-Film Systems

Tracking Systems Had Higher Installed Costs than Fixed-Axis Systems

Data indicating whether or not PV systems had tracking equipment were provided for a relatively small percentage of systems in the sample (e.g., 11% of systems and 9% of capacity installed in 2008). Based on the limited data available, Figure 18 compares the average cost of PV systems with tracking to those with fixed-axis mounting, focusing on rack-mounted systems (both roof- and ground-mounted) installed in 2008 within two size categories (≤10 kW and 10-100 kW).[31] As shown, tracking systems had higher installed costs within both size categories, as would be expected. Among systems ≤10 kW, tracking systems had average installed costs \$2.2/W (or 25%) higher than fixed-axis systems. In the 10-100 kW size range, the difference was significantly less,

[29] The previous edition of this report found that, across all size ranges, the average installed cost of thin-film systems was higher than for crystalline systems. However, that finding was the result of the misclassification of a single module model as thin-film.

[3030] We note, however, that the conventional belief that balance of systems costs are proportionally more significant for small systems is not borne out by the data presented earlier in Figure 12, which shows little variation in non-module/non-inverter costs across system sizes.

[31] There were insufficient data for systems >100 kW to warrant inclusion in the figure.

where tracking systems had average installed costs \$0.5/W (or 6%) higher than their fixed-axis counterparts. Given that the use of tracking equipment is relatively uncommon among systems ≤10 kW, the latter comparison is arguably a more meaningful representation of the incremental cost of tracking equipment, in general. However, again, some caution is warranted in generalizing from these results, given the small sample size.

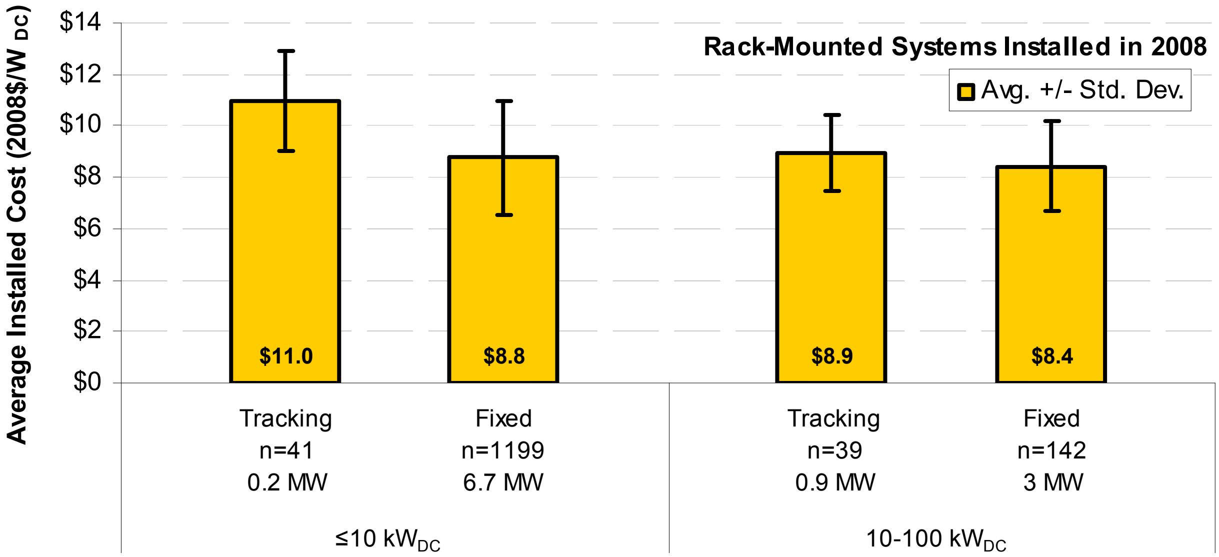


Figure 18. Comparison of Installed Costs for Tracking vs. Fixed-Axis Systems

4. PV Incentive and Net Installed Cost Trends

Financial incentives provided through utility, state, and Federal programs have been a major driving force for the PV market in the U.S. For any individual system, these incentives potentially include some combination of cash incentives provided through state or utility PV incentive programs, Federal and/or state investment tax credits (ITCs)[32], revenues from the sale of renewable energy certificates (RECs), and accelerated depreciation of capital investments in solar energy systems. This section describes trends in incentive levels (focusing specifically on state/utility cash incentives and state/federal ITCs) and net installed costs (i.e., installed costs after receipt of financial incentives) over time, by system size, and among states.

Two important caveats should be noted at the outset:

- First, the set of incentives addressed in this section are necessarily limited in scope, accounting only for the direct cash incentives provided through the specific state/utility PV incentive programs in the dataset, plus state and Federal ITCs. The analysis does not account for the incentive for commercial PV provided through accelerated depreciation (which has remained constant over the sample period),[33] nor for any additional incentives that projects may have received from state/utility incentive programs outside of the PV incentive program covered in this report.[34] The results presented in this section also do not account for revenue from the sale of RECs, although the potential magnitude of this revenue stream is briefly discussed in general terms (see Text Box 2). As such, the results presented in this section exclude New Jersey's Solar Renewable Energy Credit program (which is included in previous sections of this report), as that program provides incentives solely in the form of solar RECs, the price of which varies over time according to market conditions.
- Second, this section marks a departure from Section 3 by going beyond a simple reporting of data provided by program administrators. In particular, a variety of assumptions, as documented within this section and described further in Appendix C, were required in order to estimate the value of Federal and state ITCs for each project and to determine the net installed cost on an after-tax basis.

State/Utility Cash Incentives Continued Their Steady Decline in 2008

The PV incentive programs represented within the dataset provide cash incentives of varying forms. Most provide up-front cash incentives (i.e., "rebates"), based either on system capacity, a percentage of installed cost, or a projection of annual energy production. Several programs, instead, provide performance-based incentives (PBIs), which are paid out over time based on actual energy production, as either a supplement or an alternative to an up-front rebate.[35] Figure 19 shows the average cash incentive, on a $/W basis, received by the PV systems in the dataset, over time and

[32] Starting in 2009, the federal ITC for commercial PV can be converted to a cash grant of equal value from the U.S. Treasury.

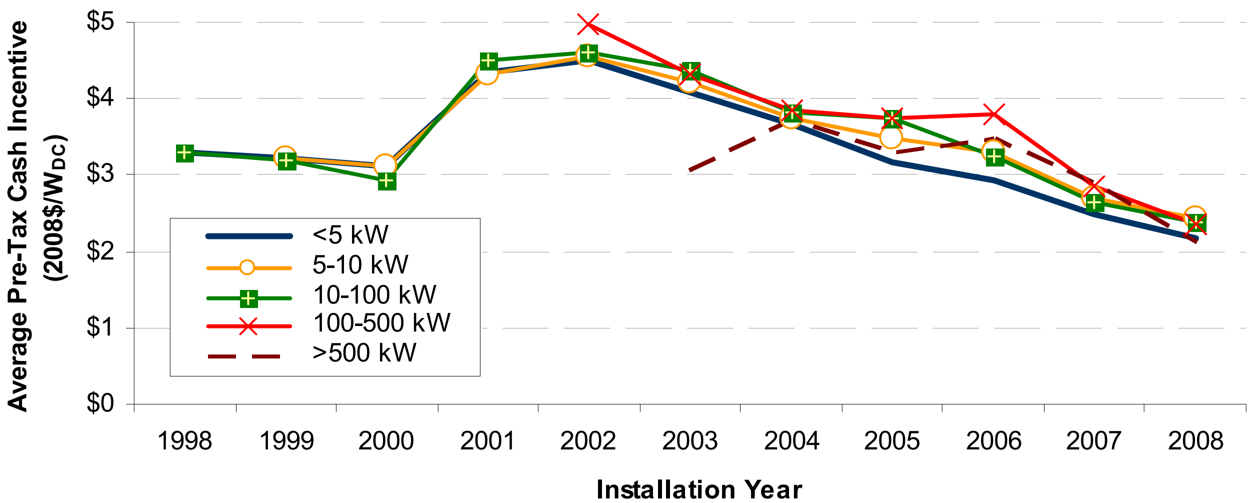
[33] For tax purposes, commercial PV owners are allowed to depreciate PV systems using an accelerated 5-year schedule. The net present value of this accelerated depreciation schedule, relative to a 20-year straight-line schedule, is equal to 12% of installed costs. See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[34] For example, in Pennsylvania, some projects may have received incentives through both the Sustainable Energy Fund's Solar Grant Program and the state's Energy Harvest Program (where the former is included in the dataset and the latter is not).

