Large-Scale Renewable Energy Development in New York:

Options and Assessment

Final Report

June 2015

Report Number 15-12

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NYSERDA provides resources, expertise, and objective information so New Yorkers can make confident, informed energy decisions.

Mission Statement:

Advance innovative energy solutions in ways that improve New York's economy and environment.

Vision Statement:

Serve as a catalyst – advancing energy innovation, technology, and investment; transforming New York's economy; and empowering people to choose clean and efficient energy as part of their everyday lives.

Large-Scale Renewable Energy Development in New York: Options and Assessment

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NYSERDA Report 15-12

June 1, 2015

Acknowledgements

NYSERDA acknowledges the valuable contributions of Sustainable Energy Advantage, LLC (SEA), New Energy Opportunities, Inc (NEO), Climate Policy Initiative (CPI), and Ed Holt & Associates, Inc. (EHA) for their assistance in the development of this study. Primary analysts and contributors include Robert Grace (Project Manager) and Jason Gifford of SEA, Barry Sheingold of NEO, Uday Varadarajan of CPI, and Ed Holt of EHA.

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BOEM	Bureau of Ocean Energy Management
Bp	Basis Points
CAGR	Compound Average Growth Rate
CARIS	Congestion Assessment and Resource Integration Study
CEF	Clean Energy Fund
CFD	Contract for Differences
CO_2	Carbon Dioxide
DOS	New York Department of State
DPS	Department of Public Service
DSCR	Debt Service Coverage Ratio
EDC	Electric Distribution Utility
EIA	Energy Information Administration
EPC	Engineering, Procurement & Construction
ESCO	Energy Services Company
FERC	Federal Energy Regulatory Commission
GW	GigaWatt
ICAP	Installed Capacity
IOU	Investor Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ITC	Investment Tax Credit
kW	KiloWatt
kWh	KiloWatt Hour
LBMP	Locational Based Marginal Price
LCOE	Levelized Cost of Energy
LSE	Load Serving Entity
LSR	Large-Scale Renewables
MACRS	Modified Accelerated Cost Recovery System
MW	MegaWatt
MWh	MegaWatt Hour
NEPOOL GIS	New England Power Pool Generation Information System
NO_X	Nitrogen Oxides
NYGATS	New York Generation Attribute Tracking System
NYISO	New York Independent System Operator
NYPA	New York Power Authority

NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
OSW	Offshore Wind
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PSC	Public Service Commission
RBB	Ratepayer Backed Bond
REC	Renewable Energy Certificate or Renewable Energy Credit
REV	Reforming the Energy Vision
ROFO	Right of First Offer
RPS	Renewable Portfolio Standard
RFP	Request for Proposals
SEP	State Energy Plan
SO_X	Sulfur Oxides
UCP	Uniform Clearing Price
UOG	Utility Owned Generation
WACC	Weighted Average Cost of Capital

Volume 1: Summary and Recommendations

Continuing New York's Commitment to Large-Scale Renewables

1 Summary

Reforming the Energy Vision (REV) is New York State's strategy to build a clean, resilient, and affordable energy system for all New Yorkers. REV includes groundbreaking regulatory reform to integrate clean energy into the core of New York State's energy system; programmatic redesign to complement and unlock private investment in clean energy; and leading by example through innovative energy solutions in the State's own facilities and operations.

REV is designed to facilitate a transformation in how we produce, deliver, and consume energy. While distributed energy resources such as energy efficiency, distributed generation, and demand response are a critical focus of the REV strategy, large-scale renewables (LSR) also have an important role to play. Central generation will continue to serve as the backbone of New York's power grid for the foreseeable future, and adding more LSRs to diversify generation sources can deliver numerous benefits to residents and businesses alike. Immediate benefits can include reduced price volatility, meaningful reductions in the State's greenhouse gas emissions and compliance with federal mandates, cleaner air, and new economic development opportunities and jobs.

In order to support LSR resources following the introduction of competitive markets for electric generation, New York State initiated its Renewable Portfolio Standard (RPS) in 2004 (New York Public Service Commission 2004). The RPS has thus far enabled developers to build nearly 1,900 megawatts (MW) of LSR generation capacity and has delivered benefits in excess of costs (NYSERDA 2013). However, NYSERDA analysis and stakeholder feedback suggest that changes in the current approach to LSR energy development – to take changing market conditions into account – are warranted to achieve core policy objectives of: achieving the lowest possible cost while maximizing customer benefits, promoting competition, and animating voluntary markets for renewables to complement public investments.

At various intervals since the inception of New York's RPS, stakeholder feedback and Commission deliberations have identified the following characteristics of the existing RPS structure as opportunities for improvement:

- **Energy price risk**. Under today's Main Tier Solicitations, renewable energy credit (REC) contracts with NYSERDA are the only source of revenue certainty for developers and financiers. Operating projects sell power into the wholesale market where it is difficult to secure revenue certainty beyond the short-term. The associated price risk leads to a higher cost of capital, and limits access to innovative financing structures, such as YieldCos, that demand a greater degree of revenue certainty. The allocation of energy price risk fully to renewable energy developers and their investors increases the overall cost of supporting LSR resources.

- **System benefits**. While LSR can provide meaningful benefits to the grid when deployed strategically, the current RPS structure does not ensure projects are sited to optimize these system benefits.
- **Value Proposition for Customers.** The current program does not capture the ability of LSR to hedge electricity price volatility for customers nor does it sufficiently engage end use customers. Projects can contract with NYSERDA for no more than 95% of REC output, and are expected to sell the remainder on the voluntary market. Without specific State supports to facilitate voluntary transactions, however, operating projects have generally sold un-contracted RECs to RPS markets outside of New York.

NYSERDA embraces these opportunities for improvement to advance options and analyses in support of the next iteration of LSR policy in New York, and presents this "Large-Scale Renewable Energy Development in New York: Options and Assessment" paper to outline proposed design principles for supporting LSR, share key findings from evaluation and analysis of a variety of different options, and advance key questions for public comment.

Through the issuance of its February 26, 2015 Order (February Order)[1], the Commission instituted a REV LSR track and instructed Department of Public Service DPS Staff (Staff) to work with NYSERDA to prepare an LSR options paper to be issued for public comment no later than June 1, 2015. NYSERDA, together with a consulting team of Sustainable Energy Advantage, LLC, its subcontractors (New Energy Opportunities, Inc. and Ed Holt & Associates, Inc.), and the Climate Policy Initiative, conducted a detailed study that contributed to the strategies advanced in this paper, which is hereby filed to support the public comment and Commission decision making process.

1.1 Proposed Design Principles and Issues for Consideration

Through the course of this analysis, NYSERDA and its consultants examined a range of policies, frameworks and structures available for procuring and financing LSR resources and also conducted detailed analyses as described further in this volume as well as Volume 2 of this report. This paper finds that State policy objectives articulated through REV and the 2014 Draft State Energy Plan (NYS Energy Planning Board 2014), will be best accomplished through a combination of near- and long-term steps that leverage existing programs and authority, provide revenue certainty for project developers, advance new

1 Case 14-M-0101; Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. "Order Adopting Regulatory Policy Framework and Implementation Plan, issued and effective February 26, 2015.

contracting and ownership models for renewables, and create new opportunities for large end users to buy the renewable energy products their shareholders demand.

In considering these objectives and options, NYSERDA recommends the following program design principles and strategies. Key questions are also posed for consideration; detailed questions will be issued by the Department of Public Service to solicit formal public comment.[2]

- **Bundled power purchase agreements (PPAs) to reduce costs and electricity price volatility.** Long-term, bundled PPAs with creditworthy entities can reduce costs and provide a long-term stable energy hedge to volatile energy prices for ratepayers. Financial modeling suggests that PPAs can reduce the levelized cost of energy for a representative project by $11-12/MWh relative to current policies. Such cost reductions could enable substantially greater deployment than current policies (70-120% more over 10 years in modeled scenarios) for the same ratepayer investment in incremental costs. Bundled PPAs achieve these cost reductions by providing long-term, predictable revenue streams to project developers, which reduces financing costs. The use of PPAs may also open access to emerging financing vehicles such as YieldCos unavailable to projects under current policy to enable even greater cost reductions.

  Furthermore, in a PPA model, customers capture the hedging benefits of diversifying the fuel mix with LSR: today's above-market premium for LSR would shrink when the rest of the customer electricity bill increases, and grow if the rest of the bill drops, thereby reducing customer electricity price volatility and, under base market forecasts, capturing net savings for customers in the latter years of the contracts. The current RPS structure does not capture these benefits, locking customers into fixed-price premiums that are non-responsive to changes in the overall bill. If utilities are selected as the entity entering into the PPAs, remuneration should be considered to compensate them for taking on the financial obligation.

  Key issues to consider include identifying the counterparty to enter into bundled PPAs with developers, and if utilities are selected as the counterparty, whether and how they should be compensated for taking on the financial obligations of PPAs to support project financing.

- **Flexible procurements to foster competition and ensure the selection of the lowest-cost projects.** Greater competition among all types of project developers and owners is likely to result in the selection of the lowest-cost projects. Current financial analysis shows privately-owned projects with bundled PPAs deliver the lowest-cost solution and that financial tools such as YieldCos can drive costs down further. As markets evolve, other models may become more cost-effective; an open-source solicitation could provide flexibility to accommodate these changes. In particular, there are scenarios where Utility-Owned Generation (UOG) of LSR could achieve the lowest costs. A key issue for further consideration through public comment is whether utilities should be permitted to own LSR projects and compete with privately-owned projects in an open-source solicitation.

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[2] A comprehensive list of questions for public comment is presented in a Department of Public Service notice issued simultaneously with the filing of this paper.

- **Centralized project solicitation / evaluation by a third party.** Appointment of an appropriate entity to facilitate the solicitation, evaluation, and selection process as well as to standardize the terms of competition is important to a fair and successful implementation. Third-party solicitation sponsorship could also help mitigate the risk of bias if UOG is permitted to compete against independent power producers seeking utility- or State-backed PPAs in an open-source solicitation. A key issue for consideration is the designation of the appropriate entity to conduct solicitations and evaluate proposals.

- **Procurements conducted based on a planned budget, system needs, and other considerations.** Project evaluation and selection should take into account not just price but also total expenditure targets, system requirements, plant retirements, current and forecasted electricity prices, technology cost trajectories, end-user demand, and the minimum level of annual investment necessary to achieve policy objectives. This can be an important mechanism for containing costs and ensuring projects are deployed where they provide the greatest benefits. The specific methodology for selecting projects and deployment levels will need to be determined. Consistent with REV principles, strategies to integrate LSR with distributed energy resources, such as storage and demand response, to increase the system and costumer benefits should also be explored.

- **New mechanisms to facilitate voluntary market activity.** The voluntary market currently suffers from insufficient demand volumes, contract durations, and credit supports. State-based market interventions could create access for voluntary buyers to power and RECs from operating or proposed renewable energy projects. Mechanisms that sufficiently aggregate or back-stop demand, duration and credit to enable attractive financing terms will be required. Any of the procurement models explored can animate the market for voluntary end-user purchases of renewable energy; renewable energy credits (RECs) and/or energy-only[3] hedges (also referred to as "brown power" hedges). In this context, revenues from voluntary REC sales can be rolled forward into the budget for subsequent procurements and will support the minimal requirement to motivate voluntary REC purchases while simultaneously allowing such sales to advance overall procurement levels. Stakeholder input will be needed to identify the most effective model for stimulating voluntary markets for renewable energy and "brown power" hedges.

- **Securitization to lower the cost of project debt.** Costs to ratepayers may be further reduced (beyond levels induced by competition) if the State offers a low-interest rate, securitized debt option. Project-level debt financing is not common in U.S. renewable energy transactions. This is due either to the investment return requirements of tax equity investors, to uncertainty in project revenue, or both. The benefits of low-cost project debt may be achievable, however, if numerous projects with long-term creditworthy PPAs can be pooled in a way that effectively manages risk and increases liquidity. This would enable the application of lower-cost project-level debt – which may not otherwise be available to the majority of developers.

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[3] Without the purchase of associated RECs.

- **Long term budget commitment to stimulate greater investment in New York and put LSR resources on a path to grid-parity.** Including a long-term budget commitment in the next generation LSR policy sends a strong signal to the LSR development community and can help drive down total project costs through increased competition. Using today's RPS/LSR investment level as a benchmark and given current electricity price forecasts, we estimate a $1.5 billion public investment committed over 10 years to enable development through bundled PPAs could deliver long-term net customer savings, help the State make meaningful progress towards achieving its statewide clean energy goals, and put the LSR market on a path to grid-parity. Alongside expected Clean Energy Fund (CEF) budget levels, the proposed LSR funding commitment would enable near-term reductions in total annual collections and significant decreases over time.

1.2 Focus and Approach

The proposed design elements described above were the result of an extensive evaluation that is described in more detail in Volume 2 and summarized below. The analysis comprehensively evaluated a broad range of LSR structures and designs that could spur increased LSR generation in New York while continuing to competitively and cost-effectively achieve the primary objectives of the REV framework. This options paper describes a range of policies, frameworks, and structures that were considered for procuring and financing LSR resources in the future. It presents criteria and economic analysis for evaluating the various options based on the goals articulated in the 2014 Draft State Energy Plan and the REV regulatory proceeding. Most notable of these goals are minimizing costs and maximizing benefits; promoting competition; and animating the voluntary market.

1.3 Historical Context

New York State has been investing in large-scale renewable electricity generation since the 1950s, when the New York Power Authority developed its first hydroelectric stations. Today, these facilities help power New York's economy, providing low-cost, zero-emissions electricity that attracts businesses to the State and helps to keep the air clean.

To build on this legacy of support for the next generation of LSR resources, New York enacted its Renewable Portfolio Standard (RPS) in 2004 through regulations adopted by the Commission (New York Public Service Commission 2004). Unlike most states with an RPS, New York State currently uses a central procurement model whereby NYSERDA administers programs that are responsible for the majority of the RPS goals. Specifically, NYSERDA is responsible for supporting the Main Tier (larger, utility-scale resources) and Customer-Sited Tier (smaller, behind-the-meter resources) targets with the remainder to be made up by the voluntary market, purchases made by State agencies under Executive Order 111, and purchases made by PSEG Long Island (Long Island Power Authority).

NYSERDA, through Main Tier contracts, pays a fixed price production incentive, procuring RPS Attributes,[4] from renewable electricity generators selected through periodic competitive solicitations for the electricity they deliver for end use in New York. Through December 31, 2014, NYSERDA has conducted nine Main Tier solicitations in pursuit of the Main Tier RPS target and released a 10th Main Tier Solicitation in early 2015. From the nine completed solicitations, NYSERDA currently has contracts with electricity generators for 65 large-scale projects. When operational, these projects will add 2,035 MW of new renewable capacity to the State's energy mix. NYSERDA is obligated to release an 11th Main Tier solicitation in 2016 to conclude the program.

1.4 Evaluation Criteria

Evaluating the suitability of potential LSR policy options must occur in the context of New York's policy objectives, most notably those inherent within the REV initiative, and take into consideration all constraints present as a result of the current market design. Fulfilling these objectives requires a procurement model that supports financing for new generators, manages risk for counterparties and facility owners, and creates access for voluntary market participants. Of course, all of this must be done as cost-effectively as possible. This means maximizing scale economies and competitive forces, and minimizing transaction costs and risk premiums.

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4 RPS Attributes include any and all reductions in harmful pollutants and emissions, such as carbon dioxide and oxides of sulfur and nitrogen. RPS Attributes are similar to Renewable Energy Certificates that are commonly used in other RPS programs to catalog and recognize environmental attributes of generation.

The statutory and other legal authority required to implement certain aspects of an LSR procurement model may represent constraints that will also need to be closely considered. The policy objectives and constraints play a role in defining general evaluation criteria and determining how they are applied to each development model being considered. Six categories of criteria were identified that address these requirements:

- Consistency with REV and the 2014 Draft State Energy Plan.
- Feasibility.
- Maximizing generation.
- Minimizing cost.
- Administrative efficiency and transparency.
- Compatibility and acceptability.

1.5 LSR Policy Considerations

The future New York LSR policy could proceed by any one of these methods, alone or in combination:

- **Target-driven.** Percentage obligations on the regulated EDCs or other entities are established based on a statewide objective, establish a procurement target to be met by State entity or EDC long-term contract procurement, or establish an obligation within which supplemental long-term contract procurement targets are established.
- **Investment-driven.** Quantities procured and their timing are dictated by a preset level of expected expenditures.
- **Integrated Resource Planning (IRP).** An administratively-driven analytical exercise is used to inform the timing, quantity, and mix of renewables development.

Considering the evolution of LSR policy, a number of structural options are also worthy of assessment, including the following:

Administration and governance. During the life of the LSR procurement, a number of potential assessments and decisions may be required, the specifics of which will depend on both the LSR policy approach ultimately chosen, and the degree to which actual experience reveals the need to refine and adapt.

Tiered support. Different approaches and separate targets, designed to work within New York's specific circumstances, could be considered for supporting development of incremental LSRs as well as supporting continued operation and/or contribution of already operating renewable energy generators (those currently under contract to NYSERDA, and the pre-restructuring fleet).

Procurement mechanism. The procurement mechanism is the means by which project offers are selected. These generally fall into two major categories—selection through *competitive bidding and through standard offers.* Competitive bidding can be implemented through use of an auction mechanism using standard contracts, or a request for proposal method using model contracts. Auction mechanisms can utilize different mechanisms to determine the price paid to selected projects, including as-bid price (used in the current New York Main Tier RPS procurements) or clearing price.

Contracting/transaction structure. Several attributes define the general contracting or transaction structure. These include the parties to the transaction; in particular, the buyer, the products conveyed, the transaction type, and the pricing structure.

Evaluation and contracting entity. In the procurement models explored in this paper, it should be noted that the entity entering into contracts for the products procured may or may not be the same entity that runs a procurement. Solicitations could be conducted by NYSERDA, the EDCs, or another State entity. Proposal evaluation could be performed by a State agency, by EDCs acting jointly or individually, by State agencies working in concert with EDCs, or by independent third party professional evaluators. Contracts could be entered into with a utility or a State entity.

Duration. Because of electricity and REC revenue uncertainty that is difficult or impossible to hedge, experience has shown that new LSRs in northeast markets generally require some measure of long-term revenue certainty in order to attract financing at reasonable cost. Common tenors in restructured RPS markets for long-term contracting policies used to minimize market price risk and generator cost of capital range from 10 to 20 years, with longer durations correlating to lower cost.

Products procured. This paper compares the current approach to one allowing generators to hedge both REC and energy market revenues through long-term contracts, either through physical or financial[5] contracts.[6]

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5 For example, through a Contract for Differences (CFD) with more or less a comparable effect on hedging energy revenues to a physical fixed-price energy payment.

6 In other states, transacting capacity under LSR procurement has proven to present a number of challenges and complexities. While conveying capacity under long-term contracts is possible it is not considered in this paper.

Disposition of products procured. It is typical in RPS-driven long-term contracting in restructured markets that the contracting enables financing using the credit-backing of EDCs or (in New York today) ratepayer collections passed through a public agency. If the contracting entity serves load (but procures electricity in a manner other than full-requirements supply) or has its own RPS obligation, it may have a need for the products procured. Otherwise, it must resell the products procured (other than RECs, which might be directly retired).

Terminal or residual value. When, after the conclusion of a typical PPA term, a renewable generation project has remaining useful life or other valuable assets (such as site, interconnection or remaining term on a land lease) or costs (such as decommissioning costs after salvage value) it may have what is referred to as residual, or terminal, value. For UOGs in rate base, this value (positive or negative) automatically accrues to utilities and their ratepayers. In contrast, this value typically remains with the owner under a PPA, unless the PPA contains terms which convey this value to the PPA counterparty. These terms can only be secured at the time of solicitation and contracting.

Evaluation/selection criteria. A final design element of LSR procurements is the basis of evaluation and selection among bids received. Decisions among those bids deemed eligible can be made on a price-only or a multi-criteria basis considering price and other desired bid characteristics, including economic benefits or reliability attributes and project viability.

1.6 LSR Development Options

A range of policy options were reviewed and considered in this assessment. Key design elements include how procurements are structured, who conducts the solicitation and evaluation, what products and project types are eligible to compete, and who serves as the counterparty. Some key elements are critical to all of the development options, such as the need for adequate mechanisms to provide project investors with assurance of promised payments, cost recovery protections for those entities that will be paying for the renewable energy procured, and the use of planning budgets to moderate the pace of deployment and ratepayer impacts. The key design elements considered in defining alternative procurement models as they apply to New York are summarized in Table 1.

Table 1. Procurement Model Design Elements

Parameters	**Design Options**
Procurement run by…	NYSERDA (current/reference case), EDCs, State Entity, or Independent Entity
Contract between generation owner and…	NYSERDA (current/reference case), EDCs, State Entity, PSEG LI
Project owned by…	Developer and/or project investors (current/reference case) State Entity, and/or EDCs
Off-take: Commodities Procured	RECs (current/reference case), RECs+Energy

Other design parameters include collection mechanisms, remuneration to EDCs, disposition of electricity commodity, disposition of RECs, and post-contract ownership and options. Within the range of development options described in Table 1, NYSERDA analyzed three primary structures with a series of variants. These options include:

- **Option 1**: NYSERDA conducts solicitations and enters into long-term contracts with renewable energy developers.
    - REC-only Contract.
    - REC Contract for Differences (CFD) Contract.
- **Option 2**: State entity conducts solicitations and enters into long-term PPAs with renewable generators.
- **Option 3**: State entity/EDC solicitations for long-term PPAs and utility-owned generation.
    - PPA-only Solicitations (Option 3a).
    - Open-source solicitations: Head-to-head competition between proposals for PPAs and utility-owned generation (Option 3b).

These options, and key variants, are described in more detail in this section and are reviewed in the context of the previously outlined evaluation criteria outlined.

1.6.1 Option 1: NYSERDA Conducts Solicitations and Enters Into Long-Term Contracts with Renewable Energy Developers

The current approach used for facilitating financing and construction of new LSR is NYSERDA's Main Tier competitive bidding program for up to 20-year fixed-price REC contracts. One programmatic option for LSR is simply to continue the existing program. This base case can be compared to other options.

An advantage of this approach is that the program is established and its fixed payments make it straightforward for New York to procure new resources at more predictable costs than other approaches and within an established budget set by a fixed collection schedule from ratepayers. This option is the only option of those evaluated that can easily be guaranteed to operate within a fixed budget. In a ddition, in terms of compatibility with the wholesale power market, the fixed price REC contract does not significantly reduce the incentives of renewable generators to locate in less transmission constrained parts of the grid.

However, this may not be the most cost-effective or efficient structure. A fixed price REC contract does not offer any energy revenue certainty to project investors, which is the largest part of the market value and revenue expectations for these projects. This has several implications that likely increase costs for customers. This type of contract may not be sufficiently attractive to incent a sufficient number of developers to create a competitive market for developing and building LSRs in New York at scale. Moreover, the additional risks associated with REC-only contracts may make financing of projects more difficult and costly than where projects have bundled energy and REC contracts. Further, the substantial amount of market price risk that the developer assumes, even with a 20-year fixed price REC contract, likely results in bidders adding a substantial risk premium in their bids.

The NYSERDA fixed-price REC contract solicitations rate highly in terms of feasibility, ease of administration, and compatibility and acceptability. However, this type of contract is substantially suboptimal in terms of the criteria of maximizing generation, minimizing cost, and achieving New

York's clean energy goals. This option may provide greater discretion over the location of eligible projects than other alternatives where EDCs are the purchasers.[7]

Another option considered includes the use of a NYSERDA REC CFD in which NYSERDA could purchase RECs from a seller while providing an indexed payment on the value of energy, thus providing an effective hedge on energy. One benefit of a CFD compared to a bundled energy/REC PPA is that it can be used by a party, like NYSERDA, that is not a market participant in the New York Independent System Operator (NYISO) energy markets to provide revenue certainty to generators. At the same time, it can provide the same benefits in terms of the ability to hedge market price risk for both generators and retail customers. However, there may be limitations in the scale of NYSERDA's ability to engage in these transactions.

1.6.2 Option 2: State Entity Conducts Solicitations and Enters Into Long-Term Contracts with Renewable Generators

A State entity[8] with the proper authority could conduct solicitations for purchasing energy and RECs under long-term PPAs. As an alternative, bidders could be offered the opportunity to bid RECs only for a CFD.

These types of solicitations are broadly summarized under two categories: (a) PPA-Only Solicitations and (b) Open-source solicitations, where bidders may submit proposals for both PPAs and UOGs via the sale of projects or project development rights to one or more utilities, or a utility may also submit a utility-initiated proposal for a utility-owned project.

Under the first category, the State entity would be the sole buyer, with all net PPA (or REC CFD) costs recovered from utility distribution customers. Designating a State entity as the procurement agent and counterparty has several advantages. First, such a State entity is presumed to be highly creditworthy, and to possess the authority to collect program costs from ratepayers. As with investor-owned utilities,

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7 In December 2012, NYSERDA filed a petition with the NYS Public Service Commission requesting a change to the rules of the RPS Program Main Tier program to limit eligibility to projects located in New York State. NYSERDA requested the change to maximize the achievement of the objectives of the program: environmental improvement, energy security, and economic benefits to New York. The Commission's May 2013 Order adopted the requested change, finding that limiting eligibility to projects located in the State would maximize the benefits that accrue to New York, while serving important State interests.

8 This entity could be NYSERDA, the New York Power Authority (NYPA) or another party identified or created by the State. Depending on the entity selected, different advantages or limitations may exist. Legislative authority may be required to pursue certain options.

investors in renewable energy projects look for PPA buyers with investment-grade credit ratings. Depending on the cost recovery arrangement, there may be no need for remuneration of EDCs as an incentive for participation. Moreover, having a State entity as sole buyer would simplify the procurement process where solicitations are seeking only contracts for RECs and/or energy and not proposals for UOGs. Finally, a State entity could provide a single contractual intermediary to facilitate other policy initiatives such as the enhancement of voluntary market transactions.

On the other hand, if UOG proposals were to be allowed to compete with PPA proposals in an open-source solicitation, this could result in both the State's investor-owned utilities as potential UOG buyers or owners, and a State entity as PPA purchaser being active parties in the same solicitations, a unique arrangement which would likely raise issues regarding roles, responsibilities, conflicts, and duplicated efforts. This would entail a solicitation design for which there are no known precedents and could result in substantial implementation issues.

All in all, the State entity PPA-only variant is likely to be feasible, but with more administrative complexity than the current NYSERDA fixed-price REC only approach. The advantages of central procurement would be retained. Compared to the current program, successful renewable project development would be more strongly facilitated with significantly lower costs due to the availability of energy price hedging for generators. However, the solicitation design would not incorporate the possibility of UOG participation and, hence, it would not create the optimal competitive playing field which could maximize renewable generation and minimize costs.

A State entity open-source solicitation variant would potentially create more value in terms of maximizing renewable generation, achieving State clean energy goals, and minimizing costs, but with the challenge of a likely need for legislative action, a disadvantage of adding complexity to implement and associated administrative costs to the procurement process.

1.6.3 Option 3: State Entity/EDC Solicitations for Long-Term PPAs and Utility-Owned Generation

These types of solicitations are broadly summarized under the same two categories as described under Option 2: (a) PPA-only solicitations and (b) open-source solicitations.

PPA-Only Solicitations (Option 3A). The most common form of utility procurement for LSR is the long-term PPA, usually 15 to 20 years in duration. Energy and RECs are purchased, sometimes with capacity, and these products are either bundled together or are purchased separately by utilities. There are however several structural and design variations in how these solicitations are conducted, the role of State agencies in the process, and the range of resources to be procured. Several different potential models were considered, including Individual Utility Procurement and Implementation; a Joint Utility RFP with Individual Utility Implementation; a Joint RFP with Common Bid Evaluation and Selection; and a State Agency-Directed Solicitation.

A solicitation process for long-term PPAs for RECs and/or energy with one or more EDCs has several important advantages. Long-term bundled product contracts with creditworthy utilities provide substantial revenue certainty to renewable generators, are the most common method of facilitating financing of new renewable generation in the United States,[9] and, as shown in Chapter 8 and below, are likely to minimize the cost to ratepayers of new renewable generation and reduce electricity price volatility compared to fixed price REC-only contracts under the current NYSERDA program. As wholesale energy market participants, the EDCs can purchase and resell the commodity electricity into the wholesale market.[10]

A key component of utility PPA procurements is the establishment of cost recovery mechanisms to provide strong assurance that the net cost of the products purchased under a PPA will be recovered from distribution customers.

EDC solicitations for PPAs would entail additional regulatory processes and new roles for the State's regulated EDCs. For the protection of both EDC investors and ratepayers, the PPAs entered into by the EDCs pursuant to solicitation should be subject to the approval of the Commission. The solicitations themselves (the design of the RFP and the evaluation framework) would also be subject to approval by the Commission.

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9 For example, through 2013, 83% of the wind generation capacity constructed in the United States is owned by independent power producers, most of which has been financed and built based on the revenue certainty created by long-term contracts with electric utilities as the buyers. (U.S. Department of Energy 2014)

10 In principle, the EDCs - as providers of default service to end users in their territories who do not choose supply from competitive energy service companies (ESCOs) – have a load obligation and might be able to use some of the energy procured towards this supply. However, as in other states, using such electricity to supply default service customers is not likely to be compatible with how default service is procured and therefore is not considered a likely approach here.

The PPA-only EDC solicitation approach has limitations. The EDCs may be ambivalent about taking on the role of purchasers under PPAs with the costs, time, and the risks associated with it, without the prospects of any upside. This could affect their motivation and effectiveness. There is also the possibility of negative effects on utility credit ratings from Standard & Poors (but are unlikely from Moody's and Fitch), which could have implications on rates at some future time. These constraints can be mitigated by providing some degree of remuneration to utilities for entering into PPAs, as has been done in some other states.

Administration of a PPA-only process presents issues of effectiveness, fairness, and efficiency. Allowing EDC affiliates to bid would expand participation of competent and creditworthy generators but would require, at a minimum, independent oversight by State agencies or independent evaluators to assure that the evaluation and selection process is free of bias. State agency responsibility for RFP design, solicitation issuance, bid evaluation, and selection would provide the strongest protections to assure fairness in the solicitation process.

EDC PPA solicitations could be conducted in various ways. A centralized process involving a common RFP and a single bid evaluation process would be most administratively efficient. From a contractual standpoint, the purchase of energy and RECs could be allocated among the utilities based on their respective load shares or on some other basis.

Open-Source Solicitations (Option 3B). Open-source solicitations – where PPA bids compete head-to-head with UOG proposals—present many similar advantages and limitations as EDC PPA-only solicitations, but also presents some additional benefits and complications. Open-source solicitations will tend to stimulate broader market participation and competition, and under certain circumstances may be expected to produce more renewable generation at lower cost. These considerations are based in part on the financial analysis in Chapter 8, which shows that projects built by independent developers under bundled energy and REC PPAs and UOGs appear to be roughly competitive with each other (taking into account the absence or presence of federal tax credits). Moreover, UOGs may have advantages with respect to terminal value ordinarily not present under PPAs where the generation owner owns a project's terminal value (which may be positive or negative, but is likely to be positive).

Open-source solicitations may significantly alter the value proposition for EDCs. EDCs would have the opportunity to acquire new renewable generation projects pursuant to bid contracts and earn a regulated rate of return on the investment if the bid projects have competitive merit. On the other hand, they would be the buyers under PPAs if PPAs are determined to have competitive merit.

In terms of limitations, open-source solicitations present issues of comparability and potential bias in evaluation and selection. This bias can be mitigated by State agency direction and Commission approval of the solicitation design, evaluation, and selection. Particular issues involving risk transfer to ratepayers associated with UOG proposals, particularly involving forecasts of energy production and long-term operations and maintenance expenses that turn out to be overly optimistic. These issues can be addressed through the retention of independent experts to aid in the bid evaluation and by imposing quality standards or risk-sharing on bidder production forecasts and long-term costs.

Allowing EDCs to compete as buyers of LSR assets or propose their own projects raises issues of vertical market power and may call for modifications to existing restrictions on utility generation asset ownership, both of which would need to be revisited by the Commission from an implementation perspective.

1.7 LSR Financing Options

New York's future LSR policy option will seek to lower financing costs to reduce the overall cost to consumers of LSR development. Recent innovations in the financing of LSR assets have centered on the use of securitization to accomplish these goals. On the equity side, this effort has been led by market participants who have focused on mechanisms that integrate renewable energy assets into a structure known as a YieldCo. On the debt side, the use of bond financing, often catalyzed by public support, is emerging as a promising option.

A YieldCo is a company (with rare exception, typically publicly traded) whose cash-flow-oriented business model is premised on delivering steady, increasing dividends to shareholders through the continued acquisition of additive, long-term, fully contracted energy generation facilities. NYSERDA's current use of fixed price REC-only contracts makes the use of YieldCos in particular unlikely, as these contracts do not offer any price certainty to project investors regarding the sale of energy. One major potential benefit of some of the alternative mechanisms described above is that New York can use the competitive procurement process to take full advantage of innovative financing vehicles available in the capital markets, including YieldCos.

Additionally, a debt securitization mechanism for LSRs could be advanced in New York to reduce the cost of debt for these projects. One way to implement debt securitization is to pool together a number of project loans into a liquid, publicly traded, high-quality debt instrument that can take advantage of project portfolio diversification benefits and project off-take contract counterparty diversity to mitigate concentration risks and reduce the cost of project debt.

However, the quality of such a securitized debt instrument is still limited by the aggregate credit rating of the project offtakers. In the case of New York utilities, this would limit the rating of such an instrument to roughly an "A" credit rating. Ratepayer-Backed Bonds Securitization (RBB Securitization) would be a novel way to move beyond this limitation. RBB Securitization would start with the issuance of New York State Green Bonds, allowing businesses and residents to directly invest in clean energy.[11] These high-quality, low-yield bonds would be issued through a special purpose, bankruptcy-remote entity and their coupons and repayments would be funded through a dedicated, non-bypassable fee paid by New York State ratepayers. The use of such a dedicated fee-payment stream creates sufficient security to allow the bonds to achieve the highest credit rating ("AAA" rating).[12]

The lower cost of debt through RBB Securitization is expected to result in ratepayer savings through lower project financing costs that exceed associated transaction, structuring and default risk costs. This mechanism, which would require legislation to implement, could apply to a variety of procurement/development models. As discussed in Appendix C, RBB Securitization could also be a particularly attractive way to support offshore wind projects in New York State.

1.8 Cost Analysis of Development and Financing Options

In light of the priority New York State has placed on selecting an LSR support structure that minimizes costs and maximizes long-term savings, cost of energy and revenue requirement modeling was performed to assess the impact on project revenue requirements and levelized cost of electricity (LCOE) of the previously discussed options – each represented by unique capital structure assumptions and customized risk premiums detailed in Appendix A.

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11 Securitization through ratepayer-backed bonds has been used elsewhere to finance retirement and/or decommissioning of aging fossil fuel and nuclear facilities.

12 RBB Securitization may only be achievable through future legislative action.

A representative set of procurement approaches was selected for the economic evaluation using conventional equity and debt assumptions. The analysis then explored the potential incremental impact of lower cost YieldCo or similar equity sources as well as RBB Securitization to drive down the cost of financing LSR. All necessary modeling input values were identified for each option, and LCOE financial analyses were conducted using a proprietary project finance model developed by Climate Policy Initiative (CPI), described in Appendix A.

