The Brattle Group

The importance of long-term contracting for facilitating renewable energy project development

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The authors are Principals of *The Brattle Group*. All results and any errors are the responsibility of the authors and do not represent the opinion of *The Brattle Group*.

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TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

Ridgeline Energy LLC ("Ridgeline"), a wholly owned indirect subsidiary of Atlantic Power Corporation, asked *The Brattle Group* to consider the extent to which long-term contracting can help facilitate the financing and construction of renewable energy projects. In particular, *Brattle* was asked to examine the potential effect of long-term contracting on the development of renewable energy generation facilities in the State of New York.

The evidence shows that for the past several years the vast majority of power plants have been built either by vertically integrated utilities or with the support of long-term contracts. This is even more the case for renewable energy projects.

At first glance, this observation may seem at odds with the underlying reasons for creating competitive markets for electric power, capacity and renewable attributes over the past two decades. A closer look, however, reveals that **there are important theoretical and practical reasons long-term contracts and utility ownership have been the dominant approaches to support the development of renewable energy projects.**

One of the primary reasons is the well-understood concept that projects with large sunk and irreversible initial investments are subject to the "hold-up" problem in the absence of liquid spot and secondary markets.[1] Large infrastructure projects such as those for renewable energy usually involve correspondingly large upfront investments. Once the investment is made, the cost of providing services from the infrastructure typically is relatively modest. Power generation is a classic example of such projects. If a power plant had just a single potential user, this user would have an incentive to offer to pay only the marginal cost of producing the power (or a tiny bit more) rather than to also paying for initial capital outlays once the plant is built. This is because once the investment is made, the cost of the investment is sunk and cannot be recovered (for example by "un-building" the plant and selling the material), and the owner of the plant will be willing to accept any price that at least covers the plant's variable cost.

When there are liquid spot and forward markets, a potential investor can ensure that enough revenues will be collected to pay for the initial investment by entering into forward contracts. In the absence of sufficiently liquid forward markets, such as in New York for energy and renewable energy certificates ("RECs"), however, potential investors will be reluctant to invest in such projects, primarily because of the risks associated with hold-up. This problem is particularly relevant for projects with long lives such as renewable energy projects.

1 Since most of the financial and economic details related to renewable energy projects are confidential, it is difficult to assess the extent to which there is evidence of the actual impact of this hold-up problem, apart from the prediction that it will lower the number of projects that can be financed/built. However, Invenergy's 10-year REC contract with NYSERDA for High Sheldon Wind Farm is indicative. Given that the REC contract was signed more than a year after the project's commercial operating date, Invenergy likely would have been willing to accept a relatively low price for RECs, since the revenues were no longer needed to get the project built and any revenue would be incremental. Likewise, NYSERDA had an incentive to offer a low price. For more details, see http://www.prnewswire.com/news-releases/invenergy-and-nyserda-enter-into-renewable-energy-credit-purchase-agreement-113344714.html.

Energy markets are subject to substantial regulation. For example, regulators have shown a tendency to impose price caps once wholesale markets rise to levels deemed unacceptably high. The market for renewable power is even more regulated, often still relying on regulatory requirements. For instance, without mechanisms like Renewable Portfolio Standards ("RPS"), the environmental attributes of renewable power would have little market value (beyond anyone willing to pay a voluntary premium for such power). Since the forward market for RECs post-2015 is illiquid, the risk of regulatory hold-up, *i.e.* of changes in regulation that effectively reduce the value of renewable attributes after projects have been built, is substantial.

Experience has shown that forward markets for energy, capacity and RECs, where they exist at all, are liquid often only for relatively short periods of time. There is some evidence that this problem has become worse after the financial crisis of 2008 and the structural reforms and restrictions on commodity trading by the Dodd-Frank Act.[2] Consequently, potential funders of renewable projects usually cannot ensure recovery of their fixed and sunk investment cost through contracting in secondary forward markets for energy, capacity and RECs. In the absence of such hedging possibilities, it is likely that renewable energy projects simply will not be financed without a long-term revenue guarantee.[3]

This explains the predominant use of long-term contracts in the restructured U.S. power markets, coupled with direct ownership by regulated vertically-integrated utilities where direct utility ownership is still permitted.

Even if it is theoretically possible to enter long-term contracts for energy, capacity and RECs separately, as is potentially the case in New York, the interaction between the separate pricing of the various products, including the potentially differing length of contracts, makes the financing of renewable projects difficult. This is because a project developer will need to contract in a way such that the sum of the separate revenue streams from energy, capacity and RECs is sufficient to recover the initial fixed outlay. Until renewable technologies become competitive with existing fossil technologies without consideration of renewable attributes, signing long-term contracts for energy and capacity alone will not provide sufficient revenues.[4] Hence, a renewable project developer could only sign such contracts once a long-term contract for RECs has been obtained and thus the REC revenue stream is known. However, the contract price a project developer would be willing to accept for RECs, in turn, depends on the incremental revenue stream needed to generate sufficient overall revenues to recover the initial investment, an amount that is known only after contracting for energy and

2 While the Act clearly affects traditional hedging activities of the electric power industry, its ultimate long-term effect is unclear. For a discussion, see Grant Thornton, "Financial reform: How the Dodd-Frank Act affects the energy industry." There is some evidence that markets may be providing some longer-term hedges. However, there is ongoing uncertainty about their treatment under the Act, and whether or not the market for such hedges is liquid and its tenor is sufficient to provide enough mark risk mitigation to have a material impact on financing costs.

3 The absence of a liquid forward market is particularly problematic for RECs, the prices of which are characterized by boom-bust cycles, that is either very high or very low prices, given the typically fixed quantity target under the RPS and an essentially zero marginal cost provision of RECs by renewable projects.

4 At present, onshore wind resources are initially eligible for capacity revenues for 10% of their installed capacity for the summer period and 30% of installed capacity for winter, After the first year, the capacity value is based on the historical production of the specific facility.

capacity. This results in a "chicken and egg" type problem, with significant uncertainty about the respective revenue streams from energy and capacity on one hand, and RECs on the other. Since the developer of a renewable project cannot independently decide how much of each product to produce, but rather incurs fixed and sunk costs for a project that generates all three products, separating the three revenue streams brings no benefits that would justify the increased uncertainty, even assuming that the developer could sign independent long-term contracts.

Not being able to lock in prices over a long period of time increases the cost of financing of such projects (since they face significant price risks while incurring a significant portion of total cost in upfront capital investment). It is likely that, as a result of providing price certainty through bundled long-term contracts over 15-20 years, financing costs can be lowered through a combination of both higher leverage and lower interest rates. Using simple examples and reasonable assumptions, we estimate that the impact of lowering the financing costs through long-term contracts could be materially beneficial to New York ratepayers. Given that less than 50% of the RPS commitment by 2015 has been met, the savings to New York ratepayers for contracts awarded between now and 2015 could realistically range from $450 million to close to $1 billion.

Hence, a mechanism that provides long-term certainty over the bundle of all products is likely a more efficient mechanism for ensuring that renewable projects can be built[5] and for lowering the financing costs of meeting the State's remaining RPS obligation with significant savings to New York ratepayers.

At present, New York provides some revenue certainty through central procurement of renewable attributes by the New York State Energy Research and Development Authority ("NYSERDA") and the corresponding awards of 10-year REC contracts. However, without the ability to reduce uncertainty over the remaining revenue streams (from energy and capacity for the life of the project and RECs after 10 years), the risk to project developers remains high. The absence of a legal requirement and the reluctance by the suppliers of electricity, based on a lack of clear endorsement from the PSC, to sign long-term contracts for energy and capacity, as well as the relative inability to hedge long-term exposure to energy and capacity prices in financial markets especially post-financial crisis, all likely lead to less renewable development in New York than would be feasible through provision of long-term contracting for bundled energy, capacity and RECs.

As long as New York retains its central procurement approach for RECs – which has some advantages over the decentralized RPS compliance requirement in other states – finding ways of centrally procuring not just RECs, but all three renewable products, is likely the most efficient approach to lower the cost to ratepayers of meeting the RPS. Requiring electricity sellers to enter into long-term contracts with renewable projects, as in Massachusetts, is one possibility but would create significant coordination problems in New York (since, in that case, RECs and energy/ capacity would be procured through two separate processes) unless New York's current central procurement model for RECs is modified.

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[5] NYSERDA's consultant Summit Blue Consulting has acknowledged the importance of liquid markets enabling market participants to create long-term revenue certainty. See, *e.g.,* New York Renewable Portfolio Standard Market Conditions Assessment Final Report, Summit Blue Consulting; February 19, 2009, p. S-25.

The current reluctance to enter into bundled (energy, capacity and perhaps RECs) long-term contracts likely stems at least in part from a perception that similar attempts, notably contracts signed with Qualifying Facilities ("QF") under the Public Utility Regulatory Policy Act ("PURPA"), and perhaps those signed in the past with Hydro Quebec, ended up being costly to New York ratepayers. It is therefore important to recognize the fundamental differences between such earlier programs and a program providing long-term contracts for energy, capacity and RECs for renewable projects targeted at meeting the New York RPS.

First, unlike earlier programs, where the goal was to sign contracts with resources estimated to provide power at a cost that was lower than the then-assumed avoided cost of generation from existing utilities, it is recognized that renewable projects may produce power at a cost that is somewhat higher than non-renewable generation. Renewable projects are required to be built in order to meet the RPS, so a public choice has already been made that such projects are necessary. Given this fact, the only relevant outstanding issue is how to ensure that such projects are built at the lowest cost to ratepayers. Second, QF and other earlier long-term contracts were based on an estimate of avoided future costs. This approach, as is now understood, has several risks:

- Avoided cost estimates, which are relatively uninformed by market decisions (they are typically model-based) turn out to be higher than they should have been, leading to high ex-post costs relative to market prices.
- In the past, there was little control over the total quantity of QFs coming online, so that, if QF prices ended up too high relative to market prices, ratepayers risked getting stuck with too many such contracts;
- Relative to a single avoided cost benchmark, individual QFs could earn excess profits.

Having learned from these mistakes, long-term contracts for renewable power can and should be structured to avoid them. Long-term contracts for renewable power projects should be procured through a process that ensures vigorous competition. NYSERDA and all of the utilities have substantial experience conducting such procurement processes. This should ensure that winning bidders can provide renewable power at least cost to ratepayers (and as described above this is the only remaining objective given the existence of the RPS). Also, not only does the RPS target itself limit the total quantity of contracts that would be necessary, but such procurement processes can be used to further ensure that there is not "too much" contracting at "too high" a price. Conducting RPS contract procurement in tranches, as is already the case for RECs under the existing NYSERDA program, allows ratepayers to benefit from cost decreases for renewable projects over time. Finally, most renewable energy procurement processes result in project-specific long-term contracts. If organized to be competitive, this results in prices close to the projects' actual expected costs rather than the avoided cost of some alternative, and hence significantly reduces the possibility of excess profits.

Given the above, and given the potential savings to New York ratepayers, the resistance to long-term contracting based on past experience should be reexamined in the context of ensuring that New York will meet its RPS at the lowest possible cost for ratepayers.