[35] PBI payments were reported by PV incentive program administrators on a $/W basis, based on estimated energy production. These $/W figures were used directly, without discounting, in the analysis provided in this section.

according to system size. These data are presented on a *pre-tax* basis – that is, prior to assessment of state or Federal taxes that may be levied if the incentive is treated as taxable income.[36] Note also that the figure does not necessarily provide an accurate depiction of the size of incentives *offered* in each year, as there is typically some lag between the time that a project reserves its incentives and the time that it is installed.

As shown in Figure 19, average cash incentives for systems installed in 2008 ranged from \$2.1/W - \$2.4/W across the system size ranges shown. Incentive levels in 2008 are roughly 50% below their peak in 2002, declining by about \$0.4/W per year, on average.[37] These trends largely reflect changes in incentives received by systems funded by California's ERP, SGIP, and CSI programs, which together represent 77% of all of the systems in the data sample. To a lesser extent, the trends in Figure 19 also reflect the growing prominence of New Jersey's CORE program, which has historically offered relatively high incentives and constitutes an increasing percentage of the sample over time, counteracting, to some degree, the decline in average incentive levels associated with the California programs. Although overshadowed by the dominant effect of the California and New Jersey programs, average incentives among other PV incentive programs in the sample also generally declined from 2002/2003 to 2008 (see Table B-3 in Appendix B).



Note: Averages shown only if five or more observations were available for a given size category in a given year.

Figure 19. Pre-Tax State/Utility Cash Incentive Levels over Time

[36] Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. Cash incentives for residential PV, however, are exempt from Federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[37] For systems >500 kW, the average cash incentive peaked at \$3.7/W in 2004, declining to \$2.1/W in 2007 (a drop of \$1.6/W). However, fewer than 10 systems in this size range were installed each year prior to 2006, and therefore the time trend during those years may not be particularly meaningful.

Text Box 2. Revenue from the Sale of RECs

PV system owners may be able to sell RECs generated by their system, adding to any direct incentives received from state/utility PV incentive programs and Federal or state ITCs (provided that REC ownership is not automatically transferred to the state/utility as a condition of providing a direct cash incentive). Projecting the value of REC sales over the lifetime of each individual PV system in our dataset would be a highly speculative task, and therefore was not undertaken for this study. Based on historical REC prices, however, the revenue potential in most states is relatively modest, compared to the value of direct cash incentives received through state/utility PV incentive programs and to the value of the Federal ITC.

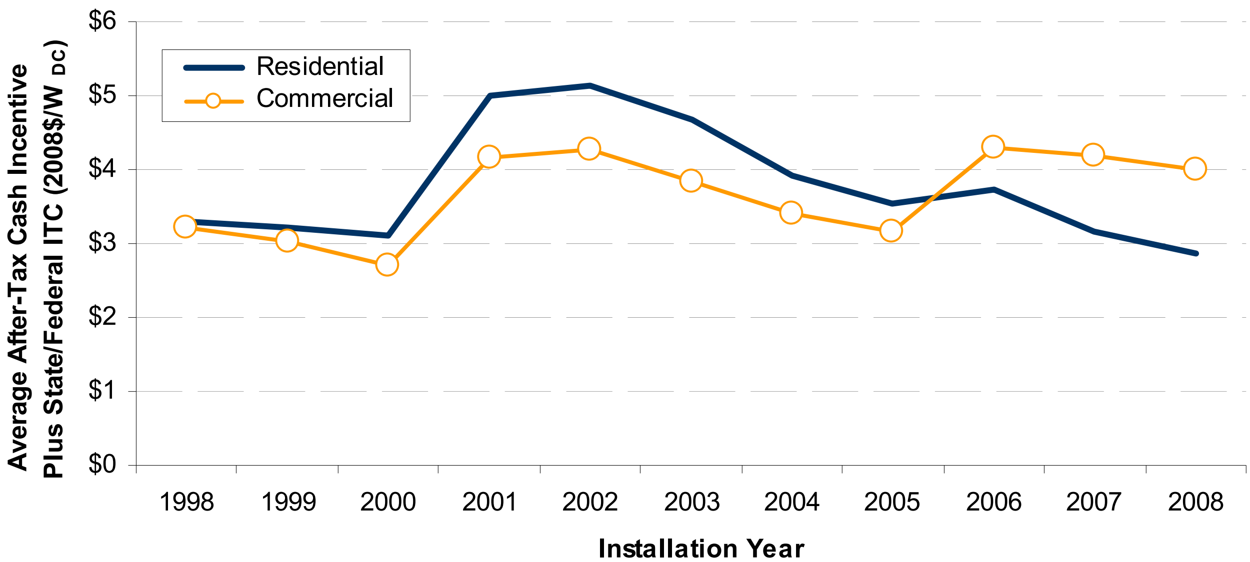
In general, the potential REC revenue for customer-sited PV depends on where the system is located, and consequently, what types of REC markets are available.

- *Voluntary REC Markets*. In most states, RECs generated by PV systems may be sold to individuals, businesses, or government agencies that are voluntarily seeking to support renewable energy. Given the voluntary nature of these transactions, prices in voluntary REC markets have historically been quite modest. For example, voluntary RECs traded through Spectron, a brokerage firm, averaged about $4/MWh in 2008. If extrapolated over 20 years, revenue from REC sales at this price would be equivalent to an up-front, pre-tax incentive of just $0.05/W on a present value basis (assuming a 10% nominal discount rate and a capacity factor of 14%).
- *General RPS Markets*. In some states, RECs generated by PV systems may be sold to electricity suppliers for compliance with state renewables portfolio standards (RPS). These markets may offer greater REC revenue potential than in voluntary markets, though REC prices in RPS markets have historically varied quite substantially across states and over time. For PV, the most critical issue typically is whether the state RPS has a specific solar requirement (i.e., a solar "set-aside" or "carve-out"). In "general" RPS markets without a solar set-aside (in which case RECs from PV systems may be used to satisfy the total renewable electricity compliance obligation), the highest average REC prices in 2008 occurred in Massachusetts, where REC prices for compliance with the state's Class I RPS requirement averaged approximately $45/MWh (again, based on REC trades through Spectron). If extrapolated over a 20-year period, using the same assumptions as before, revenue from REC sales at this price would be equivalent to an up-front, pre-tax payment of $0.52/W.
- *RPS Solar Set-Aside Markets*. Substantially greater REC revenue potential may be available in RPS states with a solar (or DG) set-aside. Through 2008, active trading of solar RECs (or SRECs) for compliance with a solar set-aside occurred primarily in New Jersey, where SRECs traded through Spectron averaged $390/MWh in 2008 (with prices rising over the course of the year to more than $600/MWh). Extrapolating this revenue stream over a 15-year period (as PV systems in New Jersey can sell SRECs for up to 15 years) yields the equivalent of an up-front, pre-tax payment of $4.0/W – a quite sizable sum that is larger than the direct cash incentives available in most states. Up until 2009, PV systems in New Jersey could receive both SREC payments and an up-front cash incentive. Starting in 2009, however, systems larger than 50 kW are no longer eligible for cash incentives, as the state shifts more fully towards an SREC-based support mechanism.

In 2008, the Combined Value of Federal & State ITCs Plus Direct Cash Incentives Was Near Its Peak for Commercial PV, but at an Historical Low for Residential PV

Although direct cash incentives received from state and utility PV programs have, on average, declined over time, other sources of financial incentives have become more significant. Most notably, starting January 1, 2006, the Federal ITC for commercial PV systems rose from 10% to 30% of project costs, and a 30% ITC (capped at $2,000) was established for residential PV. (Note that the *Energy Improvement and Extension Act of 2008* lifted the cap on the residential ITC for systems installed on or after January 1, 2009; however, this change does not pertain to the systems within our sample.) In addition to the Federal ITC, a number of states have, at various times, also offered state ITCs for PV, although these tax credits have generally been smaller and/or available to a more-restricted set of projects than the Federal tax credit (see Appendix C for details on the ITCs for PV offered by the states in our dataset).