To conduct this comparative assessment, a hypothetical, representative 100-MW wind facility to be built in Upstate New York (interconnected in NYISO Zone D, North) and assumed to start operating at the beginning of 2017 was selected.[13] This case was selected for comparative assessment because it is the LSR for which the most robust cost data is currently available. The energy market price forecast used for the analysis significantly impacts the modeling results. Base market prices were generated from GE-MAPS[14] electricity system modeling for the NYISO's 2014 CARIS 2 study, the most current CARIS price projections available.[15] The NYISO expects locational-based marginal prices (LBMP) price projections from the 2015 CARIS 1 analysis to be significantly lower than prices from the 2014 CARIS 2 study due to lower natural gas price and load forecast assumptions. Therefore, a low-price sensitivity was considered to provide a reasonable range of possible outcomes. The high and low price sensitivities were taken from EIA (2015) Annual Energy Outlook 2015 with projections to 2040.

For the purposes of financial modeling, three base options and several variants of each base option were considered. Each base option should be viewed as a simplified representation of one or more procurement and contracting options described above for financial modeling purposes.

Current/Reference Case (NYSERDA 20-year RECs): This case represents the current Main Tier RPS policy approach, and assumes that the project bids for a 20-year REC contract under a solicitation conducted in 2015 with a target commercial operation date of January 1, 2017.

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13 Although wind was the technology chosen for this modeling exercise, other LSRs would be able to compete with wind resources in any of the financial structures in this section.

14 GE MAPS is General Electric Company's Multi Area Production Simulation Software program.

15 New York State Independent System Operator's (NYISO's) 2014 Congestion Assessment and Resource Integration Study (CARIS) Base Case Modeling Results. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2014-06-30 Final%2006302014%20ESPWG%202014%20Preliminary%20CARIS%20Phase%202%20Basecase%20Results.pdf

Utility-Backed PPA Scenarios (State Entity and EDC PPAs): This base option is intended to model various alternative procurement mechanisms and contractual structures that lead to a 20-year, fixed-price, take-or-pay PPA with a credit-worthy counter-party for the purchase of bundled power and RECs from the wind facility. Possible remuneration of utilities for PPAs was not included. However, as a reference, remuneration of 1% increases the cost of a PPA by roughly $0.70-$1.00/MWh. Further, a 20-year perfect hedge CFD as described above would have the same impact on project finance as the Utility-Backed PPA structure.

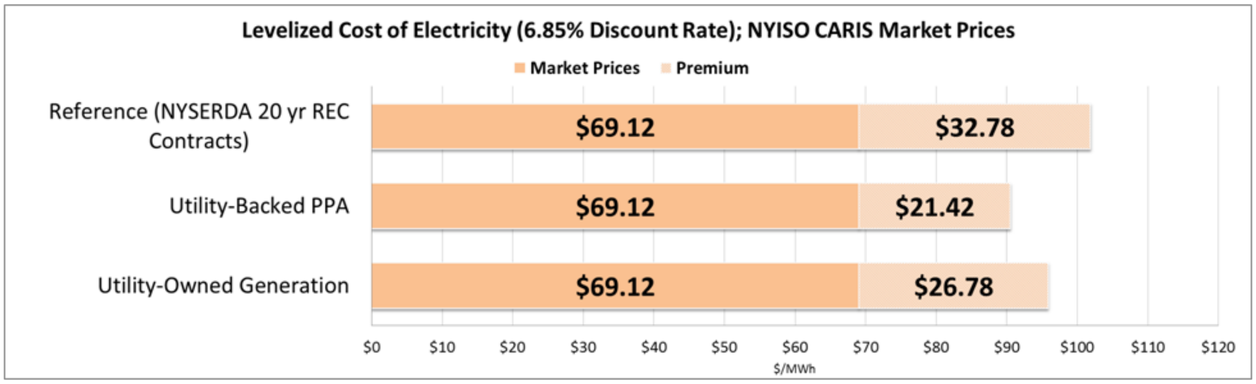
Utility-Owned Generation (UOG): To assess whether permitting UOG to compete against PPAs through an open-source auction could result in lower costs, 100% utility ownership and rate-basing of an individual project was considered. For modeling purposes, any utility ownership caps were assumed to apply at the portfolio level rather than at the project level to minimize complexity and costs. The asset was assumed to be acquired at start of operation from an independent developer and rate-based. Then, the incremental contribution of this asset to the utility's revenue requirements and the resulting levelized cost of electricity was computed.

1.8.1 Economic Modeling Results

The detailed cost of energy and revenue requirement modeling yielded four key findings:

1. **New procurement options (Utility-Backed PPAs or Utility-Owned Generation) can significantly reduce the cost of electricity relative to current policy (NYSERDA 20-year REC Contracts).** In the absence of the federal Production Tax Credit (PTC), the modeled cost of electricity for the Reference case with a NYSERDA 20-year REC Contract results in a premium relative to base case market prices of $33/MWh. With the use of Utility-Backed PPAs, the modeled cost of electricity (and premium) could fall by $11-12/MWh (a 35% reduction in cost premium). Utility-owned generation can reduce the cost of electricity by $6/MWh (Figure 1).

Figure 1. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options (no PTC)

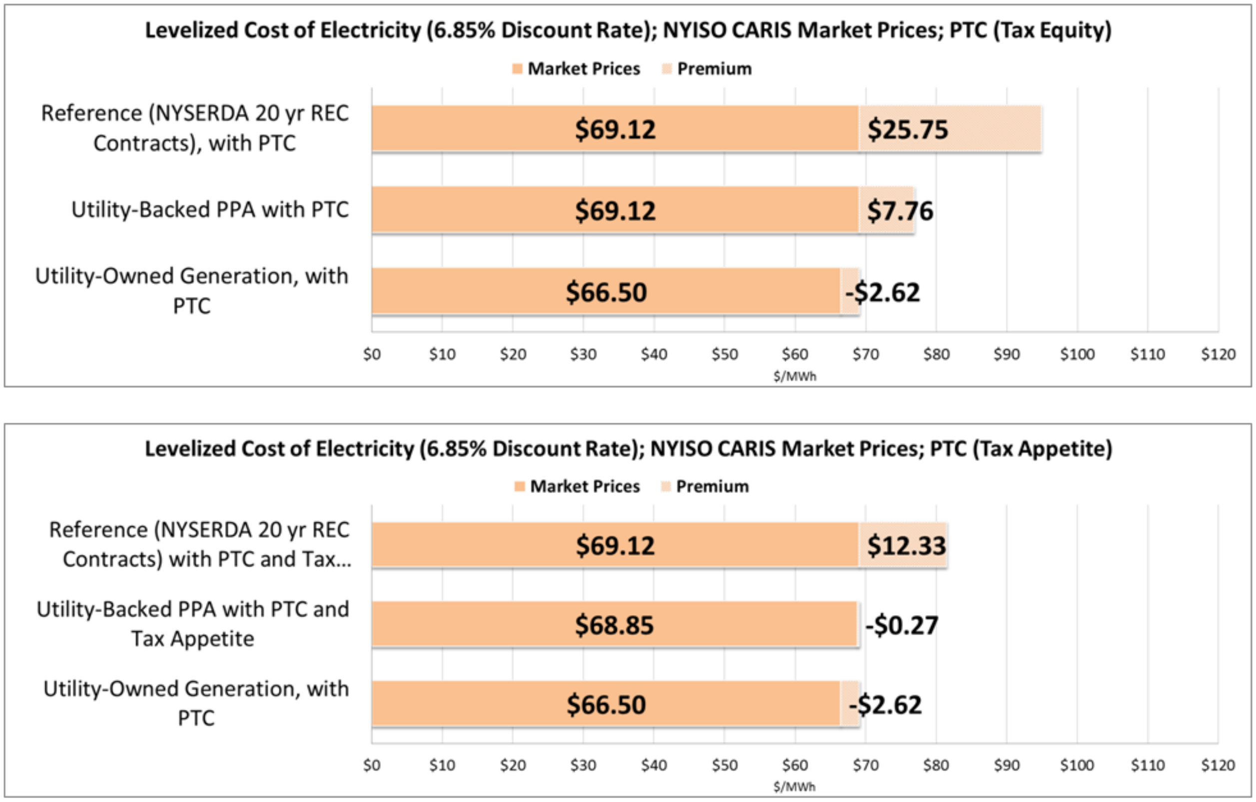


If the PPA is with a developer that has a relationship with a YieldCo, and has the confidence to bid a price based on expected sale of the asset to a YieldCo, the modeled cost of electricity for a Utility-Backed PPA could fall by an additional $3 per megawatt-hour (MWh) below the values shown in Figure 1.

If the PTC is extended, Utility-Backed PPAs with tax equity financing can bring the premium required down to below $8/MWh.[16] But in this case, UOG is particularly attractive due to the assumed pass-through of PTC benefits to ratepayers and the likely ability of New York State utilities to monetize the PTC as it is generated. In that case, UOG can result in a project with a levelized cost of electricity that is slightly below base expected market prices over the life of the project to reduce customer bills. PPAs with developers who sell their assets to long-term investors with sufficient tax appetite to fully monetize the PTC as generated (for example, the unregulated affiliates of NY utilities) can deliver a similar benefit (Figure 2).

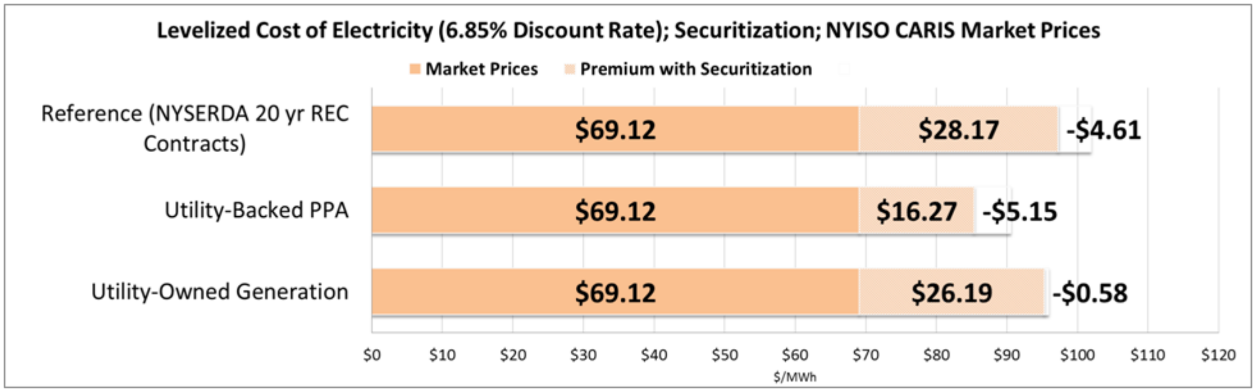
[16] It is assumed for purposes of this analysis that the typical tax equity investor may be unable to fully use the PTC as generated. This is not always the case, however.

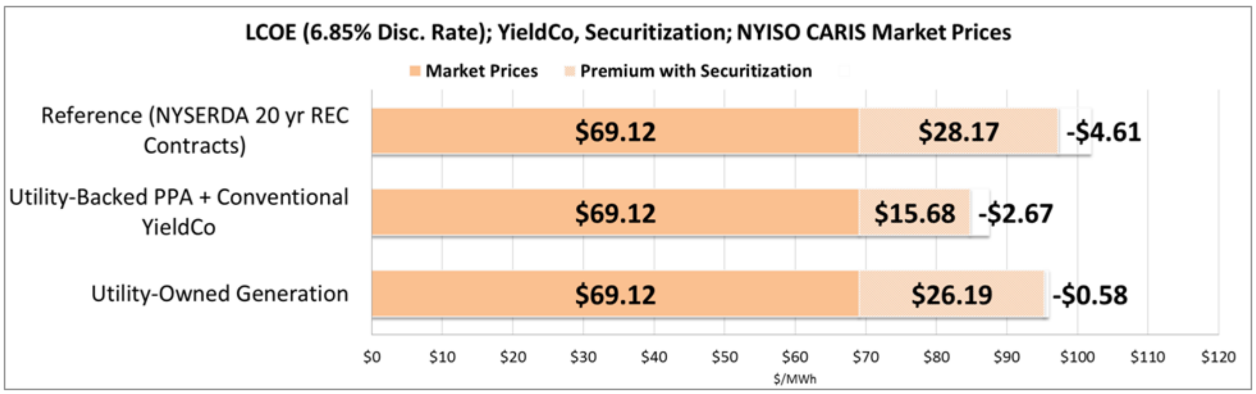
Figure 2. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options with PTC, with and without the need for tax-equity financing



2. **RBB Securitization can further reduce the premium by $1-5/MWh, with the larger benefit when securitized debt displaces project-level debt.** The benefit of RBB securitized debt financing is particularly significant for cases with project financing – the NYSERDA 20-Year REC contracts, and the Utility-Backed PPA in the absence of YieldCo financing – due to the significant spread in these cases between project debt cost and securitized debt cost. However, the benefit is relatively small for cases which feature the use of corporate debt (Utility-Backed PPA with YieldCo financing, UOG) due to the much smaller spreads between securitized debt and corporate bond yields (Figure 3).

Figure 3. Levelized Cost of Electricity for Representative 100 MW Wind Facility – Base Options (no PTC) and the use of RBB Securitization, with and without YieldCo financing





3. **With UOG, ratepayers bear the risk of wind production estimation uncertainty.** Under UOG, ratepayers will compensate the EDC regardless of the performance of the asset, whereas for the typical PPA priced on a per-MWh basis, the owner bears performance risk. The industry average actual project production variance relative to pre-construction estimates is roughly 9% (DNV GL 2014), with an estimated 4% bias towards underperformance.[17] Sensitivities were modeled to assess the variance in levelized cost for UOG associated with that production variance between 13% underperformance and 5% over performance. The 9% variance in actual project production as compared to estimates translated into a $9-10/MWh uncertainty in the cost of electricity for UOG. This risk exposure would need to be considered in head-to-head comparisons of PPAs and UOG options.

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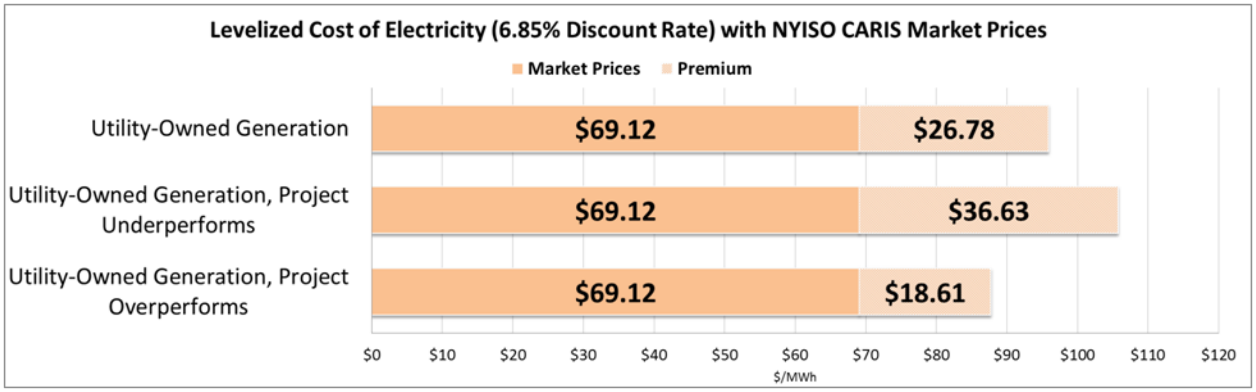
17 See, for example, DNV-GL.2014. "Wind Power Project Performance White Paper Actual versus Predicted: 2014 Update."

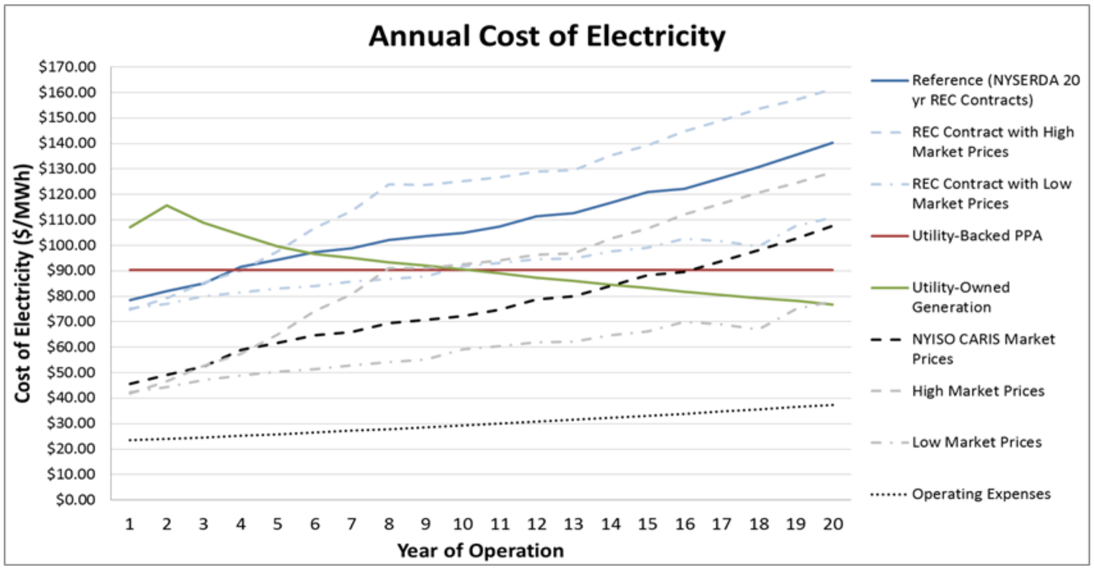
Figure 4. Sensitivity of the cost of electricity for Utility-Owned Generation to wind production estimation uncertainty



4. **The three options lead to very different rate impact time profiles.** Utility rate treatment makes the UOG option expensive in the early years, but it eventually becomes much cheaper in the later years as the value of the asset in rate base drops. Furthermore, the UOG captures any residual value of the asset after 20 years, which can only be secured under the PPA approach if residual value rights are secured through the solicitation and executed PPAs.[18] On the other hand, the NYSERDA REC contract appears cheaper at first, but as it consists of a fixed-premium over market prices, its cost will continue to increase with market prices. The PPA offers ratepayers a fixed cost of electricity and RECs for the facility that falls between the two other cases (Figure 5).

[18] See discussion of residual value and terminal options in Section 5.3.9.

Figure 5. Time profile of the cost of electricity for the three base options (no PTC), compared to base, low, and high market prices and operating expenses[19,20]



In comparison, the time profile of costs for UOG with a PTC is attractive, assuming a ratemaking treatment providing credit of PTCs during the first 10 years of operation. However, REC Contracts or PPAs with assets owned by investors with a tax appetite can close the gap. Given these findings, if an investment/planning budget-type target is employed, some flexibility will need to be provided on an annual level.

1.8.2 Annual Expenditure and Ratepayer Collection Impacts

A key consideration in evaluating options is their temporal and aggregate impacts on retail rates. Specifically, the focus of this section will be to address the incremental, annual expected impacts of the purchase of renewable electricity, as compared to the purchase of the same quantity of electricity from wholesale markets, on retail rates. Although the levelized costs and time profiles provide insight into the impact of any given project on ratepayer costs, the ratepayer collections impact is determined by the aggregate impacts of multiple projects deployed over time. These impacts will vary substantially between the three cases examined here as they have very different time profiles of ratepayer costs. In addition,

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19 The dotted gray lines show the band of uncertainty related to the high and low market price forecasts.

20 The energy market price forecast used for the analysis significantly impacts the modeling results. Base market prices were generated from GE-MAPS modeling for the NYISO's 2014 CARIS 2 study, the most current CARIS price projections available. A low price sensitivity was considered to provide a reasonable range of possible outcomes. The high and low price sensitivities were taken from EIA (2015) Annual Energy Outlook 2015 with projections to 2040.

they will be sensitive to future market price trajectories.[21] As the forecasts of electricity prices out 10 years in the future can differ by 35%, any analysis of this type can at best deliver a range of what could be expected based on best available forecasts.

To address this issue, an assessment was conducted to estimate the amount of LSR that can be deployed with an annual investment available each year to commit to pay for a set of LSR projects' future cost premiums (i.e., costs that exceed expected market prices). For example, if $100 million were available to cover any future costs over and above market prices incurred by ratepayers paying for energy and RECs from projects built in 2017; this limit was translated into a level of deployment in a particular market price scenario. Because this annual investment only represents costs incurred by ratepayers over and above market prices and does not credit future savings relative to market prices, it provides insight into incremental ratepayer collections that are necessary in the near-term to support a project or overall goal.[22]

As an analytical benchmark, a similar level of investment comparable to the current and projected RPS LSR investment was assessed.[23] Specifically, the analysis focused on a theoretical deployment scenario associated with a cumulative ratepayer investment level for LSR premiums of $1.5 billion including $100 million per year committed for five years starting in 2019, and $200 million per year for the subsequent five years. These annual investments were intentionally "back-loaded," to take advantage of the improving anticipated economics of wind energy over time resulting from the assumed flat nominal capital costs for wind combined with projected increasing electricity market prices. These funds were then assumed to be "spent out" or outlaid as collected from ratepayers to cover positive differences between contract payments and electricity resale revenues in any given year for the electricity generated by the wind facility.

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21 Note, in particular, that for the Utility-Backed PPA and UOG options, the total bundled price of electricity is not dependent on market prices. Hence, total ratepayer costs in those cases are not subject to market uncertainty. However, since the ratepayer impact of the choice to purchase renewable energy is due to the *difference* between ratepayer costs for the procured renewable energy, the ratepayer impact of this *decision* is subject to market uncertainty.

22 This analysis presumes expenditure flexibility, and the results shown here represent *expected* expenditures associated with a particular forecast. Actual expenditures (and annual collections) under two of the three structures modeled could vary higher or lower with short-term energy market volatility (which may be temporary in nature) or over a longer term if actual energy price trends diverge from forecasts. If New York were to adopt an approach with a hard cap on annual collections from ratepayers to fund PPA or UOG commitments, conservatism, reserves, short-term borrowing (in the form of financing or reallocation from other programmatic budgets) would likely be necessary, in addition to reductions in subsequent procurements shown here under low market price futures. This analysis does not account for the costs or reduced procurement volumes resulting from these factors.

23 As of December 31, 2014, approximately $1.1 billion in RPS funds were committed to Main Tier projects. When this commitment is combined with the 2015 and expected 2016 solicitation budget, a total $1.5 billion commitment is expected (NYSERDA 2015).

This analysis showed that a $1.5 billion ratepayer investment over 10 years could deliver long-term net customer savings, help the State make meaningful progress towards achieving Statewide energy goals, and put the LSR market on a path to grid-parity. Alongside expected CEF budget levels, the proposed LSR funding commitment would enable near-term reductions in total annual collections and significant decreases over time.

Table 2. Comparative deployment and net costs in each base option (no PTC) assuming a ratepayer investment for LSR premiums of $1.5 billion budgeted over 10 years

$1.5 billion Investment for LSR Premiums over 10 Years	Base Market Prices			Low Market Prices		
	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)
NYSERDA 20 Year REC	1.6	$1.1	$1.5	0.7	$1.1	$1.5
Utility-Backed 20-Year PPA	3.4	-$0.7	-$1.7	1.1	$1.1	$1.4
Utility-Owned Generation	2.1	-$0.2	-$0.8	1.0	$1.1	$1.4

If efforts were made to limit expenditures to the cumulative planning budget of $1.5 billion by adjusting procurement quantities over time, substantially different quantities would be procured under different price futures. To illustrate, Table 2 also shows that with a "back-loaded" planning budget of $1.5 billion for LSR premiums, Utility-Backed PPAs could deliver an estimated 1.1 gigawatt (GW) in a low market price scenario and 3.4 GW in a base market price scenario. Again, this range underscores the tremendous impact that the wholesale market price has the needed LSR premiums.

Nevertheless, Table 2 shows that Utility-Backed PPAs allow deployment of significantly more projects than the other two options in both price scenarios (72% more than NYSERDA RECs under low market prices, 120% more under base market prices), at roughly equal or lower real net cost (where the net cost is the sum of the annual premiums required over the life of the projects deployed in real 2017 dollars).

Further, Table 2 also shows that deployment of LSR through Utility-Backed PPAs or Utility-Owned Generation options could eventually save ratepayers money in the base market price scenario when PPA prices drop below projected market prices, in contrast to a REC-only approach which does not deliver these expected savings. Lower cost structures associated with YieldCos or RBB Securitization could further increase deployment in all options beyond the figures shown in Table 2. Of course, as noted above adjustments would need to be made in the levels of procurement as price trajectories are revealed to constrain early year expenditures in the Utility-Backed PPA and Utility-Owned Generation cases.[24]

The back-loaded expenditure profile results in relatively modest deployment in the first five years. In contrast, because LSR premiums over market are expected to fall over time, eventually reaching cost parity with the wholesale energy market, a more even pace of expenditure commitment would yield greater deployment in the early years but with slightly lower levels of overall deployment. The benefit of a less back-loaded planning budget approach is that it allows for a more measured build-out of LSR development capacity in New York to maintain a robust pipeline of projects over time.

A simplified ratepayer impact assessment also shows that deployment of LSR through Utility-Backed PPAs or Utility-Owned Generation options could eventually save ratepayers money in the base market price scenario. Future annual ratepayer impacts of the Utility-Backed PPA option with base market prices range from a peak cost of under 0.7% of utility revenues to a savings of just under 1%, not considering any potential wholesale price suppression effects which have been previously demonstrated for large penetration of LSR (NYSERDA 2013).

1.9 Policy Options for Legacy LSR, Voluntary Markets & Wholesale Competition

1.9.1 Legacy LSR Considerations

Under the Main Tier RPS procurement, 2,035 MW of renewable resources in New York have been placed under New York RPS Main Tier contracts to deliver RPS Attributes to NYSERDA. The vast majority of these contracts are for a 10 year duration and will come to an end as soon as January 2016, yet many have substantial remaining life. For purposes of this discussion, these generators are referred to as Legacy RPS Renewable Resources (Legacy LSR).

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24 For this illustration, since total ratepayer costs are treated as fixed for all operating facilities in both these cases, the risk of exceeding annual expenditure targets does not reflect actual uncertainty for ratepayers regarding total future bundled electricity and REC costs for operating LSR facilities. Rather, the risk is that future deployment may need to be adjusted to achieve a policy goal of keeping uncertain future incremental ratepayer impacts relative to uncertain future market prices below current levels.

RPS contracts with Legacy LSR projects have already led to investment in putting "steel in the ground," with its associated economic benefits. However, under these contracts New York has no residual post-contract rights to RPS Attributes. It is inevitable that in the absence of a New York policy stimulating demand that creates sufficient value for Legacy LSR RECs, the energy and RECs from some or all of these resources are likely to leave the market. This departure would impact New York's ability to claim that renewable energy supply toward RPS goals, as the right to make such claims accrues to the rightful purchasers of the associated RECs.[25] It could also impact New York's method for compliance with Clean Air Act Section 111(d) targets, either directly (based on accounting procedures) or indirectly (because exported energy would need to be replaced by increased energy production from fossil-fueled generators).

If New York State wishes to retain Legacy LSR production in-State to support fulfillment of its policy objectives or federal requirements, there is a tension between this desire and the need to do so at minimum cost to ratepayers. Most potential features of procurement options for Legacy LSR mirror those for new renewables. If desired, procurement could be accomplished together with, or separately from, new renewables, with selection by a central procurement entity, EDCs (jointly or independently), or an independent evaluator. As discussed in Volume 2, an assessment of market dynamics and options focusing on the potential attractiveness of revenue stability to Legacy LSRs, the risks to ratepayers of combining procurement of new and Legacy LSRs, and changing conditions over time, suggest preferable approaches for consideration.

1.9.2 Voluntary Market Considerations

One of the State's leading policy objectives is to increase participation, liquidity, and innovation in the voluntary renewable market. Over time, the New York voluntary market has not realized its anticipated breadth and depth. Nationwide, most competitive markets experienced voluntary penetration of well below 1%. Recently, however, an increasing number of large, sophisticated end users have engaged in meaningful purchases that have contributed to the financing and construction of new renewable energy generators.

25 Renewable energy-related claims pertaining to energy without RECs have triggered Federal Trade Commission violations.

According to the Rocky Mountain Institute (Rocky Mountain Institute 2015), corporate renewable energy procurement totaled approximately 1,000 MW nationwide in 2014; and contracts in excess of 700 MW have been announced thus far in 2015. Entities such as Google, Kaiser Permanente, and Mars have leveraged their significant demands and strong credit to enter 20-year bundled PPAs for hundreds of MWs based purely on economics. This represents a potentially significant trend and opportunity. These purchases are not easily replicated in New York, however, for two reasons. First, current voluntary market participants have thus far been unable to aggregate enough demand, demonstrate sufficient credit, and obtain approval for contract durations long enough to enable project financing. In addition, the majority of the transactions previously noted involved wind projects in superior wind resource locations, maximum economies of scale, reduced cost and complexity of both permitting and construction, and all captured the now-expired federal PTC. In short, the economics of these transactions provided corporate buyers with bundled purchases of energy and RECs at near parity to wholesale market prices, an economic outcome that may be challenging to replicate in the near-term. Additional policy instruments will be necessary to advance the voluntary market in New York, and prepare it for further expansion as cost premiums shrink in the future.

Like the retail market itself, end-user motivations for voluntarily purchasing renewable energy are not uniform. Nonetheless, an analysis of the history of end-user purchases demonstrates three recurring motivations (which vary in priority from buyer to buyer):

- Meet internal renewable energy goals.
- Reduce greenhouse gas emissions.
- Increase goodwill with customers and the public.

Looking forward, however, a fourth motivating factor for voluntary purchases is emerging with increasing frequency – the desire to stabilize, and possibly reduce, electricity costs through hedging. In today's voluntary market, participants are actively exploring whether brown power hedges can provide new opportunities for end users to achieve cost-effective, long-term budget certainty.

To secure financing, renewable energy projects must secure the sale of the majority of output under long-term contracts backed by an investment grade credit rating. This paper identifies ways to integrate voluntary participation into policy-driven renewable energy procurement models, which can enable the voluntary market to make incremental REC commitments and/or enter brown power hedges by instituting a first-of-its-kind, market-making structure that could be integrated into the procurement model to address some of the barriers and support voluntary market activity in New York. To this end, the State can take the initial, long-term position, and sells shorter term strips of RECs and/or brown power hedges to end users.

If voluntary participation increases, leverage can be created for the State's budget-limited LSR procurement under certain circumstances. When the State resells portions of its long-term purchases as short-term bundled or REC-only strips to the voluntary market, the revenue produced can be circulated back into the LSR procurement cycle. This revenue can be used to stimulate the financing of additional LSR facilities.

1.9.3 Wholesale Competitive Market Option

A final option for supporting LSR resources would involve seeking to reform wholesale market rules. Projected revenue streams from the NYISO competitive markets alone have been unable to incent the development of LSR resources. With gas prices projected to remain at low levels, the competitive market energy revenues are expected to be low relative to the level needed to finance new LSRs.

While wholesale energy market prices do reflect the valuation of the cost of externalities (SO_x, NO_x, and CO_2) to some extent, they do not reflect the full societal value of avoiding these emissions or other values that LSRs can provide to the system.

In addition to externalities, NYISO wholesale market mechanisms do not explicitly recognize the value of certain other attributes of LSR. For example, Federal Energy Regulatory Commission (FERC) regulated locational based marginal pricing LBMP, installed capacity (ICAP) and ancillary service markets do not explicitly value fuel diversity benefits a resource may bring to the electric system. This leads to the concern that the system may become overly dependent on natural gas, as evidenced in the fact that the electric prices today are largely driven by the price of natural gas. These markets also do not explicitly recognize the value of reduced price volatility that resources such as wind can offer to the system. As natural gas prices can experience dramatic spikes, especially during high gas demand periods and extreme weather events, concomitant electric prices will also be volatile. LSRs, can, to some extent, provide greater price certainty for customers.

In a business-as-usual approach, the State would continue to provide incremental payments to renewable developers to facilitate new LSR resources by augmenting the revenues from the competitive wholesale market. Although this approach may work, some argue that competitive market mechanisms can more cheaply and effectively facilitate the entry of new resources that will provide the greatest benefits to the system.

An option could be advanced to consider new market mechanisms to more explicitly reflect the value of the benefits of LSR resources (environmental, fuel diversity, price stability, fuel security etc.) and compensate those resources for those benefits. Such mechanisms could include modifications to existing NYISO market energy, capacity, and ancillary services market products or the creation of new market products. Any new proposal should also discuss whether any of these changes would be sufficient to scale the LSR sector independently, or whether an additional LSR procurement mechanism would be necessary to drive scale, whether the proposal would lead to overall lower cost to consumers compared to other procurement options discussed in this paper, and what federal and state legal issues might arise with respect to state actions influencing wholesale market prices.

Volume 2: Detailed Options and Assessment

2 Background and Purpose

2.1 Background

2.1.1 LSR in Reforming the Energy Vision

Reforming the Energy Vision (REV) is New York State's comprehensive strategy to build a clean, resilient, and affordable energy system for all New Yorkers. REV includes groundbreaking regulatory reform to integrate clean energy into the core of New York State's energy system; programmatic redesign to complement and unlock private investment in clean energy; and leading by example through innovative energy solutions in the State's own facilities and operations.

REV is designed to facilitate a transformation in how we produce, deliver, and consume energy. While distributed energy resources such as energy efficiency, distributed generation, and demand response are a critical focus of the REV strategy, LSR also have an important role to play. Central generation will continue to serve as the backbone of New York's power grid for the foreseeable future, and adding more LSRs to diversify generation sources can deliver numerous benefits to residents and businesses alike. These benefits include new economic development opportunities and jobs, enhanced customer value through reduced price volatility, a meaningful reduction in State's greenhouse gas emissions and compliance with federal mandates, as well as net customer savings in the long-run.

2.1.2 New York's Renewable Portfolio Standard – Historical Context

To support LSR resources, New York first enacted its RPS in 2004 through regulations adopted by the Commission. In an April 2, 2010 Order, the Commission established static NYSERDA Main Tier and Customer-Sited Tier program targets for supporting the production of approximately 10.4 million megawatt-hours of renewable energy annually by 2015 (New York Public Service Commission 2010).

Unlike most states with an RPS, New York uses a central procurement model whereby NYSERDA administers programs that are responsible for meeting RPS objectives. Specifically, NYSERDA is responsible for supporting specific Main Tier (larger, utility-scale resources) and Customer-Sited Tier (smaller, behind-the-meter resources) targets with the remainder of a State goal to be made up by the voluntary market, purchases made by State agencies under Executive Order 111 and purchases made by PSEG Long Island (Long Island Power Authority).

NYSERDA, through Main Tier contracts, pays a production incentive to renewable electricity generators selected through periodic competitive solicitations for the electricity they deliver for end use in New York. In exchange for receiving the production incentive, the renewable generator transfers to NYSERDA all rights and/or claims to the RPS Attributes[26] associated with each megawatt-hour of renewable electricity generated, and guarantees delivery of the associated electricity to New York State ratepayers.

Through December 31, 2014, NYSERDA has conducted nine Main Tier solicitations in pursuit of the Main Tier renewable energy procurement target and released a 10th Main Tier Solicitation in early 2015. From the nine completed solicitations, NYSERDA currently has contracts with electricity generators for 65 large-scale projects. When operational, these projects will add 2,035 MW of new renewable capacity in New York.