II. PUBLIC POLICY IS KEY TO RENEWABLE ENERGY INVESTMENT

The United States as a whole, and many individual states, use various approaches to facilitating the development of renewable energy projects. At the federal level, the main support for renewable energy has been through the use of tax-related incentives, such as accelerated depreciation and production or investment tax credits ("PTC" and "ITC"). At the same time, many states, including New York, have enacted RPS, creating a mandate to procure a certain percentage of total supply from renewable energy and hence at least some incentive for corresponding renewable energy project development. However, even among the states with RPS, there exists a relatively large degree of variation in the ways RPS rules are implemented.[6]

Public policy clearly has a material impact on renewable energy investment. In 2011, renewable energy investment in the U.S. increased by 57 percent to $51 billion, largely attributed to three significant federal incentive programs for renewable energy either expiring in 2011 or nearing scheduled expiration.[7] However, the wide range of approaches used locally, nationally, and internationally begs the question of whether there is an "optimal" way of encouraging investment in renewable energy projects, or at least whether some approaches are more effective at meeting certain objectives.[8] This paper considers the role long-term contracting might play in facilitating the financing and construction of renewable projects, with particular emphasis on its benefits relative to the current procurement process used by NYSERDA.

A. New York has a Renewable Energy Commitment

New York has had an RPS since 2004. NYSERDA is the state agency responsible for procuring sufficient renewable resources to meet the state's RPS requirement. The requirement was originally 25 percent by 2013, but was increased to 30 percent by the end of 2015 in the 2009 State Energy Plan ("2009 Plan").[9] NYSERDA is the central procurement administrator and pays a production incentive in the form of a ten-year contract for RECs to renewable generators selected through competitive solicitation process.[10]

The 2009 Energy Plan aimed to grow the state's clean energy sector using various policies, programs, and strategies to: a) contain or reduce energy costs, reduce price volatility, preserve

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6 In contrast to the RPS approach, most European countries and some Canadian Provinces have adopted some type of a feed-in tariff ("FIT") which sets the prices that renewable energy resources receive. Some countries, including Denmark and previously the United Kingdom, also have also used competitive tenders.

7 Renewable Energy Policy Network for the 21st Century, "Renewables 2012 Global Status Report," p. 61.

8 See, *e.g., The Brattle Group*, "Reforming Renewable Support in the United States: Lessons from National and International Experience" prepared for the Bipartisan Policy Center, November 2012, which discusses national and international best practices of renewable energy support and emphasizes revenue and price predictability as a key element of successful renewable energy policy. See also the recent New York Energy Highway Blueprint, which emphasizes the need to provide long-term certainty of the commitment to renewable energy beyond 2015, and recommends (at p. 67) that the New York Public Service Commission "conduct an assessment of policy options that foster activities to transform the market for these sustainable energy options, including an assessment of project investment models, cost recovery mechanisms, and associated contracting mechanisms."

9 Renewable Energy Assessment New York State Energy Plan 2009, December 2009.

10 Long Island Power Authority and NYPA purchase their own resources.

and enhance the reliability of energy and transportation delivery systems; b) expand reliance on energy efficiency and renewable energy; c) diversify fuel sources; and d) provide multiple pathways for reducing greenhouse gas emissions and other pollutant emissions from stationary and mobile sources.

Based on the 2009 Plan, New York is committed to renewable energy development because renewable energy resources are deemed to provide New York with several benefits including:

1) The reduction ofthe net retail price of electricity, including the potential for a reduction in the wholesale power prices netted against the ratepayer funded payments for purchasing renewable energy;
2) Helping to achieve environmental goals by displacing a portion of fossil-fired power sources and the associated emission of air pollutants, which in turn reduces the costs associated with emissions reduction needed from other parts of the economy to achieve the state and regional caps;
3) Creation of local jobs, income and economic development opportunities associated with construction and operation of new facilities, payments to the State and localities, payment for fuel and land leases and in-state purchase of materials and services;
4) Reducing reliance on fossil fuel imported from outside of the State and/or the nation, and thereby increasing the security of energy supplies;
5) Reducing price volatility of fossil fuels by using renewable energy to manage the risks associated with fossil fuel use;
6) Reducing negative health impacts from harmful air pollution;
7) Reducing peak demand by the use of solar power; and
8) Relieving transmission and distribution bottlenecks through the use of distributed solar resources.

These benefits have recently been reaffirmed in the New York Energy Highway Blueprint,[11] which emphasized that in order to create these benefits the current RPS goal should be extended beyond 2015 to create long-term signals for the development of renewable resources in New York.

The contracts awarded through the solicitation process are for the renewable attributes of the resources, *i.e.* RECs alone. This means that (for the Main Tier resources[12]) each resource is to sell its power to the New York wholesale market and obtain its revenues from the wholesale energy

[11] New York Energy Highway Blueprint, 2012, p. 66.

[12] In addition to the Main Tier, which covers 98% of New York's RPS targets, there also are provisions and incentives for a customer-sited tier, which we do not address in detail here.

and capacity market, while the NYSERDA contracts for up to 10 years provide supplemental payments for the renewable attributes.[13]

Through December 2011, NYSERDA's solicitations have resulted in 56 long-term contracts for RECs priced between approximately $15 to $28/REC.[14] They provide a revenue stream on top of what the resources can earn from the wholesale energy and capacity markets in New York.

B. But the Wholesale Energy Market is Separate

The New York wholesale energy market is primarily driven by the price of natural gas. In the past several years, energy prices have been quite low, reducing the revenues to all generators, including renewable energy providers. With low forward prices for electricity and for a limited duration, new renewable generators find it difficult to finance their projects from expected energy revenues alone. Given that wind generators' production output is not well-correlated with load levels, they typically only receive a relatively small amount of capacity credit and therefore earn little from the capacity market.[15] In addition, the methodology of how to calculate the capacity credit for wind generators is subject to market rule changes. Therefore, financiers may discount the expected capacity payment from the market for wind generators.

Hence, the sum of expected market revenues for energy and capacity alone is typically not yet sufficient to repay the initial capital cost of most renewable energy projects including wind projects in the state. This is not surprising. After all, RPS were created to provide revenue streams above those provided by the marketplace to enable newer forms of energy generation with associated benefits to ratepayers and society not otherwise accurately captured by existing markets for energy and capacity.

However, in addition to the fact that average expected revenue streams from energy and capacity sales are still insufficient to cover the costs of a typical renewable energy project, both energy and capacity prices tend to be volatile. Since renewable energy projects tend to involve mostly upfront fixed capital investment, energy and capacity price volatility increases risk to project developers. Forward contracting for energy and capacity in existing markets can lower this volatility, but requires the existence of liquid forward markets of sufficient length.

After the financial crisis of 2008, both the tenor and liquidity of forward markets deteriorated,[16] making it difficult to lock in energy and capacity revenues for a significant length of time at a

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[13] For a description of the Main Tier RPS implementation, see Kevin Hale, NY RPS Program Evaluation Approach and Topics, NYSERDA, October 21, 2010.

[14] See NYSERDA, The New York State Renewable Portfolio Standard Performance Report through December 31, 2011 for a description of the RPS results until year-end 2011.

[15] The New York ISO, in its planning, assumes onshore wind generation in New York contributes 10% capacity credit in the summer, *i.e.,* capacity revenues for 10% of nameplate capacity. Offshore wind facilities are assumed to contribute 30% of their nameplate capacity to overall capacity targets during the summer. For the winter, both types of wind resources are assumed to contribute 30% of their nameplate capacity. See New York ISO, 2011 Load and Capacity Data "Gold Book", page 67,

[16] In particular, the Dodd-Frank Financial Reform Act imposed significant additional restrictions and requirements on parties engaging in financial and commodity contracts. There is some evidence that this has already led to less activity and hence less hedging opportunities for market participants.

competitive price. Also, since 2009 the development of new wind projects, which represent the largest portion of incremental renewable energy development in New York, has declined significantly. For example, new wind projects resulted in incremental renewable capacity of between 200 and 600 MW per year, in 2008-2009, but fell to close to 100 MW by 2011.[17] In the last competitive solicitation administered by NYSERDA, the 7th Main Tier Solicitation, only a single NY wind project received an award, a 4MW expansion of an existing project.[18] As of the time of writing this report, results of the 8th competitive solicitation are not yet known.

This points to these risks playing at least some role in significantly slowing incremental development, perhaps exacerbated by the reduced ability to lock in non-REC revenues after the 2008 financial crisis.

In the next section of this paper (Section III), we discuss the potential advantages of using bundled long-term contracts to secure renewable energy development. Then in Section IV, we provide examples of long-term contracting resulting in relatively competitive outcomes. In Section V, we discuss how long-term contracting might be applied in New York, beyond the awarding of 10-year REC contracts as currently practiced by NYSERDA. In Section VI, we present some concluding remarks.

III. ADVANTAGES OF LONG-TERM CONTRACTS FOR RENEWABLES

In this section, we describe some of the most prominent advantages of long-term contracting for renewable energy.

A. Less Development Risk and Revenue Uncertainty

One of the primary reasons for using long-term contracts in the power sector is to provide some revenue security for the investors in, and lenders to, a renewable power generation project by fixing the price the project receives for the energy, capacity, and/or RECs it generates.[19] At present, renewable energy projects without a power purchase agreement ("PPA") face significant revenue risk due to the limited liquidity and tenor of existing forward markets for energy, capacity, and especially RECs. The resulting revenue risks primarily are due to fuel-cost risk and regulatory uncertainty. In the presence of a long-term contract, both risks are reduced significantly.

Once a commitment to add renewables to the supply portfolio has been made, as New York has done through its RPS and repeated in the Energy Highway Blueprint, removing or mitigating some of these revenue uncertainties reduces the costs to ratepayers of meeting the RPS. Long-term contracts that remove/mitigate market risk fit this description. A long-term contract that fixes the unit price of energy, capacity, and/or RECs – as opposed to assuring a fixed revenue

[17] NYSERDA, The New York State Renewable Portfolio Standard Performance Report, Through December 31, 2011, p. 10.

[18] *Ibid*, page A-2. One small (26 MW) operating Pennsylvania wind project also received a contract.

[19] As we point out below, "fixing" the price does not necessarily mean establishing a fixed price upfront. Long-term contracts for renewables may include various price adjustment mechanisms.

stream, per se – is consistent with this view, because it removes market risk (which investors cannot influence) but leaves investors bearing production risk (which they can influence).

For conventional power generation technologies such as coal plants or natural gas-fired combined cycle plants, upfront capital costs, while significant, represent a smaller share of the total lifetime cost than for typical renewable energy projects such as wind or solar PV (*e.g.,* 30-50% for fossil as compared to 80-95% for renewables). Once conventional generation is built, it hopes to recover the initial capital investment by earning margins in the energy and capacity markets.

While most renewable energy projects do not face fuel-cost risk (biomass projects are a likely exception), they face potentially more serious risks associated with much higher upfront costs relative to conventional generation. From a developer's perspective, renewable generation therefore requires higher levelized revenue over a longer period of time to recoup the high upfront investment, making those projects potentially even riskier energy investments than their conventional counterparts.