Figure 20 illustrates the combined effect of changes over time in state and Federal ITCs (assuming that all customers take advantage of available tax credits) *plus* changes to the cash incentives provided through the state and utility PV incentive programs in the dataset, expressed here on an *after-tax* basis.[38] As noted previously, this assessment ignores potential revenues from the sale of RECs, though for most of the states in our dataset (other than New Jersey), such revenues would likely add only marginally to the overall incentive received (see Text Box 2).



Notes: We assume that all systems ≤10 kW are residential and all systems >10 kW are commercial (unless indentified otherwise). For residential systems, we assume that state/utility cash incentives are non-taxable and reduce the basis of the Federal ITC. For commercial systems, we assume that state/utility cash incentives are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 20. After-Tax State/Utility Cash Incentives plus State & Federal ITCs (Calculated)

Figure 20 depicts a notably different trend for commercial PV than that exhibited in Figure 19 for larger (i.e., commercial) systems. Specifically, as shown in Figure 20, the decline in the average combined commercial incentive that began in 2002 abruptly reversed course in 2006, when the Federal ITC for commercial PV increased from 10% to 30% of project costs. As a result, the average total financial incentive received by commercial PV systems in 2008 ($4.0/W) was only slightly below its peak of $4.3/W in 2002. Residential PV also saw a slight boost in overall incentive levels when the Federal ITC was extended to these systems in 2006; however, with the $2,000 cap on the residential credit (which has since been lifted for systems installed beginning in 2009), the effect was much less dramatic than for commercial PV. Consequently, the combined

[38] By expressing the incentives on an after-tax basis, we account for state and Federal income taxes that may be levied on direct cash incentives, as described in Appendix C.

after-tax incentive (cash incentives plus ITCs) for residential PV was, in 2008, at its lowest average level ($2.9/W) within the 11-year study period. The fact that combined after-tax incentives rose substantially from 2005 to 2008 for commercial PV, while declining for residential PV, may partially explain the shift towards the commercial sector within the U.S. PV market over this period. With the lifting of the cap on the Federal ITC for residential PV beginning in 2009, however, some movement back towards the residential sector may occur.

Net Installed Costs Increased Slightly from 2007 to 2008, as Declining Incentives More than Offset the Drop in Pre-Incentive Installed Costs

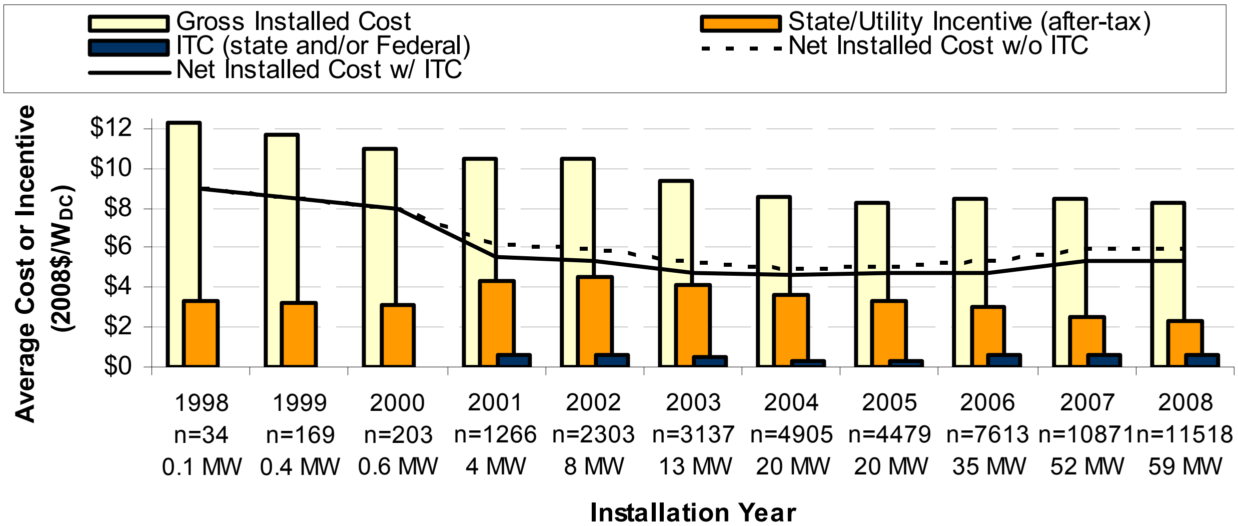
In 2008, average *net installed costs* – that is, installed costs minus the combined after-tax value of state/utility cash incentives plus ITCs – stood at $5.4/W for residential PV and $4.2/W for commercial PV, an increase over 2007 levels of 1% and 5%, respectively.

For residential PV, the average net installed cost in 2008 is effectively unchanged from its level in 2001 ($5.5/W). As discussed in Section 3, average pre-incentive installed costs declined significantly from 1998 to 2005, remained relatively stable from 2005 to 2007, and then resumed their decline from 2007 to 2008. At the same time, average after-tax incentives for residential systems steadily declined from 2002 to 2008. The net effect of these two trends, as illustrated in Figure 21, is that the net installed cost of residential PV declined by $0.9/W from 2001 to 2004 (from $5.5/W to $4.7/W), and then rose by $0.7/W from 2004 to 2008. The average net installed cost of residential PV is likely to decline substantially in 2009 compared to 2008, however, as a result of the lifting of the dollar cap on the Federal ITC for residential PV installations beginning in 2009.

As shown in Figure 22, the long-term trend for commercial PV is markedly different, by virtue of the more-lucrative Federal ITC available beginning in 2006. Specifically, in 2008, the net installed cost of commercial PV ($4.2/W) was 24% below its level in 2001 ($5.5/W). However, like residential PV, the net installed cost of commercial PV has been rising in recent years due to declining cash incentives. In 2008, the net installed cost of commercial PV was approximately 18% higher than its historical low of $3.6/W in 2006, and 5% higher than in 2007.

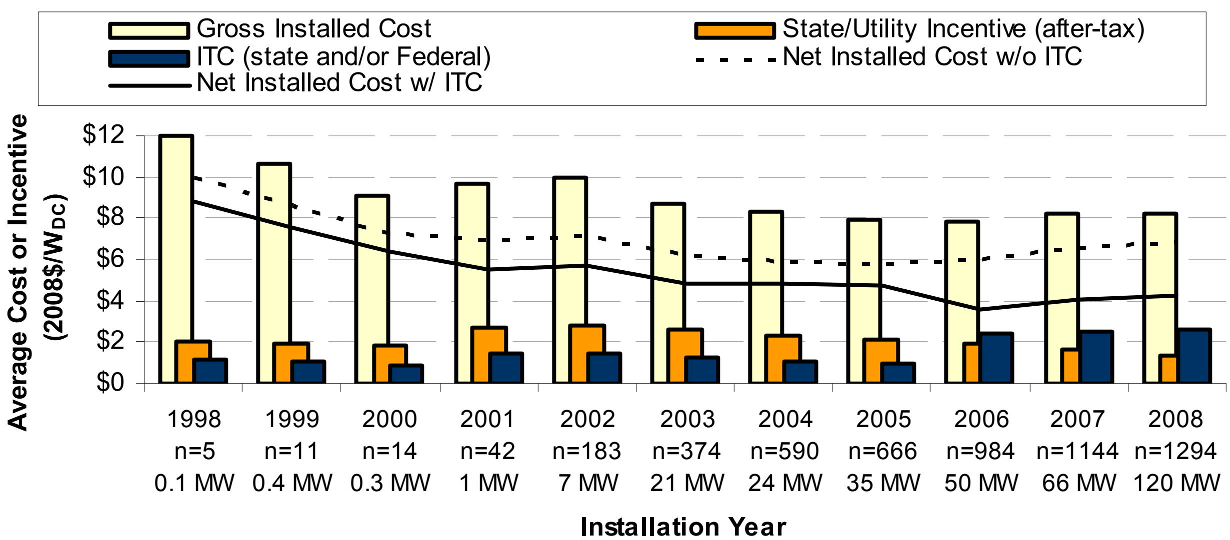
Finally, Figure 21 and Figure 22 also illustrate the potential impact of incentive levels on gross (i.e., pre-incentive) installed costs. A previous Berkeley Lab report, *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*, found a statistically significant correlation between pre-incentive installed costs in California and incentive levels under the state's two major PV incentive programs at the time (ERP and SGIP).[39] Evidence of this correlation can be seen in Figure 21 and Figure 22 (not surprisingly so, given the dominance of ERP and SGIP systems within the dataset). Most visibly, the decline in gross installed costs that had occurred during prior years ceased in 2001-2002, coinciding with a substantial increase in incentive levels under ERP and SGIP.