In support of a 2013 Main Tier evaluation, NYSERDA conducted an evaluation of the benefits and costs of the portfolio of Main Tier resources as of December 31, 2012 (NYSERDA 2013). This analysis of quantifiable impacts demonstrated that public investment through the RPS Main Tier resulted in a positive impact on the State's economy and the environment. Approximately $2.7 billion dollars of direct investments in New York State were expected over the projected life of the renewable energy facilities under contract at that time. Under a base CO_2 value assumption of $15 per ton, a statewide benefit-cost analysis showed an additional net benefit of approximately $1.6 billion, with a benefit to cost ratio of approximately 5 to 1. The cumulative net growth in gross state product from Main Tier projects as of December 31, 2012 was expected to be approximately $2 billion.

2.1.2.1 REV Regulatory Docket and Large-Scale Renewables (LSR) Track

In 2014, the Commission commenced the REV regulatory docket.[27] REV was conceived to overhaul New York's utility regulations to give customers greater value from their energy use, facilitate the rapid expansion and integration of Distributed Energy Resources into the State's energy system, and transition clean energy from the periphery to the core of investor-owned utilities' business models. The Commission has identified six core outcomes relating to customer knowledge, market animation, system-wide efficiency, fuels and resource diversity, system reliability and resiliency, and carbon reduction.

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26 RPS Attributes include any and all reductions in harmful pollutants and emissions, such as carbon dioxide and oxides of sulfur and nitrogen. RPS Attributes are similar to Renewable Energy Certificates that are commonly used in other RPS programs to catalog and recognize environmental attributes of generation.

27 Case 14-M-0101; Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

A Department of Public Service (DPS) Staff REV straw proposal issued on August 22, 2014 set forth a vision for how to accomplish the Commission's objectives.[28] Among other recommendations and observations, the Staff Report and Proposal suggested that the renewable energy credit-only program approach utilized for New York's procurement of LSRs since the early 2000s should transition to bundled contracts for energy and RECs between the utilities and competitively selected projects, but noted that the issue was not yet ripe for decision as parties had not had an opportunity to comment. In late 2014, parties offered comments in response to the Staff straw proposal; offering varying views on the appropriateness of offering bundled contracts as previously described.

In a February 26, 2015 Commission Order (February Order), a REV policy framework for a reformed retail electric industry was adopted.[29] The February Order also identified those issues that required near-term resolution, discussed numerous issues that needed further development, and specified a process for moving forward. The question of New York's future procurement of LSR was identified among those issues requiring resolution.

According to the February Order, a significant increase in the penetration of renewable resources was essential to meeting New York's economic and environmental objectives, State goals as articulated in the 2014 Draft State Energy Plan, and proposed federal requirements. The Commission recognized that New York's RPS had increased renewable procurement, but far more investment was needed. Nationally and in New York, grid-scale renewable resources must be strategically developed to diversify the energy supply mix, hedge the volatility of fossil fuel prices, and decrease greenhouse gas and other harmful emissions.

Accordingly, in response to party and public comments received through the REV proceeding, in its February Order, the Commission instituted a REV LSR track. To commence this LSR track, Staff was instructed to work with NYSERDA to prepare an LSR options paper to be issued for public comment no later than June 1, 2015. Following the issuance of this options paper, the Administrative Law Judge and Staff are instructed to solicit and schedule additional process and comment opportunity to develop a fulsome record regarding the key features of each substantive proposal.

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28 Case 14-M-0101; Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. "Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues" issued and effective August 22, 2014.

29 Case 14-M-0101; Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. "Order Adopting Regulatory Policy Framework and Implementation Plan, issued and effective February 26, 2015.

2.2 Purpose

On behalf of Staff and in fulfillment of the February Order, NYSERDA and its consulting team of Sustainable Energy Advantage, LLC, its subcontractors (New Energy Opportunities, Inc. and Ed Holt & Associates, Inc.), and the Climate Policy Initiative, have prepared this paper, with the objective of evaluating a broad range of LSR structures and designs intended to spur increased LSR generation in New York while also continuing to competitively and cost-effectively achieve the primary objectives of the REV framework.

For the purpose of this options paper and the associated assessment, LSR are defined to be renewable generation sources that are interconnected to the New York State transmission or distribution system according to the NYISO Open Access Transmission Tariff (NYISO 2015).

2.3 Organization of this Paper

This paper commences with an historical overview of relevant deliberations on development of future policy options for LSR in New York in Chapter 3. In Chapter 4, criteria for evaluating LSR policy options are discussed, along with other relevant constraints on viable options. Chapter 5 introduces a range of LSR policy structural and design considerations, laying the foundation for the analysis to follow. LSR development options are described and assessed in Chapter 6. Chapter 7 summarizes financing options. In Chapter 8, a series of cases comprised of LSR design, procurement and financing options selected for comparative cost analysis are introduced, and the results of the comparative analysis on these cases, as well as a series of sensitivity and planning budget analyses are presented. Chapter 9 summarizes policy options for LSRs already contracted to NYSERDA, for voluntary market development, and for potential wholesale market rule changes. Finally, Chapter 10 presents analysis and observations for those alternatives seen as most likely to best meet the delineated objectives and evaluation criteria. Appendices A, B, and C are included to provide additional context or detailed information regarding key concepts.

3 History of New York's Main Tier RPS

3.1 RPS Main Tier Contracts – Achievements and Challenges

The RPS Main Tier program has achieved measureable success, with over 2,000 MW of new LSR projects under contract from 65 facilities (NYSERDA 2015). Expected energy production associated with Main Tier facilities under contract as of December 31, 2014 is 5.0 million MWh, or 53% of the Main Tier target of 9.5 million MWh (NYSERDA 2015).

NYSERDA, in consultation with DPS Staff, and as a result of changing regulatory and energy market circumstances, has chosen to adopt a measured approach in issuing solicitations and awarding RPS contracts. At times throughout the RPS program's history, NYSERDA elected not to award contracts which were grossly higher than bids for like projects, even when the overall planning budget would have allowed. This approach has led to a very cost-effective program implementation with progress roughly aligning with the Commission's funding commitment allocations for the program.

However, RPS progress achieved through NYSERDA contracts has generally declined in recent years. Recent solicitation results, feedback from market participants, activity in neighboring states and evidence of stalled and/or cancelled projects in the NYISO queue and permitting process suggest a general decline in development in New York. This decline in development can be attributed to various factors, including uncertainty regarding federal renewable energy policies, project siting and permitting challenges, and the overall decline in energy prices.

According to some stakeholders, the decline in development is also partially attributable to the current contract structure, which in their view is not in alignment with the financing requirements of utility-scale renewable projects and does not attract managers toward developing assets in New York. Throughout the years, stakeholders have posited that New York should consider fundamental changes, including but not limited to, longer term contracts and a mechanism to address the commodity market risk implicit within a REC-only contract.

3.2 Alternative Model Considerations – History and Current Context

At various intervals since the inception of New York's RPS, stakeholder feedback and Commission deliberations have taken place to ascertain whether if, at that particular juncture, it was appropriate and necessary to consider changes to the current Main Tier procurement rules. Market changes in both the State and the region have been closely monitored throughout the program's history to ascertain whether a business-as-usual approach is likely to result in substantial or cost-effective progress in the near-term, and whether it will provide appropriate longer-term signals to advance the project development pipeline in New York.

Central to these deliberations has been the establishment of a reasonable balance of risk between generators, utilities, and ratepayers. The established REC-only pricing model with known ratepayer contributions places the majority of risk on renewable generators in the form of energy price risk.[30] The Commission and the stakeholders have confronted the issue of energy price risk before. In April 2010, the Commission considered making alterations to the Main Tier rules to address longer term contracts and mechanisms to address energy price risk. After an extended stakeholder process, the Commission declined to adopt a Contract for Differences hedge mechanism, finding that it was not a necessary step at that time. The Commission referenced the "robustly" competitive fourth Main Tier RFP as evidence of the health of the market. In tabling the issue, the Commission stated that "if circumstances change and/or the results of future solicitations indicate an increased need for a hedge to be provided by the program, we can consider it at that time."

Again, in 2014, similar considerations to those previously described were launched in response to a stakeholder petition to change the Main Tier procurement process to address energy price risk inherent in REC-only contracts. In July 2014, after a lengthy deliberation and considerable stakeholder feedback where the varying perspectives of the proper balance of risk between all parties were considered, the Commission authorized NYSERDA to increase the maximum length of RPS Main Tier contracts to a term not to exceed 20 years with the flexibility to set maximum contract terms of less than 20 years for select types of technologies and facilities. NYSERDA has since issued the 9th and 10th Main Tier solicitations under this structure; the extended term has yielded renewed interest from some developers who are able or willing to address the implicit energy price risk in the associated contract.

30 Although the degree of energy price risk also impacts REC price bids.

As previously discussed, the DPS Staff REV straw proposal suggested that the REC-only program approach should be reconsidered. Comments received from parties indicate varying views on the necessity of this re-examination as well as an ideal solution. However, concern about the future of renewable energy in New York was a consistent theme in public and written comments received in response to REV.

In particular, the following characteristics of the existing RPS structure represent opportunities for improvement:

- **Energy price risk**: Under today's Main Tier Solicitations, REC contracts with NYSERDA are the only source of revenue certainty for developers and financiers. Operating projects sell power into the wholesale market where it is difficult to secure any material revenue certainty beyond the short-term. The associated price risk leads to a higher cost of capital, and limits access to innovative financing structures, such as YieldCos, that demand a greater degree of revenue certainty. The allocation of energy price risk fully to renewable energy developers and their investors increases the overall cost of supporting LSR resources.
- **System benefits**: While LSR can provide meaningful benefits to the grid when deployed strategically, the current RPS structure does not ensure projects are sited to optimize these system benefits.
- **Customer engagement:** The current program does not sufficiently engage end use customers. Projects can contract with NYSERDA for no more than 95% of REC output, and are expected to sell the remainder on the voluntary market. Without specific State supports to facilitate voluntary transactions, however, operating projects have generally sold un-contracted RECs to RPS markets outside of New York.

Therefore, the time is ripe to again consider the options available to New York for support of LSR. But the lens of these deliberations is now the REV framework and objectives.

4 Criteria for Evaluating LSR Options

Evaluating the suitability of potential LSR policy options must occur in the context of New York State's policy objectives, most notably those inherent within the REV initiative, and take into consideration all constraints present as a result of the current market design. This section discusses the implications of existing objectives and provides criteria for evaluating LSR policy options.

4.1 Policy Objectives

The Commission's 2004 order adopting the RPS included the following seven prioritized objectives (New York Public Service Commission 2004):

Renewable Resources: institute an RPS to increase New York State's supply of renewable resources with the ultimate aim of establishing a viable, self-sustaining competitive renewable generation market.

Generation Diversity for Security and Independence: diversify the generation resource mix of energy retailed in New York State to improve energy security and independence, while ensuring protection of system reliability.

Economic Benefits: develop renewable resources and advance renewable resource technologies in, and attract renewable resource generators, manufacturers, and installers to New York State.

New York's Environment: improve New York's environment by reducing air emissions, including greenhouse gas emissions, and other adverse environmental impacts on New York State, including upon underserved communities, of electricity generation.

Equity and Economic Efficiency: develop an economically efficient RPS requirement that minimizes adverse impact on energy costs, allocates costs equitably among ratepayers, and affords opportunities for recovery of utility investment.

Administrative Fairness and Efficiency: develop an RPS that is administratively transparent, efficient, and verifiable.

Competitive Neutrality: develop an RPS compatible with competition in energy markets in New York State.

New York State has historically sought to attain its RPS targets through a market design that balances these seven objectives and increases end-user renewable energy purchases. Fulfilling these objectives requires a procurement model that supports financing for new generators, manages risk for counterparties and facility owners, and creates access for large end users. Of course, meeting all of these objectives must be done as cost-effectively as possible, which means maximizing scale economies and competitive forces and minimizing transaction costs and risk premiums.

Going forward, New York will be factoring in policy objectives initiated under REV and the 2014 Draft State Energy Plan. To guide the design and implementation of the next generation LSR structure, the Draft 2014 State Energy Plan presents four core principles:

- Achieve the lowest possible cost while maximizing customer benefits.
- Promote competition.
- Improve revenue certainty to enable market stability and growth.
- Animate the voluntary market for renewables to complement public investments.

4.2 Stakeholder Perspectives

Throughout the duration of the RPS program, a multitude of opportunities have arisen whereby stakeholder comments have been elicited through the provision of written comments and other public forums. These comments have been provided by stakeholders offering many viewpoints, including the generator, environmental, consumer protection, and utility perspectives.

From the generator perspective, the preferred procurement mechanism would bundle the purchase of energy and RECs, for all (or nearly all) project output, over most of the project's entire useful life, to an investment grade purchaser, to enable the best available financing terms and lowest ratepayer costs. That mechanism must be sustainable in the long run and not create additional, unrecoverable costs.

From the utility perspective, the procurement model approach to cost recovery and impact on the utility cost of capital are critical. The successful model will first effectively manage and allocate risk, and then provide utilities – either as power purchasers or facility owners – with a mechanism to collect approved costs while protecting their credit ratings.

Finally, from the ratepayer perspective, any procurement model must create a stable market, maximize competition, and allow ratepayers to reasonably share risk with generators and utilities. The ratepayer's objective is to drive down the cost per megawatt-hour of LSR and ultimately move to an unsubsidized, market-based model. The ratepayer perspective also seeks scale economies, competitive bidding, and reasonable protection from unexpected events, such as significant generator underperformance. These objectives can be achieved through many of the same procurement structures and risk mitigation techniques sought by generators and have the effect of reducing the cost of energy.

4.3 Evaluation Criteria

The statutory and other legal authority required to implement certain aspects of an LSR procurement model may represent constraints that will also need to be closely considered. The policy objectives and constraints play a role in defining general evaluation criteria and determining how they are applied to each procurement model being considered. Six categories of criteria were identified that address these requirements: (1) Consistency with REV and the 2014 Draft State Energy Plan; (2) Feasibility; (3) Maximizing Generation; (4) Minimizing Cost; (5) Administrative; and (6) Compatibility and Acceptability. Conflict between or tension among objectives is typical of LSR policy design exercises (Grace, Donovan, and Melnick 2011), and it may be necessary for some criteria to have greater weight than others. Evaluation criteria and their categorization are elaborated on in Table 3.

Table 3. Evaluation Criteria

Category	Evaluation Criteria
Consistency with REV and 2014 Draft State Energy Plan	**Ability to achieve clean energy goals.** Working with and through markets to achieve clean energy goals.
	Sustainable Markets. Animating the voluntary market and building bridges to sustainable markets that can be economically viable without incentives.
	Customer Options. Developing new value-added options for electricity customers.
	Value. Maximizing value to the electricity system.
Feasibility	**Implementation Feasibility.** These criteria capture a range of issues, such as: (i) Ability to be implemented by the Commission order/not requiring change of law
	Susceptibility to Legal Challenge. In particular, the exposure to the procurement approach being overturned, or contracts nullified, due to legal challenges.
Maximize Generation	**Encourages successful generation development**. Extent to which approach will incent development efforts and facilitate financing of new renewable generation. Furthermore, extent to which the approach encourages long-term operation of renewable generation.
	Maximize likelihood of contract leading to successful project. The industry's experience with long-term contracting for renewable energy reveals that contracts can often fail to lead to successful commercial operation of the generation facility for a variety of reasons (Wiser, et al. January 2006).
	Can be implemented at scale. Ability to meet LSR requirements in terms of amount of MWs or MWhs likely to be produced. The extent to which certain structures may limit generators' desire or willingness to participate is considered in this context.
Minimize Cost	**Minimize contract risks.** Cost of meeting a policy objective when long-term contracting is central to its design is a function of the risk profile of the contracting method. **Minimizing financing costs.** As the LSR market has matured, market participants are aiming to increase financing efficiency which reduces cost.
Ease and Transparency of Administration	**Administratively efficient**. Ease of administration and ability to minimize administrative costs, taking into consideration institutional capabilities.
	Minimize complexity and timeliness of bid evaluation.
	Minimize complexity of funding mechanism.
	Allows for continued use of Economic Benefits weighting.
Compatibility and Acceptability	**Compatible with Wholesale Competitive Markets.** Extent to which it is compatible with competitive wholesale markets and in particular provides the proper incentives in terms of locational decisions and operational decisions.
	Compatible with Competitive Retail Markets. Including minimizing adverse impacts on retail customers.
	Minimizes potential for Adverse Secondary Impacts on Transacting Parties. Potential to adversely impact purchasers and developers in terms of accounting treatment, credit rating impact, or other factors.
	Provides Acceptable Risk Allocation. The extent of, and reasonableness of, energy market price risk or other risks as born by ratepayers and project developers/owners.
	Creates equitable competitive framework. Including policies and bidding/evaluation procedures that establish a fair and level playing field.

5 LSR Policy Design Options

A number of options are available as New York State looks to evolve from its past unique approach of supporting LSR through the RPS Main Tier. This section provides a foundation for the analysis and evaluations that follow, focusing on the most important alternative policy design features considered for New York's future approach to supporting LSR. First it discusses the policy options, relationship between how LSR target quantities and the timing of those quantities would be established, and long-term contract procurement. Next, it examines major design features relevant to target-setting. It then presents a discussion of considerations for long-term contracting and procurement design, and concludes with an examination of ratepayer funding mechanism alternatives.

5.1 LSR Policy Structure: Target-Driven, Expenditure-Driven or IRP-Driven

In considering design options for future LSR support, NYSERDA and its consultants[31] examined what could be learned from the LSR support experiences of other states. The predominant State policy[32] used to support LSRs has been the RPS, which in general has relied on a combination of *quotas, targets, embedded procurement policies, and features to bound rate impacts.* A common feature of the RPS approach is a renewable energy quota expressed as a percentage of load.

RPS (and related procurement) and integrated resource planning (IRP) policies have evolved differently in competitive and regulated markets. Due to the different circumstances in market structure, policy objectives, resource availability and cost, a variety of structural approaches have evolved. In fully regulated vertically-integrated monopoly markets, the electric utilities would meet RPS targets through competitive or negotiated procurement of bundled long-term contracts (or in some cases, utility-owned supply) for energy and RECs subject to regulatory oversight. In regulated states, IRP and the means of meeting RPS targets are often intertwined. In competitive markets, specific and usually binding RPS obligations have been imposed on market participants, with obligations met and compliance demonstrated through procurement of RECs in a market environment with many sellers and buyers participating in spot or short-term transactions. To support the ability of the market to finance new renewable energy facilities, a number of competitive market states in the northeast adopted hybrid approaches combining elements of

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31 Sustainable Energy Advantage, LLC, New Energy Opportunities, Inc., Climate Policy Initiative, Inc. and Ed Holt & Associates, Inc.

32 RPS or similar policies have been established in 29 states and Washington D.C. (Barbose 2014)

the long-term contracting by the regulated EDCs with RPS obligations (usually on load-serving entities) to help assure sufficient supply could be financed to meet the obligations. Either through legislating targeted procurements within the RPS or adopting formal IRP processes, states have started to overlay elements of IRP in some competitive markets.[33] New York adopted a hybrid central procurement approach using NYSERDA to play a role within a competitive market in a manner more analogous to the regulated monopoly model (Grace 2014).

This experience underscores that LSR quota policies and long-term contract procurements are not necessarily the same thing. While LSR targets and procurement targets can be one and the same (as has been the case with New York's Main Tier to date), a LSR quota can and often does exist separately from procurement targets, with procurement operating within and supporting a portion of the overall quota. As New York considers evolving from its current RPS approach to a future LSR deployment and development policy, it is helpful to parse the relationship between quantities and types of renewables sought over time, the means of providing revenue certainty and incenting competition, and the roles of key parties.

Procurement targets are often nonbinding with no explicit repercussions to the obligated entity on failure to meet the targets. In contrast, in most competitive markets the RPS creates a binding obligation on the obligated entity, and the presence of repercussions for a shortfall can compel development activity to cure such a shortage.[34]

RPS obligations in restructured markets are most commonly delineated as a percentage of retail load readily (convertible to an annual megawatt-hour volume), with compliance verified by comparing quantities of RECs retired by obligated entities with the target following the end of each year. RPS targets (when non-binding) and related procurement targets (when established to help the market meet an RPS obligation) are also usually delineated as a percent of load. For RPS tiers driving incremental supply, policymakers establish increasing RPS obligations and targets well in advance of the applicable compliance year. Doing so provides visibility to the renewable energy development sector necessary to draw investment into creating a pipeline of projects under development in anticipation of meeting the future requirement.

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33 Connecticut, for example, uses an IRP process to dictate and prioritize procurement policies aimed at meeting RPS quotas and other policy objectives.

34 Repercussions for shortfall typically come in the form of an Alternative Compliance Payment (ACP) or penalty placed on the RPS obligated entity. The ACP or penalty is typically set at a multiple of the cost to comply with new supply, serving both as an incentive to buy and a price cap to protect ratepayers.

In the past, New York State has used a hybrid approach combining a 2015 percentage target constrained by a budget-bounded approach that provides transparency and certainty around the level of investment and cost to ratepayers. This is how New York's current RPS is structured, as well as the $1 billion NY-Sun initiative and $1 billion NY Green Bank. This paper assumes the next phase of New York's RPS will continue to be built around maximizing renewable generation within a particular planning budget.

The future New York LSR policy could proceed by any one of these methods, alone or in combination:

Target-driven: establish a percentage obligations on EDCs or other entities based on a statewide objective, establish a procurement target to be met by State entity or EDC long-term contract procurement, or establish an obligation within which supplemental long-term contract procurement targets are established.

Expenditure-driven: quantities procured and their timing are dictated by a preset level of expected expenditures.

Integrated resource planning: An administratively-driven analytical exercise is used to inform the timing, quantity, and mix of renewables development.

5.2 Design Features Applicable to LSR Policy Targets or Quotas

For the purposes of this paper, some LSR design features are assumed constant across different structures, including the applicability of the Commission's LSR policy to the load of EDCs under its jurisdiction,[35] and the conveyance of RECs minted by the pending New York Generating Attribute Tracking System[36] for offering performance-based renewable energy incentives, tracking compliance with any obligation and progress toward procurement targets. Others design features of LSR targets are subject to analysis to determine the preferred approach to meet New York's LSR objectives, and are described as follows.

35 New York has applied the Main Tier RPS to the full retail load of IOUs, with PSEG Long Island and the New York Power Authority operating their own renewables programs. However, it is possible that in the future, New York RPS targets could apply statewide.

36 In 2012, the New York State Legislature amended the Public Authorities Law to require NYSERDA to establish a generation attribute tracking system that records electricity generation attribute information within the State. NYSERDA anticipates that the system will be operational in 2016.

5.2.1 Obligated Entities

If an obligation is used for the future LSR policy, it could be placed on either:

Load-serving entities (LSEs). LSEs, consisting of competitive retail energy service companies and EDCs in their roles as generation service providers of last resort. Often a specified quantity of such long-term EDC procurement for bundled energy and RECs, or RECs alone, is mandated by statute, and sometimes it is incentivized by remuneration to EDC shareholders. In other markets, regulated EDCs enter long-term renewable energy contracts on their own initiative and bring these contracts forward for regulatory approval.[37] In the LSE obligation model in restructured markets, all generation customers share the cost of RPS compliance as part their payment for generation service. For EDCs in this model, only customers receiving generation services from the EDC (as opposed to distribution services) are assessed RPS compliance costs. This approach maintains cost parity in the marketplace. While assigning RPS obligation responsibility to LSEs is commonplace for restructured markets, New York's focus on reducing the ratepayer cost of RPS compliance through long-term contracting with credit-worthy entities does not closely align with considering this alternative for future LSR policy.

EDCs (in their role as distribution companies collectively delivering to all retail load). Placing the responsibility of meeting New York's LSR goals on EDCs through a target or obligation is a viable alternative for consideration. EDCs provide a credit-worthy counterparty, and can procure energy as well as RECs, thereby providing a superior revenue hedge to generators under long-term contracts as a means of enabling lowest-cost financing.[38] If the EDCs in New York were designated as responsible for LSR procurement, an Alternative Compliance Payment would be appropriate under a binding obligation (within which long-term procurement occurred), whereas it would be unnecessary if targets and procurement targets are identical. Incentives to proceed in this manner could include remuneration, an adder on renewable PPA costs to the EDCs if RPS compliance is obtained. Another potential benefit of assigning RPS compliance to the EDCs is that it may reduce accounting complexity on the part of the EDCs.

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37 For example, Public Service of New Hampshire has entered into long-term contracts with wind and biomass facilities in this manner. Similarly, Delmarva Power & Light Company has entered long-term contracts with wind projects. See Findings, Opinion, and Order No. 7462, PSC Docket No. 08-205, DPSC (2008).

38 While not the typical approach for restructured markets, assigning compliance responsibility to the EDCs, in their role as distribution companies, was adopted for the Delaware RPS in Delaware in 2011. (Delaware Senate 146th General Assembly 2011).

The central procurement entity. As discussed in Section 2.1, when the Commission established the RPS in 2004, it designated NYSERDA as the central administrator. Continuation of the use of a central procurement administrator is considered herein as a viable option, although for a variety of reasons discussed in Chapter 6, NYSERDA could continue in this role or another entity (State or third party) could fulfill this role. As discussed further in the next section, while the current Main Tier approach has the same entity conducting the solicitations and entering into contracts, this need not be the case.

5.2.2 Eligibility

New York's past Main Tier solicitations include an eligibility certification phase administered by DPS. Although some states use other eligibility dimensions, the primary dimensions of eligibility include:

Resource type: Typically defined by resource, technology, or fuel type.

Geographic: Either explicitly defined in terms of location or interconnection, or implicitly defined by a requirement to deliver energy into the State's wholesale market or to its retail load.

Vintage: Although not used in all RPS states, restructured states with ample available pre-restructuring supply commonly limit eligibility to generation reaching commercial operation, or being repowered or expanded, after the date of restructuring or RPS effective date.

In December 2012, NYSERDA filed a petition with the NYS Public Service Commission requesting a change to the rules of the RPS Program Main Tier program to limit eligibility to projects located in New York State. NYSERDA requested the change to maximize the achievement of the objectives of the program: environmental improvement, energy security, and economic benefits to New York.[39] In NYSERDA's view, focusing the Main Tier on the development of infrastructure in New York also brings the RPS effort more closely into alignment with the overall strategic initiative of modernizing the State's power generation and transmission system, as set forth in the 2012 New York Energy Highway

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[39] Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, "Order Regarding Retail Renewable Portfolio Standard," issued and effective September 24, 2004, p. 22.

Blueprint.[40] The Commission's May 2013 Order[41] adopted the requested change, finding that limiting eligibility to projects located in the State would maximize the benefits that accrue to New York, while serving important State interests. If out-of-state generation is eligible in the future, then economic benefits, such as job creation in New York, might continue to be an evaluation factor in an RFP process.

5.2.3 Tiered Approach to LSR Support

Options for treatment of incremental LSRs as well as supporting continued operation and/or contribution of already operating renewable energy generators (those currently under contract to NYSERDA, and the pre-restructuring fleet) should be designed to work within New York's specific circumstances. States have often established distinct RPS tiers to accomplish specific objectives. Particularly in restructured RPS markets, such tiers have often been defined by either technology and/or vintage into growth tiers (designed with increasing targets over time to drive investment in incremental supply) and maintenance tiers (designed with stable targets to maintain economically viable operation and limit attrition of the pre-restructuring renewable energy fleet). Characteristics such as vintage, size, emissions, and technology will dictate whether a facility is eligible for a particular RPS class. In addition, states have increasingly adopted targeted sub-tiers, sometimes referred to as carve-outs or set-asides, to encourage specific target technologies or applications (Barbose 2014). Such approaches have most often been applied to distributed generation or more specifically solar electric, but have also been used for offshore wind in New Jersey (N.J. P.L. 2010) and Maryland (Md. Laws 2013). New York's LSR procurement approach could similarly include a specific tier for offshore wind.

New York has a large pre-restructuring renewables fleet, as well as policy objectives to both increase the contribution of LSRs as well as support distributed renewables. This has led to establishment of New York's RPS Maintenance resources, Main Tier and Customer-Sited Tier, aimed at each of these resource groups, respectively. Unlike the traditional maintenance tiers in restructured states, New York has not created an RPS tier targeting support of the entire pre-restructuring fleet.[42] Instead New York, through

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40 New York Energy Highway Blueprint, 2012. http://www.nyenergyhighway.com/Content/pdf/Blueprint_FINAL.pdf

41 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BEE0CC261-B964-4144-8CFA-1F832B745D30%7D. The Commission accepted NYSERDA's recommendation that offshore projects directly interconnected to the New York grid should be considered in-state and therefore eligible.

42 This is due to a combination of factors, including the large size of the fleet, public ownership (through NYPA) of much of the supply, and the expected high cost of doing so.

Commission action, has created a mechanism whereby Maintenance resources can petition for a negotiated cost-based RPS Attribute contract to provide sufficient revenue to justify continued operation. New York's approach to LSRs through the Main Tier RPS procurements discussed in Chapter 3 has also created an impending novel situation not reflected in other RPS states. The 10-year Main Tier contracts signed in early Main Tier solicitations start expiring starting in February 2016, with the associated projects having ample remaining economic life, and eligibility for RPS growth tiers in neighboring states. The issues and options associated with addressing continued participation of these "Legacy LSR projects" towards New York's goals are examined in Section 9.1. It is possible that different tiers could utilize different structural approaches to LSR targets and/or procurement.

5.3 Design Features Applicable to LSR Long-Term Contracting and Procurement

A number of structural options are available considering the evolution of LSR policy, and those options are explored in this section.

5.3.1 Structural Approach to Procurement

The following aspects of procurement are relevant to developing policy options for future LSR procurement:

Procurement mechanism. The procurement mechanism is the means by which project offers are selected. These generally fall into two major categories—selection through competitive bidding and through standard offers.[43] Competitive bidding can be implemented through use of an auction mechanism using standard contracts, or a Request for Proposal method using model contracts. Auction mechanisms can utilize a variety of mechanisms to determine the price paid to selected projects, falling within broad categories of as-bid price (used in the current New York Main Tier RPS procurements) or clearing price.[44] Other methods to establish pricing, usually in the context of standard offers, are administratively-

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43 Although bilateral negotiations have sometimes been used for LSR support by other restructured states, this paper does not consider such an option at this time.

44 Although clearing price auctions are common in wholesale commodity electricity markets, they are best suited for procuring homogeneous commodities, and are ill-suited for long-term contracting for new renewable energy generation possessing material and nonuniform development risk, a limited number of bidders, or where nonprice attributes are to be considered.

set pricing or competitively derived pricing (typically, involving use of results from a recent competitive procurement).[45] Important issues include who is responsible for conducting the procurement, and whether the selection is based primarily on price alone, or price plus other attributes.

Contracting/Transaction structure. Several attributes define the general contracting or transaction structure, including:

- The parties to the transaction, in particular, who is the buyer.
- The products conveyed, i.e., are only RECs purchased or commodity electricity (energy, capacity and/or ancillary services[46]) along with RECs. Transactions conveying both commodity electricity and RECs are often referred to as bundled.[47]
- The transaction type, i.e., whether the transaction is financial or physical in nature (or a combination), e.g., a physical power purchase agreement, or a financial transaction known as a CFD. From a power markets perspective, a sale of RECs is considered a financial transaction.
- Procurement structure, i.e. procurement can be for homogeneous offers for a single type of products, or a heterogeneous mix. A homogenous solicitations could be for energy product or products is transacted, such as through a PPA. Another type is a financial transaction such as a fixed-price REC or REC CFD. Another type is where a buyer acquires or builds a generating asset (a UOG). Transactions in which PPAs, financial transactions and UOG are solicited are referred to in this paper as an *open solicitation*.
- The pricing structure, i.e., fixed, indexed, or a CFD. If only RECs are purchased, is pricing fixed, indexed, or is a CFD approach utilized?

An as-bid sealed-bid auction conducted through a RFP has been effective approach for LSRs to date under NYSERDA's Main Tier RPS program. As discussed in Chapter 3, NYSERDA and DPS Staff have explored ways over time to evolve this model to reduce the cost of financing as the primary means to reduce cost to ratepayers; a number of specific models are assessed in Chapter 6 and modeled for their cost implications in Chapter 9. The models assessed in Chapter 6 generally fall under the broad category of one-sided, or single-sided, auctions or procurements, in which there is a single buyer (or group of

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45 These approaches are more typically utilized for distributed renewables procurement and are not considered further in the LSR analysis.

46 Most wind and other renewable energy projects do not create marketable ancillary services, and these will not be discussed further in this report. Energy is typically conveyed while capacity may or may not be conveyed (or its price hedged) under the common renewable energy contracting approaches.

47 In commercial practice, bundled products often refers to contracts where multiple products are purchased for a single price, i.e., RECs bundled with the price of energy in $/MWh. This report does not use that definition of bundled products.

buyers working together) evaluating competing bids from a number of suppliers. An alternative approach examined in this paper is a double-sided procurement in which both sellers and buyers bid simultaneously. This approach is explored as a means to encourage growth of a voluntary renewable energy purchases by large retail entities by allowing their participation alongside the entity procuring for New York's LSR.[48]

5.3.2 Evaluation and Contracting

In the procurement models explored in this paper, it should be noted that the entity entering into contracts for the products procured may or may not be the same entity that runs a procurement. A survey of LSR procurement in other regulated and deregulated markets shows that several approaches have been used.

The models examined in Chapter 6 include continued procurement by NYSERDA, procurement by EDCs or by a State entity. With respect to the entity that would evaluate proposals, approaches used in other states include evaluation by a State agency, by EDCs acting jointly or individually, by state agencies working in concert with EDCs, or by independent third party professional evaluators. Many RPS markets use independent evaluators in RPS contract procurements, to provide independence, transparency, convenience, or avoidance of actual conflict of interest or appearance of conflict. An independent role may be most important, appropriate and perhaps essential when EDCs have an interest in the outcome of a procurement, either by virtue of proposing a generation project or involvement in a renewables-related transmission proposal associated with projects bid into a procurement. These issues are discussed within the context of each model examined in Chapter 6.

5.3.3 Duration

Because of electricity and REC revenue uncertainty that is difficult or impossible to hedge, experience has shown that new LSRs in northeast markets generally require some measure of long-term revenue certainty to attract financing at reasonable cost. Most eligible project types have economic lives of 20 years or longer. Common tenors in restructured RPS markets for long-term contracting policies used to minimize market price risk and generator cost of capital range from 10 to 20 years, with longer durations correlating to lower cost. This conclusion was reflected in the Commission's decision (discussed in Chapter 3) to extend NYSERDA RPS Attribute contracts to 20 years.

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48 The advantages and limitations of double-sided auctions are explored within the context of enabling voluntary participation in Section 5.6.

5.3.4 Products Procured

As discussed in Chapters 2 and 3, NYSERDA currently procures fixed-price RPS Attributes under the Main Tier RPS contracts. This paper compares the current approach to one allowing generators to hedge both REC and energy market revenues through long-term contracts, either through physical or financial[49] contracts. Capacity is another product produced by LSRs that has a value in NYISO-administered markets which is virtually impossible to hedge long-term. In other states, transacting capacity under LSR procurement has proven to present a number of challenges and complexities and, for purposes of this paper, the issue of conveying capacity under long-term contracts has been set aside. All else equal, this assumption may overstate the programmatic cost to ratepayers.