Because the output from renewable projects is produced at low incremental cost once a project is built, renewable projects are particularly vulnerable to the well-known "hold-up" problem in making capital investments. Investment in renewable energy projects depends on private-sector investment by individual developers, lenders, equity investors, and/or shareholders of integrated public utilities developing renewables. Given that renewable energy projects are developed primarily in response to state-level legal mandates, implemented primarily through RPS and complementary state laws, such as California's Assembly Bill 32 or Massachusetts' Global Warming Solutions Act and Green Communities Act, they are deemed to provide benefits to the affected state(s) and their respective ratepayers and taxpayers. But the level and cost of private investment capital available for renewable energy projects, and thus the magnitude and timing of their economic benefits, depend on the clarity and stability of public policy affecting renewables. The ability of regulators to change course *ex post* in ways which could lead to either stranded cost risk or a lack of bargaining power for investors, they will be reluctant to make the necessary investment upfront.

Well-established economic theory explains why long-term contracts help overcome this obstacle and why, in many situations, long-term contracts (rather than short contracts, spot market transactions) or vertical integration are in the best interests of both buyers and sellers and are thus the dominant kind of transaction.[20] A transaction will take whatever form minimizes its costs. Because contracts are costly to write and enforce, there must be net benefits associated with choosing contracts over spot markets. When a particular supply relationship relies on an investment that, once made, cannot be redeployed to support an alternative supply relationship, the party sinking the investment is potentially subject to hold-up, where the subsequent value of

[20] Ronald Coase was awarded the 1991 Nobel Prize for introducing this theory (in 1937). More recently, Oliver Williamson was awarded the 2009 Nobel Prize for related work on governance and the boundaries of a firm. See, *e.g.,* Williamson, The Economic Institutions of Capitalism, New York: Free Press, 1985. For a specific discussion of the hold-up problem in the power sector, see Richard Meade and Seini O'Connor, "Comparison of long-term contracts and vertical integration in decentralized electricity markets," EUI Working Paper RSCAS 2009/16, 2009. Much new generation in the U.S. is built by vertically integrated utilities. However, that is not always an option in restructured parts of the U.S., leaving long-term contracting as the only viable option for dealing with hold-up.

the project is expropriated by driving the price of the project's output to its marginal cost absent the initial capital costs. A long-term contract is designed to reduce the likelihood that the counterparty will attempt a hold-up by committing each side for a long period.

For example, suppose a renewable energy developer has an informal understanding with an electric utility that the utility will purchase energy from a project at a price that just covers the project's operating costs and reasonable return on the upfront capital sunk into it. That price is the lowest price the developer is willing to take and still go ahead with the project at the start. At any lower price, the developer would not recoup the upfront investment at the same return available from putting the same capital into an alternative investment of equivalent risk, and the project would not be built. After the renewable project is built, however, the capital cost of the project is sunk. Without a long-term contract, the purchasing utility could offer only lower prices, at which the developer would not have built the project in the first place. Knowing this risk, it would be difficult to find financing to get the renewable energy project built unless the utility first signed a long-term PPA to provide relative revenue certainty by creating a degree of certainty around the project's future unit prices.

The Data: Nearly All New Generation Requires Relative Revenue Certainty

Nearly all new electric generation projects, not only renewables, appear to require a high degree of revenue certainty and they largely rely on PPAs to achieve it.

A recent report of the financial arrangements underlying new U.S. electric generation projects in 2011[21] finds just two percent of new capacity (by MW) being built, regardless of technology (*i.e.,* renewable and conventional), is left to sell into the wholesale market. Sixty-one percent is owned by a utility and is used to supply its load and/or for balancing and ancillary services. The other 37 percent of new generation is developed by an independent power producer selling the output under a long-term PPA either to a utility (29 percent) or to a power marketer or individual customer (7 percent) or is customer-owned (1 percent).[22]

The percentage of new wind projects being built under long-term contracts is even higher. Only 11 percent of new *wind* projects in 2011 were built for merchant sales; 74 percent of the wind projects have a PPA and the rest are utility or privately owned.[23]

The apparent need for long-term contracts to enable the financing of renewable energy projects may reflect imperfections in wholesale energy (and REC) markets, in the sense of not permitting potential project developers to lock in the required revenues through forward sales of the primary outputs from a renewable energy project, namely energy, capacity, and RECs. There is some indication that existing wholesale markets and associated secondary markets do not provide sufficient long-term hedging opportunities. In some parts of the United States, including New York, the existence of capacity markets, which provide some revenue visibility for future years, helps alleviate this problem for traditional fossil generation. However, since most renewable

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21 Elise Caplan, "What Drives New Generation Construction? An Analysis of the Financial Arrangements behind New Electric Generation Projects in 2011," *The Electricity Journal* 25(6), pp. 48-61, July 2012.

22 Ibid, Table 2, p. 52.

23 Ibid, Table 3, p. 52.

technologies receive relatively less capacity credit, even this partial hedge is largely ineffective as a tool for lowering revenue uncertainty. Explaining exactly why this is the case is beyond the scope of this paper. But it is possible that the absence of liquid forward markets far enough into the future to lock in the necessary revenue stream for a wind or solar PV project is, itself, a reflection of regulatory risk.

Wholesale energy and capacity markets are heavily regulated and future market prices can be substantially influenced by changes in regulation. For example, regulators have imposed price caps when wholesale energy prices reached certain levels deemed politically unacceptable. If energy market prices are subject to regulatory risk, REC prices are likely even more so, because there is practically no underlying demand for RECs apart from the demand created by the RPS requirements.[24] For the most part, the form of the RPS creates relatively high volatility even before the effects of changes to the RPS are considered.[25] In addition, changes to RPS rules can have a dramatic impact on REC prices. For example, changes to the set of eligible technologies have a dramatic effect on the total supply of RECs and can thus reduce the price of RECs practically overnight. Given these risks, market participants may be reluctant to function as buyers or sellers of forward products beyond a relatively short time period, over which significant regulatory changes are unlikely or foreseeable.

An important objective of public policy in regulating power markets is to promote and protect sunk investments in projects which benefit ratepayers but otherwise would not be undertaken. The RPS in New York and other states reflect a decision that renewable energy projects are beneficial and, therefore, are to be encouraged. Given the shortcomings of forward markets for energy, capacity and RECs discussed above, long-term contracts are the most common practical tool for backing-up this policy objective with a meaningful degree of regulatory assurance where direct utility ownership of renewable generation is not allowed, as is generally the case in restructured U.S. power markets, including New York. In the absence of the relative revenue certainty long-term contracts such as PPAs provide, it is difficult to envision investor willingness to finance any electric generation, especially renewable energy projects prone to uncertainty surrounding the RPS and how the current regulatory environment will evolve over the long-term. Entering into a PPA demonstrates a real commitment to getting a renewable project up and running economically. Merely demonstrating that long term commitment through a contractual relationship is beneficial to ratepayers and helps get renewable energy projects built, as discussed further below.

B. Lower Project Cost of Capital

Increased price certainty for renewable energy projects reduces risk to the project's lenders and investors and thereby reduces the cost of capital for the project. A project's cost of capital is the rate of return required to compensate its investors at the same rate of return they would realize from available alternative investments of equivalent risk. With increased price certainty for a

[24] There is a small voluntary market for RECs as well. However, in general this market is characterized by relatively low prices, which would likely be insufficient to support significant new renewable energy development.

[25] See Weiss, "Are REC Markets a Wreck Waiting to Happen?," Natural Gas and Electricity, November 2006, for a discussion of the REC price distribution and its tendency to be either high or low, but rarely in-between.

project, investors require a lower return, which in turn reduces the cost of financing for the project, when compared with a project that relies purely on spot market dynamics for revenues. The degree of uncertainty surrounding the revenue stream of an intermittent resource, such as a renewable energy project, impacts the amount of debt financing it can attract and the cost of attracting that debt financing. In the absence of a mechanism to reduce this uncertainty, such as obtaining a long-term PPA with some level of revenue assurance based on power production, a renewable energy project (all else equal) will attract less and more costly debt and more costly equity than traditional power project operating in the same wholesale power market.

Capital market imperfections and information problems generate uncertainty about risks, which prevents both lenders and equity investors from investing in renewable projects or, at a minimum, increases the rates of return required to do so. There is both regulatory and technological uncertainty in addition to purely financial and market risk. PPAs can solve the information problem, which may not immediately or directly reduce cost, and so lower the cost of capital by removing an information barrier and by addressing the agency (hold-up) problem of relatively high initial fixed costs. Lowering the cost of capital needed to finance new renewable energy projects has been characterized as, "the opportunity for policy to create a more stable, transparent, and predictable market for renewable energy, which in turn will lower financing costs and improve the flow of capital to the sector."[26]

One obvious hurdle for renewable energy developers to clear is securing the financial capital required to build a relatively capital-intensive enterprise with high upfront costs. Typically, renewable energy projects have relied on financing both from private capital markets and tax equity investors, with state and federal incentives bridging the financial gap between a project's economics at market prices for energy and capacity and its required rate of return (*i.e.,* its cost of capital). Because investment risks differ by the type of investment, investors will require different returns for different projects – lower return when the expected risk level is low, and higher return when the expected risks are high.

Most projects are financed through a combination of debt and equity, so the cost of capital is a weighted-average of a project's cost of each. While there are a range of potentially complex financing structures for renewable energy projects, they tend to be heavily debt-financed, in part due to the existence of long-term contracts, state RPS, and public subsidies (*e.g.,* ITC, PTC, and loan guarantees). Projects without long-term contracts are generally forced to use higher levels of equity and consequently face a higher total financing costs. Generally, the riskier the investment, the less debt financing is available as a percentage of total capital.

Finance theory posits that the cost of capital of an incremental investment is independent of the capital structure of a particular asset. In practice, however, the cost of capital is estimated by observing the proportions of debt and equity in a project or company and calculating the weighted average cost of capital ("WACC"), typically on an after-tax basis.[27] Currently, New York is missing out on the relatively low-cost debt available in today's market. As we will demonstrate

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[26] Baratoff, *et al.,* "Renewable Power, Policy, and the Cost of Capital Improving Capital Market Efficiency to Support Renewable Power Generation Projects," Frederick A. & Barbara M. Erb Institute for Global Sustainable Enterprise, University of Michigan, April 2007.

[27] See Brealey, Richard, Stuart C. Myers, and Franklin Allen (2011). Principles of Corporate Finance. New York: McGraw-Hill/Irwin.

below, it is likely that only a small amount of debt can be applied to projects in markets without PPAs, such as New York, which in turn increases the cost to ratepayers relative to using PPAs, which allow for a higher share of debt.

Since there are virtually no new generation projects in the U.S. (renewable or otherwise) being built without direct utility ownership or long-term PPAs with utilities,[28] no data are available to directly compare the cost of capital for projects built with and without PPAs. Therefore, it is difficult to directly quantify the beneficial impact of PPAs on the cost of capital for renewable projects. However, some empirical evidence from Europe provides useful benchmarks. One study analyzed the specific project financings of four large-scale renewable energy projects: a 20 MW onshore wind project, a 100 MW offshore wind project, a 0.5 MW solar PV project, and a 10 MW biomass co-generation project. It evaluated the financial performance of the projects under different representative policy regimes, including feed-in tariffs and renewable quota obligations.[29]

The key difference between these policy regimes is the degree of revenue certainty they create for renewable energy projects. Feed-in tariffs are designed to accelerate investment in renewable energy projects by offering long-term contracts, usually on a cost-plus basis, where the "plus" includes the return to investors for the risks they bear. Renewable quota obligations, such as state-level RPS in the U.S., set a minimum quantity of generation from renewable energy projects in a given year, but they create less certain revenues (*i.e.,* price x quantity) than feed-in tariffs which offer guaranteed power purchases under long-term (*e.g.,* 15–25 year) contracts.