[39] Wiser, R., M. Bolinger, P. Cappers, and R. Margolis. 2006. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. LBNL-59282. Berkeley, California: Lawrence Berkeley National Laboratory.



Notes: We assume that all systems <10 kW are residential (unless identified otherwise) and that state/utility cash incentives for residential systems are non-taxable and reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 21. Net Installed Cost of Residential PV over Time (Calculated)



Notes: We assume that all systems >10 kW are commercial (unless identified otherwise) and that state/utility cash incentives for commercial systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 22. Net Installed Cost of Commercial PV over Time (Calculated)

Incentives Differ Widely Across States

The preceding incentive-related trends are drawn from the entire dataset, and are therefore dominated by the PV incentive programs in California and New Jersey. Incentives and net installed costs, however, vary significantly across all the states in the sample. Figure 23 and Figure 24 compare average incentive levels and net installed costs across states in 2008, for residential and commercial PV systems, respectively.[40] Again, note that this analysis does not capture all types of financial incentives that may be available to PV systems in each state (e.g., incentives offered by PV incentive programs outside of those included in the data sample, or revenue from the sale of RECs). In addition, systems participating in New Jersey's SREC-Only program are excluded from the analysis in this section, and the New Jersey results presented in Figure 23 and Figure 24 are based solely on data from the state's Customer Onsite Renewable Energy (CORE) program.[41] New Jersey's position within this analysis – especially among commercial PV systems – could look substantially different if both programs were included, and if the value of SRECs (which have significant value in New Jersey, as discussed in Text Box 2) were included.

Among residential systems installed in 2008 (Figure 23), average after-tax incentives (i.e., direct cash incentives from state/utility PV incentive programs plus state and Federal ITCs, but excluding revenue from sale of RECs) ranged from a low of $2.5/W in California to a high of $5.1/W in New York. The high level of incentives provided in New York contributed to it being the state with the lowest net installed cost for residential PV systems installed in 2008, averaging $3.5/W. At the other end of the spectrum was Vermont (which had the second-lowest residential incentives after California), with an average net installed cost of $6.9/W. Of note, the two largest PV markets, California and New Jersey, fall nearly at opposite ends of the spectrum in terms the size of the incentives provided to residential PV in 2008 ($2.5/W for California and $4.6/W for New Jersey).

For commercial PV (Figure 24), average after-tax incentive levels and net installed costs also varied considerably across states in 2008, ranging from $3.1/W in Vermont to $5.7/W in Oregon. The lowest average net installed cost belongs to Connecticut, at $3.0/W, while Vermont claims the highest net installed cost for commercial PV in 2008 ($5.8/W).

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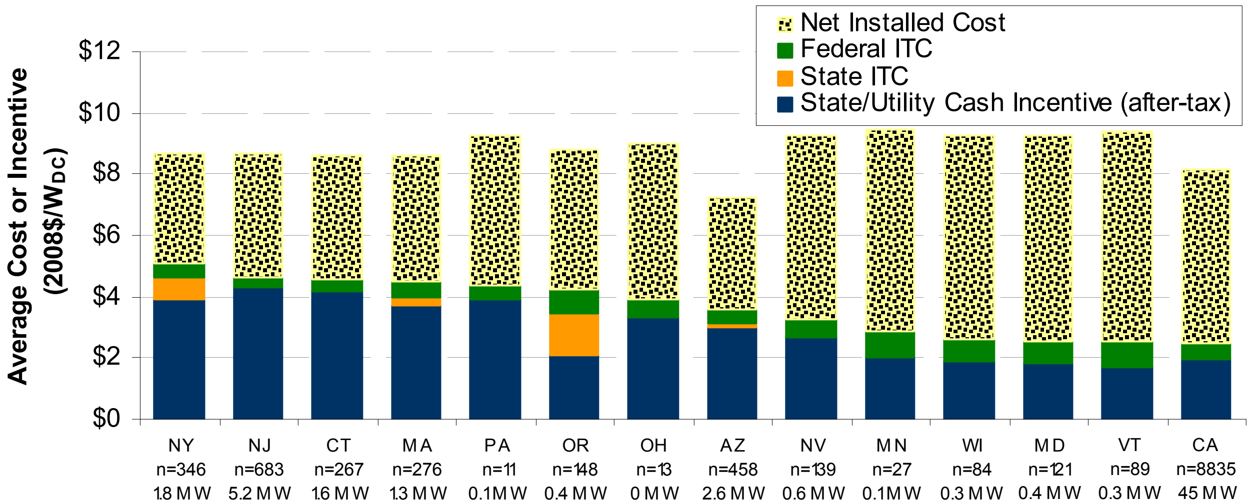
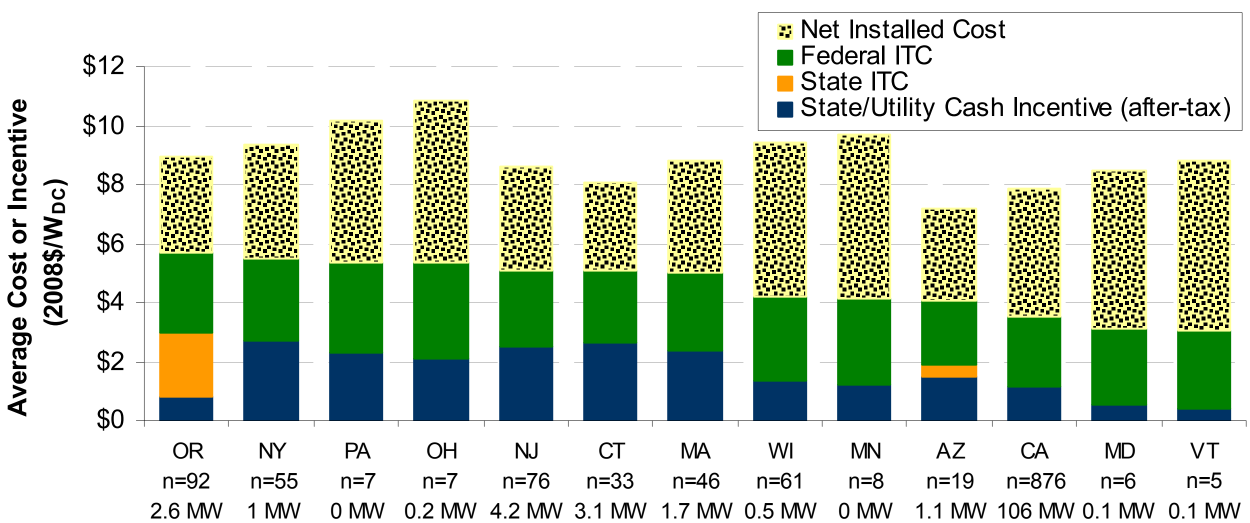
[40] See Appendix B for data on the average annual cash incentive for each of the PV incentive programs in the dataset.

[41] Within the data sample, the CORE program represents the vast majority (97%) of New Jersey residential PV systems installed in 2008. The commercial PV systems are more evenly distributed between the two programs, with CORE representing 67% of the New Jersey commercial PV systems installed in 2008, but only 33% of the capacity, with the remaining systems funded through the SREC-Only program.



Notes: We assume that all systems ≤10 kW are residential unless identified otherwise, and that direct cash incentives for residential PV are non-taxable and reduce the basis of the Federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE program. CO and WA are excluded from the figure, as the sample size for both states is small relative to the number of residential PV systems installed in each state in 2008.

Figure 23. Comparison of Incentive Levels and Net Installed Cost across States for Residential PV Systems Installed in 2008 (Calculated)



Notes: We assume that all systems >10 kW are commercial unless identified otherwise, and that direct cash incentives for commercial systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE program. States are excluded from the figure if the database contains fewer than five commercial PV systems installed in that state in 2008.

Figure 24. Comparison of Incentive Levels and Net Installed Cost across States for Commercial PV Systems Installed in 2008 (Calculated)

5. Conclusions

The number of photovoltaic systems installed in the U.S. has been growing at a rapid pace in recent years, driven in large measure by government incentives. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage cost reductions over time. Out of this goal arises the need for reliable information on the historical installed cost of PV. To address this need, Lawrence Berkeley National Laboratory initiated a series of reports focused on describing trends in the installed cost of grid-connected PV systems in the U.S. The present report, the second in the series, describes installed cost trends from 1998 through 2008, based on project-level data for more than 52,000 grid-connected systems deployed across 16 states.