5.3.5 Disposition of Products Procured

It is typical in RPS-driven long-term contracting in restructured markets that the contracting enables financing using the credit-backing of EDCs or (in New York today) ratepayer collections passed through a public agency, beyond the needs of the contracting entity. If the contracting entity serves load (but procures electricity in a manner other than full-requirements supply) or has its own RPS obligation, it may have a need for the products procured. Otherwise, it must resell the products procured (other than RECs, which might be directly retired, depending on the approach).[50]

5.3.6 Terminal or Residual Value

When, after the conclusion of a PPA term, a renewable generation project has remaining useful life or other valuable assets (such as site, interconnection or remaining term on a land lease) it may have what is referred to as residual, or terminal, value. Terminal value is the dollar value – which is most often positive but may also be negative – of a project and site, including project-owned interconnection facilities, minus the cost of decommissioning. After the capital investment has been fully amortized and any debt paid off,

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[49] For example, through a CFD with more or less comparable effect on hedging energy revenues to a physical fixed-price energy payment.

[50] It is typical in other restructured RPS states where EDCs engage in long-term contracting in support of RPS obligations that the EDCs will resell both RECs and energy (all, or amounts in excess of their own needs) into spot or short-term markets, passing the positive or negative difference between purchase and sale price through to regulated EDC distribution customers as a non-bypassable adjustment to distribution rates. Alternatively, as in Massachusetts, RECs may be retained by the EDC to serve their basic service customers but priced at a spot market price with energy resold into the market, with the net difference between contract and spot (energy and REC) prices assigned to EDC distribution customers. Either way, the intent is not to interfere with the workings of competitive retail electricity markets and REC markets, where an RPS obligation on retail suppliers may be present.

if the ongoing operating, maintenance and capital replacement costs of a project (or the costs to repower the site) plus salvage value minus ultimate decommissioning costs are lower than the commodity market value of its production, it remains a valuable asset. For utility-owned generation in rate base, this value (positive or negative) automatically accrues to utilities and their ratepayers. In contrast, this value typically remains with the owner under a PPA, unless the PPA contains terms which convey value to the PPA counterparty. PPA owners can usually provide substantial terminal value by offering buyers terminal options to extend the PPA at specified prices for a specified term (often, five years).[51] Additionally or as an alternative, a terminal option could be included for utility purchase of the asset following the initial or extended PPA term. Due to income tax considerations, options allowing the buyer to purchase generating assets have typically been priced at or tied to fair market value,[52] but perhaps further research and analysis may reveal conditions under which purchase options at below-market pricing would be viable.

The value of a terminal option may be substantial for LSR generators with low variable costs. The current low-cost of the legacy hydroelectric fleet in New York provides an example of the potential upside (although wind projects have shorter useful economic lives[53] and most are sited on leased property rather than owned property). Seeking to secure terminal value for ratepayers may be desirable in meeting the State's policy objectives. The only way to secure this value (while assessing benefits, costs and risks) is to do so up-front through the procurement process or as an option to allow bidders to improve their bids. A development policy may be designed to attempt to capture some of this terminal value upside under PPA solicitations.

51 The buyer would exercise the option only if the contract price offered for the extension term is less than the market value (from the buyer's perspective) of the energy and RECs. The underlying asset would remain with the seller, including decommissioning obligations.

52 The pertinent income tax considerations are described in Eriksson and Holmes, "The Law of Wind: Power Purchase Agreements and Environmental Attributes," Section XII, http://www.agmrc.org/media/cms/WindPowerPurchaseAgreements_E4AEB5E96D0B5.pdf, and referenced in U.S. Department of Energy on PPAs, U.S. Department of Energy, Request for Information Response Summary (2013), http://energy.gov/sites/prod/files/2013/10/f3/ppa_rfi_summary.pdf

53 Technological obsolescence may be an issue, but it is also an opportunity to repower the site.

5.3.7 Evaluation/Selection Criteria

A final design element of LSR procurements is the basis of evaluation and selection among bids received. Typically, all bids must meet minimum threshold requirements prior to comparative evaluation. Decisions among those bids deemed eligible can be made on a price-only or a multi-criteria basis considering price and other desired bid characteristics. Many such RPS long-term contract procurements use a combination of price and non-price factors; for example, Massachusetts and Connecticut place 80% of evaluation points based on price with 20% based on a variety of non-price criteria (MA D.P.U. 13-146, 2014)[54].

Historically, NYSERDA has used bid price for 70% of evaluation weight, and also assessed a bid project's economic benefits to the New York economy, giving it a weight of 30% in its evaluation process. This requirement led to the quantification of $2.7 billion in New York economic benefits resulting from the then-current portfolio of Main Tier projects in the 2013 program review (NYSERDA 2013). As a result, one factor in reviewing procurement/contracting approaches is what implications are there, if any, for continued use of this economic benefit approach in the bid evaluation. Another factor is whether the different procurement approaches would be amenable to consideration of non-price factors (other than economic benefits); if New York determines that it is important to do so.

5.3.8 Administration and Governance

Finally, during the life of the LSR procurement, a number of potential assessments and decisions may be required, the specifics of which will depend on both the LSR policy approach ultimately chosen, and the degree to which actual experience reveals the need to refine and adapt. Some of the issues and options associated with managing the overall policy are identified here. Options for those providing such functions include a State entity that plays the solicitation role, the DPS, or the EDCs.

The most obvious administrative issue is the need to identify a party to actually conduct solicitations and evaluate and select the proposals. Although the contracting party could fill this role (and several options for contracting are considered in Chapter 6, including EDCs), the potential for real or apparent conflict with EDC ownership or interest in renewables-related transmission projects may suggest that a State entity (or independent third party reporting to a State entity) may be required.

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[54] Department of Energy and Environmental Protection, Notice of Request for Proposals for Private Developers (2013), Section 2.3

Another category of administration and governance topics depends on the means chosen to specify LSR targets and the timeline for solicitations. Under megawatt-hour quota system, the management needs may be minimal. If a budget-limited approach is chosen, a process to course-correct needs to be established in the event the procurement subject to the planning budget diverges materially from the sought-after megawatt-hour quantity targets. Under an IRP-driven approach, an entity must determine the preferred targets, technology/location preferences[55] and timetables that best meet policy objectives.

Finally, initial experience with the new procurement approach may illuminate a need to adjust the details of the selected procurement approach, for instance to improve the means of comparing PPAs and utility-owned projects under an open solicitation.

5.4 Ratepayer Funding Mechanism

Another key dimension of the LSR support structure relates to the nature of the ratepayer funding mechanism. Specifically, in a bundled PPA or UOG approach, the ratepayer funding mechanism provides a partial hedge for customers. The cost of the LSR resource is primarily fixed, thus changes in market prices are offset by an effective premium that falls when the rest of the bill increases, and rises when the rest of the bill decreases. In a REC-only model, the ratepayer funding mechanism results in fixed premium expenditures which are not responsive to changes in the overall bill over the lifetime of the program.

In most competitive states offering long-term contracting in support of meeting RPS goals as well as most regulated RPS states, the ratepayer funding mechanism takes the form of a partial hedge. As noted in Section 5.1, in fully regulated vertically-integrated monopoly RPS markets, electric utilities have either procured renewables through long-term fixed-price PPAs for energy and RECs, or in some cases have owned the generation. In the case of fixed price PPAs, typically prices are fixed on a dollar per MWh basis, providing generators the certainty of a known $/MWh revenue stream that results in a low cost of capital while providing ratepayers with a portion of their power supply that is fixed rather than following a fluctuating wholesale market price.[56] When utilities rate base utility-owned generation to meet LSR

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55 To ensure LSR resources are used strategically to capture the greatest benefits at the lowest cost, a methodology could be advanced to determine when, how, and where new projects should be constructed. This methodology could factor in a number of important considerations, including: total budget, system needs and plant retirements, electricity prices, and the minimum level of annual investment necessary to maintain market interest.

56 Implicitly, in hedging a part of the supply, there would be a varying premium or discount relative to a similar quantity of short-term market purchases, but this variation from the alternative would never be explicitly visible to ratepayers.

goals or obligations, ratepayer costs associated with that generation are similarly largely fixed, although costs per MWh can vary somewhat year-to-year based on actual production and O&M costs. In the competitive RPS markets described in Section 5.1 with binding obligations imposed on market participants who demonstrate compliance through market REC procurement, REC prices float with market conditions and customers effectively fund renewables through an annually varying component of the cost of generation service supply. In the hybrid competitive markets using long-term contracting within RPS obligations to support LSR financing, as described in Section 5.1, the implicit effect on ratepayers mimics the vertically-integrated utility case by hedging a portion of their generation supply costs, but arrives at this impact in a different manner. In these instances, the contracting EDC typically resells the purchased energy and RECs into spot or short-term markets, with the positive or negative difference between the bundled PPA price and the resale revenue passed through all EDC customers as an explicit and varying adjustment to distribution rates.[57] Under all of these models, the cost to ratepayers is implicitly stable, with varying premium or discount directly offsetting varying wholesale market energy (and REC) prices.

Some RPS states have imposed a rate impact cap for cost containment. If applied on a firm basis precluding collections from ratepayers, such an approach risks making contracts unfinanceable or at least substantially more expensive. Alternatively, such a cap can be implemented on a prospective basis, curtailing future procurements if projected net outlays would exceed the cap.

In contrast, under New York's current Main Tier RPS, planning budgets have been created for Main Tier renewables (as well as other clean energy programs) and NYSERDA has conducted competitive solicitations for REC-only contracts, the magnitude of which has been constrained by the budgets available for such solicitations. The costs for these contracts have been recovered from New York's distribution customers of its investor-owned utilities through predetermined wires charges dedicated to that purpose. Budgeting has been relatively predictable since the payments due have been simply the function of a fixed $/MWh contractual charge and the MWhs produced by contracted projects.

57 Such pass-throughs are not capped in any manner, as EDCs would not accept the PPA obligation without assured cost recovery.

For the purposes of New York's future LSR support, in general, if a quota-based obligation is established and not coupled with long-term contracting, the ratepayer impact will by its nature float, as market REC prices will fluctuate due to supply, demand and other factors over time. As such an approach is not consistent with the stated policy objectives for support of new renewables; it will not be discussed further here.[58] Where long-term contracting is involved, the primary options[59] are as follows:

- **Fixed price, varying collection:** If LSR support is offered in the form of fixed prices for bundled energy and REC supply, the EDC or other purchasing entity will resell energy into the NYISO spot markets, with the net positive or negative difference passed through to EDC distribution ratepayers through a varying (reconciling) charge or collection mechanism (See Figure 6 below). While the quantities in successive procurements can be adjusted upward or downward to compensate for market price movements to track a desired cumulative expenditure level, providing a fixed hedge to generators requires an explicit variable annual distribution charge through an annually varying collection mechanism (assuming that the entity paying the generator is allowed to fully recover its costs). When this variable distribution charge is combined with varying market generation service costs, the variations in the collections and generation costs implicitly offset each other, providing a partial hedge to ratepayers and reducing price volatility. Under this structure, the "collection" will also be negative (i.e. turn into a bill credit) when market prices exceed the fixed-price LSR portion of their bill. This is what enables the program overall to generate net customer savings under base price forecasts, as described in Chapter 8.

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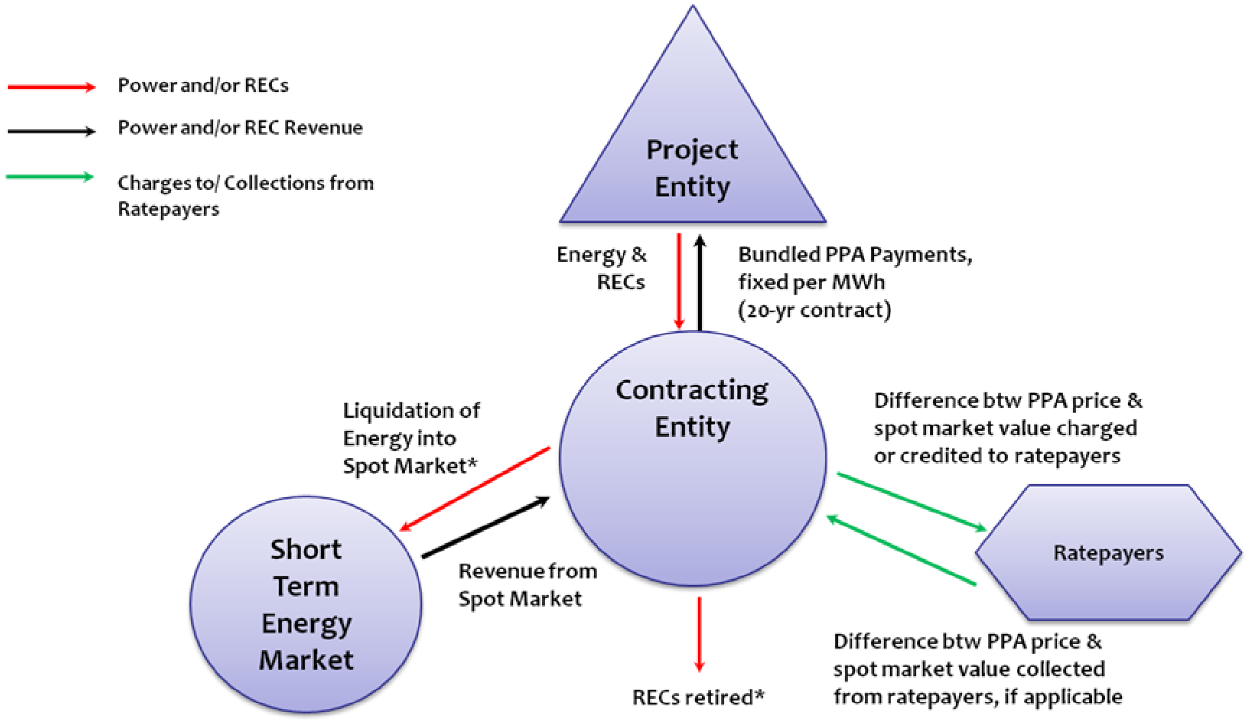
58 However, we note that if support is provided for operating resources, as discussed further below, such an approach might be considered.

59 Contract pricing structural variations in between those described are possible, for example, capping REC payments or premium collections. Any such adjustment to limit a floating implicit or explicit premium under a specific contract will impose risk on generators that will be reflected in higher pricing, which undermines the objectives.

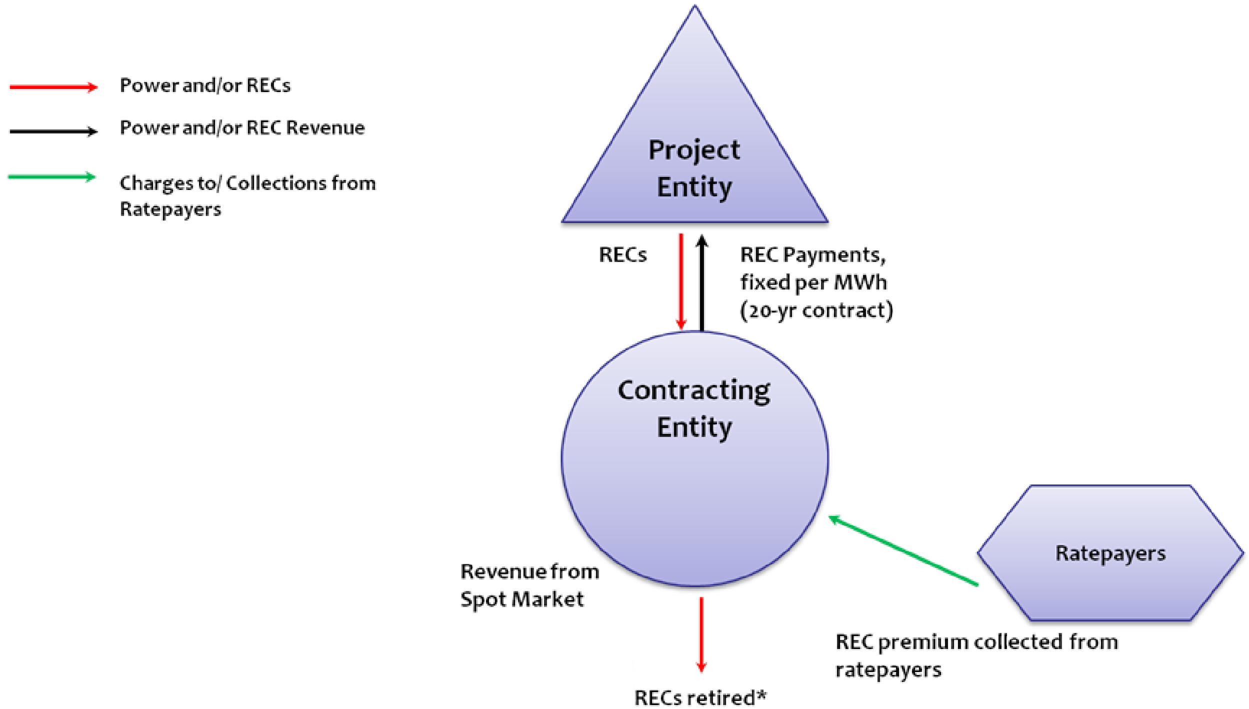
Figure 6. Payments and Collections Following Successful Solicitation: Bundled PPA



** Portions of energy and/or REC contracts may also be resold to voluntary market participants. Revenues from such sales can be used to supplement future procurements.*

- **Fixed premium, fixed collection**: If future LSR support is provided in the form of fixed REC prices (as under the current Main Tier RPS contracts), an explicit fixed per-MWh cost premium through ratepayer collections would be imposed, on top of the varying market prices faced by ratepayers (See Figure 7, below). Neither the generator nor the ratepayer receive a hedge on energy prices, and the ratepayer pays an above-market premiums for the lifetime of the contracts with no opportunity for the collection to turn negative and produce customer savings.

Figure 7. Payments and Collections Following Successful Solicitation: REC Only



** REC contracts may also be resold to voluntary market participants. Revenues from such sales can be used to supplement future procurements.*

Analysis provided in Chapter 8 presumes that the projected net expenditure for LSRs is not capped but rather represents a budgetary target (associated with a particular forecast) which ultimately could float higher or lower with actual wholesale market energy prices.

If there is a desire to manage the achievement of renewable energy quantity targets within a budgetary framework, however, this can be managed through the scheduling and sizing of future procurements. In other words, a future procurement schedule (developed based on energy market price trend projections) could be modified if payment obligations exceed targets, reducing the schedule of future procurements until projected net expenditures are brought back in line with expenditure targets.

5.4.9 Reconciling Targeted Expenditures with Efficient and Effective Procurements to Grow Large-Scale Renewables

New York has several competing objectives: to expand the effectiveness of its LSR generation fleet to achieve higher levels of greenhouse gas emissions reductions while to do so as efficiently as reasonably possible and within targeted costs. Based on forecasted energy prices, it would be expected that an effective premium of the lowest cost bids in a solicitation where a bidder could bid for a bundled energy and REC PPA would be lower than bids for RECs-only on an expected value basis. However, the variance in payments over time—where energy would be sold into the market and ratepayers would pay for the difference between the contract price and the LBMP at the time and place of sale—could be substantial, and net payments could be significantly higher or lower than projected at the time of the solicitation. Energy market prices could turn out to be lower than projected, with the result that effective REC payments are higher than expected, or market prices could be higher than projected, resulting in lower premiums than expected.

Going forward, if there is a desire to have explicit collections from ratepayers contained, whether generation will be procured under PPAs, REC-only contracts or through utility-owned generation, once a commitment is made by contract and/or regulatory approval for a specific project, it is important that the commitment to pay be honored and, for PPAs and REC contracts, that the paying party be assured that it will recover its costs. Otherwise, investment will be deterred or the cost of capital increase, and, hence, cost to ratepayers will be increased, undermining the goal of growing LSR at a reasonable cost.

Cost containment can be best achieved consistent with other competing LSR objectives through the use of flexible budgetary targets coupled with procurement management. Specific strategies could include one or more of the following:

- Use procurement levels to course-correct, slowing down subsequent procurements if energy prices are cumulatively below projections (and potentially accelerating procurements if energy prices rise);
- Execute contracts relative to the quantities solicited based on the reasonableness of contract pricing offered;
- Procurements could be back ended to defer high levels of purchases to a later time period when presumably, energy prices will be higher, which will reduce renewable premiums;
- Bids for fixed-priced RECs as well as for bundled energy and RECs could be sought; fixed-price REC bids if competitive could be selected to mitigate renewable premium variance relative to a planning budget;
- Conservatism in the quantities solicited (e.g. solicit on the basis of a low-cost energy price future scenario).

These approaches could result in a slower ramp-up toward meeting procurement targets but a far stronger likelihood of staying within the planning budget.

As noted above, the mechanism typically used for cost recovery for amounts paid under long-term PPAs is a power cost recovery clause which would guarantee to the buyer, typically, a distribution utility, prompt and complete recovery of the net costs paid under a PPA. As described in more detail in Chapter 8, use of such a mechanism will be critical in terms of the effectiveness and efficiency of an LSR program that utilizes PPAs. Use of this mechanism will also make it easy to track net outlays against budgeted amounts. To the extent a LSR program will incorporate utility-owned generation, accounting should also be achievable. If traditional cost-of-service ratemaking is utilized, project-specific costs over time and actual output will need to be tracked against the market price for the energy (the sale price if energy is sold or the value of energy if the energy is used for ratepayers) to derive net REC payments.

6 LSR Development Options

6.1 Solicitation Design for New Renewables

This section addresses the options specifically available to New York as it considers approaches to support new LSR development. It includes discussion regarding how procurements are structured, who conducts the solicitation and evaluation, what products and project types are eligible to compete, and who serves as the PPA counterparty. Several elements are critical to the development of all options, such as the need for adequate mechanisms to provide project investors with assurance of promised payments, cost recovery protections for those entities that will be paying for the renewable energy procured, and the use of planning budgets to moderate the pace of deployment to moderate ratepayer impacts. The key design elements considered in defining alternative procurement models are summarized in Table 4.

Table 4. Procurement Model Design Elements

Parameters	Design Options
Procurement run by…	NYSERDA (current/reference case) EDCs State entity
Contract between generation owner and…	NYSERDA (current/reference case) EDCs State entity PSEG LI
Project owned by…	Developer and/or project investors (current/reference case) State entity EDCs
Off-take: Commodities Procured	RECs (current/reference case) RECs+Energy

Other design parameters include collection mechanisms, remuneration to EDCs, disposition of electricity commodity, disposition of RECs, and post-contract ownership and options. The discussion in this section focuses on procurements where only new renewable generating capacity would be eligible to bid. Options for procuring Legacy LSR projects (Main Tier RPS projects whose contracts have expired), animating the voluntary market, and NYISO reforms that would be supportive of LSRs are discussed in Chapter 9.

Within the range of development options described in Table 4, three primary structures with a series of variants emerge as key options for further assessment. These options include:

Option 1. NYSERDA conducts solicitations and enters into long-term contracts with renewable energy developers (Section 6.2).

- REC-only Contract.
- REC CFD Contract.

Option 2. State entity conducts solicitations and enters into long-term contracts with renewable generators (Section 6.3).

Option 3. State Entity/EDC solicitations for long-term PPAs and utility-owned generation (Section 6.4).

- PPA-only solicitations (Option 3a)
- Open-source solicitations: Head-to-head competition between proposals for PPAs and utility-owned generation (Option 3b)

These options, and key variants, are described in more detail below and are reviewed in the context of the evaluation criteria outlined in Chapter 4. Some of the evaluation criteria—animating the voluntary market, building bridges to non-incentivized markets and creating new value-added options for customers— do not differentiate among the procurement options and are further addressed in Chapter 9.

6.2 Option 1: NYSERDA Conducts Solicitations and Enters Into Long-Term Contracts with Renewable Energy Developers

6.2.1 Fixed-Price REC Contracts

The current approach used for facilitating financing and construction of new LSR is NYSERDA's Main Tier competitive bidding program for up to 20-year fixed-price REC contracts. One programmatic option for LSRs is simply to continue the existing program. This option is presented here as the base case upon to which other options are compared. An advantage of this approach is that the program is established and its fixed payments make it easier (than other approaches) for New York to procure new resources at more predictable costs and within an established planning budget set by a fixed collection schedule from ratepayers. This option is the only option of those evaluated that can easily be guaranteed to operate within a fixed budget. Moreover, there are no apparent feasibility issues with continuing with this approach. In addition, in terms of compatibility with the wholesale power market, the fixed price REC contract does not significantly reduce the incentives of renewable generators to locate in less transmission constrained parts of the grid. That is because the value of energy revenues is fully dependent on where the generator locates and the quality of its interconnection to the grid. However, associated challenges exist.

NYSERDA's continued use of the fixed price REC contract as the primary LSR procurement vehicle poses risks for New York's ability to meet its objectives. The fixed price REC contract does not offer any energy revenue certainty to project investors, which is the largest part of the market value and revenue expectations for these projects. This option has several implications. This type of contract may not be sufficiently attractive to incent developers to develop and build LSRs in New York, especially given more attractive alternatives available in New England and other regions, such as longer term utility contracts for bundled energy and RECs. Moreover, the additional risks associated with REC-only contracts may make financing of projects more difficult than where projects have bundled energy and REC contracts.

Further, the substantial amount of market price risk that the developer assumes, even with a 20-year fixed price REC contract, almost certainly results in bidders adding a substantial risk premium in their bids. Alternatively, bidders might lay off some of this risk (or assume that it will be laid off) through an energy price swap (or other energy hedge) with a bank or other swap dealer, but at a substantial cost likely leading to higher bid prices.[60] As of last year, several banks and energy marketing firms had exited the energy hedge market, resulting in the reduced availability and quality of commercial energy hedges.[61] The resulting increase in energy price risk to developers, combined with the decline in wholesale energy prices (caused primarily by declines in natural gas prices) have created upward pressure on REC contract prices. However, these factors have been partially mitigated by the recent increase of the duration of REC contracts from 10 to 20 years.

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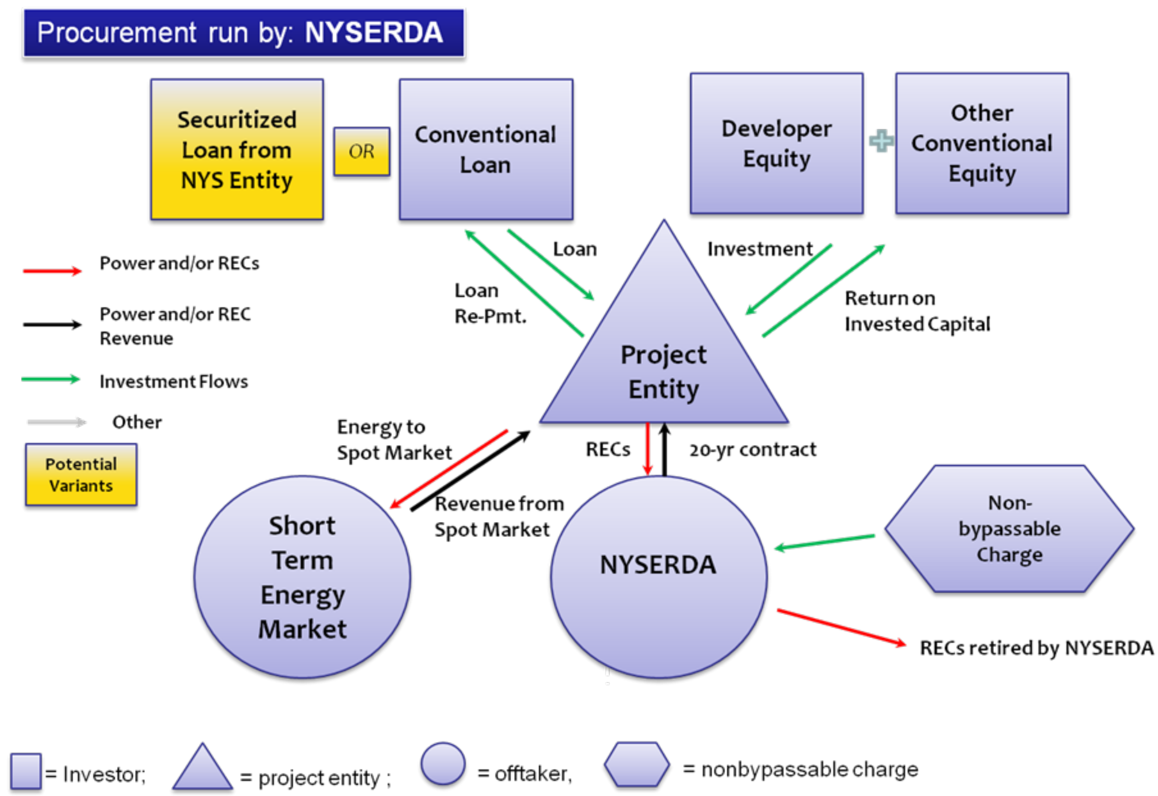
60 An energy price swap is a financial derivative contract where a party (Party A) pays another entity (Party B) to the extent actual market prices for a particular commodity index exceed a contractually-specified fixed price and conversely, Party A receives payment from Party B to the extent actual market prices for a particular index are lower than the contractually-specified fixed price. Commercial energy swaps offered by banks or bank-affiliated energy traders are often priced off forward price curves, which tend to be lower than the expected value of energy over the same period (based on contemporaneous energy price forecasts especially beyond the near-term), and have substantial bid-ask spreads. In addition, counterparties to these swaps impose substantial security requirements that pose additional real costs to project owners, which tend to be reflected in higher bid prices.

61 Banks that have exited the power trading business or sharply curtailed activities include J.P. Morgan, Morgan Stanley, Deutsche Bank, and Barclays. *See*, e.g., (Hoffman 2014); (Krishan 2013); (Robinson 2012); (Bethelson 2014).

All in all, the NYSERDA fixed-price REC contract solicitations rate highly in terms of feasibility, ease of administration, and compatibility and acceptability. However, these types of contracts are substantially suboptimal in terms of the criteria of maximizing generation, minimizing cost, and achieving New York's clean energy goals.

Figure 8 provides an overview of a NYSERDA-run fixed price REC procurement approach.

Figure 8. NYSERDA Fixed Price REC Procurement



6.2.2 Purchase of Energy and RECs

NYSERDA does not have the legal authority to buy and sell electric energy. Hence, NYSERDA is not in the position to physically procure bundled energy and RECs under long-term contracts.[62] As a result, this variant does not pass the feasibility test.

[62] Even if NYSERDA had the legal authority to do so, NYSERDA is not a wholesale electricity market participant and would need the assistance of a third party to sell into the market (i.e., liquidate) energy it would purchase under long-term contracts.

6.2.3 REC Contract for Differences

A REC CFD is a form of contract in which NYSERDA could purchase RECs from a seller while providing a fixed-for-floating swap on the value of energy, thus providing an effective hedge on energy. One benefit of a CFD compared to a bundled energy/REC PPA is that as a purely financial transaction, it can be used by a party like NYSERDA that is not a NYISO market participant to provide revenue certainty to generators. It can provide the same benefits in terms of the ability to hedge market price risk for both generators and retail customers.

Although a NYSERDA solicitation offering REC CFDs would be more administratively complex than a fixed-price REC-only solicitation, it also should be feasible to implement and should provide better opportunities for maximizing generation at lower costs than the current procurement mechanism. On the other hand, it is possible that restrictions in the Dodd-Frank Act could potentially limit the magnitude of the CFD transactions that NYSERDA could enter with generators. Implementing this approach would require a collection mechanism that could support expenditures that vary with market energy prices.

6.3 Option 2: State Entity Conducts Solicitations and Enters Into Long-Term, Bundled Contracts with Renewable Generators

A State entity[63] could conduct solicitations for purchasing energy and RECs under long-term PPAs. As an alternative, bidders could be offered the opportunity to bid RECs only for a CFD. This option would also require a State entity to enter a new, substantive market role that would require legislation.

These types of solicitations are broadly summarized under two categories: (a) PPA-Only Solicitations and (b) Open-source solicitations, where bidders may submit proposals for both PPAs and UOGs via the sale of projects or project development rights to one or more utilities, or a utility may also submit a utility-initiated proposal for a utility-owned project.

[63] This entity could be NYSERDA, NYPA or another party identified or created by the state. Depending on the entity selected, different advantages or limitations may exist. Legislative authority may be required to pursue certain options.

Under this option, the State entity would be the sole buyer, with all net PPA (or REC CFD) costs recovered from utility distribution customers. The State entity would need to have the authority to purchase energy and to liquidate (sell) the energy into the market. It would be helpful if the State entity was also a wholesale market participant (alternatively, the State entity could contract with a wholesale market participant to provide a service to liquidate the energy). There are several advantages to designating a State entity as the procurement agent and counterparty. First, such a State entity is presumed to be highly creditworthy, and to possess the authority to collect program costs from ratepayers. As with investor-owned utilities, investors in renewable energy projects look for PPA buyers with investment grade credit ratings. Depending on the cost recovery arrangement with EDCs, there may be no need for remuneration of EDCs as an incentive for participation. Moreover, having a State entity as the sole buyer would simplify the procurement process where solicitations are seeking only contracts for RECs and/or energy and not proposals for UOGs. Finally, a State entity could provide a single contractual intermediary to facilitate other policy initiatives such as the enhancement of voluntary market transactions as described in Section 9.2. Non-inclusion of residual value post PPA, compared to UOGs, could be mitigated by requiring or encouraging terminal options to capture residual value in a PPA solicitation.

On the other hand, if UOG proposals are to be allowed to compete with PPA proposals in an open-source solicitation, the additional complexity would likely be the predominant effect (see also Section 6.4for further discussion of the conduct of an open-source solicitation). This is based on the assumption that the State's investor-owned utilities would likely be the interested buyers of proposals to sell renewable project development assets probably in conjunction with engineering, procurement and construction (EPC) proposals, or alternatively, owners of utility-initiated proposals. This option would result in both the State's investor-owned utilities as potential UOG buyers or owners and a State entity as PPA purchaser being active parties in the same solicitations, a unique arrangement which would likely raise issues regarding roles, responsibilities, conflicts, and duplicated efforts. This would entail a solicitation design for which there are no known precedents and could result in substantial implementation issues.

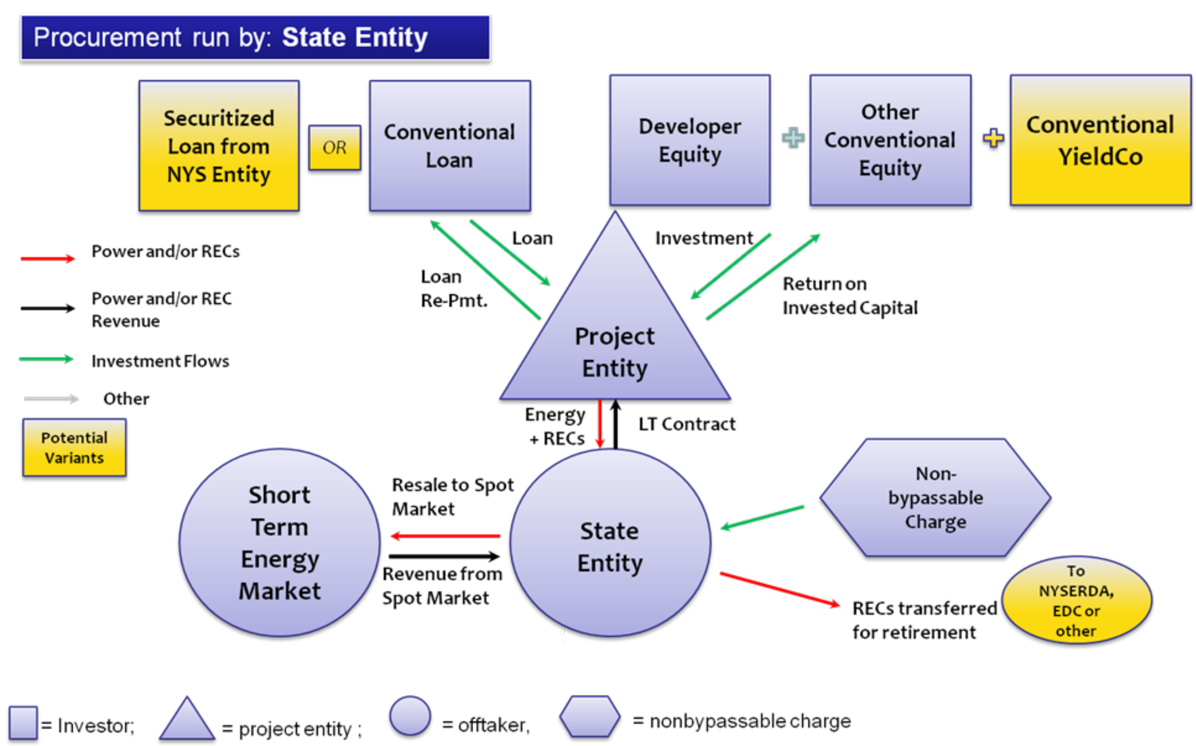
A State entity open-source solicitation variant would potentially create more value in terms of maximizing renewable generation, achieving state clean energy goals, and minimizing costs, but with the challenge of a likely need for legislative action, a disadvantage of adding complexity to implement and associated administrative costs to the procurement process.