The study found that the levelized cost of electricity is lower by 10 to 30 percent, depending on the project type, in regulatory regimes that convey a long-term policy commitment to renewable energy through a stable and reliable commitment mechanism. This happens because increased predictability reduces regulatory risk and hence significantly reduced the cost of capital of renewable energy projects. Countries with feed-in tariffs (France, Germany) and long-term contracting procedures (California and Quebec and more recently Massachusetts) have already realized a significant part of this cost reduction potential, more than 20 percent, for onshore and offshore wind and solar PV projects.

Similarly, a 2011 report by the Climate Policy Initiative[30] used six case studies, three from the U.S. and three from Europe, to estimate the impact of various aspects of revenue and cost drivers on the total levelized cost of wind and solar projects. It identified the length and certainty of revenue support as the top two drivers determining the financing costs of renewable projects. It estimates that 10 fewer years of revenue support increases financing cost as a percentage of the cost of electricity without support by 10 to 15 percent. Similarly, the impact of changing from a fixed priced revenue support, through a feed-in tariff or a PPA, to a mix of fixed support and market prices, increases financing costs representing 4 percent to 11 percent of the levelized cost

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28 Caplan, July 2012, *op. cit.*

29 Ecofys, "Policy instrument design to reduce financing costs in renewable energy technology projects," for the IEA Implementing Agreement on Renewable Energy Technology Deployment, October 2008.

30 Uday Varadarajan, David Nelson, Brendan Pierpont and Morgan Hervé-Mignucci, The Impacts of Policy on the Financing of Renewable Projects: A Case Study Analysis, October 2011.

of power from such projects.[31] Notably, the impact of facing market risk is greater than the impact of facing resource availability or technology risks associated with renewable technologies. The scenario modeled in the study, a comparison of a fixed PPA and a market price with a fixed premium for renewables, closely approximates the difference between the current situation in New York, where renewable generators receive market revenues for energy and capacity and a fixed premium for RECs and a long-term contract for all products.

Just lowering a project's debt cost by as little as one to two percentage points through the use of PPAs can decrease the resulting levelized cost of electricity significantly, according to the studies. PPAs also have beneficial effects on other key financial metrics as well, such as the overall amount of debt a project can assume and the terms and conditions of its debt. A project able to assume more debt at a lower debt cost can generate and sell power at a lower levelized cost. In a relatively competitive market setting, that would translate directly into lower power prices for the ratepayers buying energy from the project.

Example: Lowering the Cost of Capital Lowers the Levelized Cost of Energy

Consider, for example, the cost of capital for a typical onshore wind project with and without a PPA, excluding any federal incentives such as the Production Tax Credit.

Without a PPA, the project will be financed mostly with equity rather than debt, due to the credit risk of a developer with an uncertain and potentially volatile revenue stream. If the project is financed with 70 percent equity at a required rate of return of 12 percent and 30 percent debt at a 7 percent interest rate, then its after-tax weighted average cost of capital is 9.8 percent:

$$\begin{aligned} WACC &= \left(\frac{E}{D+E}\right) \times R_E + \left(\frac{D}{D+E}\right) \times R_D \times (1-t) \\ &= 0.70\ x\ 0.12 + 0.30\ x\ 0.07\ x\ (1-0.35) \\ &= 0.098 \end{aligned}$$

The same project financed under a long-term PPA is less risky for potential lenders (and equity investors). Rather than facing the uncertainty of future spot market conditions, a PPA essentially confers to the project the risk profile of the buyer, typically a utility with a regulated rate of return. As a result, the project is able to attract more debt at a lower cost.[32] Contracting with a creditworthy entity allows the renewable energy developer to obtain financing at a lower rate than it otherwise could, because the more creditworthy entity has a lower cost of debt. Similarly, investors in such projects face lower risks, lowering the expected rate of return required. The overall degree of risk associated with the project is unchanged, but the cost of bearing that risk is lower. Since New York has already committed, through the RPS, to developing renewable energy projects, long-term contracting simply helps assure ratepayers pay the lowest cost for this renewable generation.

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[31] *Ibid,* pp. ii-iii and p. 19.

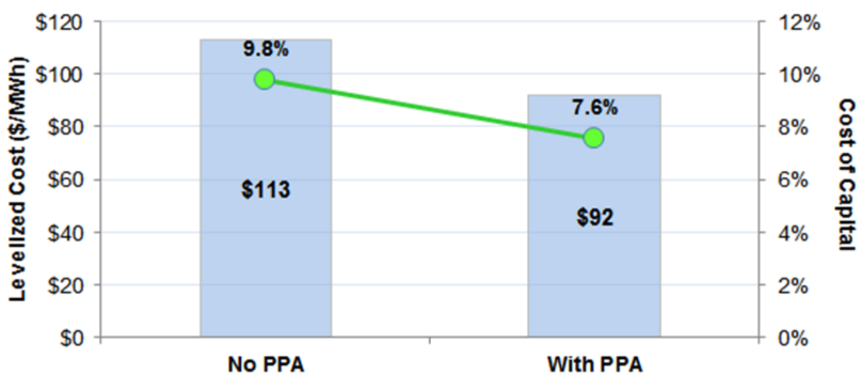
[32] In turn, the project also requires less equity, and may be able to attract equity at a lower cost as well. To the extent PPAs make the project more attractive to both debt and equity investors, they help to create an economic incentive to develop such projects, and to do so at the lowest possible cost. For simplicity, this example assumes the cost of equity remains unchanged.

There is some evidence that projects supported by PPAs are able to employ project-level non-recourse debt for 70 percent or more of total project capital.[33] If the onshore wind project in the example above can change its financial structure by attracting 55 percent debt financing (rather than 30 percent) at a 6 percent cost of debt (rather than 7 percent in the absence of a long-term contract), and assuming the required return to equity stays at 12%, its after-tax cost of capital drops to 7.6 percent:

$$WACC = \left(\frac{E}{D+E}\right) \times R_E + \left(\frac{D}{D+E}\right) \times R_D \times (1-t)$$
$$= 0.45\ x\ 0.12 + \mathbf{0.55}\ x\ \mathbf{0.06}\ x\ (1-0.35)$$
$$= 0.076$$

This represents a significant decrease of almost 20 percent relative to having no PPA. Assuming capital costs of $2,000/kW, $30/kW-year in fixed operating and maintenance costs, $6/MWh in variable costs, and not including the value of the PTC, the levelized cost of energy at a 9.8 percent cost of capital is roughly $113/MWh,[34] as shown in Figure 1 below. At a 7.6 percent cost of capital, the levelized cost drops to $92/MWh, a decrease of $21/MWh or 19%.

Figure 1: Illustrative Change to Levelized Project Cost due to PPA



Since, in either case, the project just covers its costs plus its cost of capital, it could afford to pass through the entire $21/MWh in cost reduction to ratepayers. In a competitive procurement process, that is exactly what would happen, since all projects would have an incentive to offer the lowest possible pricing. Thus, the ability for the project developer to enter into a long-term contract with a credit worthy counterparty helps the project get built and/or lowers the cost of doing so. Even if not all of the cost savings get passed on to ratepayers through lower rates (*e.g.,* leaving some money on the table for the developer to have an incentive to lower the project's

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[33] For example, Robert Grace, Jason Gifford and Wilson Rickerson, Renewable Energy Cost Modeling: A Toolkit for Establishing Cost-Based Incentives in the United States, NREL March 2010 — March 2011, p. 67, assumes that renewable projects operating under the FIT/PPAs in Ontario, Canada are financed with 70% project debt (p. 74).

[34] This assumes the project sells all of the energy it generates at a 33 percent capacity factor and at prices just sufficient to cover its costs and the cost of capital (*i.e.,* cost-plus). It also assumes cost inflation of 2.5 percent per year, a 20-year project life and 30-year debt and equity terms.

cost), the project still gets built at a cost to ratepayers that is lower than what would happen absent the long-term contract, thus reducing the cost to ratepayers of meeting the RPS.

While the numbers presented here are indicative and not related to any real project, they broadly represent the changes in financing structure and resulting cost of capital corresponding to the two types of funding: merchant and with a long-term contract. To illustrate further the impact of a lower cost of capital, enabled by a long-term bundled contract, on New York's cost of meeting its RPS, we can use the difference in cost of capital and the resulting change in levelized cost to estimate the change in total payments for RECs to NYSERDA (and therefore to New York ratepayers) resulting from providing long-term price certainty for renewable projects.

Assuming that electricity and capacity prices remain unaffected by a move to long-term contracts for renewable projects, the change in cost of capital translates into a lower implicit payment needed for a project's renewable attributes. In the case above, a reduction of the levelized cost of capital from $113/MWh to $92/MWh would be equivalent to a decline in implicit REC prices by $21 per REC over the entire life of the project. However, estimating the impact on required payments for RECs of moving from 10-year REC only contracts to 20-year bundled contracts also requires taking into account the facts that:

a) any costs in excess of market costs for conventional generation (equivalent to REC revenues) will have to be recovered during the contract term, and

b) moving to a 20-year contract term will mean NYSERDA would have to pay RECs for 20 years, rather than only 10 years.[35]

Intuitively, project developers under the current rules likely would need a significantly higher REC price during the current 10-year contract term than under a 20-year contract because the bulk of costs would have to be recovered over a shorter (10-year) period, and total project costs would be higher than under a 20-year contract because of higher financing costs as described above. On the other hand, New York ratepayers would have to provide REC payments for only 10 years under the current rules, and for 20 years under a 20-year contract. To estimate the relative total payments for New York ratepayers, we calculated the average 10-year and 20-year payments per REC necessary for project developers to just earn their required return, assuming the levelized costs of our illustrative example. Because the required payments under the two approaches take place over different lengths of time, a comparison between the two requires an assumption about the time preference for money, or the discount rate, to be applied to REC payments made in the future. There is a large literature on appropriate discount rates for public expenditures and a detailed discussion is beyond the scope of this paper. At the low end, without discounting, our sample calculations show that the equivalent 10-year REC price could drop by approximately $9/REC[36] when moving from a 10-year REC only contract to a 20-year bundled contract. At the

[35] It also would have to pay for energy for 20 years. However, for reasons of simplicity we assume actual market prices equal expected market prices.

[36] We use a simple discounted cash flow model to calculate the change in REC prices. Using the levelized costs and financing costs assumed in the example above, we calculate the REC payments necessary to make total discounted revenues equal to discounted levelized costs under the assumptions that such REC payments are received for 10 years and 20 years, respectively. The fact that under the suggested 20 year contract energy payments also would be received under contract is reflected in the lower levelized cost and financing costs under this option. To compare "apples to apples", we converted the resulting

higher end, assuming a 5% public discount rate, the corresponding drop in equivalent 10-year REC prices would be almost twice as large (close to $18/REC). [37]

As of December 2011, NYSERDA had committed to REC contracts covering 1,841 MW of large-scale renewable projects representing 48% of its 2015 target of generating 10.4 TWh from renewable energy sources under the Main Tier Program.[38] This means that by 2015, New York will have to add sufficient capacity to generate approximately 5,103 GWh of additional renewable electricity generation. The decline in REC costs in one single year, 2015, stemming from a move towards long-term contracts and associated decreases in financing and consequently levelized cost, would then be roughly 5,103,000 MWh multiplied by $9/MWh (the implied decline in REC prices over the equivalent of 10 years, even though actual REC price declines would be stronger in the 20-year contract case, with REC prices being paid for 20 rather than 10 years), or $44 million per year.[39] The higher REC prices due to the absence of long-term contracting therefore imply that **NYSERDA may have to pay approximately $445 million more to meet the 30% RPS by 2015 than it would pay if renewable projects benefitted from the revenue stability afforded by (bundled) long-term contracts and associated decreases in financing costs, even without considering the time value of money (no discounting). This represents approximately 10% of the expected remaining cost to meet the 2015 RPS target. Assuming a 5% public discount rate, the savings relative to the current approach would double to almost $1 billion**.