Available evidence confirms that the installed cost of customer-sited PV systems has declined substantially since 1998, though both the pace and the source of those cost reductions have varied over time. Prior to 2005, installed cost reductions were associated primarily with a decline in non-module costs. Starting in 2005, however, cost reductions began to stall, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding demand. In 2008, installed costs resumed their downward trajectory, as module prices began to fall in response to expanded manufacturing capacity and the global financial crisis. Preliminary evidence and industry expectations suggest that module price will continue to fall through 2009.

The historical trend towards declining installed costs, along with the narrowing of cost distributions, suggests that PV deployment policies have achieved some success in fostering competition within the industry and in spurring improvements in the cost structure and efficiency of the PV delivery infrastructure. Moreover, the fact that states with the largest PV markets also appear to have somewhat lower average costs than most states with smaller markets lends some credence to the premise that state and utility PV deployment policies can affect local costs. Yet, even lower average installed costs in Japan and Germany suggest that deeper near-term cost reductions may be possible. Indeed, further cost reductions will be necessary if the PV industry is to continue its expansion in the customer-sited market, given the desire of PV incentive programs to ratchet down the level of financial support offered to PV installations.

Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents the data as provided directly by PV incentive program administrators. That said, several steps were taken to clean the data and standardize it across programs, described below.

Projects Removed from the Dataset: The initial data sample received from PV incentive program administrators consisted of 53,046 PV systems installed through 2008. To eliminate presumably erroneous numerical data entries, systems were removed from the dataset if the reported installed cost was less than $2/W (63 systems) or greater than $30/W (52 systems), or if the incentive amount was zero (25 systems) or greater than $30/W (4 systems). For the California Self Generation Incentive Program, systems receiving incentives from other subsidy programs were dropped (89 systems). In addition, systems missing installed cost data (185 systems), incentive data (11 systems), or system size data (55 systems) were removed from the dataset. Finally, 206 systems with battery back-up were removed from the dataset. In total, 690 systems, out of an initial sample of 53,046, were removed from the dataset as a result of these filters, yielding a final sample of 52,356 systems.

Manual Data Cleaning: City, installer, zip code, module manufacturer/model, and inverter manufacturer/model data were reviewed in order to correct obvious misspellings and misidentifications, and to create standardized identifiers for individual module and inverter models.

Completion Date: The data provided by several PV incentive programs did not identify the system completion date. In lieu of this information, the best available proxy was used (e.g., the date of the incentive payment or the post-installation site inspection).

Identification of Residential New Construction and Residential Retrofit Systems: Section 3 compares the cost of systems installed in residential new construction to those installed in residential retrofit applications, focusing specifically on 1-3 kW systems installed through three California programs in 2008: the California Energy Commission (CEC)'s Emerging Renewables Program (ERP), the CEC's New Home Solar Partnership (NHSP) program, and the California Solar Initiative (CSI). Residential new construction systems were identified within the ERP dataset if the data field labeled "Category" contained the value "Development," "New Home," or "n", whereas all systems installed through NHSP are assumed to be residential new construction, while all residential systems installed through CSI are assumed to be retrofit.

Identification of Building-Integrated and Rack-Mounted Residential Systems: The comparison between residential new construction and residential retrofit systems funded through ERP, NHSP, and CSI is further differentiated between building-integrated PV (BIPV) and rack-mounted systems. The raw data provided by PV incentive program administrators did not include explicit identifiers for these categories; thus, systems were identified as either BIPV or rack-mounted by cross-referencing data provided on the module manufacturer and model for each system with the California Solar Initiative (CSI)'s List of Eligible Modules, which explicitly identifies whether modules are BIPV or rack-mounted.[42] Based on this procedure, 2,193 of the 2,201 applicable systems (i.e., 1-3 kW systems funded through ERP, NHSP, and CSI and installed in 2008) were identified as either BIPV or rack-mounted.

Identification of Crystalline and Thin-Film Systems: Section 3 compares the installed cost of systems with thin-film modules to those with crystalline modules. The raw data provided by PV program administrators generally do not include explicit identifiers for these categories. Thus, systems were categorized as thin-film or crystalline by cross-referencing data provided on module manufacturer and model with the CSI's List of Eligible Modules, which explicitly identifies whether modules are crystalline or thin-

[42] http://www.gosolarcalifornia.org/equipment/pvmodule.php

film. Based on this procedure, 45,586 of the 52,356 systems were identified as employing either thin-film, crystalline, or hybrid modules.

Conversion to 2008 Real Dollars: Installed cost and incentive data are expressed throughout this report in real 2008 dollars (2008$). Data provided by PV program administrators in nominal dollars were converted to 2008$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to DC Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most of the capacity data were already provided in units of DC-STC; however, three programs (California's Emerging Renewables Program, Self-Generation Incentive Program, and Anaheim Solar Advantage Program) provided capacity data only in terms of the CEC-AC rating convention. Capacity data from these programs were converted to DC-STC, according to the procedures described below.

Anaheim Solar Advantage Program: The data provided for the Anaheim Solar Advantage Program included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC module ratings were identified for most of these systems by cross-referencing the information provided about module type with the CSI's 2008 List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through the Anaheim program. The DC-STC rating for each module was then multiplied by the number of modules to determine the total DC-STC rating for the system, as a whole. This approach was used to determine the DC-STC capacity rating for 59% of the systems in the Anaheim dataset. For the remaining systems, either the module data fields were incomplete, or the module could not be cross-referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.128 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the averages for other systems in the Anaheim dataset.

Emerging Renewables Program (ERP): The data provided for the ERP included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC ratings were identified for most modules by cross-referencing the information provided about the module type with the CSI's 2008 List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through the ERP. The DC-STC rating for each module was then multiplied by the number of modules to determine the total DC-STC rating for the system, as a whole. This approach was used to determine the DC-STC capacity rating for 86% of the systems in the ERP dataset. For the remaining systems, either the module data fields were incomplete, or the module could not be cross-referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.200 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the averages for other systems in the ERP dataset.

Self-Generation Incentive Program (SGIP): The data provided for the SGIP included data fields identifying module manufacturer and model (but not number of modules), and inverter manufacturer and model. DC-STC module ratings and DC-PTC module ratings (i.e., DC watts at PVUSA Test Conditions) were identified by cross-referencing the reported module type with the CSI's 2008 List of Eligible Photovoltaic Modules. Similarly, the rated inverter efficiency for each project was identified by cross referencing the reported inverter type with the CSI's 2008 List of Eligible Inverters, which identifies inverter efficiency ratings for most of the inverters employed in the systems funded through the SGIP.[43] In cases where data on inverter manufacturer and model either was not provided or could not be matched with the CSI's list, the inverter

[43] http://www.gosolarcalifornia.org/equipment/inverter.php

efficiency was stipulated, based on the average inverter efficiency of systems in the SGIP dataset installed in the same year and for which inverter efficiency ratings could be identified (ranging from 92.0% to 94.5%).

These pieces of information (module DC-STC rating, module DC-PTC rating, and inverter efficiency rating), along with the reported CEC-AC rating for the system, were used to estimate the system DC-STC rating according to the following:

$$System_{DC\text{-}STC} = (System_{CEC\text{-}AC} / \text{Inverter Eff.}) * (Module_{DC\text{-}STC} / Module_{DC\text{-}PTC})$$

This approach was used to determine the DC-STC capacity rating for 88% of the systems in the SGIP dataset. For the remaining systems, either the module data fields were incomplete, or the module could not be cross referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, annual average conversion factors (1.17-1.23 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$) were used, which were derived based on the other systems in the SGIP dataset.