The State entity PPA-only variant is likely to be feasible, but with more administrative complexity than the current NYSERDA fixed-price REC-only approach. The advantages of central procurement would be retained. Compared to the current program, successful renewable project development would be more strongly facilitated with significantly lower costs due to the availability of energy price hedging for generators. However, the solicitation design would not incorporate the possibility of renewable generator asset sales to utilities and, hence, it would not create the optimal competitive playing field which could maximize renewable generation and minimize costs.

As with other procurement options involving long-term PPAs for energy and RECs, the solicitation and contracting process can be designed to be compatible with wholesale markets. Solicitations can be implemented to take into consideration the value of energy based on location and transmission constraints, thus providing strong signals to renewable energy developers to site their projects in suitable locations. Contracts can be designed to provide appropriate operational incentives that allocate the risks of negative LBMPs between the counterparties while providing sufficient revenue assurances for financing purposes.

Figure 9 provides an overview of a State entity-run procurement approach.

Figure 9. State Entity Procurement



6.4 Option 3: State Entity/EDC Solicitations for Long-Term PPAs and Utility-Owned Generation

The most common form of utility procurement for LSR is the long-term PPA, usually 15 to 20 years in duration. Energy and RECs are purchased, sometimes with capacity, and these products are either bundled together for a single $/MWh payment or the products are purchased separately (with energy and RECs priced in $/MWh) by utilities. There are many examples of utility solicitations for long-term PPAs across the country and there are a number of differences in the way the solicitations have been conducted and structured. Many of the examples referenced are in neighboring Northeastern states, which share a number of characteristics with New York: retail competition, renewable portfolio standards, similar wholesale market structures, renewable energy resources and project costs. In some of these states, the EDCs are individually responsible for conducting solicitations, evaluating and selecting bids, and negotiating contracts, subject to regulatory review (and, in many cases, oversight by an independent third party). In other states, state agencies are primarily responsible for the conduct of the solicitation and work with the EDC or EDCs who would be counterparties to the contracts. As wholesale energy market participants, under a PPA, the EDCs can purchase and resell the commodity electricity into the wholesale market.[64]

For purposes of this paper, such solicitations are broadly categorized as (a) PPA-only solicitations and (b) open-source solicitations, where bidders may submit proposals for both PPAs and the sale of projects or project development rights to one or more utilities, or where a utility may also submit a utility-initiated proposal for a utility-owned project.

6.4.1 PPA-Only Solicitations: Option 3A

The most common competitive solicitation approach for renewable energy is to seek bids from renewable energy developers for energy, RECs (and sometimes capacity) under long-term contracts. There are however several structural and design variations in how these solicitations are conducted, the role of State entities in the process, and the range of resources to be procured. Several different potential models are outlined in this section.

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64 In principle, the EDCs - as providers of default service to end users in their territories who do not choose supply from competitive energy service companies (ESCOs) – have a load obligation and might be able to use some of the energy procured towards this supply. However, as in other states, using such electricity to supply default service customers is not likely to be compatible with how default service is procured and therefore is not considered a likely approach here.

6.4.1.1 Individual Utility Procurement

One approach is for each EDC to conduct its own solicitation, subject to obtaining any required regulatory review. California has taken this approach in implementing its RPS procurement process. Draft requests for proposals (RFPs) are submitted by the State's three investor-owned utilities for approval by the California Public Utilities Commission (CPUC). The RFPs are reviewed collectively and usually approved (with any ordered modifications) in a single order.[65] Renewable energy developers may submit bids to any or all of the utilities following issuance of the RFPs. The results of the individual solicitations, including executed PPAs, are then submitted to the CPUC for approval. Upon initial operation of a project under a PPA, the utility is then entitled to recover the cost under a power cost recovery tariff (CPUC 2015).[66]

6.4.1.2 Common RFP: Individual Utility Implementation

Another approach is for the State's EDCs working in consultation with a lead State agency, to develop a common (or joint) RFP, subject to approval by the respective state's regulatory commission. Bidders may decide whether to bid to all of the utilities or a subset of them. In New York State, the utilities are responsible for evaluating bids, selecting winners, and negotiating contracts, subject to Commission approval. The Massachusetts EDCs used this approach, working in consultation with the Massachusetts Department of Energy Resources (DOER) in a 2010-11 procurement process under Section 83 of the Green Communities Act (NSTAR Electric Company 2011).

6.4.1.3 Common RFP: Bid Evaluation and Selection

Another approach is for the State's EDCs working in consultation with a lead State agency to develop and issue a common RFP, subject to approval by the Commission, and to collectively evaluate bids and select winning bidders. Contracts, based on a pro forma PPA, are subject to negotiation with the EDCs. The energy and RECs from successful projects can be allocated to individual EDCs based on their load share (which is reflected in individual contracts). The Massachusetts EDCs also used this approach, working in consultation with DOER, in a 2012 procurement process under Section 83A of the Green Communities

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65 An example of an order approving multiple utility RFPs is Decision Conditionally Accepting 2014 Renewables Portfolio Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan, D 14-11-042 (November 11, 2014).

66 In California, cost recovery of purchased power costs is through what is called the Energy Resource Recovery Account.

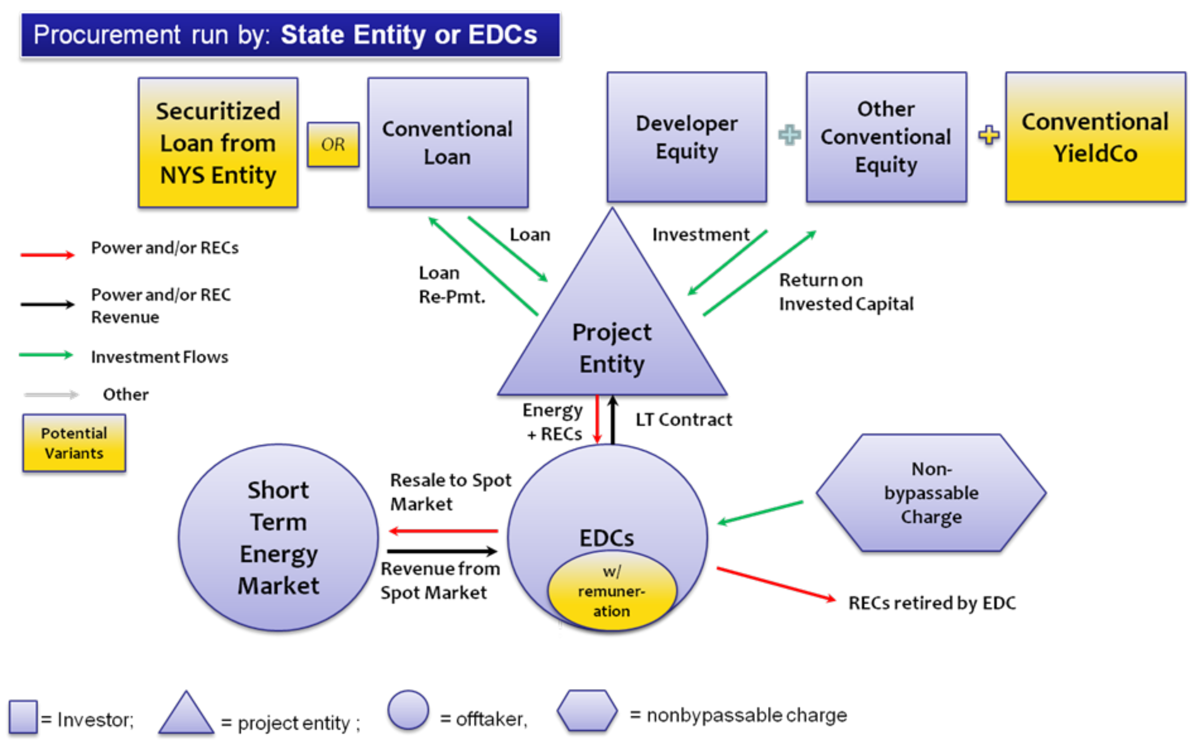
Act (General Laws of Massachusetts 2012, Fitchburg Gas and Electric Company et al. 2014). Alternatively, successful bids could be allocated among the utilities on some other basis.

6.4.1.4 State Entity-Directed Solicitation

A final approach is for a lead State entity to be responsible for the issuance of a solicitation, bid evaluation and bid selection, in consultation with the EDCs. The lead State entity would work with the EDCs to develop a pro forma PPA, with the utilities responsible for negotiating with respect to any bidder exceptions to the pro forma PPA. Connecticut and Maine have used this approach for renewable energy solicitations.[67]

Figure 10 depicts this scenario; in this example, the PPA is assumed to be with an EDC.

Figure 10. EDC PPA Scenario



[67] In 2013, Connecticut conducted a solicitation pursuant to statutory provisions which authorized the Department of Energy and Environmental Protection ("DEEP") to seek long-term renewable energy PPAs. The solicitation conducted by DEEP (in consultation with the Public Utilities Regulatory Authority ("PURA") procurement manager, the Office of Consumer Counsel, and the Attorney General), resulted in two PPAs, which were executed by the state's two regulated utilities and then approved by PURA, CT PURA Docket 13-09-19 (2013). The Maine Public Utilities Commission has conducted solicitations for long-term contracts for capacity and energy pursuant to An Act to Enhance Maine's Energy Independence and Security, P.L. 2005, ch. 677, as revised, and has directed the state's investor-owned utilities to enter into contracts with winning bidders.

6.4.1.5 Potential for Affiliate Transactions and Need for Independent Oversight

Several of New York's utilities have affiliates that are active developers of renewable energy projects. The eligibility of affiliates should be addressed by the stakeholders and the Commission. If affiliates of the New York utilities are allowed to bid in solicitations, the processes and Commission rules should be set up to ensure a level playing field and comply with criteria and guidelines established by the Federal Energy Regulatory Commission (FERC) pertaining to power sales contracts between a generator and an affiliated utility buyer. FERC has established criteria and guidelines for the conduct of solicitations.

For competitive bidding processes, FERC has required assurance that:

- The process was designed and implemented without undue preference for the affiliate.
- The analysis of the bids or responses did not favor the affiliate, particularly with respect to evaluation of non-price factors.
- The affiliate was selected based on some reasonable combination of price and non-price factors (Boston Edison Electric Company re: Edgar Electric Energy Company 1991).

FERC has also enunciated four guidelines for evaluating whether an affiliate has received undue preference during any stage of a solicitation process (Allegheny Electric Supply Company, LLC 2004):

- Transparency: the competitive solicitation process should be open and fair.
- Definition: the product or products sought through the competitive solicitation should be precisely defined.
- Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.
- Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

One way to avoid or mitigate the potential for bias is to not allow affiliates to bid. However, this would constrain and limit the competitive supply of competent and creditworthy market participants. If affiliates are allowed to bid, there are several matters that would need to be addressed:

- Designing of the solicitation process with sufficient independent oversight to assure a fair and unbiased bidding process.
- Addressing concerns regarding the exercise of vertical market power by utilities to favor their unregulated affiliate generators.
- Addressing existing prohibitions against bilateral contracts with affiliates (where they exist).

The strongest degree of independent oversight is where a State agency is responsible for bid evaluation and selection rather than the utilities themselves. However, use of an independent evaluator or State agency oversight where utilities conduct bid evaluation and are responsible for selecting winners, subject to regulatory review, could also be effective.

Due to concerns that an utility could use its role as a transmission owner to favor generation affiliates in the interconnection process, the Commission in 1998 adopted a policy creating a rebuttable presumption against utility ownership of generating assets through affiliates in the context of divestiture of generating assets associated with industry restructuring (Statement of Policy Regarding Vertical Market Power 1998). Subject to the adoption of appropriate mitigation measures and limits, the Commission has in recent years allowed utility affiliates to develop renewable generation projects.[68] Whether additional mitigation measures are needed, and the scope of such mitigation measures, should be explored in the context of allowing bidding by affiliates. This issue may also need to be addressed in the case of direct utility ownership, where concern would exist over preferential treatment of a utility-owned project during the interconnection process.

Finally, New York State Electric and Gas Company (NYSEG) and Rochester Gas and Electric Company (RG&E), affiliates of Iberdrola, S.A., and a major U.S. wind energy development company are precluded from entering into bilateral contracts with any affiliate.[69] This condition may need to be modified if renewable generation affiliates of NYSEG and RG&E are to be allowed to participate in solicitations that may result in PPAs with these utilities.

6.4.1.6 Utility Issues: Economics, Credit Rating and Accounting Treatment, and Remuneration

From an economic standpoint, the major risk to EDCs entering into long-term PPAs is their ability to recover the net costs over the term of the contracts. To the extent that risk is substantial, it could affect their cost of capital, which could increase ratepayer costs over time. As a value proposition, adding long-term PPAs to utilities' existing business mix may not be attractive, other things being equal, if they are only allowed to recover their costs without any opportunity for incremental earnings.

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[68] Consolidated Edison Company of New York, Inc., et al., Case 10-E-0497 (2011); Order Authorizing Merger subject to Conditions, Case 07-M-0906 (2008) ("Iberdrola Merger Order").

[69] This is a condition of Iberdrola's acquisition of NYSEG and RG&E. Order Authorizing Acquisition Subject to Conditions, Case 07-M-0906 (2009) Appendix 3, # 4.

6.4.1.7 Economics of Cost Recovery

There are few, if any, examples in recent years where utilities with power cost adjustment tariffs have been unable to recover costs incurred under renewable energy PPAs. However, the nature of the power cost adjustment tariff is extremely important. Utilities have resisted entering into long-term PPAs with cost recovery only from basic service/standard offer service customers due to the potential, based on the size, cost, and duration of the contracts, that they could lead in the future to substantial over-market costs resulting in migration of customers to competitive retail suppliers, leading to a dynamic of higher costs being shared among dwindling customers.[70] Cost recovery from distribution customers mandated by regulatory commissions avoids these issues. Where cost recovery is legislatively mandated, the perceived risks are even lower.

6.4.1.8 Credit Rating Impacts

The impact on credit rating is one issue identified by utilities that pertains to long-term PPAs. More specifically, the issue related to how credit rating agencies assess the impact of PPAs on ratings of utility long-term debt obligations. If utility credit ratings are negatively impacted, costs of new utility debt issuances could increase or more costly equity could be issued to provide more protection for bondholders, either of which could increase the overall cost of capital and increase ratepayer costs. There are three major credit rating agencies—Standard & Poor's Financial Services (S&P), Moody's Investors Service (Moody's), and Fitch Ratings (Fitch). According to S&P, "The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in its rates."[71] Although the other rating agencies' view on the principal risk is similar, they have different views on the level of risk associated with long-term power purchase agreements and treat them differently in their credit evaluations.

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70 This occurred in Delaware and Maryland involving solicitations for long-term capacity and energy for the purpose of serving standard offer service customers. See Order No. 85501, Case No. 9214 (MD PSC 2013) and Findings, Opinion and Order No. 7199, PSC Docket No. 06-241 (DE PSC 2007) at 19.

71 Key Credit Factors for the Regulated Utilities Industry, November 19, 2013, ¶ 57. http://www.standardandpoors.com/prot/ratings/articles/en/us?articleType=HTML&assetID=1245380821638.

S&P treats most long-term PPAs as creating a debt-like obligation for the buyer, often referred to as "imputed debt." S&P imputes as debt the product of (a) the net present value of fixed charge obligations under a PPA (or imputed capacity payments for typical $/MWh renewable energy PPAs) and (b) a risk factor, which is dependent on the strength of the cost recovery mechanism.[72] As more long-term contracts are entered into, there is more of a possibility that the utility's credit rating for its debt obligations could be reduced, although evaluation of a utility's overall business risk, including regulatory treatment, is also part of the equation. If a utility's credit rating is downgraded, the cost of debt could be increased or there could be pressure on the utility to issue more equity, either of which could increase the utility's cost of capital. This, in turn, could ultimately increase distribution rates.

Moody's ordinarily views PPAs as operating expenses and not as debt-like obligations where there are strong cost recovery provisions available to utilities:

> Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly, Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes.[73]

Fitch takes a similar approach that purchased power costs under PPAs are operating costs and not a form of debt:

> Fitch does not adjust the debt of issuers in the sector to reflect long-term purchase obligations, such as power or capacity contracts, as quasi-debt and does not impute a portion of these expenses as interest expense. Fitch treats purchases under such procurement contracts as a part of normal ongoing operating expenses affecting future EBITDA[74], operating margin, and operating cash flow. However, Fitch may consider a long-term contract that is significant in size relative to cash flow and grossly uneconomical as debt-like in its rating analysis in exceptional circumstances.[75]

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72 Where there are no fixed capacity charges in a PPA, as in many PPAs for renewable energy projects, S&P imputes capacity payments. For a typical $/MWh-based wind energy PPA, S&P has used the cost of a combustion turbine multiplied by the wind project's capacity factor as the imputed capacity payment (Standard & Poors 2007). The risk factor is based on the strength of a utility's cost recovery mechanism. Where a regulatory commission mandates dollar-for-dollar cost recovery for prudently incurred costs, the risk factor is typically 25%. Where cost recovery is mandated legislatively, the risk factor is between 0% and 15%. S&P will adjust a utility's capital structure—its debt/equity ratios—based on imputed debt as well as other financial ratios it uses in its credit evaluation (e.g., ratio of funds from operations to total debt).

73 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, Appendix H p. 59 (December 23, 2013).

74 Earnings Before Interest Taxation Depreciation and Amortization

75 Fitch Ratings, "Rating North American Utilities, Power, Gas, and Water Companies," May 16, 2011, page 7.

In solicitations where generators compete against each other for PPAs from utilities, the treatment of whether PPAs create an indirect financial cost differs, just as the credit rating agencies have different treatments. In some cases, the S&P method of imputing debt to PPA capacity charges (or imputed capacity charges) is utilized to estimate a "cost of rebalancing" the capital structure.[76] In most other cases, no such cost is imputed, consistent with the Moody's and Fitch approaches.[77] In either case, it does not make much difference in the evaluation of renewable energy PPA bids on a relative basis.

6.4.1.9 Accounting Considerations

Financial accounting is the process of recording, summarizing, and reporting the myriad transactions from a business, so as to provide an accurate picture of the company's financial position and performance. With respect to long-term PPAs, utilities sometimes express concern that required accounting treatments may not track the economic situation of net operating costs on one side being matched with cost recovery from ratepayers (plus remuneration, if applicable) on the other side.

One concern is that a long-term PPA might constitute a capital lease, which for accounting purposes would be treated as a long-term liability on the company's balance sheet. However, long-term renewable energy PPAs priced solely on a $/MWh basis are either not treated as leases, and hence, cannot be capital leases, or if treated as leases, are typically treated as operating leases.[78]

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[76] See Decision on Petitions for Modification of Decision 07-12-052 (California Public Utilities Commission, 2008) at 14-17.

[77] Other factors may include whether entry into a specific contract, even assuming the S&P perspective, is sufficient to "move the needle" to have a significant credit rating impact, whether buying as opposed to building mitigates business risk, and the relative persuasiveness of the S&P approach.

[78] Contracts with multiple buyers, similar to the contracts entered into under Massachusetts Section 83A, contracts where the buyer is taking less than 90% or so of the output and contracts where PPA prices are solely on a fixed $/MWh basis, are not likely to be treated as leases. A lease involves the right to control the use of the plant, which can be demonstrated by one of the following conditions:

- The purchaser has the right to operate the plant or direct others to operate the plant while obtaining or controlling more than a minor amount of the output.
- The purchaser has the right to control physical access to the plant while obtaining or controlling more than a minor amount of the output.
- It is remote that parties other than the purchaser will take more than a minor amount of the output during the agreement and the pricing in the contract is neither fixed per unit of output, nor equal to the market price per unit of output at the time of delivery.

PricewaterhouseCoopers LLP, Guide to Accounting for Utilities and Power Companies ("PwC Guide"), Section 2.2.2 (2013), http://www.pwc.com/us/en/cfodirect/publications/accounting-guides/guide-to-accounting-for-utilities-and-power-companies-2013.jhtml

A typical industry approach is to allow utilities to structure PPAs (and sometimes cost recovery and other regulatory mechanisms) to avoid undesirable accounting treatments as long as the structuring does not result in higher costs or risks to ratepayers,[79] an approach which New York could also take.

6.4.1.10 Remuneration to Utilities

Massachusetts and Rhode Island have provided for remuneration to EDCs in consideration for their purchase of energy and RECs under long-term PPAs entered into as a result of conducting solicitations to facilitate the financing of new LSR projects (General Laws of Massachusetts 2012; R.I. General Laws 2014). This remuneration is based on 2.75% of the cost of energy and RECs purchased under a long-term PPA (in Massachusetts, it had been 4% under a previously enacted statute[80]). The purpose of the "adder" under Massachusetts law is to "compensate the company for accepting the financial obligation" of the PPA. Both in Massachusetts and Rhode Island, the adder was created legislatively and there appears to be no specific basis for the particular level of remuneration. It may be viewed as (a) compensation for a cost incurred, (b) an incentive to make long-term contracting for renewables a more attractive value proposition or (c) a combination of both factors. Taking another perspective, it may be viewed as providing a form of "equity cushion" for utilities to counteract the risk of potential non-recovery for some PPA costs that will be incurred.

Other states, including Connecticut and California, have required utilities to enter into long-term PPAs for renewable energy but without any remuneration tied to PPA purchases. In these and other states, utilities are allowed to present arguments in base rate cases, usually based on the S&P credit rating methodology, that long-term PPAs have created levels of imputed debt that warrant a higher share of equity in the capital structure for ratemaking purposes, a higher return on equity or both.

Just as potential impacts of long-term PPAs on utility credit ratings is a matter of some controversy, providing for remuneration to utilities for conducting solicitations, entering into PPAs, and paying for energy and RECs is also a matter on which opinions strongly differ.

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79 For example, National Grid has structured its renewable energy PPAs in Massachusetts (subsequently approved by the Massachusetts Department of Public Utilities) to address accounting concerns. See Joint Direct Testimony of Jefferey S. Waltman, Corinne M. Abrams, and Robert S. Furino, D.P.U. 13-46 et al., (September 20, 2013) at 14, http://www.mass.gov/eea/docs/dpu/electric/13-147-initial-filing-9-20-13.pdf and Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 10-54 (November 22, 2010) at 317-318.

80 Section 83 of the Massachusetts Green Communities Act of 2008.

6.4.2 Open-Source Solicitations: Head-to-Head Competition between Proposals for PPAs and Utility-Owned Generation: Option 3B

Another renewable energy procurement approach used in a number of states with vertically integrated utilities is for the utility (or utilities) to seek bids in a solicitation for both PPAs and the acquisition of renewable generating assets that would become UOGs. Usually, UOG proposals are LSR projects that a third party has developed. Bids can be a package of an asset sale agreement (typically, involving the real estate interests, interconnection queue position, permits, etc.) combined with an EPC contract. Another potential structure is a build-transfer agreement in which a developer sells a constructed renewable energy project to the utility buyer. A third possible structure is where the utility offers a utility-initiated project proposal, sometimes involving an EPC contract where the utility has already acquired a project site.

Figure 11 depicts the mechanism for a typical UOG project. Figure 12 shows a typical scenario whereby PPA and UOG proposals can be compared through an open-source solicitation.

Figure 11. Utility-Owned Generation

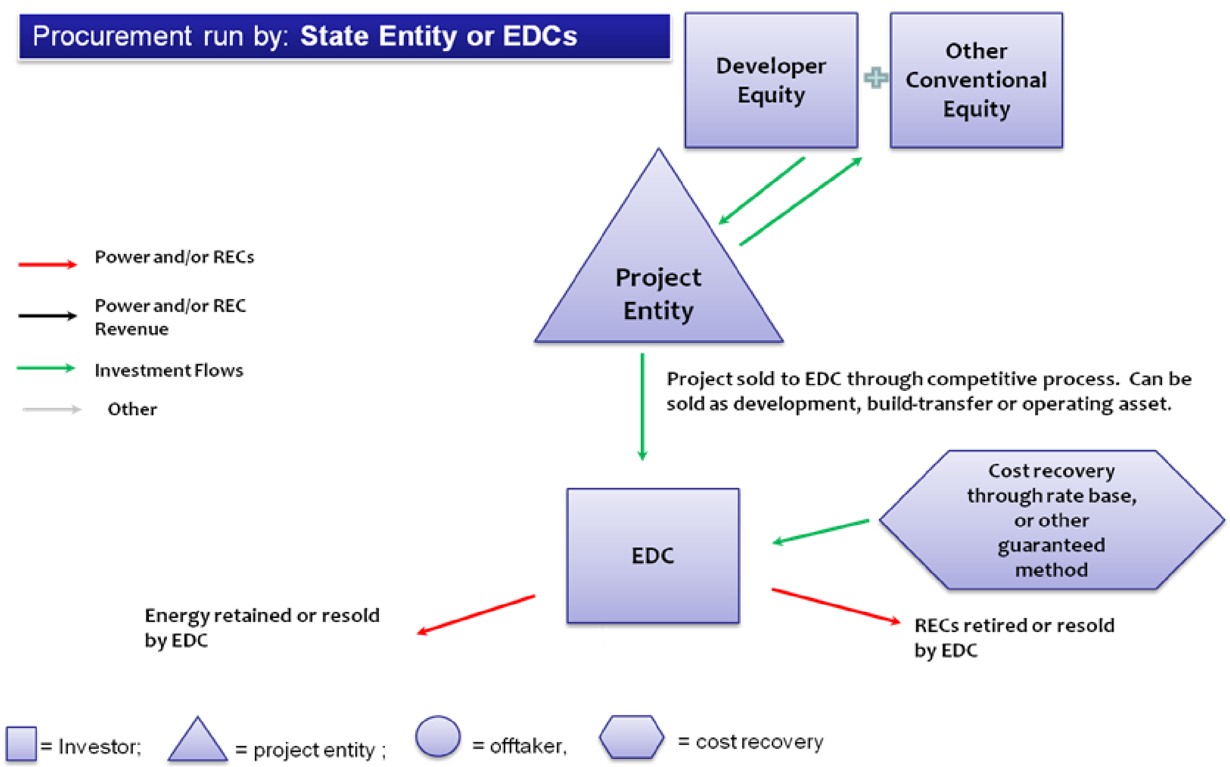
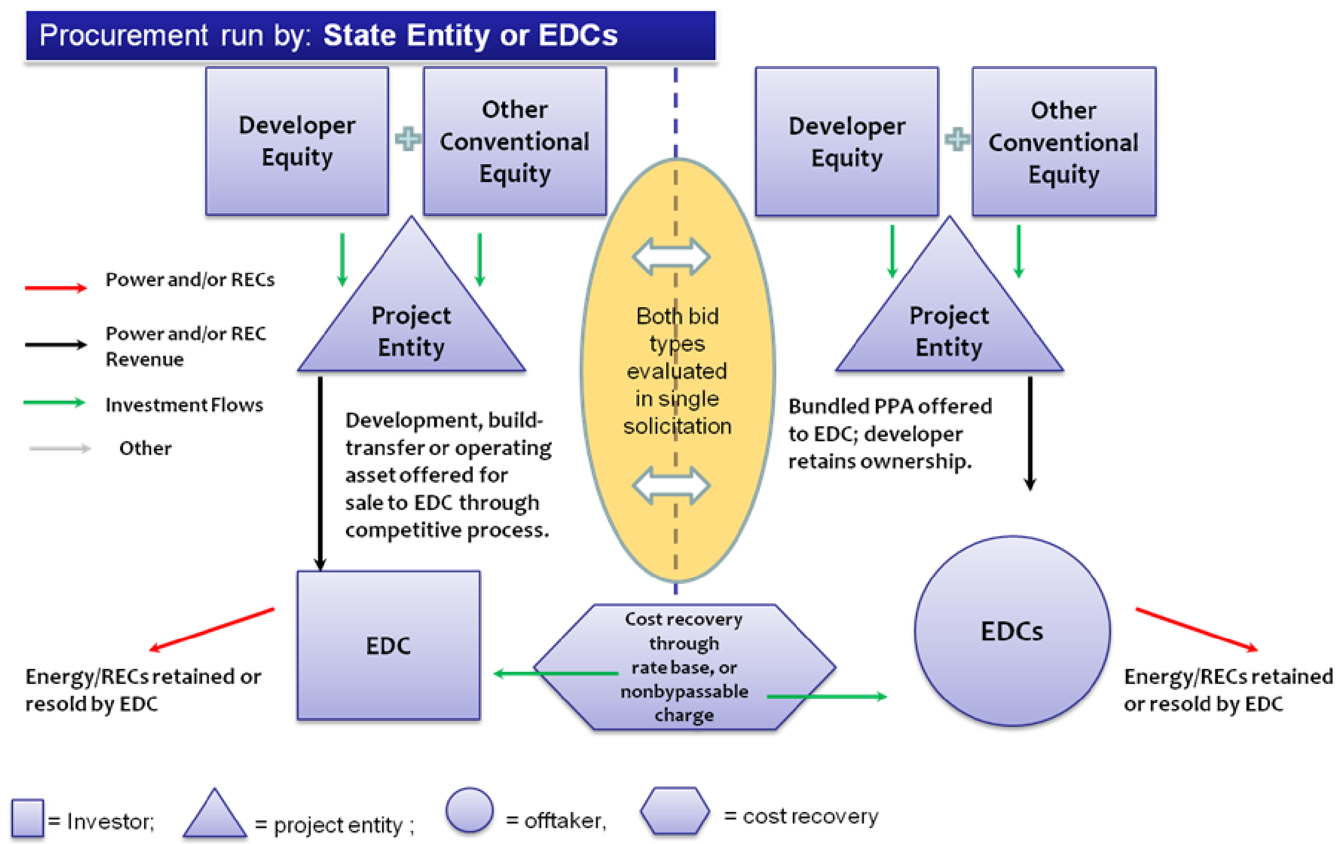


Figure 12. Open-Source Solicitation



An advantage of this type of open solicitation is that it expands the competitive market for different types of transactions, with potential advantages for ratepayers. With this approach, options are preserved if circumstances change and different strategies become more cost-effective (see Chapter 8) or if highly capital-intensive resources are needed to achieve State objectives.

Another advantage is that it creates a more attractive value proposition for utilities in the form of an opportunity for them to own and profit from competitively-priced projects without customers having to pay remuneration on projects the utilities would not own. This scenario could provide opportunities for utilities to provide new clean energy products to customers.[81]

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81 Also, certain LSR development projects may benefit from a combination of utility equity investments and private developer equity due to the magnitude of such projects. Offshore wind is an example of an LSR that could benefit by having the option for both utility-backed PPAs and utility asset ownership.

However, several issues need to be addressed in the open-source solicitation, a competitive process in which PPA proposals and proposals for UOG will be evaluated against each other using a common set of metrics. These issues include:

- Difficulties in evaluating very different types of transactions with very different risk profiles (the "comparability" problem).
- Potential bias in favor of UOGs if utilities are responsible for conducting the bid evaluation and selecting winners.
- Potential adverse impacts on the competitive market for generation.
- Potential adverse impacts on ratepayers, who may be assuming risks for underperformance and higher-than-estimated costs.
- Additional complexity in solicitation design and implementation.

Next, this paper examines how an open-source solicitation could be conducted in a manner that could maximize advantages and mitigate disadvantages of this approach.

6.4.2.1 Comparability Issues

The characteristics and risk allocation associated with UOG project proposals differ greatly from those associated with PPA bids. This makes proposals difficult to compare with each other. Key differences pertain to:

- variance between projected energy output and actual energy output;
- variance between projected and actual O&M costs;
- variance between projected and actual initial capital costs; direct and
- indirect financial cost impacts.

Other key issues pertain to PPA term length and UOG useful life and terminal value.

Energy Output. With regard to renewable energy projects, and wind projects in particular, a major issue is the risk that output of a project will be lower than projected. Developers under PPAs assume that risk. For UOG projects, ratepayers take the risk since almost all of the project costs are either capital costs or fixed O&M costs, and ratepayers will be obligated to pay those costs (unless there is a finding that some costs were imprudently incurred), regardless of whether the project performs or underperforms with regard to pre-construction energy output estimates. This is especially a problem with regard to wind projects since historically actual performance has been lower than energy output estimates. As of 2008, data has clearly shown that actual energy output from wind turbine projects in North America was 10 percent lower than forecasts (White et al. 2009, Allevato 2011, Johnson 2008). More recent data suggests that wind resource assessment firms have made considerable improvements in their resource assessment methodologies and assumptions but overestimated energy output still persists

(White et al. 2009). One of the top firms in the field has shown that in the last few years projects for which it had conducted the resource assessments underperformance declined to 5% (including the effects of curtailment), with a normal distribution and an uncertainty of 9%, and with additional adjustments to its methodologies and assumptions it projects that its future estimates will further reduce what some observers refer to as “wind forecast error” (DNV GL 2014).[82]

Bidders are typically required to provide wind resource assessments with their bids. UOG project developers may have an incentive to provide less conservative energy output assessments since it may help in the evaluation of their projects but they are not held accountable for the accuracy of those assessments (absent any capacity factor guarantees, which if provided tend to be limited in a variety of respects). On the other hand, if actual performance were to exceed estimated performance, ratepayers would benefit.

Long-Term O&M Costs. Another issue pertains to long-term O&M cost projections. Under PPAs, developers are responsible for the risk that O&M costs will be higher than projected. With UOG projects, ratepayers assume that risk subject to regulatory lag between rate cases. As with energy output projections, the project developer who proposes to sell its planned wind farm (or other project) typically provides long-term cost estimates with its bid (including property tax, lease costs and insurance). The estimates may tend to be insufficiently conservative as the project developer is not accountable for long-term O&M costs which receive cost-of-service rate treatment (they may, however, provide certain warranties and even an O&M contract for the first several years of operation). If O&M costs, however, turn out to be lower than forecast, ratepayers would benefit.

Initial Capital Costs. Often, a UOG bidder provides a proposal, usually with respect to a pro forma agreement that the utility provides in RFP documentation, to sell the project development assets packaged with an EPC contract at a fixed price subject to change order/force majeure provisions. For wind projects, the contracts usually fix the great bulk of the capital cost risk. Remaining for the utility buyer and ratepayers are utility costs associated with buying the project and supervising construction, and contingency for residual risks. Under PPAs, developers are responsible for all capital cost risk. Regulatory commissions often approve utility projects subject to a defined capital cost cap, while

82 Based on stated improvements to methodologies and assumptions and taking into consideration a wide range of resource assessment firms in the market, a 4% average underperformance estimate is used in the financial analyses for UOG projects in this report. See Section 7.3.3.

providing utilities with the ability to seek additional capital cost recovery if they exceed the cap if they can show that the additional costs were prudently incurred (and the project has gone into service, has been determined to be used and useful, and has been included in rate base) (State Corporation Commission of the State of Kansas 2007).