This simple calculation therefore shows that the lack of revenue predictability for renewable generation afforded by long-term contracts and available in other jurisdictions, which are ramping up their renewable generation, could mean that New Yorkers pay a significantly higher cost for their renewable generation than ratepayers elsewhere.

It is important to note that, depending on the nature of the counter party to the long-term contract, costs to ratepayers may not decline *dollar-for-dollar* with the levelized cost of the renewable project. If the counterparty is a private unregulated entity, the cost of capital to such a buyer may well increase as a result of signing the contract for two reasons. First, the long-term contract could be considered a form of debt, since it creates an obligation for the utility to make payments to the project developer for the duration of the contract. This increased leverage can increase the

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20-year REC price into a 10-year REC price. Without discounting, this simply means multiplying the 20-year REC price by two. In the discounted approach, we use the difference in discounted net present values and divide by 10 years.

37 Since our example does not include the impact of the Production Tax Credit, actual levels of REC prices would likely be lower than in our examples.

38 See NYSERDA, The New York State Renewable Portfolio Standard Performance Report, Through December 31, 2011, pp. 3-4.

39 It is not easy to calculate the expected savings from long-term contracts for bundled power, which our examples assume to be for 20 years, within the structure of NYSERDA's current 10-year REC program. We used a simple levelized cost analysis to calculate the contract prices that would be needed to generate revenue streams from contract sales and market sales post contract to be exactly sufficient to cover all expenses including the cost of financing. In this calculation, assumptions about future market prices matter. For reasons of simplicity, we have assumed a constant $60/MWh and no value of RECs beyond payments under any contract offered. Also, we use a range of public discount rates (lower than the private costs of capital we use) to estimate the impact of discounting on potential program savings through long-term contracting.

utility's cost of debt. Second, at least some of the regulatory risk shifts from project developer to the utility, which also can increase the utility's cost of capital. On the other hand, it is also possible that avoiding exposure to electricity price volatility will have the countervailing effect of lowering such a buyer's cost of capital.

If, as will often be the case, the developer's counterparty is a regulated utility, one way to limit the latter of the two risks mentioned above is by getting regulatory approval for the contract at the time of signing, thus creating a strong expectation that the incurred costs can be recuperated through rates, if necessary. If the counterparty is a public entity, such as NYSERDA in New York or another public agency, the risks of ex-post regulatory changes are in fact born by the entity directly or indirectly responsible for the regulation in the first place and thus ultimately by all ratepayers as citizens. Since regulations such as an RPS are decisions ultimately made through democratic processes – the RPS is the result of regulation enabled by underlying legislation- the collection of citizens, in one way or other bears this regulatory risk.

While ratepayers may or may not realize every dollar of the cost savings from long-term contracting, the net cost of meeting the RPS for ratepayers will decline, as a regulated utility, especially with regulatory approval for the contract, will likely have a lower cost of capital than a renewable developer, and also will face lower regulatory risk – in essence a lower hold-up problem.

C. More Renewable Projects Get Built

If the economics of a renewable energy project on pure market terms cannot cover its cost of capital, the project will either not be built or it will fail. Some renewable projects face non-trivial regulatory and technological uncertainties in addition to market and revenue risks. Renewable energy projects typically involve large capital investments that must be incurred upfront at the construction stage of a project. These capital costs form the majority of the cost of the power produced from wind and solar projects since there is no fuel cost and the variable maintenance costs tend to be relatively small when compared to the upfront capital cost.

These capital costs are uncorrelated with future market prices for electric power. Operating and maintenance costs are also unrelated to market prices. This is fundamentally different from traditional power generation technologies, most notably natural gas-fired generation, since the cost of natural gas as input into the power plant affects the market price of the power. The same holds true for coal-fired generation although to a lesser degree and only in certain regions and/or time periods (when coal-fired power generation sets the market price). For the traditional power generation technologies, a significant share of a project's total lifetime cost is variable (*e.g.,* fuel-related) costs, and market prices are effectively set by fuel prices, creating a natural hedge between the fuel prices and power prices. For renewable energy projects, the absence of this natural hedge between fuel prices and project cost creates substantial risk around renewable energy projects. This is particularly so for debt holders.

Because lenders, unlike equity investors, generally have no possibility of earning "upside" beyond the stipulated debt interest rate, they must apply conservative criteria in a project finance credit evaluation. Renewable energy project developers can only secure project financing if lenders are highly confident that cash flows from the project will be sufficient to repay principal plus interest. The most important factor that can provide this confidence is a long-term contract to sell power (and other products produced) at predictable prices. With a PPA, even relatively small companies with a limited track-record and limited borrowing capacity may be able to develop renewable energy through project financing.[40] Without a PPA, the share of a project that lenders are willing to support through project financing drops substantially. In either case, there is some evidence that post-financial crisis lenders willingness to finance renewable projects has declined or become more costly.[41]

As a renewable project increases its financial leverage, however, its cost of equity may also increase. The more debt the company has in its capital structure, the greater its financial risk. Risk tolerances and revenue needs vary considerably by type of investor. To underwrite project finance loans with no upside opportunities, lenders must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error.[42] Diversified borrowers can partially offset project-specific risks and can borrow at lower cost across a range of project types. However, an undiversified borrower with little or no performance track record relying on substantial leverage through project-specific, non-recourse debt financing and relatively little equity, such as a prospective renewable energy project, might ultimately be pushed out of the market unless it can secure a long-term PPA.

PPAs can be tailored to reduce risk to both project stakeholders and buyers. In any number of ways, depending on the circumstances, PPAs can be designed to allocate cost savings between project developers and buyers. This assures that renewable energy projects actually get built, that payments are sufficient to recover capital costs and that the prices ratepayers pay for renewable power going forward are reasonable, given a project's costs.

While contracting for renewable energy through a long-term PPA may reduce project risk, it does not entirely eliminate it, and renewable energy projects still face additional significant risks and uncertainties outside of a particular project. For example, any long-term PPA prices negotiated today for renewable energy projects in the U.S. bear significant risk around development costs. Renewable energy projects for which there is relatively limited development experience (*e.g.,* offshore wind) introduce the most uncertainty and cost risk.

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[40] There is some evidence that, in New York, *i.e.* in a situation where only RECs can be sold under a longer term, *i.e.*(10 –year) contract, but energy and capacity have to be sold either on spot markets or on shorter term forward markets, larger developers with large enough balance sheets not requiring third-party project debt have become more dominant as they can diversify project and regulatory risk over many projects and jurisdictions. See Summit Blue Consulting and Nexus Market Research, New York Renewable Portfolio Standard Market Conditions Assessment, Final Report, February 2009, pp. 4-21.

[41] For a discussion of the impact of the financial crisis on renewable energy financing see, *e.g.,* Schwabe, Cory, and Newcomb, Renewable Energy Project Financing: Impacts of the Financial Crisis and Federal Legislation, NREL, July 2009.

[42] Lenders typically use debt service coverage ratios, *i.e.* a measure of the multiple of certain cash flows relative to interest and principal payments related to debt, to assess the ability of a project to take on project-level debt. A minimum debt service coverage ratio and a given certain revenue stream implies a maximum amount of project debt. Lenders are generally conservative when assessing the certainty of revenue streams. For example, revenues from energy and capacity sales into highly volatile markets may only be given a relatively low certainty equivalent relative to energy and capacity sales under a long-term contract.

Two Types of Long-Term Contracts

It is important to distinguish between long-term contracts that are intended to compensate the seller for the cost of building a plant (or other piece of infrastructure) versus contracts that try to compensate the seller or buyer for the opportunity cost of the products produced by the plant.

In the power sector, contracts with QFs under PURPA pay generators the avoided cost of generation, an estimate of the alternative cost of building, owning and operating a plant with comparable attributes. This is an example of a contract designed to compensate the seller for the associated opportunity cost, as are many long-term contracts associated with the development of natural gas fields, natural gas pipelines or LNG facilities.

By contrast, long-term contracts for new power plants including renewable power projects, such as those signed in California or Massachusetts and further discussed below, are often the result of competitive procurement processes and result in contract prices equal to (or close to) the actual estimated economic cost of building a facility, irrespective of future market conditions. These contracts have the advantage that they are less subject to being out of line with economic realities ex-post, as can be the case with QF contracts if avoided cost calculations end up being incorrect and too high. Cost-based contracts also closely resemble the contractual equivalent of vertical integration, i.e. of a regulated utility building and owning a power plant rather than signing a contract with a third-party for doing so. In addition to mitigating the risk of prices being "too high", long-term contracts for renewables also do not result in a risk of over-procurement. Rather, the quantity of renewable energy procured is typically well known in advance and limited by both the RPS target itself and the proportion of the target procured in each round of a process that tends to be repeated in stages over time.

However, cost-based contracts result in two potential risks of their own. First, the winning bidder's actual cost of building the project may end up being lower than the estimate reflected in the long-term contract price. Second, at some point in the future, due to a variety of factors including technological progress, the cost of building a similar project may decline, making the contract price look high *ex post*.

When vertically-integrated utilities build power plants, the regulatory approval process attempts to limit both risks. When signing long-term contracts with third-parties, the risk of contract prices being seemingly too high after the fact due to technological progress and other factors making similar projects less expensive in the future is real, but is addressed in a similar way if the counterparty is a regulated utility, namely by seeking regulatory approval for a contract. It is also possible that under certain circumstances, notably for quickly evolving technologies and projects with long lead time, it is possible to deal with the second risk to buyers under such a contract, namely that contract prices represent an estimate of project cost that is higher than actual costs. We point to one example of such a learning contract with residual incentives for developers below.

PPAs signed under such circumstances create risk for both parties: project developers bear the risk that actual costs may be significantly greater than those projected and therefore need to include that risk premium into the price, and buyers and consumers bear the risk of overpaying if the actual costs are significantly lower than those projected and reflected in the PPA if the PPA is cost based, or that payments under the PPA are higher than market prices ex-post, as illustrated in the text box above.[43] However, under specific circumstances, notably when technology risks remain high (due to the immature nature of the technology) or lead times are long,[44] building adjustment factors into PPA terms can create some degree of certainty for both parties, and ultimately ratepayers. Such price adjustments balance the need for relatively certain project revenues to developers and costs to ratepayers and the need to protect ratepayers from unanticipated out-of-market costs in the future. Most importantly, if the long-term contract is the consequence of a competitive procurement process or if it is a contract that is explicitly cost-based, including financing costs, then ratepayers have the assurance of paying the lowest possible prices over the term of the contract on an *ex ante* basis.