Appendix B: Detailed Sample Size Summaries

Table B-1. Program-Level Annual Installation Data, Based on Final Study Sample

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
AZ	APS Solar & Renewables Incentive Program	*No. Systems*	-	-	-	-	4	10	42	73	183	231	369	***912***
		MW	-	-	-	-	0.0	0.1	0.2	0.4	1.1	1.4	3.0	***6.2***
	SRP EarthWise Solar Energy Program	*No. Systems*	-	-	-	-	-	-	-	26	115	97	108	***346***
		MW	-	-	-	-	-	-	-	0.1	0.5	0.5	0.7	***1.7***
CA	Anaheim Solar Advantage Program	*No. Systems*	-	-	-	1	8	14	15	3	3	4	21	***69***
		MW	-	-	-	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.1	***0.3***
	CEC Emerging Renewables Program	*No. Systems*	39	178	213	1,238	2,246	2,964	4,540	3,862	6,117	5,862	688	***27,947***
		MW	0.2	0.7	0.9	4.8	9.8	15.1	22.4	20.4	34.2	34.3	3.6	***146.4***
	CEC New Home Solar Partnership	*No. Systems*	-	-	-	-	-	-	-	-	-	134	405	***539***
		MW	-	-	-	-	-	-	-	-	-	0.4	1.1	***1.6***
	CPUC California Solar Initiative	*No. Systems*	-	-	-	-	-	-	-	-	-	3,363	8,170	***11,533***
		MW	-	-	-	-	-	-	-	-	-	25.0	121.7	***146.7***
	CPUC Self-Generation Incentive Program	*No. Systems*	-	-	-	-	15	71	147	190	144	142	87	***796***
		MW	-	-	-	-	2.3	11.4	17.2	26.7	29.5	33.3	24.4	***144.9***
	LADWP Solar Incentive Program	*No. Systems*	-	2	4	69	201	220	41	77	137	308	404	***1,463***
		MW	-	0.1	0.0	0.5	2.9	5.9	0.4	1.4	1.3	1.8	3.3	***17.6***
	Lompoc PV Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	5	***5***
		MW	-	-	-	-	-	-	-	-	-	-	0.0	***0.0***
	SMUD Residential Retrofit and Commercial PV Buydown Programs	*No. Systems*	-	-	-	-	-	-	-	19	29	57	65	***170***
		MW	-	-	-	-	-	-	-	0.1	0.1	0.4	0.4	***1.0***
CO	Governor's Energy Office Solar Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	16	***16***
		MW	-	-	-	-	-	-	-	-	-	-	0.1	***0.1***
CT	CCEF Onsite Renewable DG Program	*No. Systems*	-	-	-	-	-	1	2	2	7	14	40	***66***
		MW	-	-	-	-	-	0.0	0.0	0.0	0.3	1.6	3.6	***5.6***
	CCEF Solar PV Program	*No. Systems*	-	-	-	-	-	-	-	32	86	169	270	***557***
		MW	-	-	-	-	-	-	-	0.1	0.4	0.9	1.6	***3.1***
MA	MTC Small Renewables Initiative	*No. Systems*	-	-	-	-	1	70	127	91	259	207	336	***1,091***
		MW	-	-	-	-	0.0	0.3	0.6	0.8	1.8	1.5	3.1	***8.1***
MD	MEA Solar Energy Grant Program	*No. Systems*	-	-	-	-	-	-	-	7	43	45	135	***230***
		MW	-	-	-	-	-	-	-	0.0	0.2	0.1	0.5	***0.8***
MI	MSEO Solar Electric Rebate Program	*No. Systems*	-	-	-	-	1	9	23	12	24	38	38	***145***
		MW	-	-	-	-	0.0	0.0	0.1	0.0	0.1	0.2	0.1	***0.5***
NJ	NJCEP Customer Onsite Renewable Energy Program	*No. Systems*	-	-	-	-	-	32	267	484	988	592	804	***3,167***
		MW	-	-	-	-	-	0.2	2.1	5.5	17.8	16.4	12.3	***54.2***
	NJCEP Solar Renewable Energy Credit Program	*No. Systems*	-	-	-	-	-	-	-	-	-	2	56	***58***
		MW	-	-	-	-	-	-	-	-	-	0.0	8.4	***8.4***

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
NV	NPC/SPPC RenewableGenerations Rebate Program	*No. Systems*	-	-	-	-	-	-	5	65	73	105	145	***393***
		MW	-	-	-	-	-	-	0.0	0.3	0.4	0.6	0.7	***2.0***
NY	NYSERDA PV Incentive Program	*No. Systems*	-	-	-	-	-	43	98	94	191	331	401	***1,158***
		MW	-	-	-	-	-	0.2	0.5	0.6	1.1	2.0	2.8	***7.2***
OH	ODOD Advanced Energy Fund Grants	*No. Systems*	-	-	-	-	-	-	-	2	4	6	23	***35***
		MW	-	-	-	-	-	-	-	0.0	0.0	0.0	0.2	***0.3***
OR	ETO Solar Electric Program	*No. Systems*	-	-	-	-	-	57	138	89	131	215	248	***878***
		MW	-	-	-	-	-	0.3	0.6	0.3	0.6	1.0	3.7	***6.6***
PA	SDF Solar PV Grant Program	*No. Systems*	-	-	-	-	3	17	28	23	54	21	18	***164***
		MW	-	-	-	-	0.0	0.1	0.1	0.1	0.2	0.1	0.1	***0.7***
VT	RERC Small Scale Renewable Energy Incentive Program	*No. Systems*	-	-	-	-	-	-	31	15	24	61	94	***225***
		MW	-	-	-	-	-	-	0.1	0.0	0.1	0.2	0.4	***0.8***
WA	Klickitat PUD Solar PV Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	5	***5***
		MW	-	-	-	-	-	-	-	-	-	-	0.0	***0.0***
	Port Angeles Solar Energy System Rebate	*No. Systems*	-	-	-	-	-	-	-	-	-	1	1	***2***
		MW	-	-	-	-	-	-	-	-	-	0.0	0.0	***0.0***
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	*No. Systems*	-	-	-	-	10	18	23	27	65	98	145	***386***
		MW	-	-	-	-	0.0	0.0	0.1	0.1	0.2	0.5	0.9	***1.7***
	Total	*No. Systems*	***39***	***180***	***217***	***1,308***	***2,489***	***3,526***	***5,527***	***5,193***	***8,677***	***12,103***	***13,097***	***52,356***
		MW	***0.2***	***0.8***	***0.9***	***5.4***	***15.1***	***33.5***	***44.2***	***57.1***	***89.8***	***122.3***	***196.9***	***566.3***

Table B-2. Sample Size by Installation Year and System Size Range

System Size Range	Installation Year											Total
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	
No. Systems												
0-5 kW	31	156	180	1,108	1,886	2,287	3,436	3,009	4,859	6,853	7,186	**30,991**
5-10 kW	3	13	24	159	428	887	1,540	1,512	2,791	3,932	4,273	**15,562**
10-100 kW	5	10	12	36	154	309	510	577	915	1,174	1,315	**5,017**
100-500 kW	-	1	1	5	18	36	34	87	91	114	258	**645**
>500 kW	-	-	-	-	3	7	7	8	21	30	65	**141**
Total	39	180	217	1,308	2,489	3,526	5,527	5,193	8,677	12,103	13,097	**52,356**
Capacity (MW)												
0-5 kW	0.1	0.3	0.4	3.0	5.0	6.5	9.9	8.9	15.1	22.0	23.2	**94.4**
5-10 kW	0.02	0.09	0.16	1.03	2.83	5.93	10.41	10.50	19.43	27.15	29.25	**106.8**
10-100 kW	0.1	0.3	0.2	0.6	2.5	6.6	11.9	13.8	18.4	23.9	30.1	**108.5**
100-500 kW	-	0.1	0.1	0.8	3.1	8.1	7.0	17.4	20.1	25.8	61.8	**144.2**
>500 kW	-	-	-	-	1.7	6.4	5.1	6.5	16.8	23.4	52.6	**112.5**
Total	0.2	0.8	0.9	5.4	15.1	33.5	44.2	57.1	89.8	122.3	196.9	**566.3**

Table B-3. Annual Average Installed Cost and Direct Cash Incentives, by PV Incentive Program and System Size