Direct and Indirect Financial Costs. Under a PPA, the bidder/seller assumes the risk that its actual costs to finance a wind project are higher than projected (resulting in developer equity returns that may be lower than projected). However, PPAs may impose indirect costs, or at least the risk of indirect costs, with respect to the utility's cost of capital based on credit rating assessments. As indicated previously, the credit rating agencies have different approaches, and S&P's imputed debt approach may imply indirect costs but Moody's and Fitch's approach, which would ordinarily treat PPA costs as normal operating costs where there are strong cost recovery provisions, would not imply an indirect cost.

There are also financial-related risks associated with UOG projects. Primarily, there is the risk that the utility's cost of capital will change over time. Whereas capital costs could either increase or decrease, given the currently low interest rate environment there is a greater likelihood that the capital costs will increase over time, resulting in higher costs to ratepayers since the higher cost of capital would apply to the undepreciated rate base associated with the UOG. Secondarily, there is the risk that both the capital commitment required by a UOG project and the associated terms regarding cost recovery may increase the utility's risk profile and indirectly increase the utility's cost of capital, resulting in higher costs to customers.

The countervailing risks are difficult to assess, which may lead to the view that neither should be explicitly taken into consideration in the evaluation process.[83]

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[83] Similar reasons have been used as the basis for not including imputed debt as an evaluation factor where UOGs and PPAs are competing in solicitations in a number of states, including California, Decision for Petitions for Modification of Decision 07-12-052 (CPUC 2008), and Minnesota, Order adopting recommendations of the Department of Commerce Regarding Bison 4 Wind Project, Docket No. E-015/M-13-907 (MN PUC 2014). In Oregon, imputed debt is not to be considered at the short-listing stage but may be for the final evaluation of bids, subject to the utility providing an advisory opinion from a ratings agency to substantiate its analysis if requested by the commission. Guidelines Adopted, Order No 06-446, Docket UM 1182 (OR PUC 2006).

Term of PPAs, UOG Useful Life, Evaluation Period, and Terminal Value. Typically, PPAs have a term of 15 years to 20 years. For utility-owned wind projects the useful life and term over which the projects are depreciated are often for 20 years but sometimes for 25 years (other types of LSR generation may have different lives; a hydroelectric generator, for example, may have a much longer useful life). Using the same term for evaluation purposes tends to put the different types of transactions more on an equal footing. Regardless of the assumed useful life of a UOG project, there will be a terminal value for UOG projects. One consideration for wind is whether the underlying real estate rights have been purchased or leased and, if leased, the duration of the lease rights. UOGs may provide substantial positive terminal value that can benefit ratepayers (based on expected economic operation of the plant beyond its evaluation period or through repowering of the site), although valuation is difficult. In contrast, the terminal value for PPAs typically resides with the project owners. However, PPA owners can usually provide substantial terminal value by offering buyers options to extend the PPA at specified prices for a specified term (often, five years).[84] A RFP process can incorporate consideration for terminal value for both UOGs and PPAs and can encourage PPA bidders to increase their likelihood of success by offering post-contract term options that will provide substantial terminal value to ratepayers.

6.4.2.2 Potential Bias

Two sources of bias exist in solicitations where UOGs can compete with PPAs. The first is on the part of UOG bidders who have an incentive to underestimate long-term O&M costs and overestimate energy output without having substantial accountability.[85] The second is on the utility buyers who, other things being equal, tend to prefer owning projects upon which they are allowed to earn a return on investment rather than PPAs which provide for no economic rewards but some degree of risk (even if it is very small).

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[84] In 2014, the Oregon Public Utilities Commission modified its competitive bidding guidelines to allow PPA bidders to submit bids with and without a buyer option to extend the term of the PPA Order, Investigation Regarding Competitive Bidding, Docket UM 1182 (April 30, 2014). Another way a developer can offer value is to offer to sell the generating asset at the end of the PPA term, which is typically done at fair market value due to tax considerations.

[85] This is more of a potential concern from a utility-originated proposal. On the other hand, if utilities ask for (a) purchase of development assets packaged with an EPC contract and/or (b) build-transfer agreement, which fixes almost all of the capital cost, this source of potential bias may not be present. Hence, there isn't an incentive on the part of the bidder to underestimate capital costs. However, the utility will incur costs which will be capitalized. The evaluation needs to take these costs into consideration as well.

Ways to Address Comparability, Bias, and Competitive Impact Issues

There are ways to counteract bias, facilitate a fair evaluation between UOG and PPA proposals, and provide a result that is protective of ratepayers. These ways include:

- Commission approval of RFP issuance (or multiple rounds of RFPs) and any contracts arising from the process.
- Independent entity responsible for RFP design, bid evaluation, and selection.
- Mitigate energy output overestimation bias and long-term O&M cost underestimation bias by:
    - Requiring UOG bidders to provide resource assessments by most credible firms and/or
    - Retain technical experts to evaluate UOG bids.
- Create a RFP design and evaluation process that addresses how various risks will be treated and how terminal value will be evaluated.
- Contractual transfer of some risks to sellers of generation assets potentially, including the risk of wind forecast error/plant underperformance through build-transfer and other arrangements).
- Commission approval conditions for UOG projects:
    - Capital cost cap, with provisions for utility to seek cost recovery for overages by showing costs were prudently incurred.
    - Periodic reviews to compare estimated and actual energy output and O&M costs (including capital replacement costs), with the ability of utilities to show that underperformance and/or higher costs were not the result of imprudence.
    - Require disclosure of all costs to ratepayer for a project including profit on capital investments (in UOG case) and remuneration, if applicable (in utility-backed PPA case).

In addition, similar to the issues previously addressed regarding vertical market power in the context of participation by utility affiliates, the Commission could entertain any further conditions appropriate to address vertical market power concerns in addition to those already in place.[86] Also, any prohibitions or limitations on utility ownership of generating assets may need to be revisited.[87] Additional limitations may need to be added, especially where a utility is actively developing renewable generation projects itself in preparation for a solicitation in which it or any partners or associates would bid.

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86 For example, the need for mitigation, particularly with respect to the interconnection process, may need to be greater where a utility is developing a renewable project that would be interconnected to its own system or may buy a project that would interconnect to its own system. There appears to be no reason to limit utility ownership to projects that would tie into its own system. In fact, a utility willing to forego ownership of projects interconnected to its own system may present issues of less significance regarding vertical market power.

87 For example, NYSEG and RG&E are not allowed to own wind generating assets under the Iberdrola Merger Order Appendix 3, Condition 3.

6.4.2.3 Conduct of Procurements

In Section 6.4.1 of this paper, different structures of procurement processes were identified in the context of PPA-only solicitations. Similar options present themselves for open-source solicitations. However, the need for independent oversight is more pressing where there will be head-to-head competition between UOGs and PPAs. Also, the procurement process will be more complex, with the need for bid evaluators to review cost and output estimates, which is usually not necessary or as important in PPA solicitations in which sellers assume capital and operating cost overrun risks and project underperformance risks. Moreover, there would be the need to develop pro forma contracts for asset purchase transactions. This process will entail additional administrative cost. In view of these considerations, a central procurement process with a State agency playing a key role may minimize cost, best address concerns regarding bias, and enhance transparency.

Similar issues as those pertaining to a PPA-only solicitation would need to be addressed, such as, how asset ownership would be allocated among the utilities interested in owning the assets if UOG bids are successful. For example, would the utilities own percentage shares in the same project? Or would individual utilities own projects, with a method to be worked out for allocating different winning bids to different utilities? Where the utilities are responsible for entering into contracts based on their respective load shares, allocation of winning bids, whether PPAs or UOGs, would be addressed in this context (i.e., sharing based on respective load share would be a key guiding principle). There are other questions pertaining to potential caps on UOG projects. Should there be any caps? If so, what should be the percentage of capped UOG ownership? Should the cap be determined as a percentage of the total portfolio?[88]

6.4.2.4 Market-Related, Legal and Competitive Issues

In designing pro forma PPAs, consideration should be given to both the effectiveness of the contract to facilitate financing of new renewable generation, and the interaction of the operation of the generator with the wholesale energy market administered by the NYISO. In other jurisdictions—including Massachusetts, Connecticut, and California—contractual provisions have been incorporated that provide for an economic disincentive to operate (or curtailment where the buyer is responsible for scheduling)

88 A potential alternative is to limit UOG ownership in individual projects, which would require a PPA for part of a project and UOG ownership for the remainder of the project (which may be among more than one utility). However, this alternative may be unnecessarily complicated.

when locational marginal energy prices are negative (with or without caps).[89] UOG projects, which will likely provide for revenue recovery irrespective of actual operation, should be even more sensitive to market signals from an operational standpoint. With regard to incentives regarding where to locate generation, the solicitation process itself, which should value generation that is located in less constrained areas more highly, should provide the proper price signals.

Implementing one of the models discussed in this paper would require action by the Commission to modify or replace the RPS program. The Commission established RPS based on the authority granted by Section 5(2) of the Public Service Law (PSL), which directs the Commission to:

> encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs . . . for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources.

That authority would also support many of the models presented in this paper. The Commission could direct the implementation of certain models based on its supervisory authority over utility performance of public service responsibilities, as granted in PSL Sections 4, 65, and 66. Some models may also consider legislation as a supplement or alternative to action by the Commission.

The selected model should avoid any conflict with federal law or FERC policy. Pursuant to the Federal Power Act, FERC has asserted jurisdiction over the wholesale sale of energy and capacity by generators to load-serving entities or wholesale customers. Moreover, in developing program designs and eligibility rules for projects, the "dormant" aspect of the Commerce Clause of the U.S. Constitution should be considered. That doctrine prohibits state regulation that unduly discriminates against or burdens interstate commerce, with certain exceptions.

Another matter is whether allowing utilities to solicit bids for both UOGs and PPAs will have a negative impact on the competitiveness of the renewable generation market. There are several aspects to this question. First, it will be up to the renewable generators alone as to whether they wish to bid for PPAs or to sell their development-stage projects to utilities or to offer both types of transactions. Second, if utilities wish to develop renewable projects themselves, as opposed to simply allowing independent

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[89] This has been accomplished through pricing provisions allocating risk of negative energy prices to the seller where the seller is responsible for scheduling and bidding energy under the PPA and on provisions allowing the buyer to curtail when energy prices are negative, subject to quantity caps and payment obligations with respect to such curtailments.

power developers to propose the sale of assets to them, there should be, at a minimum, a functional separation within the utility from those involved in RFP design and bid evaluation and selection, and an associated code of conduct. Further, development costs associated with unsuccessful projects should not be subject to cost recovery while development costs associated with successful projects should be recoverable only following project commercial operation. Finally, any additional mitigation measures regarding vertical market power should also be considered.

6.4.3 Evaluating the EDC Solicitation Options

In this section, the main utility solicitation variants are evaluated in the context of the evaluation criteria outlined in Section 4.3.

6.4.3.1 PPA-Only Solicitations

A solicitation process for long-term PPAs for RECs and/or energy with one or more EDCs has several important advantages. Long-term bundled product contracts with creditworthy utilities provide substantial revenue certainty to renewable generators, are the most common method of facilitating financing of new renewable generation in the United States,[90] and, as shown in Chapter 8 and below, are likely to minimize the cost to ratepayers of new renewable generation and reduce electricity price volatility compared to fixed price REC-only contracts under the current NYSERDA program. As wholesale energy market participants, the EDCs can purchase and resell the commodity electricity into the wholesale market.[91]

A key component of utility PPA procurements is the establishment of cost recovery mechanisms to provide strong assurance that the net cost of the products purchased under a PPA will be recovered from distribution customers.

EDC solicitations for PPAs would entail additional regulatory processes and new roles for the State's regulated EDCs. For the protection of both EDC investors and ratepayers, the PPAs entered into by the EDCs pursuant to solicitation should be subject to the approval of the Commission. The solicitations

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[90] For example, through 2013, 83% of the wind generation capacity constructed in the United States is owned by independent power producers, most of which has been financed and built based on the revenue certainty created by long-term contracts with electric utilities as the buyers. (U.S. Department of Energy 2014)

[91] In principle, the EDCs - as providers of default service to end users in their territories who do not choose supply from competitive energy service companies (ESCOs) – have a load obligation and might be able to use some of the energy procured towards this supply. However, as in other states, using such electricity to supply default service customers is not likely to be compatible with how default service is procured and therefore is not considered a likely approach here.

themselves (the design of the RFP and the evaluation framework) would also be subject to approval by the Commission.

The PPA-only EDC solicitation approach has limitations. The EDCs may be ambivalent about taking on the role of purchasers under PPAs with the costs, time, and the risks associated with it, without the prospects of any upside. This could affect their motivation and effectiveness. There is also the possibility of negative effects on utility credit ratings from Standard & Poors (but are unlikely from Moody's and Fitch), which could have implications on rates at some future time. These constraints can be mitigated by providing some degree of remuneration to utilities for entering into PPAs, as has been done in some other states.

Administration of a PPA-only process presents issues of effectiveness, fairness, and efficiency. Allowing EDC affiliates to bid would expand participation of competent and creditworthy generators but would require, at a minimum, independent oversight by State agencies or independent evaluators to assure that the evaluation and selection process is free of bias. State agency responsibility for RFP design, solicitation issuance, bid evaluation, and selection would provide the strongest protections to assure fairness in the solicitation process.

EDC PPA solicitations could be conducted in various ways. A centralized process involving a common RFP and a single bid evaluation process would be most administratively efficient. From a contractual standpoint, the purchase of energy and RECs could be allocated among the utilities based on their respective load shares or on some other basis.

6.4.3.2 Open-Source Solicitations

Open-source solicitations – where PPA bids compete head-to-head with UOG proposals—present many similar advantages and limitations as EDC PPA-only solicitations, but also presents some additional benefits and complications. Open-source solicitations will tend to stimulate broader market participation and competition, and under certain circumstances may be expected to produce more renewable generation at lower cost. These considerations are based in part on the financial analysis in Chapter 8, which shows that projects built by independent developers under bundled energy and REC PPAs and UOGs appear to be roughly competitive with each other (taking into account the absence or presence of federal tax credits). Moreover, UOGs may have advantages with respect to terminal value ordinarily not present under PPAs where the generation owner owns a project's terminal value (which may be positive or negative, but is likely to be positive).

Open-source solicitations may significantly alter the value proposition for EDCs. EDCs would have the opportunity to acquire new renewable generation projects pursuant to bid contracts and earn a regulated rate of return on the investment if the bid projects have competitive merit. On the other hand, they would be the buyers under PPAs if PPAs are determined to have competitive merit.

In terms of limitations, open-source solicitations present issues of comparability and potential bias in evaluation and selection. This bias can be mitigated by State agency direction and Commission approval of the solicitation design, evaluation, and selection. Particular issues involve risk transfer to ratepayers associated with UOG proposals, particularly involving forecasts of energy production and long-term operations and maintenance expenses that turn out to be overly optimistic. These issues can be addressed through the retention of independent experts to aid in the bid evaluation and by imposing quality standards or risk-sharing on bidder production forecasts and long-term costs.

Allowing EDCs to compete as buyers of LSR assets or to propose their own projects raises issues of vertical market power and may call for modifications to existing restrictions on utility generation asset ownership, both of which would need to be revisited by the Commission from an implementation perspective

Finally, open-source solicitations will produce substantial administrative complexity in the design and implementation of solicitations that is incremental to PPA-only solicitations. The complexity and associated timing and cost impacts are due primarily to the need to review estimates of energy output and O&M and capital replacement costs for UOG projects as well as evaluating terminal value, all in a fair, unbiased manner. Another factor adding to complexity is the allocation of UOG and PPA contracts to utilities assuming a centralized procurement approach is used. With the utilities participating as both PPA buyers and UOG buyers, however, open-source solicitations should be less complex to implement with utilities as PPA counterparties than in the model where a State Entity is the PPA counterparty and the soliciting entity but the regulated utilities are the potential asset buyers.

Despite the added complexity, open-source utility solicitations are feasible to design and implement, and the increased competition and available structural options may produce benefits in terms of increased renewable generation at lower costs that outweigh the effects of incremental complexity.

7 Financing Options

New York's future LSR policy option will seek to lower financing costs to reduce the overall cost to consumers of LSR development. Several strategies are presented for consideration in this chapter, and their potential quantitative impacts explored in Chapter 8.

7.1 Context: Financial Innovation and Renewable Energy

Project developers and investors use a diverse set of approaches to finance projects. Each approach may differ in its capital structure, sources of financing, and/or ownership allocation. In general, all projects strive to maximize returns by designing ownership and financing structures that optimize the allocation of cash and tax benefits,[92] and minimize the cost of energy by allocating risk efficiently and attracting capital on the most favorable terms possible. As the LSR energy market has matured, market participants are aiming to increase financing efficiency and reduce cost. In particular, recent financial innovations in the financing of LSR assets have centered on the use of securitization to accomplish these goals. On the equity side, this effort has been led by market participants who have focused on mechanisms that integrate renewable energy assets into structures known as YieldCos. On the debt side, the use of bond financing, often catalyzed by public support, is emerging as a promising option.

This short overview describes the current status of YieldCos and an innovative option for utilizing bond financing in New York to efficiently provide low-cost debt to LSR.

These vehicles may be able to provide benefits to LSR energy projects at multiple stages – including fundraising from the substantially greater volumes of capital available in public markets, potential tax advantages, and liquidity benefits upon exit. As noted in Chapter 5, achieving a reasonable degree of revenue certainty for capital-intensive LSR projects will be a key element to successfully implementing these investment options and attracting new investors to participate in wind energy markets. This

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92 The importance of such tax benefits is driven primarily by the Federal renewable energy incentive regimes involving (Production Tax Credits and Investment Tax Credits (PTCs and ITCs), as well as accelerated depreciation (Modified Accelerated Cost Recovery System, or MACRS). The PTC/ITC incentive available to wind and other grid-scale renewable projects have expired for projects not commencing construction before December 31, 2014, and the future availability of these or similar Federal tax incentives is uncertain. Without extended PTC/ITC, the tax benefits play a lesser role.

underscores the intuitive conclusion that the ability to access lower cost capital is determined by the amount of revenue risk present. For this reason, these new investment tools are more likely to be used to hold assets once they become operational (and produce a relatively stable cash flow) and less likely to be used to fund development assets.

The potential impact of these financing tools also relies upon building developer confidence that low-cost, long-term financing for the project will be available when the project is either in construction or in operation. Once this confidence is built, it should allow developers to bid into competitive processes at a lower cost of electricity as a result of lowered long-term capital cost expectations.

7.2 Equity Mechanisms: YieldCos

A YieldCo is a company (with rare exception, typically publically traded) with a cash-flow-oriented business model that is premised on delivering steady, increasing dividends to shareholders through the continued acquisition of accretive, long-term, contracted energy generation facilities. NYSERDA's current use of fixed price REC-only contracts makes the use of YieldCos in particular unlikely, as these contracts do not offer any price certainty to project investors regarding the sale of energy. One major potential benefit of some of the alternative solicitation mechanisms described in Chapter 6 is that New York can use the competitive procurement process to take full advantage of innovative financing vehicles available in the capital markets, including YieldCos.

Most YieldCos are spin-offs of existing investor-owned utilities or independent power producers (IPP or the YieldCo parent) that focus in particular on long-term ownership of renewable and other generation assets whose revenues are based on long-term power purchase agreements with credit-worthy counterparties. For the parent, the YieldCo offers a way to recycle capital by raising relatively low-cost equity through public markets.

YieldCos are valued both for the steady, long-term contracted cash flows from their existing assets as well as the implied dividend growth associated with a pipeline of increasingly economically attractive assets currently owned or being developed by their parent. This pipeline of assets is often made available for drop-down into the YieldCo through a (relatively weak) Right of First Offer (ROFO) contract with the parent. However, as the parent also generally owns a majority of the shares of the YieldCo and often has incentives tied to achieving dividend growth targets, the ROFO nevertheless has a meaningful impact on YieldCo valuations.

YieldCos are currently bringing down renewable costs because the equity return hurdles for projects acquired by YieldCos are now significantly lower than those of their IPP parents – and even lower than that of many regulated investor-owned utilities. The reasons are tied to the two sources of YieldCo value:

- **The focus on assets with low revenue volatility.** As the YieldCo consists only of assets with revenues not subject to market price volatility – and as portfolios of such assets can be diversified to reduce any residual volatility – the YieldCo's revenues and dividends are significantly less volatile than its parent's. As a result, investors will value YieldCo cash flows more than those of its parent, and consequently, accept a lower yield.
- **The promise of dividend growth through a robust project pipeline.** Because YieldCo returns are both a function of actual current dividends and dividend growth expectations, YieldCo investors are willing to accept relatively low yields on assets early in the life of the company with the expectation that future acquisitions will drive dividend growth, lowering the cost of capital and the ultimate cost of the project.

Although it is not clear if YieldCos can sustainably provide low-cost capital indefinitely, at present most YieldCos are between one or two years old and growing substantially, with new YieldCos being announced on a regular basis. As a result, it is reasonable to expect that the low costs of capital should be sustainable in the near-term. However, a part of the current appeal of YieldCos is certainly due to the relatively low-interest rate environment of the last decade. If interest rates rise substantially, the relative appeal of YieldCos may well decline, significantly impacting their ability to raise additional capital.

7.3 Debt Mechanisms: RBB Securitization

LSR generation provides public benefits (reduced emissions, fuel source diversity, and market price hedge) that are broadly shared among ratepayers. As a result, it may be appropriate to use the broad risk-bearing capacity of ratepayers to help finance the procurement of these assets – particularly if such financing can reduce overall costs.

One way to achieve this goal is through debt securitization. In a typical renewable project financing, the owner of the project will often finance the asset in part through a project loan. This loan is made directly to a special purpose company that is set up to own and operate the project, rather than to the sponsor directly. As a result, the loan only has recourse to the assets and cash generated by the project in the event that the project owner defaults on the loan, and has no claim on any other assets owned by the sponsor. Further, such loans are provided by a limited number of large financial entities, their covenants are not uniform, and the loans cannot easily or quickly be sold to another entity (that is, they are illiquid instruments). These restrictions mean that project debt tends to have more concentrated risk and higher cost than, for example, sponsor corporate bonds with a similar credit rating. The idea of debt securitization is to pool together a number of project loans into a liquid, publicly traded, high-quality debt instrument. The securitized debt can take advantage of portfolio diversification, including the benefit of multiple contract counterparties, to mitigate risk and reduce the cost of project debt.

However, the quality of such a securitized debt instrument is still limited by the aggregate credit rating of the project offtakers. In the case of New York utilities, this instrument would limit the rating of such an instrument to roughly an "A" credit rating. Ratepayer-Backed Bonds securitization (RBB securitization) is a novel way to move beyond this limitation through the issuance of New York State Green Bonds, allowing businesses and residents to directly invest in clean energy.[93] RBB securitization would start with the issuance of high quality, low-yield bonds, through a special purpose, bankruptcy-remote entity. These bonds' coupons and repayments are funded through a dedicated, non-bypassable fee paid by all New York State ratepayers. The use of such a dedicated fee-payment stream creates sufficient security to allow the bonds to achieve the highest credit rating ("AAA" rating).[94]

The proceeds from the bond offering would then used to provide loans to renewable projects at significantly lower interest rates than would be otherwise possible. In turn, ratepayers can receive credits to offset fee payments from funds generated by sales of power from the projects (and/or repayment of the project loans). These credits cover the fee only as long as the projects generate sufficient cash from their operations. As a result, ratepayers broadly share some of the risk of project underperformance or failure. However, the lower cost of debt through RBB securitization is expected to result in ratepayer savings through lower project financing costs – and resulting cost of electricity – exceeding costs associated with bearing the risk of project default. Further, note that this mechanism could apply to a variety of procurement/development models. As discussed in Appendix C, RBB securitization could also be a particularly attractive way to support offshore wind projects in New York State.

93 Securitization through ratepayer-backed bonds has been used elsewhere to finance retirement and/or decommissioning of aging fossil fuel and nuclear facilities

94 Note that RBB Securitization may only be achievable through future legislative action.

8 Cost Analysis of Development & Financing Options

In light of the priority New York has placed on selecting an LSR support structure that minimizes costs and maximizes long-term savings, detailed cost of energy and revenue requirement modeling was performed to assess the impact on project revenue requirements and levelized cost of electricity (LCOE) of the options discussed in previous sections – each represented by unique capital structure assumptions and customized risk premiums detailed in Appendix A[95]. A representative set of procurement approaches was selected for this economic evaluation. All necessary modeling input values were identified for each option, and LCOE financial analyses were conducted using a proprietary project finance model developed by Climate Policy Initiative (CPI) and described in Appendix A.

8.1 Project Assumptions

To conduct this comparative assessment, a hypothetical, the revenue requirements and LCOE was projected for a representative 100-MW wind facility to be built in Upstate New York (interconnected in NYISO Zone D, North) and assumed to start operating at the beginning of 2017, under different scenarios. See Table 5 for key assumptions for the project. Although wind was the technology chosen for this illustrative modeling exercise and is expected to be a major contributor to meeting the LSR targets, other LSRs would be able to compete with wind resources in any of the structures described in this paper.

95 These financing assumptions were developed by the Consulting Team based on industry experience and analysis, and vetted and refined through discussion with finance experts at utility and regulatory agencies.

Table 5. Key Project Modeling Assumptions

Category	Input
Project Schedule and Costs	
Commercial Operation Date	January 1st, 2017
Installed Cost[a]	$2,044 / kW
Fixed O&M[b] (Year 1)	$70 / kW - yr (escalated at 2.5% annually)
Variable O&M (Year 1)	0.06¢ / KWh (escalated at 2.5% annually)
Project Capacity and Production	
Project Size	100 MW
Capacity Factor	35% (No annual degradation)
Project Useful Life	20 years
Taxes and Macroeconomics	
Federal Tax Rate (%)	35%
State Tax Rate (%)	6.5%
Inflation	2.0%
Revenue	
Energy Market Prices[c]	NYISO CARIS 2014 Zone D Forecast, AEO 2015 High Oil & Gas Resource Case (Low Market Prices) and the High Price Case (High Market Prices) for Upstate NY
Capacity Market Prices	No capacity revenues assumed.

[a] Assumed bid in 2015, with commercial operation date = 1/1/2017, Nominal $, costs updated based on estimates of recent wind capital costs by LBNL

[b] Includes insurance, project management, property taxes, and land lease/royalty.

[c] Note: The Market Price Forecast significantly impacts the modeling results. Prices were generated from GE-MAPS modeling for the NYISO's 2014 CARIS 2 study, the most current CARIS price projections available (see NYISO (2014) *2014 Preliminary CARIS 2 Base Case Results*). The NYISO has started its 2015 CARIS 1 analysis, and updated draft prices (10 year projection) will be released in June 2015. The NYISO expects LBMP price projections from this analysis to be significantly lower than prices from the 2014 CARIS 2 study due to lower natural gas price and load forecast assumptions. The high and low price sensitivities are taken from EIA (2015) *Annual Energy Outlook 2015 with projections to 2040.*

Alternative cases with differing procurement models, contracting structures, and policy assumptions were then modeled as scenarios, each based on the same underlying physical project characteristics but varying revenue, financial, and ownership models. See Appendices A and B for a detailed discussion of the financial model and key financial assumptions.

8.2 Options Analyzed and Financial Assumptions

For the purposes of financial modeling, three base options and several variants of each base option were considered. Each base option should be viewed as a simplified representation of one or more procurement or contracting options described in Chapter 6 for financial modeling purposes. As discussed in this section, some of these base options may represent multiple procurement options and contracting structures that are not materially distinguishable from a project financial modeling perspective.

8.2.1 Definitions of Three Base Options

Current/Reference Case (NYSERDA 20-year Fixed Price RECs). This case represents current policy, and assumes that the project bids for a 20-year fixed price contract under solicitation conducted in 2015 with target commercial operation date of January 1, 2017.

Utility-Backed PPA Scenarios (State Entity and EDC PPAs). This option is intended to model various alternative procurement mechanisms and contractual structures that lead to a 20-year, fixed-price, take-or-pay PPA with a credit-worthy counter-party for the purchase of bundled power and RECs from the wind facility.[96] Note that:

- P**ossible remuneration of utilities for PPAs was not included.** As a result, this modeling does not distinguish between cases with different PPA counterparties (e.g. a State Entity, one or more investor-owned electric distribution companies, etc.). Therefore, the results and discussion of all such PPA cases are combined in this section.
- However, note that **remuneration of 1% increases the cost of a PPA by roughly $0.70-$1.00/MWh**
- Further, a 20-year perfect hedge CFD as described in Section 6.2.3 would have the same impact on project finance as the Utility-Backed PPA structure.

[96] Capacity revenues were ignored for purposes of this illustrative analysis. In practice, inclusion of capacity revenues in the analysis, either through including them in the bundled sale, or accounting for some projected revenue from a separate generator sale in the NYISO market, would reduce the over-market premiums shown.

Utility-Owned Generation (UOG) – To assess whether permitting UOG to compete against PPAs through an open-source auction could result in lower costs, 100% utility ownership and rate-basing of an individual project was considered. For modeling purposes, any utility ownership caps were assumed to apply at the portfolio level rather than at the project level to minimize complexity and costs. The asset was assumed to be acquired at the start of operation from an independent developer and rate-based, so that no development risk is assumed. Then, the incremental contribution of this asset to the utility's revenue requirements and the resulting levelized cost of electricity was computed.

Based on FERC data provided by DPS Staff on recent federal tax payments by the six largest electric distribution companies, they appear to have enough capacity to fully monetize PTCs from at least 1 GW of wind in the near-term. Further, based on input from DPS Staff, the revenue requirement calculation assumes that the benefits of the PTCs are passed through immediately to ratepayers and not subject to normalization.

The utility could also, in principle, rate-base development and construction. However, in that case, the cost of development failure (the 'dry hole' risk faced by developers who incur costs for both successful and unsuccessful development efforts) would also need to be modeled. Based on the consulting team's assessment, the premium implicit in the outside developer equity return models this cost adequately. To test the impact of relaxing this assumption, a sensitivity was considered in which the developer equity return is assumed to be equal to utility equity returns (9%). The impact of this reduction in developer equity required return was to reduce the cost of UOG by $1.18/MWh.[97]

8.2.2 Key Financial and Modeling Assumptions

The following key financial and modeling assumptions are relevant to two or more of the base options and their variants:

- **Federal Production Tax Credit (PTC):** All cases assume no PTC extension unless otherwise noted.
- **The default financial structure used for the Current/Reference Case and Utility-Backed PPAs is a project financing:** Although not all market participants use project-level debt and sponsor equity, and in the current market there exists a significant diversity of capital structures, such a structure is a good representative of the achievable cost of capital in the absence of the PTC and YieldCo financing (which are treated as sensitivities).

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97 This value represents the potential cost in the event that the utility funded development and construction and did not experience cost overruns or include and costs associated with unsuccessful development efforts.

- **No curtailment:** The PPAs are assumed to be true take-or-pay contracts and not subject to curtailment. The UOG projects are similarly not assumed to be curtailed.
- **Based on recent data, actual energy production is assumed to fall 4% below pre-construction projections:** Recent analysis of the performance of pre-construction production estimates suggest a systematic bias toward over-estimation of wind generation by roughly 4%.[98] This only affects costs per MWh for ratepayers in the UOG cases. Asset owners (e.g., developers/investors) bear this risk in the other two cases.
- **6.85% discount rate:** This discount rate is based on average estimated after-tax utility long-term capital costs (WACC) during 2002-2007.
- **All PTC sensitivities with tax equity are modeled as leveraged with debt:** As a simplifying assumption for modeling purposes, all cases with the PTC and tax equity include debt leverage at the project level (these are known as "levered tax equity structures"). These structures are not common in large-scale wind transactions (due to issues related to asset control in the event of a default), but closely related structures that involve back-leverage – debt at the sponsor level – are relatively common and result in similar costs of electricity. Further, the use of leverage in all cases allows for apples-to-apples comparisons of the potential impact of securitized debt financing, which could be structured to encourage levered tax equity structures.
- **The potential cost savings from the provision of RBB Securitization are net of the expected cost to ratepayers of covering defaults (net of recoveries):** As discussed in Chapter 7, ratepayers bear the risk of project defaults or failures in an RBB Securitization. The cost savings estimates for a securitization presented in this section are net of costs associated with defaults net of recoveries, roughly $1/MWh. These costs are calculated based on the Net Present Value of expected defaults net of recoveries, using cumulative default probabilities and ultimate recoveries.[99]

Table A-1 in Appendix A summarizes key financial metrics for each base option. This set includes the assumed equity return requirements along with assumptions regarding debt cost and conditions relevant for the financial analysis. Table A-3 provides a complete list of all cases modeled – the base options as well as any variants and sensitivities – and summarizes key financial metrics for each case.

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98 See, for example, DNV-GL.2014. "Wind Power Project Performance White Paper Actual versus Predicted: 2014 Update."

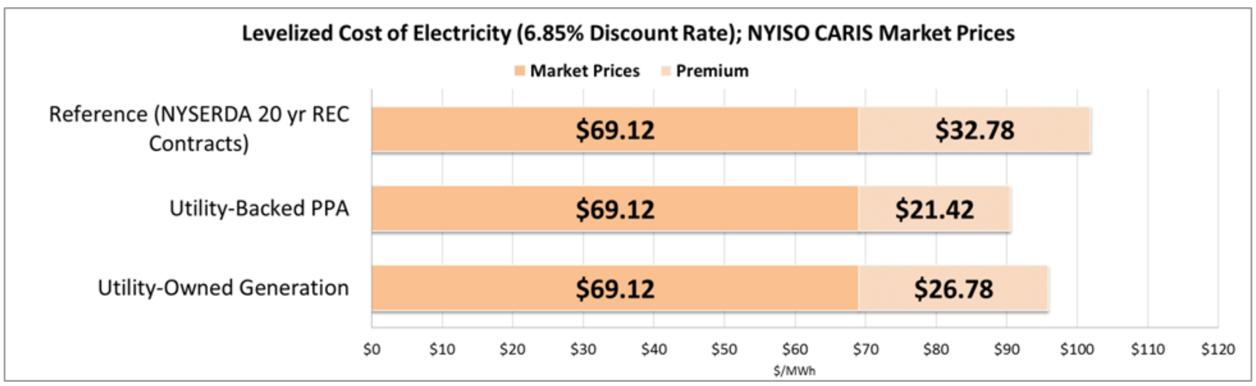
99 As reported for North American project loans from Moody's "Default and Recovery Rates for Project Finance Bank Loans, 1983-2013."