D. Lower Cost to Ratepayers of Meeting the RPS

Long-term contracts to meet RPS under competitive procurement essentially result in cost-based pricing, with a financing cost commensurate to the risk born by investors. This is a critical distinction relative to simply comparing the outcome under a PPA with a renewable project to power purchases from non-renewable generation sources *ex post* over time. Once the policy decision has been made to commit to a certain amount of renewable projects in any given year, as is the case under most RPS regimes, market prices for energy and capacity, today or in the future, are no longer the relevant benchmarks for assessing whether any given project is cost-effective or not.

If the RPS creates no upper boundary to the cost of renewable energy projects relative to conventional fossil generation, then ratepayers can be deemed to benefit from the construction of renewable energy projects independent of cost as long as the renewable energy facilities that are constructed are chosen based on a procedure that leads to competition amongst potential projects. Many RPS programs do however include a hard or soft cap on the premium renewable projects can receive over and above other market-based revenues. Often, this cap takes the form of an alternative compliance payment ("ACP"). With some form of a cap, renewable projects resulting from a competition-inducing process such as competitive procurement should then be deemed beneficial to ratepayers if, at the time of signing, as long as they receive pricing below this cap.[45]

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43 We assume that for renewable projects ratepayers care about meeting environmental goals, such as the RPS, at the lowest cost. In that case it is desirable that procedures to sign PPAs be competitive. Nonetheless, it is possible that at the time of the signing of a PPA the actual construction costs are as of yet unknown. In that sense ratepayers bear the risk of overpaying for a project if the project developer is able to build the project at a lower cost than what has implicitly or explicitly been assumed as the cost basis for the PPA.

44 For example, building a renewable energy project using a new technology may involve large lead times and high uncertainty concerning the actual construction costs at the time such a project would be built. With large lead times, actual financial market conditions at the time financing must be obtained may be unknown. Consequently, if a political desire exists to support an emerging technology through a commitment through long-term contracting it may be appropriate not to lock-in assumed cost parameters sometimes many years prior to actual project completion and without the benefit of learning about actual project and financing costs as a project proceeds.

45 In some instances it may be in the ratepayers interest to incur higher costs. For example, to the extent higher costs for a contract signed today contribute significantly to the developing of an emerging technology and associated learning and scale benefits, the total costs to ratepayers of meeting renewable energy targets over

Under this type of contract, developers essentially accept a cap on total project costs that can be recovered through the contract. If a project costs more to build than anticipated, ratepayers are insulated from the cost overruns, which lower the developer's profits instead. Especially for emerging technologies, accurately estimating the cost of a project can be tricky and the associated risks significant. On the other hand, it is also possible that the ultimate cost of a project could be lower than the pricing reflected in a contract, which is likely based on an estimate (assuming a contract is signed prior to completion of a project).

As discussed above, under certain specific circumstances (such as long lead times and uncertain technology costs) contracts can be structured so buyers will not end up paying for open-ended rates of return to a project's developer or equity investors. Instead, the PPA can promote an equitable and economically efficient allocation of the relative benefits and risks. In general, PPAs under such circumstances can be structured to give developers an incentive to minimize project costs in exchange for a share of the realized cost savings, while returning to ratepayers the balance of the cost reductions which would have otherwise entirely gone to the project in the form of a higher rate of return.[46]

The text box below provides an example of modifications to a PPA that creates benefits from lower actual project costs while maintaining incentives for project developers to build projects at the lowest cost. Therefore, PPAs make it not only more likely that renewable energy projects get built, but that the developer, investors, and buyers all have a greater degree of certainty about the relative costs and benefits of the project.

time may be lowered by "overpaying" for some technologies relative to the market or relative to the pricing of other renewable technologies today.

46 We do not suggest that developing PPA terms to provide optimal incentives under such circumstances is easy. However, as our example indicates, there are mechanisms that have been proposed and which, at least in theory, should provide better incentives than standard PPAs with fixed upfront commitments in the narrow circumstances described above.

An Unlikely Model: Adjustment Factors in the Cape Wind PPAs

The PPAs between the Cape Wind project and two utilities in Massachusetts are unique. However, they are also examples of long-term contracts designed both to get a renewable energy project built and to explicitly create a degree of price certainty for both the project and the buyers in a situation where there remains significant uncertainty about the cost of an emerging technology – in this case offshore wind – and project lead times are long, leading to substantial uncertainty about ultimate financing costs.

Importantly, the Cape Wind PPAs did not result from the typical competitive solicitation process in place to meet Massachusetts' renewable energy targets. The PPAs were privately negotiated and then approved by the regulator. Also, offshore wind is relatively costly, and the Cape Wind project in particular has been a subject of some controversy. In that sense, it is not a natural example of efficient contracting. However, the adjustment mechanisms in the Cape Wind PPAs are worth noting.

They include various downward price adjustments that give ratepayers a share of the project's expected future benefits and any cost savings relative to the expected cost of the project at the outset. For example, the PPAs include an adjustment for lower debt costs, giving ratepayers 75 percent of any reductions in the after-tax financing costs of the project.[47] In that way, the PPAs tie the cost ratepayers will pay to the project's actual cost, while giving the developer an incentive to minimize that cost. In addition, the PPAs give ratepayers the option of extending the PPAs beyond their initial 15-year term at cost-plus pricing.

For Cape Wind, the revenue certainty provided by the PPAs was critical to the prospect of getting the project financed. For the utilities and ratepayers, the various adjustment factors designed to price-protect them as buyers were equally critical. While Cape Wind is a unique case, it demonstrates the ability of PPAs for renewable energy projects to create both sufficient price certainty and future flexibility to take into account the respective opportunities and risks faced by developers and buyers in signing long-term contracts.

In summary, this section shows that assuming meeting an RPS target is desirable, long-term contracts likely lower the costs relative to the situation where all or some of the revenue streams from a renewable project are subject to spot market risk (as long as contracts are either the result of a competitive procurement process and/or written with clauses creating incentives to build renewable projects at the lowest cost).

IV. EVIDENCE OF THE IMPACT OF LONG-TERM CONTRACTS ON RENEWABLE ENERGY DEVELOPMENT

In this section we provide case examples from California and Massachusetts where long-term power purchase contracts have been used to procure renewable energy resources. These examples demonstrate that long-term contracts have been used successfully in several states to meet the renewable energy policy mandates. Specifically, we provide one example of a state, California, which not only has the United States' most ambitious renewable energy targets, but which also has used long-term contracting as the primary tool for meeting this ambitious goal, with considerable success. We also examine the experience in Massachusetts, which over time has

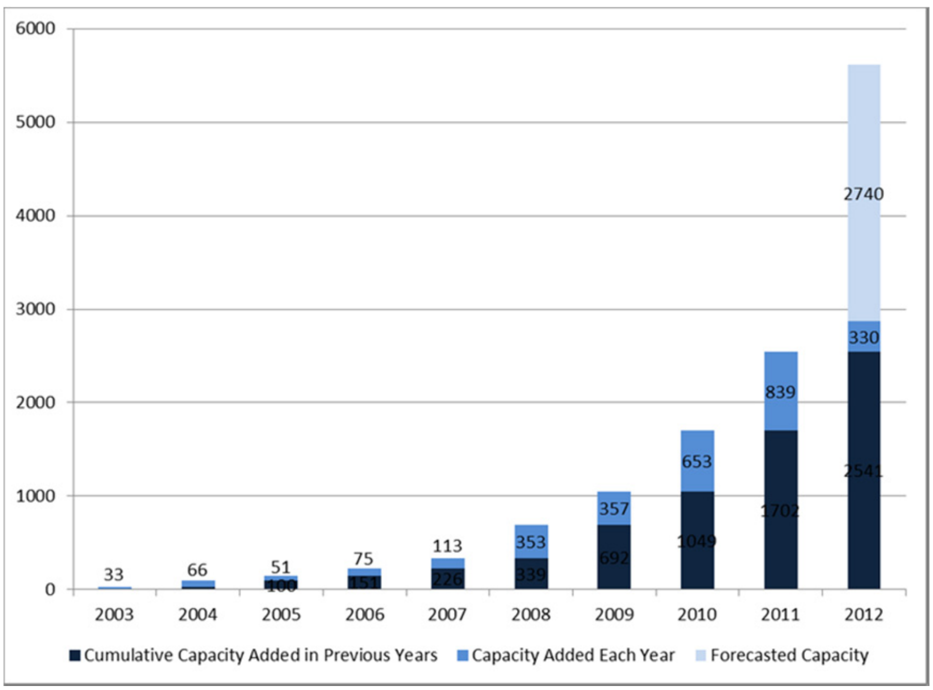
[47] Amended PPA, Appendix X to Exhibit E, Section 3.

been moving towards increased use of long-term contracts after falling short of its own renewable targets early on when relying on renewable procurement mechanisms other than long-term contracts alone.

A. California

California is often seen as a leader in the development of renewable energy in the United States. Given the size of the state economy, the renewable electricity target of 33 percent by 2020 is likely the most ambitious in the United States, at least in relative terms. It seems therefore appropriate to look at how California plans to reach its ambitious targets. Figure 2 below shows how renewable electricity has been growing in the state since 2003.

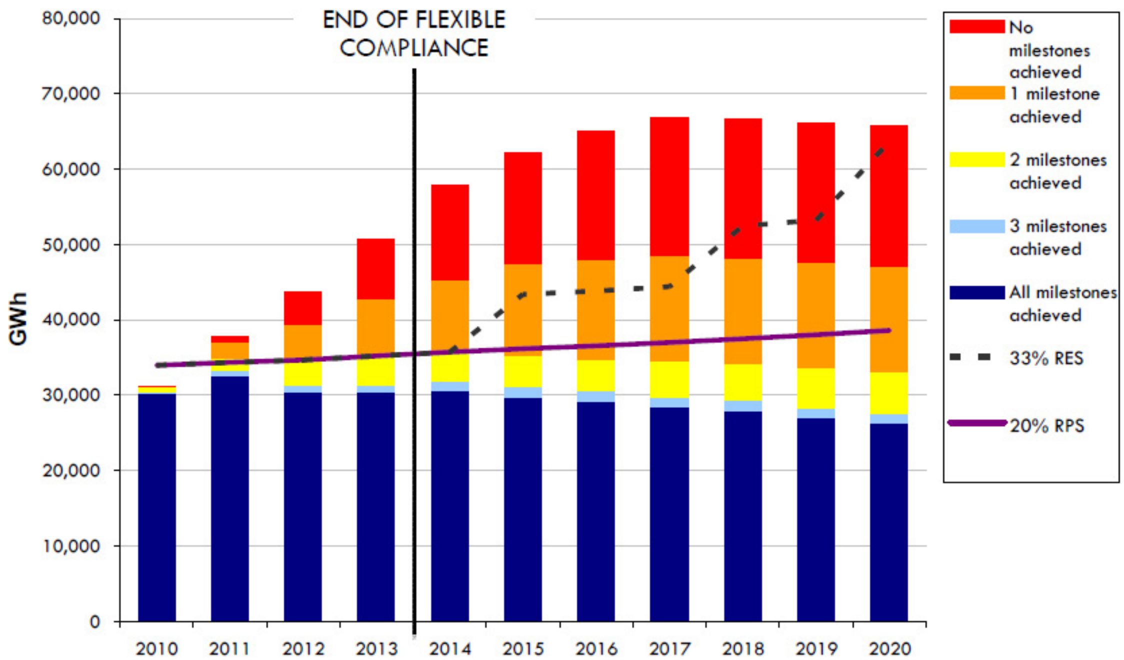
Figure 2: RPS Capacity installed per year since 2003



Source: Reproduced from Figure 1, California Public Utilities Commission, Renewable Portfolio Standard Quarterly Report, 1st and 2nd Quarter 2012

As Figure 3 below shows, there is some indication that California has ramped up renewable electricity development so fast that it is now clearly on a path to reaching its ambitious goal.