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
AZ	APS Solar & Renewables Incentive Program	≤10 kW	No. Systems	-	-	-	-	4	9	40	68	173	219	331
			Avg. Cost	-	-	-	-	*	10.9	7.7	7.8	8.1	7.6	7.3
			Avg. Incentive	-	-	-	-	*	3.8	3.8	3.8	3.7	3.1	3.0
		10-100 kW	No. Systems	-	-	-	-	-	1	2	5	9	11	34
			Avg. Cost	-	-	-	-	-	*	*	10.3	8.0	8.7	6.8
			Avg. Incentive	-	-	-	-	-	*	*	3.3	3.8	3.5	2.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*
AZ	SRP EarthWise Solar Energy Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	26	113	93	100
			Avg. Cost	-	-	-	-	-	-	-	7.6	8.2	7.4	7.1
			Avg. Incentive	-	-	-	-	-	-	-	3.3	3.2	3.1	3.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	2	4	8
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	6.9
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	2.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	Anaheim Solar Advantage Program	≤10 kW	No. Systems	-	-	-	1	6	14	15	1	3	4	20
			Avg. Cost	-	-	-	*	9.9	8.3	8.3	*	*	*	8.3
			Avg. Incentive	-	-	-	*	4.9	5.0	5.0	*	*	*	3.4
		10-100 kW	No. Systems	-	-	-	-	2	-	-	2	-	-	1
			Avg. Cost	-	-	-	-	*	-	-	*	-	-	*
			Avg. Incentive	-	-	-	-	*	-	-	*	-	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	CEC Emerging Renewables Program	≤10 kW	No. Systems	34	168	200	1201	2107	2728	4184	3519	5498	5203	595
			Avg. Cost	12.3	11.6	11.0	10.5	10.5	9.4	8.6	8.2	8.3	8.5	8.1
			Avg. Incentive	3.3	3.2	3.1	4.3	4.4	3.9	3.5	2.9	2.6	2.4	2.3
		10-100 kW	No. Systems	5	9	12	33	135	234	356	343	619	659	93
			Avg. Cost	12.0	11.2	9.1	10.1	10.0	8.7	8.0	7.6	7.7	8.1	7.8
			Avg. Incentive	3.3	3.2	2.9	4.4	4.4	4.0	3.5	2.9	2.6	2.4	2.4
		>100 kW	No. Systems	-	1	1	4	4	2	-	-	-	-	-
			Avg. Cost	-	*	*	*	*	*	-	-	-	-	-
			Avg. Incentive	-	*	*	*	*	*	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CA	CEC New Home Solar Partnership	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	132	398
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.0	7.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.3	2.3
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	7
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	6.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	2.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	CPUC California Solar Initiative	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	3104	7200
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.4	8.2
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	1.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	242	777
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.2	7.7
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	1.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	17	193
			Avg. Cost	-	-	-	-	-	-	-	-	-	7.1	7.2
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	2.0
CA	CPUC Self-Generation Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		10-100 kW	No. Systems	-	-	-	-	9	44	109	107	73	53	30
			Avg. Cost	-	-	-	-	9.6	8.2	8.5	8.0	7.8	7.5	7.1
			Avg. Incentive	-	-	-	-	4.4	3.9	4.0	3.8	3.3	2.6	2.4
		>100 kW	No. Systems	-	-	-	-	6	27	38	83	71	89	57
			Avg. Cost	-	-	-	-	8.0	7.0	7.9	7.5	7.5	7.3	7.2
			Avg. Incentive	-	-	-	-	4.0	3.4	3.8	3.7	3.4	2.7	2.4
CA	LADWP Solar Incentive Program	≤10 kW	No. Systems	-	1	4	65	183	189	37	69	125	275	376
			Avg. Cost	-	*	*	11.0	10.7	9.6	9.2	8.0	8.6	8.8	8.4
			Avg. Incentive	-	*	*	5.7	6.4	6.0	3.8	3.2	3.6	3.7	3.7
		10-100 kW	No. Systems	-	1	-	3	7	18	3	4	9	33	24
			Avg. Cost	-	*	-	*	9.6	9.6	*	*	7.7	8.7	8.0
			Avg. Incentive	-	*	-	*	6.2	6.2	*	*	3.1	3.5	3.6
		>100 kW	No. Systems	-	-	-	1	11	13	1	4	3	-	4
			Avg. Cost	-	-	-	*	9.8	8.5	*	*	*	-	*
			Avg. Incentive	-	-	-	*	5.8	5.9	*	*	*	-	*

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CA	Lompoc PV Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	8.1
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	3.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	SMUD Residential Retrofit and Commercial PV Buydown Programs	≤10 kW	No. Systems	-	-	-	-	-	-	-	16	27	55	63
			Avg. Cost	-	-	-	-	-	-	-	10.6	10.3	9.8	9.5
			Avg. Incentive	-	-	-	-	-	-	-	3.4	2.9	2.5	2.3
		10-100 kW	No. Systems	-	-	-	-	-	-	-	3	2	2	2
			Avg. Cost	-	-	-	-	-	-	-	*	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	*	*	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CO	Governor's Energy Office Solar Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	16
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	8.3
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	1.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CT	CCEF Onsite Renewable DG Program	≤10 kW	No. Systems	-	-	-	-	-	1	1	1	1	2	7
			Avg. Cost	-	-	-	-	-	*	*	*	*	*	8.2
			Avg. Incentive	-	-	-	-	-	*	*	*	*	*	7.1
		10-100 kW	No. Systems	-	-	-	-	-	-	1	1	5	8	21
			Avg. Cost	-	-	-	-	-	-	*	*	8.8	8.5	8.2
			Avg. Incentive	-	-	-	-	-	-	*	*	4.8	4.6	4.3
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	4	12
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	4.2

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CT	CCEF Solar PV Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	32	85	163	242
			Avg. Cost	-	-	-	-	-	-	-	9.0	9.1	9.2	8.7
			Avg. Incentive	-	-	-	-	-	-	-	5.0	4.8	4.4	4.2
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	6	28
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.4	8.3
			Avg. Incentive	-	-	-	-	-	-	-	-	*	3.8	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
MA	MRET Commonwealth Solar Program	≤10 kW	No. Systems	-	-	-	-	-	65	118	74	242	194	296
			Avg. Cost	-	-	-	-	-	10.5	9.3	9.3	9.5	9.5	8.7
			Avg. Incentive	-	-	-	-	-	4.9	5.0	5.0	4.2	4.2	3.7
		10-100 kW	No. Systems	-	-	-	-	1	5	9	17	14	11	34
			Avg. Cost	-	-	-	-	*	13.0	10.9	10.3	10.6	9.1	8.7
			Avg. Incentive	-	-	-	-	*	15.2	8.5	11.2	8.3	7.9	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	3	2	6
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.4
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	3.3
MD	MEA Solar Energy Grant Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	7	42	44	131
			Avg. Cost	-	-	-	-	-	-	-	10.4	11.0	10.4	9.3
			Avg. Incentive	-	-	-	-	-	-	-	1.2	1.5	1.4	1.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
MN	MSEO Solar Electric Rebate Program	≤10 kW	No. Systems	-	-	-	-	1	9	23	12	24	36	37
			Avg. Cost	-	-	-	-	*	9.9	7.8	9.6	8.6	9.2	9.6
			Avg. Incentive	-	-	-	-	*	2.3	2.2	2.2	2.1	2.0	2.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
NJ	NJCEP Customer Onsite Renewable Energy Program	≤10 kW	No. Systems	-	-	-	-	-	32	246	407	812	480	669
			Avg. Cost	-	-	-	-	-	9.3	9.1	8.7	8.6	8.7	8.7
			Avg. Incentive	-	-	-	-	-	6.2	6.2	6.0	5.6	5.0	4.3
		10-100 kW	No. Systems	-	-	-	-	-	-	20	69	143	81	117
			Avg. Cost	-	-	-	-	-	-	9.4	8.7	8.5	9.1	8.4
			Avg. Incentive	-	-	-	-	-	-	5.3	5.6	5.3	4.8	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	1	8	33	31	18
			Avg. Cost	-	-	-	-	-	-	*	7.5	8.0	7.3	7.4
			Avg. Incentive	-	-	-	-	-	-	*	4.3	4.5	3.5	3.5
NJ	NJCEP Solar Renewable Energy Credit Program**	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	21
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.1
			Avg. Incentive	-	-	-	-	-	-	-	-	-	**	**
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	15
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	7.5
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	**
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	20
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	6.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	**
NV	NPC/SPPC RenewableGenerations Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	5	57	68	98	141
			Avg. Cost	-	-	-	-	-	-	10.0	9.4	9.1	9.6	9.2
			Avg. Incentive	-	-	-	-	-	-	5.7	5.0	3.7	3.1	2.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	8	5	7	4
			Avg. Cost	-	-	-	-	-	-	-	13.9	8.3	7.6	*
			Avg. Incentive	-	-	-	-	-	-	-	5.2	4.3	3.9	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
NY	NYSERDA PV Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	37	89	79	170	305	356
			Avg. Cost	-	-	-	-	-	9.6	9.6	9.2	9.2	9.1	8.7
			Avg. Incentive	-	-	-	-	-	4.8	4.7	4.5	4.3	4.2	4.0
		10-100 kW	No. Systems	-	-	-	-	-	6	9	15	21	26	45
			Avg. Cost	-	-	-	-	-	9.6	8.5	8.7	9.3	9.4	8.8
			Avg. Incentive	-	-	-	-	-	5.6	5.4	4.7	4.4	4.2	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
OH	ODOD Advanced Energy Fund Grants	≤10 kW	No. Systems	-	-	-	-	-	-	-	2	4	6	18
			Avg. Cost	-	-	-	-	-	-	-	*	*	10.6	9.9
			Avg. Incentive	-	-	-	-	-	-	-	*	*	3.5	3.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	4
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	*
OR	ETO Solar Electric Program	≤10 kW	No. Systems	-	-	-	-	-	55	136	86	124	200	201
			Avg. Cost	-	-	-	-	-	8.1	7.4	7.8	8.6	8.9	8.7
			Avg. Incentive	-	-	-	-	-	4.7	4.1	3.2	2.1	2.0	1.9
		10-100 kW	No. Systems	-	-	-	-	-	1	1	3	7	15	39
			Avg. Cost	-	-	-	-	-	*	*	*	7.4	9.1	9.4
			Avg. Incentive	-	-	-	-	-	*	*	*	1.2	1.5	1.3
		>100 kW	No. Systems	-	-	-	-	-	1	1	-	-	-	8
			Avg. Cost	-	-	-	-	-	*	*	-	-	-	8.1
			Avg. Incentive	-	-	-	-	-	*	*	-	-	-	1.4
PA	SDF Solar PV Grant Program	≤10 kW	No. Systems	-	-	-	-	3	17	28	23	53	21	16
			Avg. Cost	-	-	-	-	*	9.2	10.9	9.5	8.9	9.2	9.9
			Avg. Incentive	-	-	-	-	*	5.7	5.1	5.1	4.9	4.7	3.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	-	2
			Avg. Cost	-	-	-	-	-	-	-	-	*	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
VT	RERC Small Scale Renewable Energy Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	31	15	24	60	89
			Avg. Cost	-	-	-	-	-	-	8.9	9.5	9.2	9.3	9.4
			Avg. Incentive	-	-	-	-	-	-	2.9	2.6	2.1	1.8	1.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	0.7
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WA	Klickitat PUD Solar PV Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	9.4
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	0.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WA	Port Angeles Solar Energy System Rebate	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	≤10 kW	No. Systems	-	-	-	-	10	18	23	27	62	88	125
			Avg. Cost	-	-	-	-	11.1	10.9	8.0	9.9	8.8	9.2	9.4
			Avg. Incentive	-	-	-	-	3.3	2.7	2.2	2.5	2.6	2.0	2.1
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	3	10	20
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.2	8.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	2.2	1.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