8.3 Results

8.3.1 Cost Comparison: Base Options

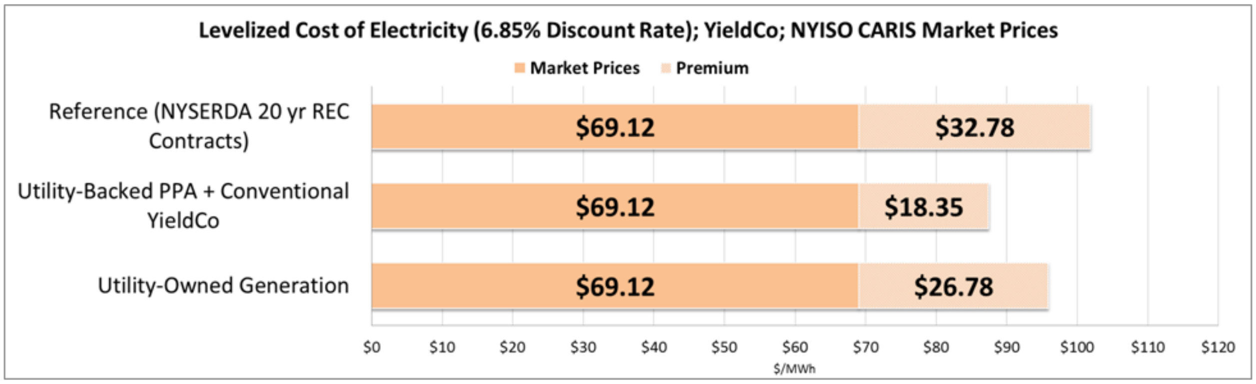
New procurement options (Utility-Backed PPAs or Utility-Owned Generation) can significantly reduce the cost of electricity relative to current policy (NYSERDA 20-year REC Contracts). In the absence of the Federal PTC, the modeled cost of electricity for the Reference case with a NYSERDA 20-year REC Contract results in a premium relative to base case market prices of $33/MWh. With the use of Utility-backed PPAs, the modeled cost of electricity (and premium) could fall by $11-12/MWh (a $35% reduction in cost premium). Utility-owned generation can reduce the cost of electricity by $6/MWh (Figure 13).

Figure 13. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options (no PTC)



If the PPA is with a developer that has a relationship with a YieldCo, and has the confidence to bid a price based on expected sale of the asset to a YieldCo, the modeled cost of electricity for a Utility-Backed PPA could fall by a further $3/MWh below the values shown in Figure 13 (see Figure 14).

Figure 14. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options with YieldCo (no PTC)



If the PTC is extended, utility-backed PPAs with tax equity financing can bring the premium required down to below $8/MWh.[100] But in this case, UOG is particularly attractive due to the assumed pass-through of PTC benefits to ratepayers and the ability of New York utilities to monetize the PTC as it is generated. In that case, UOG can result in a project with a levelized cost of electricity that is slightly below base expected market prices over the life of the project (Figure 15). Note, however, that PPAs with developers who sell their assets to long-term investors with sufficient tax appetite to monetize the PTC as generated (for example, the unregulated affiliates of NY utilities) can deliver a similar benefit.

Appendix B discusses the robustness of these conclusions under changes in key input parameters, specifically market price assumptions, interest rate projections, and discount rates.

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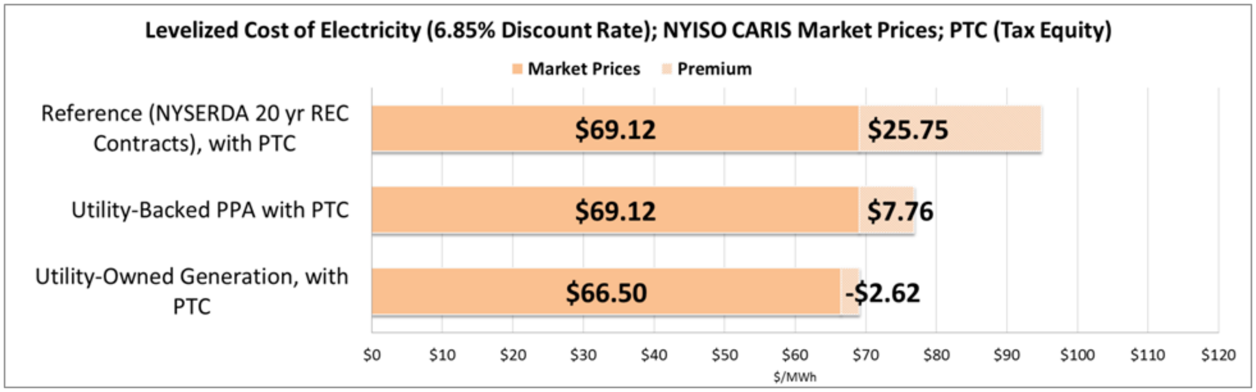
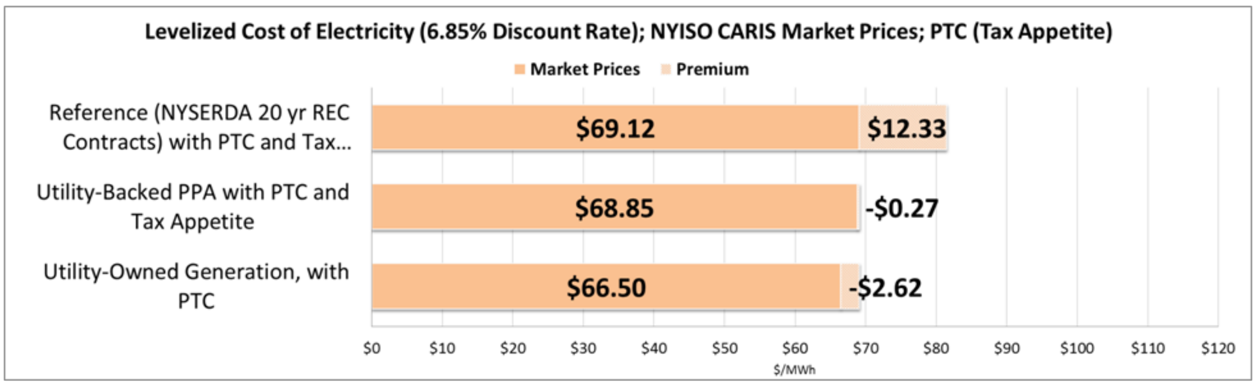
[100] It is assumed for purposes of this analysis that the typical tax equity investor may be unable to fully use the PTC as generated. This is not always the case, however.

Figure 15. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options with PTC, with and without the need for tax-equity financing

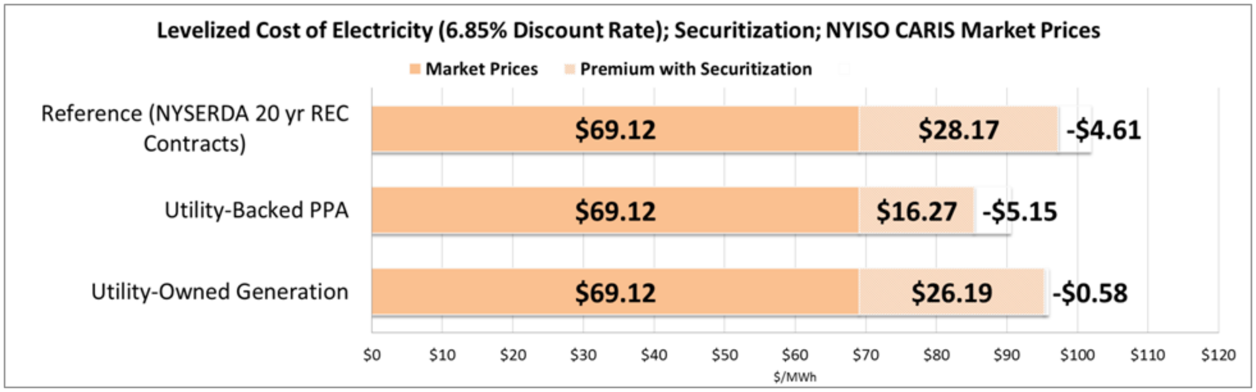


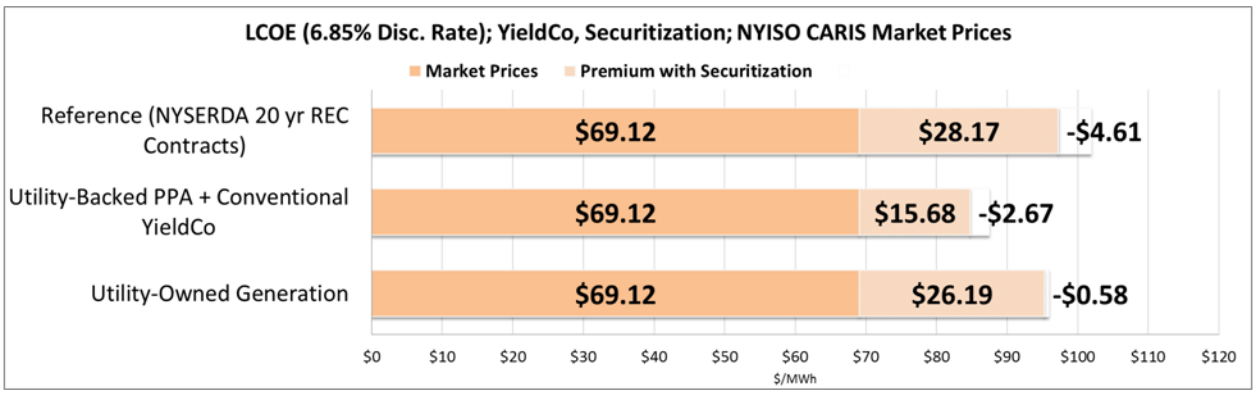


8.3.2 The Impact of RBB Securitization

RBB Securitization can further reduce the premium by $1-5/MWh, with the larger benefit when securitized debt displaces project-level debt. As discussed in the previous section, this benefit is net of the roughly $1/MWh cost of expected project defaults net recoveries that would be borne by ratepayers. The benefit of securitized debt financing is particularly significant for cases with project financing because of the significant spread in these cases between project debt cost and securitized debt cost (Figure 16). Examples include the NYSERDA 20-Year REC contracts, and the Utility-Backed PPA in the absence of YieldCo financing. However, the benefit is relatively small for cases that feature the use of corporate debt (Utility-Backed PPA with YieldCo financing, UOG) due to the much smaller spreads between securitized debt and corporate bond yields.

Figure 16. Levelized Cost of Electricity for Representative 100 MW Wind Facility - Base Options (no PTC) and the use of RBB Securitization, with and without YieldCo financing





8.3.3 UOG Risk to Ratepayers Associated with Production Estimation Uncertainty

With UOG, ratepayers bear the risk of wind production estimation uncertainty. Ratepayers are responsible for compensating the EDC regardless of the performance of the asset, whereas for the typical PPA priced on a per-MWh basis, the owner bears performance risk. The industry average actual project production variance relative to pre-construction estimates is roughly 9%, with an estimated 4% bias towards underperformance. [101] Sensitivities were modeled to assess the variance in levelized cost for UOG associated with that production variance between 13% underperformance and 5% over performance. The 9% variance in actual project production as compared to estimates translated into a $9-10/MWh uncertainty in the cost of electricity for UOG (Figure 17). This risk exposure would need to be considered in head-to-head comparisons of PPAs and UOG options.

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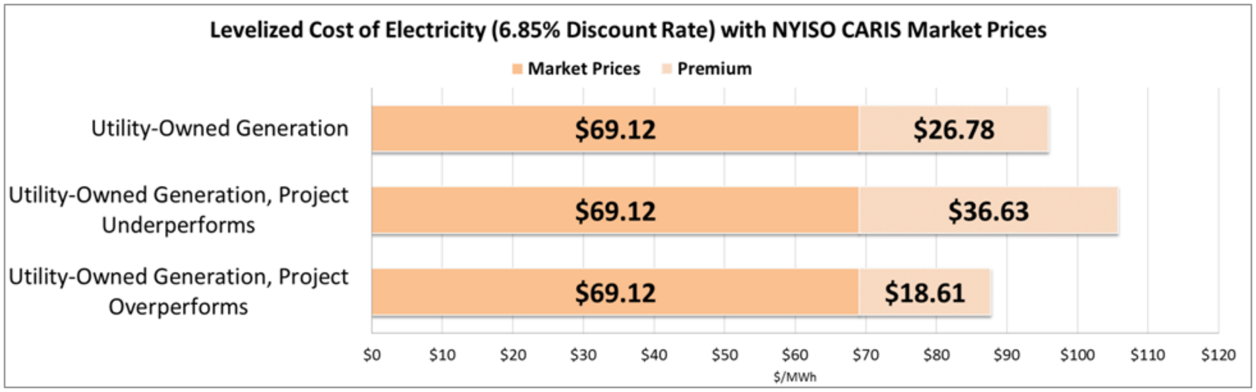
[101] See DNV-GL (2014) "Wind Power Project Performance White Paper Actual versus Predicted: 2014 Update"

Figure 17. Sensitivity of the cost of electricity for Utility-Owned Generation to wind production estimation uncertainty

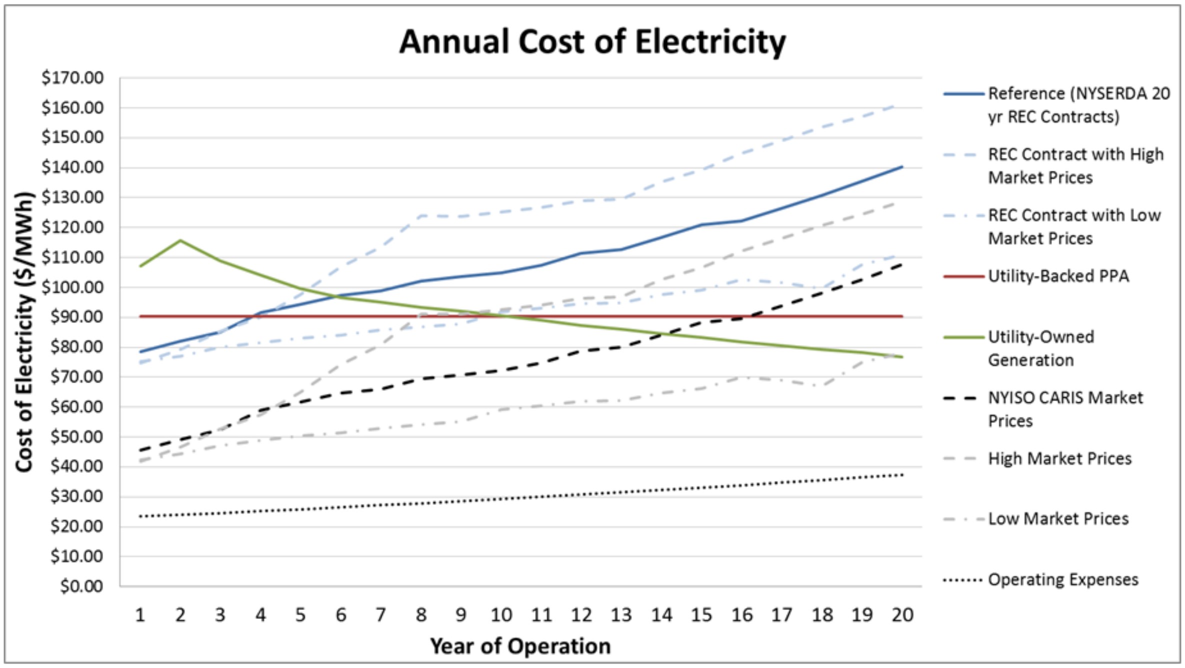


8.3.4 Differences in Time Profile of Rate Impacts among Cases

The three options lead to very different rate impact time profiles**.** Utility rate treatment makes the UOG option expensive in the early years, but it eventually becomes much cheaper in the later years as the value of the asset in rate base drops. Furthermore, the UOG automatically captures on behalf of ratepayers any residual value of the asset (net of decommissioning costs) after 20 years; such value can only be secured under the PPA approach if residual value rights are secured through the solicitation and associated PPAs.[102] On the other hand, the NYSERDA REC contract appears cheaper at first, but as it consists of a fixed-premium over market prices, its cost will continue to increase with market prices. The PPA offers ratepayers a fixed cost of electricity for the facility that falls between the two other cases, appearing somewhat expensive early on, but eventually falling below market prices (Figure 18).

[102] See discussion of residual value and terminal options in Section 5.3.9.

Figure 18. Time profile of the cost of electricity for the three base options (no PTC), compared to base, low, and high market prices and operating expenses[103], [104]



In comparison, the time profile of costs for UOG with a PTC is attractive, assuming ratemaking treatment providing credit of PTC during the first 10 years of operation. However, REC Contracts or PPAs with assets owned by investors with tax appetite can close the gap (Figure 19).

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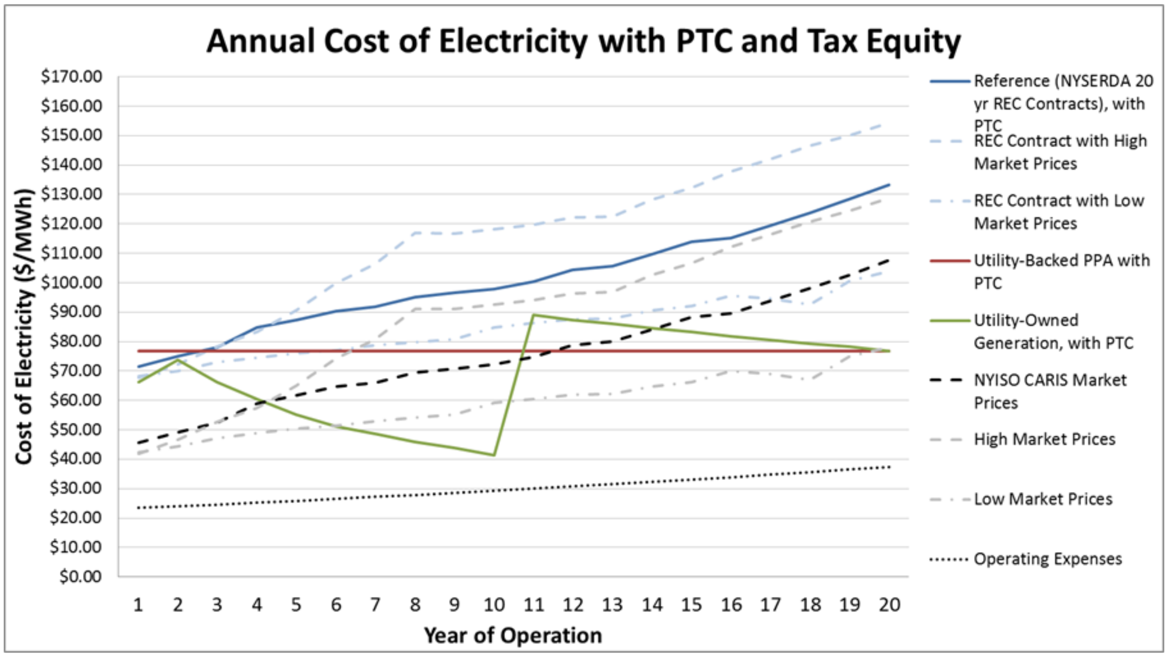
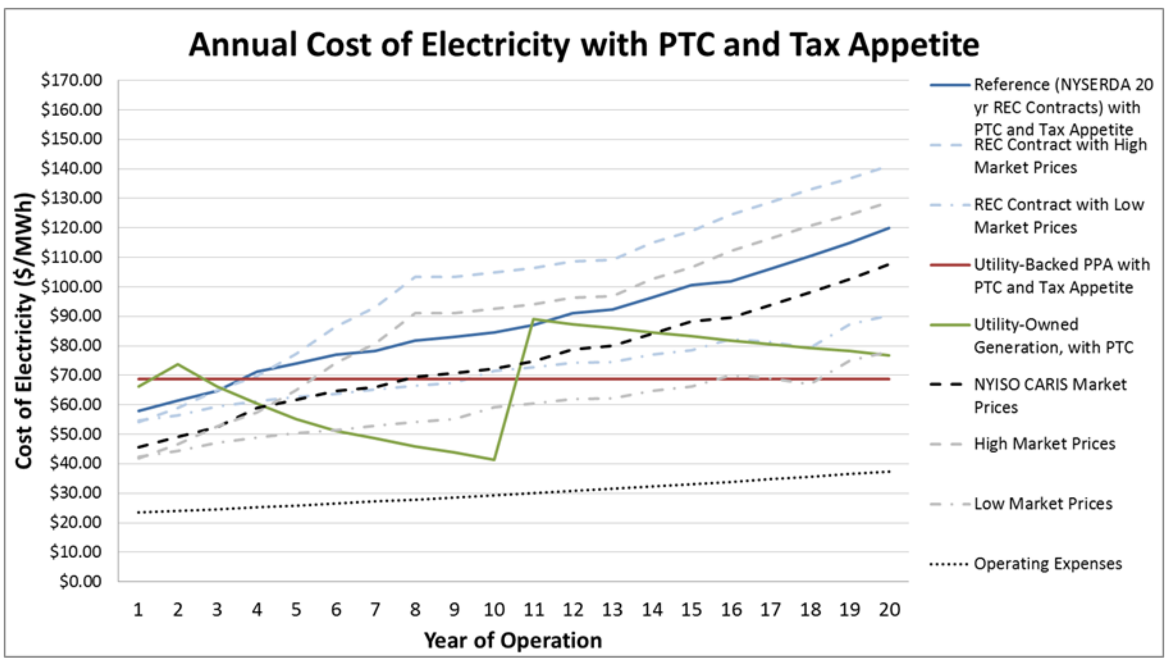
103 The dotted gray lines show the band of uncertainty related to the high and low market price forecasts

104 The energy market price forecast used for the analysis significantly impacts the modeling results. Base market prices were generated from GE-MAPS modeling for the NYISO's 2014 CARIS 2 study, the most current CARIS price projections available. A low price sensitivity was considered to provide a reasonable range of possible outcomes. The high and low price sensitivities were taken from EIA (2015) Annual Energy Outlook 2015 with projections to 2040.

Figure 19. Time Profile of the Cost of Electricity for the Three Base Options[105]





105 Options are with the PTC and either tax equity financing or owners with tax appetite, compared to base, low, and high expected market prices and operating expenses.

8.4 Annual Expenditure and Collection Impacts

A key consideration in evaluating options is their temporal and aggregate impacts on retail rates. Specifically, the focus of this section will be to address the incremental, annual expected impacts of the purchase of renewable electricity, as compared to the purchase of the same quantity of electricity from wholesale markets, on retail rates. Although the levelized costs and time profiles provide insight into the impact of any given project on ratepayer costs, the ratepayer collections impact is determined by the aggregate impacts of multiple projects deployed over time. These impacts will vary substantially between the three cases examined here as they have very different time profiles of ratepayer costs. In addition, they will be sensitive to future market price trajectories.[106]

The most significant factor in determining the cost premium for renewable resources is the market price of electricity, and the forecasts of electricity prices out 10 years in the future can range by 35%; hence any analysis of this type can at best deliver a range of what could be expected based on best available forecasts. To address this issue, the amount of wind that can be deployed with a fixed an annual target expenditure (or "planning budget") available each year to commit to pay for a set of projects' future costs that exceed expected market prices was assessed. For example, if $100 million were available to cover any future costs over and above market prices incurred by ratepayers paying for energy+RECs from projects built in 2017, this limit was translated into a level of deployment that would be expected to fully use the $100 million to cover such costs in a particular market price scenario. Because this "budget" only represents costs incurred by ratepayers over and above market prices and is not assumed to get credit for future savings relative to market prices, it provides insight into incremental ratepayer collections that are necessary in the near-term to support a project or overall goal.

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[106] Note, in particular, that for the Utility-Backed PPA and UOG options, the total bundled price of electricity is not dependent on market prices. Hence, total ratepayer costs in those cases are not subject to market uncertainty. However, since the ratepayer impact of the choice to purchase renewable energy is due to the *difference* between ratepayer costs for the procured renewable energy, the ratepayer impact of this *decision* is subject to market uncertainty.

This analysis presumes expenditure flexibility, and the results shown in this chapter represent *expected* expenditures associated with a particular forecast. Actual expenditures (and annual collections) under two of the three structures modeled could vary higher or lower with short-term energy market volatility (which may be temporary in nature) or over a longer term if actual energy price trends diverge from forecasts. If New York were to adopt an approach with a hard cap on annual collections from ratepayers to fund PPA or UOG commitments, conservatism, reserves, short-term borrowing (in the form of financing or reallocation from other programmatic budgets) would likely be necessary, in addition to reductions in subsequent procurements shown here under low market price futures. This analysis does not account for the costs or reduced procurement volumes resulting from these factors.

As an analytical benchmark, a similar level of investment comparable to the current and projected RPS LSR investment was assessed.[107] Specifically, the analysis focused on a cumulative ratepayer investment level for LSR premiums of $1.5 billion including $100 million per year committed for five years starting in 2019, and $200 million per year for the subsequent five years. These annual investments were intentionally "back-loaded", to take advantage of the improving anticipated economics of wind energy over time resulting from the assumed flat nominal capital costs for wind combined with projected increasing electricity market prices. This level is roughly representative of the current LSR investment level and is used here to illustrate the magnitude of LSR that could be stimulated by such an investment. That level of LSR development could then be compared to renewable resource goals established in the 2014 Draft State Energy Plan and the Commission can assess whether the funding for LSR is appropriate given a range of considerations.

Alongside expected CEF budget levels, the proposed LSR funding commitment would enable near-term reductions in total annual collections and significant decreases over time.

Because the projects in this scenario are deployed over many years, future trajectories for market prices as well as financing and cost assumptions must be specified. Two market price scenarios were analyzed: the base market price case and a low price scenario. Wind capital costs were assumed to remain constant in nominal dollars, but operating expenses were escalated at 2.5% annually. Data on historical spread, yield, and equity premium sensitivities to interest rate were used to project debt and equity costs over 10 years (see Appendix A for details).

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[107] As of December 31, 2014, approximately $1.1 billion in RPS funds were committed to Main Tier projects. When this commitment is combined with the 2015 and expected 2016 solicitation budget, a total $1.5 billion commitment is expected (NYSERDA, 2015).

The estimated budget was $100 million/year committed for five years starting in 2019, and $200 million/year for the subsequent five years. These annual planning budgets are back-loaded, with two-thirds of the investment made in the last five years. This choice was made to take advantage of the improving anticipated economics of wind energy over time resulting from the assumed flat nominal capital costs for wind combined with projected increasing electricity market prices. These funds were then assumed to be "spent out" or outlaid as collected from ratepayers to cover positive differences between contract payments and electricity resale revenues in any given year for the electricity generated by the wind facility. Table 6 shows the resulting deployment possible within this planning budget for each of the three base options, under base and low market price scenarios.

Table 6. Comparative deployment and net costs in each base option (no PTC) assuming a ratepayer investment for LSR premiums of $1.5 billion budgeted over 10 years

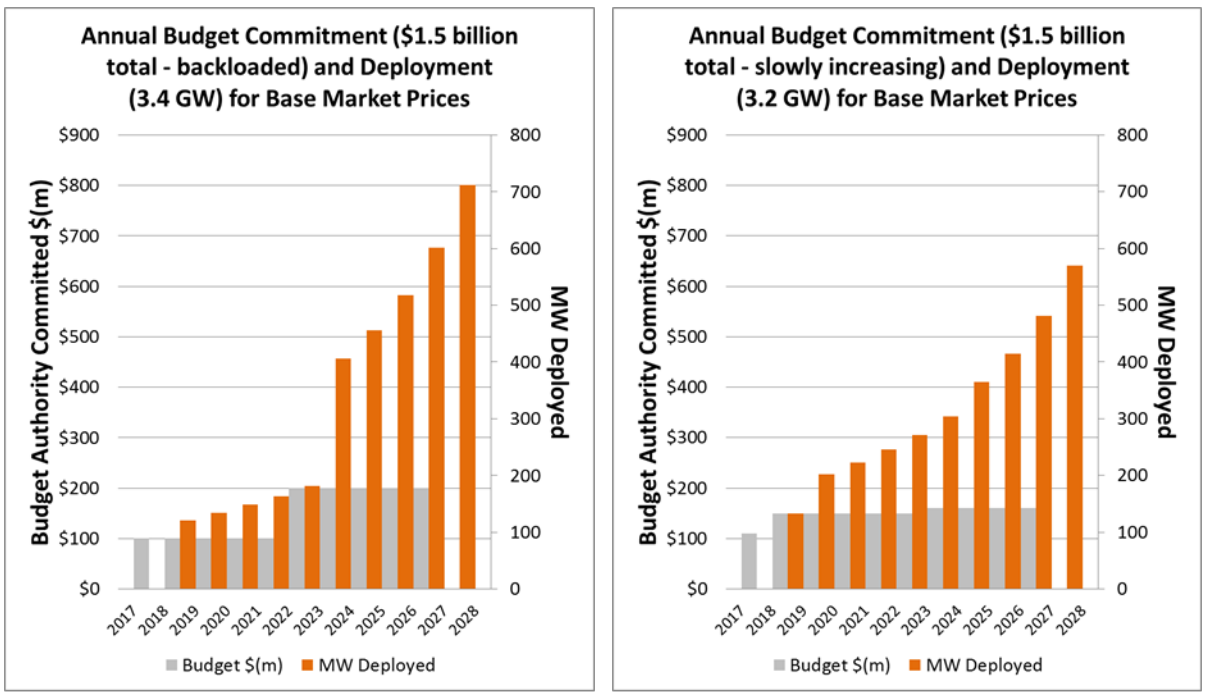
$1.5 billion Investment for LSR Premiums over 10 Years	Base Market Prices			Low Market Prices		
	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)
NYSERDA 20 Year REC	1.6	$1.1	$1.5	0.7	$1.1	$1.5
Utility-Backed 20-Year PPA	3.4	-$0.7	-$1.7	1.1	$1.1	$1.4
Utility-Owned Generation	2.1	-$0.2	-$0.8	1.0	$1.1	$1.4

If efforts were made to limit actual expenditures to the cumulative planning budget of $1.5 billion by adjusting procurement quantities over time, substantially different quantities would be procured under different price futures. To illustrate, Table 6 shows that with a back-loaded planning budget of $1.5 billion, Utility-Backed PPAs could deliver an estimated 3.4 GW in a base market price scenario and an estimated 1.1 GW in a low market price scenario.

Nevertheless, Table 6 shows that Utility-Backed PPAs allow deployment of significantly more projects than the other two options in both price scenarios (72% more than NYSERDA RECs under low market prices, 120% more under base market prices), at roughly equal or lower real net cost (where the net cost is the sum of the annual premiums required over the life of the projects deployed in real 2017 dollars).

Lower cost structures associated with YieldCos / RBB Securitization could further increase deployment in all options beyond the figures shown in Table 6. The back-loaded planning budget results in relatively modest deployment in the first five years – however, a more even pace of budget commitment can result in greater deployment in the early years but slightly lower deployment overall(Figure 20). The benefit of the latter approach is that it allows for a more measured build-out of wind development capacity in New York. Of course, as noted above, adjustments would need to be made as price trajectories are revealed to constrain early year expenditures in the Utility-Backed PPA and Utility-Owned Generation cases.[108]

Figure 20. Comparison: LSR Deployment for $1.5 billion Back-loaded vs. Alternative Expenditure Pattern (Base Market Price Forecast)[109]



[108] Because ratepayer costs are fixed for all operating facilities in both these cases, the risk of "budget deficits" does not reflect actual uncertainty for ratepayers regarding total future bundled electricity and REC costs for operating LSR facilities. Rather, the risk is that future deployment may need to be adjusted to achieve a policy goal of keeping uncertain future incremental ratepayer impacts relative to uncertain future market prices below current levels.

[109] Alternative assumes $1.5 billion committed at a more gradual pace to encourage greater deployment in first 5 years.

Table 6 also shows that deployment of LSR through utility-backed PPAs or utility-owned generation options could eventually save ratepayers money in the base market price scenario as PPA prices drop below projected market prices. For both the utility-backed PPA and utility-owned generation options, the aggregate net cost in 2017 dollars is actually negative with base market price projections. In both of those cases, this result is due to the fact that the cost of electricity, particularly for projects built in later years, is eventually lower than base projected market prices (which are projected to increase at nearly 6% per year, much more rapidly than project costs). Therefore, the cost of procuring electricity from the portfolio of projects in both the utility-backed PPA and utility-owned generation options is lower in 2017 dollars than the projected costs for procuring the same amount of electricity at market prices.

If, on the other hand, market prices ultimately trend lower than expected, "planning budget" commitments made under base market price expectations may need to be adjusted upwards. If such trends are identified early enough during the 10-year commitment period, future commitments can be adjusted downwards to mitigate the likelihood of exceeding the total "planning budget."

One way to mitigate this risk is to make commitments assuming a low price scenario, but one that is updated annually. If the low price scenarios prove to be too conservative over time, additional "planning budget" resources may become available to allow for greater deployment in future years. This adjustment process can lead to a further back-loading of deployment that mitigates the risk of exceeding the "planning budget" but nevertheless retains the option to accelerate renewable deployment if revealed prices justify such investment. Total deployment in this case would be reduced, falling between the low and base market price scenarios.

Future annual ratepayer impacts of the Utility-Backed PPA option with base market prices range from a peak cost of under 0.7% of utility revenues to a savings of just under 1% (Table 7) not considering any potential wholesale price suppression effects which have been previously demonstrated for large penetration of LSR (NYSERDA, 2013). Peak costs under the utility-backed PPA option are expected to be approximately $150 million (in 2013 dollars) in 2028, or 0.7% of 2013 New York utility revenues (0.8% excluding PSEG LI) while peak savings of approximately $210 million (in 2013 dollars) or 1.0% (1.2% excluding PSEG LI) are realized much later, in 2043. In a low price scenario, the peak costs are 0.4% (0.5% excluding PSEG LI and the peak savings are 0.04% (0.05% excluding PSEG LI).

Table 7. Comparative Future Ratepayer Peak Annual Savings and Costs[110]

$1.5 billion Planning Budget over 10 Years	Base Market Price Planning Scenario		Low Market Price Planning Scenario	
	Peak Savings (Excl. PSEG LI)	Peak Costs (Excl. PSEG LI)	Peak Savings (Excl. PSEG LI)	Peak Costs (Excl. PSEG LI)
NYSERDA 20 Year REC	n/a (n/a)	0.3% (0.3%)	n/a (n/a)	0.3% (0.3%)
Utility-Backed PPA	1.0% (1.2%)	0.7% (0.8%)	0.04% (0.05%)	0.4% (0.5%)
Utility-Owned Generation	0.7% (0.8%)	0.7% (0.8%)	0.07% (0.09%)	0.5% (0.6%)

110 In 2013$ as a percentage of 2013 utility revenues (with and without PSEG LI) for each base option (no PTC) assuming an expenditure of $1.5 billion over 10 years.

9 Policy Options for Legacy LSR, Voluntary Markets, and Wholesale Competition

9.1 Contracting with Legacy RPS Renewable Energy Resources

9.1.1 Legacy LSR

Under the Main Tier RPS procurement, 2,035 MW of renewable resources in New York have been placed under New York RPS Main Tier contracts to deliver RPS Attributes to NYSERDA. These contracts, the vast majority of which are for 10 years in duration, will come to an end as soon as February 2016. With the possible exception of a few landfill methane generators, these projects have substantial remaining economic life. For purposes of this discussion, these generators are referred to as Legacy RPS Renewable Resources (Legacy LSR).

RPS contracts with Legacy LSR projects have already led to investment in putting "steel in the ground" with its associated economic benefits. However, under these contracts New York has no residual post-contract rights to RPS Attributes. From the perspectives of New York claiming the production from these renewables towards any goal, or (more concretely) reducing carbon or other emissions, this lack of long-term rights may lead to some unforeseen impacts.