Figure 3: California's Renewable Development Path relative to RPS Targets



Source: Reproduced from Figure 1, California Public Utilities Commission, Division of Ratepayer Advocates, *Green Rush: Investor-owned Utilities Compliance with the Renewables Portfolio Standard*, February 2011

To date, the vast majority of compliance with the California RPS has been through the signing of long-term contracts for bundled electricity and RECs. More specifically, the RPS allows the three large investor-owned utilities to contract with renewable generators using either bilateral contracting or through the annual issuing of Requests for Offers ("RFOs"). The RFOs are preceded by an annual RPS procurement plan submitted to the California Public Utilities Commission ("CPUC"). Until 2008, all procurement for renewable energy was through bundled contracts.[48]

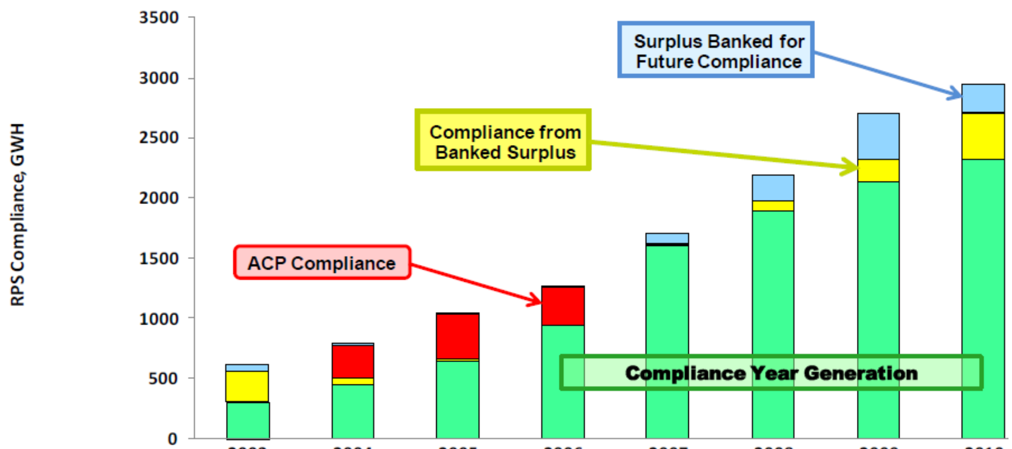
[48] See, *e.g.,* Kamins and Stoddard, *California's Renewable Energy Portfolio Standard: Implementing one of the most ambitious renewable energy standards in the country*, CPUC, April 2008.

Recent revisions to the RPS allow procurement of unbundled products for some portion of the overall RPS obligation. The portion of the total obligation required to be procured through bundled products is 50 percent between 2011 and 2013 and increases to 65 percent between 2014 and 2016 and to at least 75 percent between 2017 and 2020. At the same time, the portion of the RPS obligation that can be met through "REC-only" contracts declines from up to 25 percent between 2011 and 2013 to 15 percent and ultimately 10 percent after 2017.[49] Consequently, by 2017 and thereafter at least between 75% and 90% of RPS procurement will be for bundled products.

B. Massachusetts

Massachusetts provides evidence on the importance of long-term contracting for two reasons: First, like California, Massachusetts is generally seen as a state aggressively pursuing renewable energy. However, as Figure 4 below shows, early ambitions created through its RPS failed to develop sufficient renewable energy sources to meet the state's RPS. As a consequence, Massachusetts policies towards renewable electricity have been evolving. In particular, Massachusetts renewable energy support has been moving towards increasing reliance on long-term contracting, in part as a result of relatively slow renewable development in the early years of the state RPS.

Figure 4: Massachusetts RPS Compliance since 2003



	2003	2004	2005	2006	2007	2008	2009	2010
Surplus Banked	61	20	1	9	81	211	386	241
ACP Compliance	0	265	368	323	11	1	0	4
Compliance from Banked	255	61	20	2	7	81	190	381
Compliance Year Generation	304	445	645	939	1600	1896	2130	2324

Source: Figure One, RPS Class I Compliance, 2003-2010, Massachusetts Renewable and Alternative Energy Portfolio Standards (RPS & APS) ANNUAL COMPLIANCE REPORT FOR 2010, January 11, 2012, page 11.

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49 See CPUC, *Decision (D.) 11-12-052 on Portfolio Content Categories implements SBx1 2 restrictions on unbundled renewables*,

Massachusetts established its RPS as part of its electric industry restructuring legislation in 1997. In 2002, the Division of Energy Resources ("DOER") adopted RPS regulations requiring a share of 4 percent renewable electricity by 2009. At the time, it was assumed that the RPS by itself would lead to the least-cost renewable energy generation sources to be built. However, early experience with the RPS showed that project developers found it difficult to obtain financing for their projects based on uncertain revenues from the wholesale energy and capacity markets and from the sale of RECs. Part of the problem was perceived regulatory risk, given that the Legislature and Executive Branch could revise or repeal the RPS at any time. Also, even if the RPS remained unchanged, predicting future REC prices was difficult.[50]

Over time, it also became clear that the RECs market for Massachusetts is quite volatile. Because a majority of the renewable resources built in New England and adjacent power pools like New York, Quebec, and New Brunswick all can qualify to meet Massachusetts' RPS requirements, changes in the public policies in other New England states can dramatically affect the REC prices in Massachusetts, creating uncertainties in the RECs market for Massachusetts renewable project owners. Those uncertainties create significant volatility in the REC prices and the revenue stream that project owners can expect.

To address these concerns, the Massachusetts Technology Collaborative ("MTC") established the Massachusetts Green Power Partnership ("MGGP") in 2003. Through the MGGP, MTC offered to purchase RECs under 10-year contracts as well as to sell various financial instruments designed to lower the revenue risk associated with selling future RECs, in particular various types of option contracts.[51] Under the MGGP program, MTC initially made 13 awards with a total obligation of $73.4 million. Some of these projects were later cancelled or received other funding, but MTC claims that MGGP funding helped secure 99 MW of new renewable capacity.[52] Nonetheless, development of renewable energy in the early years of the RPS was sluggish, with a significant portion of the RPS compliance obligation being covered through payments of the ACP rather than through RECs that have been generated through actual renewable energy production.[53] There is therefore at least some indication that firming up REC revenues for 10 years was insufficient to stimulate the investment needed to meet the RPS target.

With the passing of the Massachusetts Green Communities Act ("GCA") in 2008, the state's RPS goal was increased to 15 percent by 2020 and increasing by 1 percent per year for years beyond 2020.

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[50] MTC, *Renewable Energy Results for Massachusetts, A Report on the Renewable Energy Trust Fund 1998–2008*, p. 9.

[51] Nils Bolgen, *Using Long-Term REC Contracts to Help Developers Secure Project Financing*, Massachusetts Technology Collaborative, 2004

[52] MTC, *Renewable Energy Results for Massachusetts, A Report on the Renewable Energy Trust Fund 1998–2008*, p. 9.

[53] Rick Hornby, Ben Warfield, Robin Maslowski, *Role of Long-Term Power Purchase Agreements in Fostering Development of Wind Energy Projects in New England*, Synapse Energy Economics, Inc., December 2007, pp. 1-2.

The GCA not only increased the RPS targets, it also included, for the first time, a formal requirement for the regulated distribution utilities to purchase a portion of the state's renewable energy requirement under long-term contract. This policy change was in part due to evidence suggesting the importance of long-term contracts for renewable energy project development.[54] In particular, Section 83 of the GCA requires at least two solicitations for renewable energy through long-term contracts between 2009 and 2014 for a total of approximately 3 percent of the state's distribution utilities' total retail load. By 2012, all distribution companies had solicited and subsequently signed contracts.

In April 2012, the Massachusetts Senate passed Senate Bill (SB) 2214, which adds a Section 83a to the existing legislation and would increase the percentage of total retail load to be covered with long-term contracts from renewables with durations between 10 and 20 years from 3 percent to 7 percent by December 31, 2016. In 2016, the Massachusetts RPS will require that 11 percent of total demand be supplied from Class I renewable resources. This implies that with SB 2214, almost two-thirds of the state's RPS requirements will be met through long-term contracts signed under Section 83 or Section 83a of the GCA.[55] The recently released RFP for proposals under Section 83 specifically states that long-term contracts are to be executed to facilitate the financing of renewable energy projects. [56]

It seems clear that the important role long-term contracting plays in making renewable projects feasible is at the core of the desire to increase the portion of total demand met by long-term contracts for renewable power. Hence, the state law explicitly states that the long-term contracting requirement is "to facilitate the financing of renewable energy generation."[57] For example, Massachusetts Governor Deval Patrick noted in a speech given on May 30, 2012, "We are working closely with the Legislature for an increase in the long-term contracts requirements so that more projects get built in the next few years."[58]

V. BENEFITS TO NEW YORK OF LONG-TERM CONTRACTS FOR FULL RENEWABLE OUTPUT

As described above, the centralized procurement in New York through NYSERDA is currently for RECs alone for 10 years. Massachusetts' experience suggests ten-year REC contracts alone are likely insufficient to support the development of many new renewable

[54] *Ibid*. The study provides both theoretical arguments in favor of long-term contracting and empirical evidence that the vast majority of renewable energy projects analyzed relied on some form of long-term contracting.

[55] For a detailed description of the current RPS, see Massachusetts Department of Energy Resources , Executive Office of Energy and Environmental Affairs , Commonwealth of Massachusetts , *Massachusetts Renewable and Alternative Energy Portfolio Standards (RPS & APS), ANNUAL COMPLIANCE REPORT FOR 2011*, January 11, 2012

[56] Request for Proposals for Long-Term Contracts for Renewable Energy Projects; April 1, 2013, p.1.

[57] 220 CMR 17.01 (1): Purpose

[58] Governor Deval L. Patrick, *Shaping Our Energy Future* - As Delivered FastCap, Boston, Wednesday, May 30, 2012, downloaded from http://www.mass.gov/governor/pressoffice/speeches/20120530-shaping-our-energy-future.html

resources, primarily because the large initial capital outlay needed for new projects can be a significant barrier for new investments, given the uncertainty concerning non-REC revenues and REC revenues beyond the ten-year contract term. Using long-term contracts for the full output or bundled products from renewable resources can provide project developers and their financiers more certainty around the revenue stream and thereby reduce the cost of financing.