* Average cost and incentive data are omitted if there are fewer than five systems.
** The NJ SREC-Only Pilot does not provide any direct cash incentive, but instead, provides financial support solely though the sale of solar renewable energy certificates based on solar energy production.

Appendix C: Calculating After-Tax Cash Incentives and State and Federal Investment Tax Credits

Section 4 presents trends related to combined after-tax financial incentives (direct cash incentives from state/utility PV incentive programs plus state and Federal ITCs) and net installed costs after receipt of these incentives. Calculating this value required that several operations first be performed on the data provided by PV program administrators, as described below.

1. **Segmenting Systems as Residential, Commercial, or Tax-Exempt.** Data provided by many of the programs did not explicitly identify whether the PV systems were owned by residential, commercial, or tax-exempt entities. Unless otherwise identified, we classified all systems ≤10 kW as residential and all systems >10 kW as commercial.

2. **Estimating the After-Tax Value of Cash Incentives from State/Utility Incentive Programs.** Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. As such, the cash incentives provided for systems in the dataset identified as commercial PV were assumed to be taxed at a Federal corporate tax rate of 35%. The taxation of cash incentives for commercial PV at the state level may vary by state; for simplicity, we assume that all commercial PV systems are taxed at the "effective" state corporate tax rate, which accounts for the fact that state corporate taxes reduce the incentive-recipient's Federally-taxable income. The effective state corporate tax rate applied to the cash incentive is equal to 65% (i.e., 1 minus 35%) of the nominal state corporate tax rate in 2008, which ranged from 0% to 9.99% among the 16 states in our dataset.[44]

   Cash incentives paid to residential PV system owners are exempt from Federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." Notwithstanding this uncertainty, we assume that cash incentives provided to all systems in the dataset identified as residential PV are exempt from Federal income taxes. The taxation of cash incentives for residential PV at the state level may vary by state, but for simplicity, we assume that all residential PV systems are also exempt from state income tax.

3. **Estimating the Value of State ITCs.** We identified 5 of the 16 states in our dataset as having offered a state ITC for PV at some point from 1998-2008. Based on the information contained in Table C-1, we determined whether each project in the dataset was eligible for a state ITC, and if so, estimated the amount of the tax credit. In all cases, we assumed that the size of the state ITC was not impacted by any Federal ITC received, though for several states (CA and NY), we assumed that the basis for the state ITC was reduced for any direct cash incentives ("rebates") received through the state/local PV incentive program. In addition, we accounted for the fact that state tax credits are financially equivalent to Federally taxable income, because they increase the recipient's Federally-taxable income by an amount equal to the size of the state tax credit. The net value of state ITCs was therefore reduced by the assumed Federal income tax levied on the increased income. For commercial customers, we assumed a Federal income tax rate of 35%. For residential customers, we assumed that the increased income would be taxed at the marginal rate applicable to a married couple filing jointly with federally taxable income of $150,000 (e.g., 28% in 2008).[45]

[44] http://www.taxadmin.org/fta/rate/corp_inc.html
[45] http://www.taxfoundation.org/taxdata/show/151.html

4. **Estimating the Value of Federal ITCs.** Projects in the dataset identified as residential PV and installed on or after January 1, 2006 were assumed to receive a Federal ITC equal to the lesser of 30% of the tax credit basis or $2,000. Projects in the dataset identified as commercial PV are assumed to receive a Federal ITC equal to 10% of the tax credit basis if installed prior to January 1, 2006, or 30% of the tax credit basis if installed after that date.

   The tax credit basis on which the Federal ITC is calculated depends on whether cash incentives received by a project are Federally-taxable. If the cash incentives are Federally-taxable, as assumed for all commercial PV, then the Federal ITC is calculated based on the full installed cost of the system. If, on the other hand, the cash incentives are not Federally-taxable, as assumed for all residential PV, then the Federal ITC is calculated based on the installed cost minus the value of the tax-exempt cash incentives.

Table C-1: State ITC Details

State	Applicable Customers	System Size Cap	Applicable Period	Tax Credit Amount	Cap
AZ	Residential	None	1995-indefinite	25% of *pre-rebate* installed cost	$1,000
	Non-Residential and Tax-Exempt	None	2006-2012	10% of *pre-rebate* installed cost	$25,000
CA	All	200 kW	2001-2003	15% of *post-rebate* installed cost	None
	All	200 kW	2004-2005	7.5% of *post-rebate* installed cost	None
MA	Residential	None	1979-indefinite	15% of *pre-rebate* installed cost	$1,000
NY	Residential	10 kW	1998-9/1/2006	25% of *post-rebate* installed cost	$3,750
	Residential	10 kW	9/1/2006-indefinite	25% of *post-rebate* installed cost	$5,000
OR	Residential	None	11/4/2005-indefinite	$3/W based on rated capacity (DC-STC)*	$6,000 up to 50% of pre-rebate installed cost
	Non-Residential and Tax-Exempt	None	1981-2006	35% of *pre-rebate* installed cost	$10,000,000
	Non-Residential and Tax-Exempt	None	2007-2017	50% of *pre-rebate* installed cost (up to max. eligible cost**)	$10,000,000

* Tax credit paid out over multiple years, with an annual limit of $1,500/yr.

** Max. eligible cost varies by system size: currently $9/W for systems up to 100 kW, ramping down linearly to $7.50/W for systems >1,000 kW. The tax credit is paid out over five years.

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