Rather than using long-term contracts, New York has so far preferred to rely on markets to establish wholesale energy prices, establish incentives for the development of new generation, and condition the underlying fuel and technology choices. This approach is consistent with one of the original intents of restructuring the New York power market, to transfer risk from ratepayers to project developers. However, as described above, one effect of this approach is that total revenues needed to support the level of economic infrastructure investment in new power projects to meet the RPS is potentially significantly higher than those needed under a system, where long-term PPAs provide more revenue certainty. While companies are free to voluntarily enter into PPAs under current market conditions and rules, NYSERDA has said electric utilities and retail service providers should be encouraged to enter into long-term contracts to meet their service obligations and the policies and goals of New York's statewide energy plan.[59] In its order in the same proceeding, the Commission explicitly acknowledged the role of long-term contracts in achieving the goals of the RPS, commenting:

> We conclude that utility long-term contracts may be required to support new construction to maintain reliability, if adequate reliability is not provided by the wholesale market or to be judiciously used to achieve other policy goals (*e.g.,* RPS).[60]

The Commission characterized voluntary long-term contracts as "an important element in the wholesale market," and said it is unclear whether any of the projects in the majority of capacity resources added under such contracts since restructuring would have been viable without them. Thus, the Commission wrote:

> Accordingly, it is our policy to continue to encourage the use of voluntary forward contracts of all durations by all parties, together with all other instruments legitimately used in any competitive market. If the wholesale markets have a reasonable balance of spot purchases together with short-, medium-, and long-term contracts, retail price volatility and the opportunities to exercise market power at the wholesale level could be reduced, as could the investment risks of both new and existing generation.[61]

[59] Comments of NYSERDA, June 5, 2007, p. 3, in response to the Commission's order in New York State Public Service Commission, Case 06-M-1017 and Case 07-E-1507.

[60] Order Initiating Electricity Reliability and Infrastructure Planning, Case 06-M-1017 and Case 07-E-1507, issued and effective December 24, 2007, p. 21.

[61] *Ibid,* pp. 21-22.

The Commission specifically recognized that capital markets seemed unwilling to fund new technologies offering environmental, hedging, fuel diversity, or other benefits on a pure merchant basis. It concluded that it may be beneficial to shift some investment risk back to ratepayers to achieve state energy policy objectives and to avoid subjecting ratepayers to a more volatile, and potentially more costly, market otherwise unable to attract renewable energy investment.

Given the current structure in the New York market and our observation of the procurement process in Massachusetts, we find that a shift toward allowing or requiring long-term contracts for bundled energy, capacity and RECs would be efficiently accomplished by using a centralized renewable energy procurement process for the state. The procurement would be similar to the current one that NYSERDA conducts but it would include a bundled product of energy, capacity and RECs.

There are several reasons for using a centralized procurement for the bundled products. First, the renewable energy requirement is uniform across the state. The quantity requirement is based on a percentage of load and there is no need to differentiate the renewable energy requirements based on the characteristics of the load-serving entities. Since the renewable resource requirements are identical for all load-serving entities, a centralized and unified procurement process can be efficiently developed to serve the state, with its costs allocated across the state based on load shares of various load-serving entities. A centralized procurement process (just like the one that NYSERDA already conducts for RECs) also helps ensure that there is one procedure for evaluating and selecting the best supplier offers. Having one consistent evaluation and selection process would streamline the administrative burden and reduce inconsistent treatment and/or procurement processes across different load-serving entities. A centralized procurement also avoids duplicative efforts and ultimately allows for efficient renewable energy procurement for all consumers.

Under the current NYSERDA process, NYSERDA procures RECs alone under a 10-year contract and renewable developers are free to sell energy and capacity into wholesale markets or secure long-term contracts for such products from load-serving entities. At present, there are some instances of load serving entities signing long-term contracts for energy and capacity with renewable projects. For example, the New York Power Authority has recently renewed long-term contracts for hydropower projects in northern New York and both NYPA and the Long Island Power Authority have issued RFPs for long-term contracts for large-scale solar PV projects.[62] LIPA is implementing its solar PV contracting through a feed-in PPA.[63] NYPA's bundled energy contract for the Maple Ridge wind farm is of the form of a Contract for Differences (CfD), which also provides the developer with predictable revenue streams for all products.[64]

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62 See Renewable Energy Assessment New York State Energy Plan 2009, December 2009, p. 26.

63 See http://www.lipower.org/FIT/faq.html

64 See http://www.nypa.gov/trustees/2005%20minutes/November/05Nov.pdf , pp. 16-18.

However, in the absence of a formal long-term contracting requirement such as Section 83 of the Green Communities Act in Massachusetts, load serving entities may be reluctant to enter into long-term contracts in spite of the fact that the potential importance of long-term contracts has been recognized as described above.[65] This reluctance stems in part from regulatory hurdles, such as the need to get long-term contracts approved, and in part from potential risk related to losing customers while being "stuck" with long-term contracts, or being settled with long-term contracts that appear out-of-the-money relative to the market after the fact.[66] Therefore, even though as of today it seems theoretically possible for New York load serving entities to enter into long-term contracts for energy and capacity, there is no general preference – with the potential exception of LIPA – to do so. Without a long-term contract for energy and capacity, a significant portion of the total revenue stream required by a renewable energy project to cover its costs remains exposed to short-term market price fluctuations.

While a long-term contract for energy and capacity would likely lower the REC prices required through the NYSERDA procurement process, in cases where long-term contracts for energy and capacity and a separate contract for RECs are a feasible option, the separation of contracting likely creates some potentially significant inefficiencies. In particular, developers need to figure out how to simultaneously secure both contracts for energy and capacity and for RECs in an efficient manner. For instance, a developer wishing or needing to secure a long-term contract for the full output of a renewable energy project would need to secure a RECs contract through the NYSERDA's current procurement process and simultaneously secure long-term contracts from one or more load-serving entities. Not only does this process require a significant amount of time to coordinate between the multiple procurement processes, it also creates significant pricing challenges because the offer prices for RECs, energy and capacity are mutually dependent.

For example, suppose the total all-in levelized cost of a renewable energy project were \$100/MWh and that the investor would need to secure a long-term contract for energy and capacity from a load-serving and then separately secure a REC contract from NYSERDA. The value of the separate contracts would need to add up to the levelized value of \$100/MWh. If the separate procurement processes take place simultaneously, the developer would need to strategically bid to win contracts in the separate processes. If only successful in one and not the other, the developer may need to back out of the winning contract, which creates uncertainties for both the seller and the buyers. Due to such uncertainties, New York may

[65] For some early objections to mandated long-term contracts by load serving entities, see Initial Comments of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Concerning Long-term Contracts, New York State Public Service Commission, Case 06-M-1017, p. 8.

[66] Many states including New York have, in the past, signed long-term contracts of this type. The contracts for Qualifying Facilities (QFs) under PURPA are one example. Long-term contracts signed with Hydro Quebec are another. In each case, PPA prices were in essence tied to a market price forecast or estimated avoided cost rather than on the cost of the project. For a discussion of the experience with long-term contracting in New York and the current status, see State of New York Public Service Commission, Order Initiating Electric Reliability and Infrastructure Planning, December 24, 2007, p. 21.

need to increase the set amount to be procured just to ensure sufficient renewable resources are procured, accounting for the potential cancellation after-the-fact.

This situation is potentially worse if the separate procurement processes are not simultaneous. For example, if the load-serving entities only procure contracts for energy and capacity whenever they anticipate a need based on their load and supply balance, which in turn could depend on the volume of successfully procured resources in the prior period, the opportunity to secure energy and capacity contracts may be infrequent for renewable developers. Even if there are ample opportunities, the relative timing of those opportunities could present significant hurdles for developers. For example, suppose the developer wins a long-term contract for energy and capacity for $50/MWh, he would need to secure the rest of value from the RECs procurement process. But if other developers could bid lower REC prices, the developer would need to reduce its bids in the RECs market to obtain the necessary contract to match the energy and capacity contract that he already has in hand. By under-bidding, the developer may piece together contracts that have prices that are too low to cover its costs. If that happens, the developer would need to either ask for *ex post* contract changes or revoke the contracts that he had already entered into to ensure he does not lose money.

Again, the risk of contract revocation could increase the risks for the load-serving entities. In addition, given the risks associated with the developer's inability to match both the timing and the prices of a REC contract with a separate energy and capacity contract, the bids would likely need to include a risk premium to cover for the costs associated with revoking the contracts.

On the flip side, the utilities that have entered into a long-term contract for energy and capacity might be faced with contract cancellations. To avoid such risk, utilities might need to procure more than they need if they are mandated to procure a certain quantity. At minimum, separating the procurement of RECs from energy and capacity would introduce inefficiencies into the process, create uncertainties for both the supplier and purchaser, and thereby increase the overall costs of renewable energy for New York ratepayers.

In addition to the direct cost impact, a commitment to renewable energy development by setting a policy of using long-term contracts for the bundled products will also send an enduring investment signal to investors, demonstrating that New York is committed to ensuring that its ratepayers and citizens can benefit from renewable energy resources from a long-term perspective. Such commitment would bring broader project development to New York, which would help New York materialize the vision of benefits identified in the 2009 State Energy Plan as well as in the New York Energy Highway Blueprint, including increasing economic development activities by creating local jobs in construction and the operations of the projects.

While it is not clear whether NYSERDA meets the legal requirements of being the central procurement agency for the State for the bundled renewable energy products, it seems that at minimum **NYSERDA could be the coordinator and in turn assign and transfer the contract obligations to load-serving entities.** In Massachusetts, the law required the largest distribution utilities to enter into long-term contracts directly with suppliers for the bundled renewable energy products. The Massachusetts method is also worth considering.

VI. CONCLUSIONS

In this paper, we summarize the potential advantages of using long-term contracts for energy, capacity and RECs as a means of enabling the development of capital-intensive renewable energy projects, both in general and with particular focus on the implied changes to the current central procurement process for RECs only through NYSERDA in New York.

Based on both the economic theory and practical reality of making large irreversible sunk investments in the absence of a long-term contract, as well as the observed practice in states successfully building out significant quantities of renewable energy, we conclude that long-term contracts are an important means of overcoming hurdles to renewable energy development. Put simply, in the absence of long-term contracts for the outputs from a renewable energy project, investors in, and lenders to, renewable energy projects will be reluctant to commit funds. If they are at all willing, investors will likely require significantly higher rates of return, since there is a substantial perceived risk that expected revenue streams in particular from renewable attributes will be lower than required and originally expected due to *ex post* regulatory changes. As a result, meeting RPS in the absence of long-term contracts is likely substantially more costly to ratepayers than it needs to be.

NYSERDA's current 10-year REC contracts are a partial solution relative to an approach that has renewable developers rely entirely on spot market sales for all products including RECs. However, the current approach in New York does not address the inter-dependency of revenue streams from energy, capacity and RECs, which, in their totality, have to be sufficient to provide investors and lenders with the required returns to their investment.

We therefore suggest that a contracting mechanism that bundles all three major products through a single long-term contracting mechanism would provide the degree of revenue certainty required to attract private equity and debt and hence enable significant additional renewable development in New York. Relative to the current situation, where only REC contracts are for 10 years but energy and capacity revenues are either procured through wholesale energy market transactions or through uncoordinated longer term contracts with load serving entities, the risk to investors and lenders would be significantly reduced. This in turn would lower the cost of financing these capital intensive renewable energy projects substantially. As a result, the cost of meeting New York's RPS would be lower and therefore bundled long-term contracts represent a better use of ratepayer funds than the current approach.

Finally, we believe that procuring renewable energy in New York through long-term contracting can be structured in a way that avoids the perceived negative results of past long-term contracting efforts.

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