In the absence of any New York policy that would create material value for these resources, owners of Legacy LSR projects are already looking to other markets. Energy and associated RECs from New York projects under contract to NYSERDA, but above and beyond the quantities purchased by NYSERDA, are already being exported to New England.[111] And while available space on existing transmission interconnections between New York and New England is insufficient to reliably accommodate export of the entire Legacy LSR fleet's production, independent transmission developers are planning new ties to

[111] See, for example, Massachusetts Renewable & Alternative Energy Portfolio Standards RPS & APS ANNUAL COMPLIANCE REPORT FOR 2013, Dec. 17, 2014 (http://www.mass.gov/eea/docs/doer/rps-aps/rps-aps-2013-annual-compliance-report.pdf), and NEPOOL GIS Generator Report (available at http://www.nepoolgis.com/public-reports/).

enable more of this work to occur, working with and attempting to subscribe generators to fund the lines.[112] Although some portion of the Legacy LSR production could find a home in New York's voluntary market, as discussed in Section 9.2, the scale of that market is a small fraction of the volume of Legacy LSR production, at best. Given these observations, it is inevitable that in the absence of a New York policy stimulating demand that creates sufficient value for Legacy LSR RECs, the energy and RECs from some or all of these resources are likely to leave the market.

9.1.2 Implications of Legacy LSR Exports

Legacy LSR projects would need to export the energy production from these projects from New York in order to enable REC creation in these neighboring markets. Further, under Massachusetts' Class I RPS regulations, capacity may not committed to NYISO markets associated with RECs used for the State's Class I RPS compliance (MA DOER 2010). Under these circumstances, the impacts on New York would include:

- The State would lose the ability to claim that renewable energy supply towards RPS goals, as the right to make such claims accrues to the rightful purchasers of the associated RECs.[113]
- Negatively impact New York's compliance with Clean Power Plan (EPA 111(d)) targets, either directly (based on accounting procedures) or indirectly (because exported energy would need to be replaced by increased energy production from fossil-fueled generators).

There are implications to other markets, as well, since the volume of New York's Legacy LSR generation could swamp neighboring RPS markets. Conversations between the authors and policymakers and RPS administrators in New England have identified this potential as an issue of concern. More broadly, these implications should also trigger design consideration for future New York large sale renewable energy contracting.

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112 For example Anbaric's Vermont Green Line is being proposed explicitly to expand transmission capacity between upstate New York and the New England grid for these purposes (see http://anbarictransmission.com/projects/vermontgreenline/).

113 Renewable energy-related claims pertaining to energy without RECs trigger Federal Trade Commission violations. See for instance a recent letter dated February 5, 2015, in which the Federal Trade Commission asserted jurisdiction over claims regarding energy from which RECs have been sold separately, strongly warned Green Mountain Power to improve disclosures to customers and communications, and directed GMP to "carefully review its current and future communications" to ensure that market participants understand that GMP has sold its RECs, and cannot therefore claim the power it supplies as renewable. It appears that the Connecticut PURA's examination into Vermont goals associated with renewable from which RECs have been sold (in Docket 15-01-03) are on the verge of causing Vermont to abandon their SPEED program goals in favor of an RPS requiring retirement of RECs (see http://legislature.vermont.gov/assets/Documents/2016/Docs/BILLS/H-0040/H-0040%20As%20Introduced.pdf).

9.1.3 Considerations in Retaining Legacy LSR Supply in New York

If New York State wishes to retain Legacy LSR production in-State to support fulfillment of its policy objectives or federal requirements such as the EPA's Clean Power Plan, there is a tension between this desire and the need to do so at minimum cost to ratepayers. As ratepayers have already paid for a material portion of the benefits (the economic benefits), all else equal going forward, there is less incremental

benefit per megawatt-hour than a megawatt-hour of new generation in New York that triggers additional economic benefits dollar than spending associated with new project construction. This potential limit on willingness to pay may inhibit New York's ability to retain Legacy LSR production, particularly if its owners can earn more elsewhere.

9.1.4 Options for Procuring Legacy LSR

Most potential features of procurement options for Legacy LSR mirror those for new renewables, although other options are also worthy of consideration. Procurements can be long-term, but unlike with new renewables requiring financing, shorter-term procurement is also viable. Procurement could be accomplished together with, or separately from, new renewables, with selection by a central procurement entity, EDCs (jointly or independently), or an independent evaluator. An entirely distinct approach could be used for Legacy LSR, such as a traditional RPS tier obligation placed on EDCs or load-serving entities.

Preliminary analysis of market dynamics and options suggests some insight into potentially preferable approaches to retaining Legacy LSRs:

- **PPA Structure and Duration:** Alternative markets for Legacy LSRs (the most attractive would likely be New England 'Class I' RPS requirements) are volatile, and generators face transaction costs and risks associated with energy exports, and potential loss of New York capacity revenues in accessing these alternative markets. These generators may find the REC revenue stability and energy market hedge of bundled PPA in New York to be attractive.[114]
- **Head-to-Head Procurement with New LSRs vs. Distinct Procurements:** Because new LSRs will require long-term revenue certainty and Legacy LSRs do not, the competitive bidding dynamics in a head-to-head procurement could produce undesirable results. For example, if the

[114] Bundled PPAs may enable cost reduction through re-financing. For example, the YieldCo thirst for assets with reliable revenue streams may create an opportunity whereby New York's offering of bundled fixed price contract to Legacy RE projects may enable their sale to a YieldCo, enticing existing investors to sell Legacy LSR projects to a YieldCo at a profit while still being able to offer New York a competitive price.

quantity sought (or expenditure target) allows for enough supply that new supply would be the marginal resource, a combined new and Legacy RE procurement may end up paying Legacy LSRs at ‘new’ prices. On the other hand, if a smaller expenditure target only allows limited supply, Legacy LSRs could potentially fulfill the entire procurement, dictating price, with a result in which little or no new LSRs were supported.

- **Changing Conditions**: If procurement of Legacy LSRs is pursued, the preferred Legacy LSR procurement mechanism may change over time. In the near-term, because only one project will initially fall into this category in 2016, a short-term competitive procurement will not initially be viable; however, a longer-term approach for which a greater number of projects would compete may be workable. In the longer-term, if and when the cost to procure new renewables through bundled energy and REC long-term PPAs falls, if sufficient new renewables can be developed, then allowing head-to-head competition with new renewables may reduce the cost to retain Legacy LSR because of price competition from new supply.

9.2 Voluntary Market Considerations

9.2.1 Context and Opportunity

One of the State’s leading policy objectives is to increase participation, liquidity, and innovation in the voluntary renewable market. Markets for voluntary purchases of renewable energy began to form in the earliest days of electric industry restructuring. At that time, it was assumed by many that Renewable Portfolio Standards, or other State-mandated renewable energy policies, would become a conservative floor, and that voluntary markets would drive customer participation and renewable energy penetration to much higher levels. Whereas early adopter groups such as the EPA’s Green Power Partnership and World Resources Institute’s Green Power Market Development Group spurred REC purchases among select Fortune 500 companies, the voluntary market did not realize its anticipated breadth and depth. Nationwide, most competitive markets experienced voluntary penetration of well below 1%.

Recently, however, an increasing number of large, sophisticated end users have engaged in meaningful purchases that have contributed to the financing and construction of new renewable energy generators. According to the Rocky Mountain Institute (Rocky Mountain Institute 2015), corporate renewable energy procurement totaled approximately 1,000 MW nationwide in 2014; and contracts in excess of 700 MW have been announced thus far in 2015. Entities such as Google, Kaiser Permanente and Mars have leveraged their significant demands and strong credit to entered 20-year bundled PPAs for hundreds of MWs based purely on economics. This result represents a potentially significant trend and opportunity. Although there are reasons discussed later in this section that these purchases are not easily replicated in New York, policy instruments could be advanced to help animate the market, and prepare it for further expansion as cost premiums shrink in the future.

9.2.2 End-User Motivations for Voluntary Purchases

Like the retail market itself, end-user motivations for voluntarily purchasing renewable energy are not uniform. Nonetheless, an analysis of the history of end-user purchases demonstrates three recurring motivations (which vary in priority from buyer to buyer):

- **Meet internal renewable energy goals:** shareholder mandates for renewable energy purchasing and other sustainability practices are increasingly common. Renewable energy goals may be regional, national or international, and may include both LSR PPAs and ownership of distributed generation.
- **Reduce greenhouse gas (GHG) emissions:** Corporate sustainability is also measured using GHG emissions, which is also referred to as carbon footprint. Whether spurred by internal goals or a desire to manage risk exposure to future carbon policy, end-user GHG objectives drive renewable energy purchases.
- **Increase goodwill with customers and the public:** Shareholder sustainability directives, renewable energy targets and carbon footprint objectives all relate to the end user's goal of improving – or at least maintaining – its public image and bank account of "goodwill" with its current and prospective customers. End users hope that such actions, like marketing expenditures, will ultimately increase sales.

Looking forward, however, a fourth motivating factor for voluntary purchases is emerging with increasing frequency – the desire to stabilize, and possibly reduce, electricity costs through hedging. Conventional means of hedging electricity costs are available in today's market, but are rarely used by retail end users and seldom extend beyond three to five years in duration. LSRs, by comparison, hold the potential to offer a fixed price electricity cost hedge for up to 25 years. Such hedges may come in the form of a "brown power hedge" (delivering energy, but no RECs) or a "green hedge" (delivering both energy and RECs). Although the difference in market prices between the generator's location and the end user's location make these hedges imperfect, the concept has the potential to deliver significant benefits to both generators and end users. It is also important to point out that although a hedge would provide buyers and sellers with a known price for the duration of the contract, it would not guarantee the relationship of that price to the market price of energy (NYSERDA 2014). By definition, the hedge should be valued based on its ability to insulate the buyer from market volatility, and should not be thought of or described as a vehicle for guaranteed savings compared to market prices (NYSERDA 2014). In today's voluntary market, participants are actively exploring whether brown power hedges can provide new opportunities for end users to achieve cost-effective, long-term budget certainty. Renewable energy asset owners and retail buyers are each coming up with innovative product designs (such as converting variable renewable energy production into a fixed quantity block product), but it is premature to conclude whether these concepts will be successfully adopted by the mass market.

9.2.3 Barriers to Growth

To secure financing, renewable energy projects must secure the sale of the majority of output under long-term contracts backed by an investment grade credit rating. Experience tells us that a 10-year contract is likely the minimum duration, and that a 15- or 20-year term provides for the most attractive financing terms. The volume and price of long-term contracts must be sufficient to support the cost of new construction and the return on invested capital. All else equal, stable pricing options will improve financing terms because they mitigate market price risk. All of this information must be supported by an investment grade credit rating or an alternative – such as an irrevocable parent guarantee – to the same effect. As credit quality declines, seller risk increases and higher contract pricing is required (if the project is financeable at all).

From the voluntary buyers' perspective, in contrast to current hedging mechanisms that are available to retail end users for three, or possibly up to five years, renewable energy hedges (while imperfect) have the potential to go much longer. The certainty of an effective long-term hedge represents both potential benefit and potential cost. The ability for a large end user to fix the cost of a portion of their energy supply in a rising electricity price market is balanced by the risk that market prices will not, in fact, be greater than their contract price in enough hours to produce a net benefit. Innovation is beginning to yield complex structures aimed at reducing risk,[115] but voluntary buyers tend to shy away from excessive complexity as well – a fact demonstrated by the lack of depth in the voluntary market beyond the first

[115] Consider recent purchases by Google, Kaiser Permanente and Mars, as well as Google's certification as a wholesale power marketer in order to play a greater role in the management of its own power supply in regulated markets.

movers. Buyers who are not wholesale market participants need to "convert" intermittent energy into full or partial retail requirements service and to manage RECs. The least complex and most practical approach is for a buyer to enter into separate transactions with a generator, a separate market participant who liquidates the renewable energy into the wholesale market (for a fee), and a competitive supplier for retail requirements supply. Depending on the contract structure, buyers will also need to consider whether accounting issues may be present and onerous, especially if the product is determined to be a derivative.

Whereas recent corporate procurements may represent renewed appetite for these kinds of contracts, the conditions under which these purchases were made are not easily replicated in New York. The majority of these deals involved wind projects located in premiere wind resource locations – often yielding capacity factors well in excess of 40%. These locations also afforded maximum economies of scale, and reduced cost and complexity of both permitting and construction. In short, these deals were approved by corporate buyers based on the economics. The bundled purchases of energy and RECs came at parity to wholesale market prices; this means that the implied REC premium is minimal in the short-term and zero (or negative) in the long-term, and also provide the buyer with a hedge against electricity price volatility.

Finally, distributed generation – particularly on-site solar – has emerged as a compelling alternative for corporate buyers entertaining long-term renewable energy contracts with off-site LSR's. Whether intuitive or not, on-site generation is often an easier hurdle for corporate decision-makers to clear than long-term contracts with third parties. Regardless of the type of contract for which a buyer's management approval is sought it is important for policymakers and end users alike to recognize that origination, negotiation, approval and implementation of such transactions consumes buyer time and financial resources. Any successful project will require tireless internal champions at both the executive (vision) and manager (annual budget) level. Commitment cycles can be long, and intervening changes in corporate priorities may strand interest in such commitments, even if substantial time has been invested. Internal champions are a requirement to successfully navigate these challenges.

9.2.4 Designing Models to Animate the Voluntary Market

Given the history and existing market barriers, what can we realistically expect in the way of voluntary end user contribution to New York's LSR objectives? This subsection focuses on ways to integrate voluntary participation into policy-driven renewable energy procurement models, which can enable the voluntary market to make incremental REC commitments and/or enter brown power hedges.

A first of its kind, market-making structure could be integrated into the LSR procurement model to address some of the barriers and support voluntary market activity in New York State. The majority of potential voluntary purchasers lack the volume, credit, and long-term appetite required to support a new project financing. If, however, the State or distribution utilities plays counterparty to the generator, and in turn makes shorter term, lesser volume, contracts available to voluntary buyers, then the State has crafted a policy that creates access (for the voluntary buyer) to products that did not previously exist. To this end, the State takes the initial, long-term position, and sells shorter term 'strips' of energy, RECs or both to end users. This type of back-stop is required as a result of the limited volume, duration, and credit reasonably achievable from the voluntary market.

This structure creates the near-term liquidity required to increase voluntary participation and has thus far been absent. If voluntary participation increases, leverage can be created for the State's budget-limited LSR procurement under certain circumstances. When the State resells portions of its long-term purchases as short-term bundled or REC-only strips to the voluntary market, the revenue produced can be circulated back into the LSR procurement cycle. This revenue can be used to stimulate the financing of additional LSR facilities. This effect is based on the premise that the sales include RECs. Where the State resells portions of its long-term purchases as brown power hedges to end users, the revenue is circulated back into the procurement cycle but no incremental demand for renewables can be claimed because the RECs remain with the State. Further, there is only a net financial benefit to the State if the price of the brown power hedge is greater than the State would have received through liquidation of energy into the NYISO spot market.

The remainder of this section describes potential new structures to stimulate New York's voluntary renewable energy market.

9.2.4.1 Double-Sided Solicitations

In a double-sided solicitation, multiple buyers and sellers are active in the marketplace at the same time, similar to stock exchanges.

Model 1. In a single solicitation including generators, a State procurement entity and end users, the end users purchase energy and/or RECs directly from generators, and the procurement entity buys all energy/RECs not purchased by end users. For the purpose of this paper, this is referred to as a Direct, Open solicitation.

Model 2. In a single competitive solicitation, end users purchase energy and/or RECs directly from generators, and the procurement entity agrees to both purchase remaining energy/RECs and guarantee end-user performance by backstopping and unfulfilled end-user purchase commitments. For the purpose of this paper, this is referred to as a Direct, Open Solicitation with Backstop.

Challenges with Double-Sided Solicitations. The presence of multiple buyers and sellers in the same solicitation at the same time creates a great deal of complexity. It is not the number of participants but the lack of homogeneity that creates these challenges. It is hard for sellers to bid products and services to buyers who have differing appetites for volume and term, and variable credit quality. Consideration of a double-sided solicitation will require the State to determine whether successful bidders will be paid their individual bid prices or a uniform clearing price (UCP) For example, historic RPS procurements have been “as bid,” whereas the location-based wholesale electricity market has a UCP.

As a practical matter, double-sided auctions generally have a UCP, with homogenous product and buyer credit standards. The key to its feasibility is simplification in, and limitation of, product design parameters. By comparison, having price discrimination in double sided auctions raises challenging questions:

- How can sellers accurately reflect risk in price bids when buyers’ credit quality varies?
- Can a seller bid a single price in this environment?
- How does the entity managing the solicitation objectively allocate bid of various prices to buyers with varied credit seeking different product durations and quantities? In other words, how does one clear this type of market equitably?
- Will project financiers be able (and willing) to deal with the lack of homogeneity and all of its attending complexity?

With these potentially daunting challenges in mind, an alternative approach was considered that mitigates many of the limitations of double-sided solicitations.

9.2.4.2 Two, One-Sided Solicitations

In a construct with two, one-sided solicitations, a single procurement entity first purchases all energy and RECs from selected renewable energy generators through a single competitive solicitation and then – separately and subsequently – this procurement entity resells the maximum possible amount of energy and/or RECs to voluntary purchases. It is referred to here as an Indirect, Separate Buy/Sell Solicitations.

Model 3. The single buyer solicitation comes first. Then end users contract with the single buyer for portions of procured supply. Bundled, REC-only and commodity hedge procurement options are made available.

The presence of separate buying and selling solicitations means that the procurement:

- Can be from Legacy RPS Resources or new generating units.
- Can be unit-contingent or a specified amount (fixed MW block).
- Can be for end users' desired amount and contract term.
- It is less clear whether such a solicitation approach could or would be structured as an auction. based on a homogeneous product definition.

9.3 Wholesale Competitive Market Option

A final option for supporting LSR resources would involve reforming wholesale market rules. Projected revenue streams from the NYISO competitive markets alone have been unable to incent the development of LSR resources. The LSR developers presently are relying on various incentives or adders such as Production Tax Credits and REC long-term contracts, including those awarded through the RPS program. With gas prices projected to remain at low levels, the competitive market energy revenues are expected to be low relative to the level needed to finance new LSRs. Energy sales are a primary revenue source for renewable resources; with low energy revenue projections along with uncertainty associated with that revenue stream, they are expected to be insufficient to facilitate merchant entry of renewable resources. It is true that wholesale energy market prices do reflect the valuation of the cost of externalities (SO_x, NO_x, and CO_2) to some extent although few would claim that the full external cost has been included. Unless natural gas prices increase considerably, wholesale competitive market energy revenues will not sufficiently drive entry of new merchant LSR resources. In addition, the capacity revenues from the market typically are a smaller segment of the revenue stream for variable renewable resources than for dispatchable resources.

In addition to externalities, NYISO wholesale market mechanisms do not explicitly recognize the value of certain other attributes of LSR. For example, FERC regulated LBMP, ICAP and ancillary service markets do not explicitly value fuel diversity benefits that a resource may bring to the electric system; leading to the concern that the system may become overly dependent on natural gas, as evidenced in the fact that the electric prices today are largely driven by the price of natural gas. These markets also do not explicitly recognize the value of price volatility reductions that resources such as wind can offer to the system. As natural gas prices can be volatile, especially during high gas demand periods, concomitant electric prices will also be volatile. While bilateral contracts for LSR are a place that such attributes can be valued by market participants, it does not appear such transactions are happening to facilitate new entry of those resources.

In a business-as-usual approach, the State would continue to provide incremental payments to renewable developers to facilitate new LSR resources by augmenting the revenues from the competitive wholesale market. Whereas this approach may work, some argue that competitive market mechanisms can more cheaply and effectively facilitate the entry of new resources that will provide the greatest benefits to the system.

Therefore, the State could advance an option to consider new market mechanisms to more explicitly reflect the value of the benefits of LSR resources (environmental, fuel diversity, price stability, fuel security etc.) and compensate those resources for those benefits. Such mechanisms could include modifications to existing NYISO market energy, capacity, and ancillary services market products or the creation of new market products. Any new proposal should also discuss whether any of these changes would be sufficient to scale the LSR sector independently, or whether an additional LSR procurement mechanism would be necessary to drive scale, whether the proposal would lead to overall lower cost to consumers compared to other procurement options discussed in this paper, and what federal and state legal issues might arise with respect to state actions influencing wholesale market prices.

10 Conclusions

In this section, the evaluation criteria outlined in Chapter 4 are applied to the procurement options summarized in Chapter 6 and their financial impacts as assessed in Chapter 8, to facilitate a discussion of the advantages and limitations of each type of development strategy with respect to New York's renewable energy objectives.

The State policy objectives through REV and the 2014 Draft State Energy Plan, of supporting and accelerating the development of large-scale renewable resources as cost effectively as possible, provided direction for this options paper. Two principles articulated in the 2014 Draft State Energy Plan, namely to ensure a pathway to an "80 by 50" future and to increase private investment in New York's clean energy economy, evaluation criteria identified in this paper, best practices from the current RPS structure, and the analysis contained within this paper have informed the options presented here. These objectives will be best accomplished through a combination of near- and long-term steps that leverage existing programs and authority, provide revenue certainty for project developers, advance new contracting and ownership models for renewables, and create new opportunities for large end users to buy the renewable energy products their shareholders demand.

In considering these objectives and options, NYSERDA recommends the following program design principles and strategies. Key questions are also posed for consideration; detailed questions will be issued by the Department of Public Service to solicit formal public comment.[116]

- **Bundled power purchase agreements (PPAs) to reduce costs and electricity price volatility.** Long-term, bundled PPAs with creditworthy entities can reduce costs and provide a long-term stable energy hedge to volatile energy prices for ratepayers. Financial modeling suggests that PPAs can reduce the levelized cost of energy for a representative project by $11-12/MWh relative to current policies. Such cost reductions could enable substantially greater deployment than current policies (70-120% more over 10 years in modeled scenarios) for the same ratepayer investment in incremental costs. Bundled PPAs achieve these cost reductions by providing long-term, predictable revenue streams to project developers, which reduces financing costs. The use of PPAs may also open access to emerging financing vehicles such as YieldCos unavailable to projects under current policy to enable even greater cost reductions.

[116] A comprehensive list of questions for public comment is presented in a Department of Public Service notice issued simultaneously with the filing of this paper.

Furthermore, in a PPA model, customers capture the hedging benefits of diversifying the fuel mix with LSR: today's above-market premium for LSR would shrink when the rest of the customer electricity bill increases, and grow if the rest of the bill drops, thereby reducing customer electricity price volatility and, under base market forecasts, capturing net savings for customers in the latter years of the contracts. The current RPS structure does not capture these benefits, locking customers into fixed-price premiums that are non-responsive to changes in the overall bill. If utilities are selected as the entity entering into the PPAs, remuneration should be considered to compensate them for taking on the financial obligation.

Key issues to consider include identifying the counterparty to enter into bundled PPAs with developers, and if utilities are selected as the counterparty, whether and how they should be compensated for taking on the financial obligations of PPAs to support project financing (and whether this compensation should apply only in solicitations limited to PPAs or should also apply for PPAs executed in open-source solicitations where utility-owned generation is a competitive option).

- **Flexible procurements to foster competition and ensure the selection of the lowest-cost projects.** Greater competition among all types of project developers and owners is likely to result in the selection of the lowest-cost projects. Current financial analysis shows privately-owned projects with bundled PPAs deliver the lowest-cost solution and that financial tools such as YieldCos can drive costs down further. As markets evolve, other models may become more cost-effective; an open-source solicitation could provide flexibility to accommodate these changes. In particular, there are scenarios where UOG of LSR could achieve the lowest costs. A key issue for further consideration through public comment is whether utilities should be permitted to own LSR projects and compete with privately-owned projects in an open-source solicitation.
- **Centralized project solicitation / evaluation by a third party.** Appointment of an appropriate entity to facilitate the solicitation, evaluation, and selection process as well as to standardize the terms of competition is important to a fair and successful implementation. Third-party solicitation sponsorship could also help mitigate the risk of bias if UOG is permitted to compete against independent power producers seeking utility- or State-backed PPAs in an open-source solicitation. A key issue for consideration is the designation of the appropriate entity to conduct solicitations and evaluate proposals.
- **Procurements conducted based on a planned budget, system needs, and other considerations.** Project evaluation and selection should take into account not just price but also total expenditure targets, system requirements, plant retirements, current and forecasted electricity prices, technology cost trajectories, end-user demand, and the minimum level of annual investment necessary to achieve policy objectives. This can be an important mechanism for containing costs and ensuring projects are deployed where they provide the greatest benefits. The specific methodology for selecting projects and deployment levels will need to be determined. Consistent with REV principles, strategies to integrate LSR with distributed energy resources, such as storage and demand response, to increase the system and costumer benefits should also be explored.

- **New mechanisms to facilitate voluntary market activity.** The voluntary market currently suffers from insufficient demand volumes, contract durations, and credit supports. State-based market interventions could create access for voluntary buyers to power and RECs from operating or proposed renewable energy projects. Mechanisms that sufficiently aggregate or back-stop demand, duration and credit to enable attractive financing terms will be required. Any of the procurement models explored can animate the market for voluntary end-user purchases of renewable energy; RECs and/or energy-only[117] hedges (also referred to as "brown power" hedges). In this context, revenues from voluntary REC sales can be rolled forward into the budget for subsequent procurements and will support the minimal requirement to motivate voluntary REC purchases while simultaneously allowing such sales to advance overall procurement levels. Stakeholder input will be needed to identify the most effective model for stimulating voluntary markets for renewable energy and "brown power" hedges.
- **Securitization to lower the cost of project debt.** Costs to ratepayers may be further reduced (beyond levels induced by competition) if the State offers a low-interest rate, securitized debt option. Project-level debt financing is not common in U.S. renewable energy transactions. This is due either to the investment return requirements of tax equity investors, to uncertainty in project revenue, or both. The benefits of low-cost project debt may be achievable, however, if numerous projects with long-term creditworthy PPAs can be pooled in a way that effectively manages risk and increases liquidity. This would enable the application of lower-cost project-level debt – which may not otherwise be available to the majority of developers.
- **Long term budget commitment to stimulate greater investment in New York and put LSR resources on a path to grid-parity.** Including a long-term budget commitment in the next generation LSR policy sends a strong signal to the LSR development community and can help drive down total project costs through increased competition. Using today's RPS/LSR investment level as a benchmark and given current electricity price forecasts, we estimate a $1.5 billion public investment committed over 10 years to enable development through bundled PPAs could deliver long-term net customer savings, help the State make meaningful progress towards achieving its statewide clean energy goals, and put the LSR market on a path to grid-parity. Alongside expected CEF budget levels, the proposed LSR funding commitment would enable near-term reductions in total annual collections and significant decreases over time.

The following sections elaborate on the analysis underlying these findings.

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117 Without the purchase of associated RECs.

10.1 Application of Evaluation Criteria to Procurement Options

This section summarizes the assessment of the procurement and contracting approaches featured in this paper by focusing on soliciting entity, contracting entity and contract type. The evaluation of advantages and limitations for each structure is impacted by assumptions about New York's renewable energy policy design. For the purpose of this concluding analysis, New York's policy is assumed to maximize renewable energy procurement subject to planning budget constraints, rather than to mandate a percentage (or MWh) target and require penalty payments for noncompliance. This policy is assumed to be at a level that will make material progress toward the long-term renewable energy and carbon reduction goals established in the 2014 Draft State Energy Plan. Further, the State's renewable energy policy is assumed to be carried out through solicitations and contracts with State entities,[118] the utilities (EDCs), or both. It is assumed impractical to apply a binding renewable energy obligation to load-serving entities other than the State's utilities.[119] The LSR policies are also assumed to apply only to new resources; the contributions and implications for legacy renewables and the voluntary market are discussed separately.

Many of the evaluation criteria identified in Chapter 4 do not differentiate materially among the options considered here, or these options are equally effective at achieving them. These criteria include achieving clean energy goals, maximizing the value to the electric system, potentially allowing for the continued use of economic benefits weighting, and compatibility with wholesale competitive markets. Further, achieving sustainable markets by animating the voluntary market and building bridges to sustainable markets that can be economically viable without incentives, as well as enhancing customer options by developing new value-added options for electricity customers, are achievable through measures to stimulate voluntary markets which can be applied across any of the core procurement designs (see Section 9.2).

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118 This entity could be NYSERDA, NYPA, or another party identified or created by the state. Depending on the entity selected, different advantages or limitations may exist. Legislative authority may be required to pursue certain options.

119 This obligation is separate from the fact that all ratepayers, including ESCO customers and voluntary renewable energy buyers, will continue to pay to support the LSR program.

Evaluation criteria most relevant to distinguishing preferences among the models considered include maximizing generation (encouraging successful generation development, maximizing the likelihood of contract leading to successful projects, and able to be implemented at scale), minimizing costs, ease and transparency of administration, and compatibility and acceptability (including compatibility with retail markets, minimizing potential for adverse secondary impacts, and providing acceptable risk allocation).

Based on the evaluation criteria presented in Chapter 4 (and first applied in the detailed discussion in Chapter 5), the financial modeling results in Chapter 8, and the advantages and limitations discussion in this section, the preferred LSR support mechanism is the open-source solicitation using a State entity as soliciting entity and the EDCs as Bundled PPA buyer or project owner. Other mechanisms considered include Bundled PPA (or CFD) procurements solicited by a State entity with either the EDCs or State entity as the contracting party, and CFD solicitations and contracting by NYSERDA. These alternatives are also compared to the continued use of NYSERDA to solicit and contract for RECs.

For any of the LSR support mechanisms previously identified as relying on Bundled PPAs, it is assumed that solicitations would provide for and allow REC-only bids in order to offer flexibility to market participants. However, this flexibility is not central to the mechanism and is not expected to contribute materially to the anticipated cost impacts. To simplify the discussion to follow, this feature is presumed to apply across all models but is not discussed further.

10.1.1 NYSERDA as Solicitor and Purchaser: REC-Only Contract (Option 1)

This path represents a continuation of the existing NYSERDA solicitation and long-term (20-year) REC contract. This option could be adapted to allow for a CFD, which should be feasible to implement and should provide better opportunities for maximizing generation at lower costs than the current procurement mechanism. However, bundled contracts are not an option since NYSERDA is not a wholesale market participant and lacks authority to contract for energy.

The NYSERDA fixed-price REC contract solicitations rate highly in terms of feasibility, ease of administration, and compatibility and acceptability. However, these types of contracts are substantially suboptimal in terms of the criteria of maximizing generation, minimizing cost, and achieving New York’s clean energy goals.

An advantage of this approach is that the program is established and its fixed payments make it easier (than other approaches) for New York to procure new resources at more predictable costs and within an established budget set by a fixed collection schedule from ratepayers. This option is the only option of those evaluated that can easily be guaranteed to operate within a fixed budget. In addition, in terms of compatibility with the wholesale power market, the fixed price REC contract does not significantly reduce the incentives of renewable generators to locate in less transmission constrained parts of the grid. That is because the value of energy revenues is fully dependent on where the generator locates and the quality of its interconnection to the grid.

NYSERDA's continued use of the fixed price REC contract as the main procurement vehicle poses risks for New York's ability to meet its objectives. This type of contract may not be sufficiently attractive to incent developers to develop and build LSRs in New York. Moreover, the additional risks associated with REC-only contracts may make financing of projects more difficult than where projects have bundled energy and REC contracts.

A REC CFD is a form of contract in which NYSERDA could purchase RECs from a seller while providing a fixed-for-floating swap on the value of energy, thus providing an effective hedge on energy. One benefit of a CFD compared to a bundled energy/REC PPA is that as a purely financial transaction, it can be used by a party like NYSERDA that is not a NYISO market participant to provide revenue certainty to generators. It can provide the same benefits in terms of the ability to hedge market price risk for both generators and retail customers.

Although a NYSERDA solicitation offering REC CFDs would be more administratively complex than a fixed-price REC-only solicitation, it also should be feasible to implement and should provide better opportunities for maximizing generation at lower costs than the current procurement mechanism. On the other hand, it is possible that restrictions in the Dodd-Frank Act could potentially limit the magnitude of the CFD transactions that NYSERDA could enter with generators. Implementing this approach would also require a collection mechanism that could support expenditures that vary with market energy prices.

10.1.2 State Entity as Solicitor and Renewable Energy Purchaser: Bundled PPA with REC-Only or CFD Option (Option 2)

In this approach, the role of soliciting and contracting is fulfilled by a State entity.[120] This option could allow REC, Energy + REC[121], and CFD contracts.

For developers offering PPAs, a long-term bundled purchase backed by the State's credit ratings enables attractive financing terms, and provides the type of revenue certainty attractive to low-cost equity vehicles such as YieldCos. Also, a State entity may not require remuneration as an incentive for participation.

This paper finds that a State entity PPA-only variant is likely to be feasible, but with more administrative complexity than the current NYSERDA fixed-price REC-only approach. The advantages of central procurement would be retained. Compared to the current program, successful renewable project development would be more strongly facilitated with significantly lower costs due to the availability of energy price hedging for generators. Non-inclusion of residual value post PPA, compared to UOGs, could be mitigated by requiring or encouraging terminal options to capture residual value in a PPA solicitation.

Compared to the current program, successful renewable project development would be more strongly facilitated with significantly lower costs due to the availability of energy price hedging for generators. However, the solicitation design would not incorporate the possibility of renewable generator asset sales to utilities and, hence, it would not create the optimal competitive playing field which could maximize renewable generation and minimize costs. This would also require a State entity to enter a new, substantive market role that would require legislation.

As with other procurement options involving long-term PPAs for energy and RECs, the solicitation and contracting process can be designed to be compatible with wholesale markets. Solicitations can be implemented to take into consideration the value of energy based on location and transmission constraints, thus providing strong signals to renewable energy developers to site their projects in suitable locations. Contracts can be designed to provide appropriate operational incentives that allocate the risks of negative LBMPs between the counterparties while providing sufficient revenue assurances for financing purposes.

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120 This entity could be NYSERDA, NYPA or another party identified or created by the state. Depending on the entity selected, different advantages or limitations may exist. Legislative authority may be required to pursue certain options.

121 This factor may also potentially include capacity.

A State entity open-source solicitation variant would potentially create more value in terms of maximizing renewable generation, achieving State clean energy goals, and minimizing costs, but with the challenge of a likely need for legislative action, a disadvantage of adding complexity to implement and associated administrative costs to the procurement process.

10.1.3 State Entity or EDC as Solicitor; EDC as Renewable Energy Purchaser: Bundled PPA with REC-Only Option (Option 3a)

In contrast to the preferred open-source solicitation approach, this model is a PPA-Only solicitation; EDC ownership options are not included. PPAs under this approach could be for energy only, RECs only, or bundled (both energy and RECs). Access to EDC longevity, load volume, credit, and the ability to contract for both energy and RECs makes this an attractive policy to stimulate LSR.

A solicitation process pursuant to which renewable generation developers would bid to obtain long-term PPAs for RECs and/or energy with one or more utilities has several important advantages. Long-term bundled product contracts with creditworthy utilities provides substantial revenue certainty to renewable generators, is the most common method to facilitate financing of new renewable generation in the United States,[122] and, as shown in Chapter 8, is likely to minimize the cost to ratepayers of new renewable generation compared to fixed price REC-only contracts under the current NYSERDA program. As wholesale energy market participants, the utilities can purchase and either use or liquidate the commodity electricity. This approach is likely to maximize LSR generation and should facilitate the ability of New York to achieve clean energy goals. Non-inclusion of residual value post PPA, compared to UOG could be mitigated by requiring or encouraging terminal options to capture residual value in a PPA solicitation.

A key component of utility PPA procurements is the establishment of cost recovery mechanisms which would provide strong assurance to utilities that the net cost of the products (energy and RECs) purchased under a PPA are recovered from distribution customers. Because net costs would be recovered from (or net benefits would accrue to) distribution customers on an equal basis, there should be no impact on competitive retail markets. As with State entity PPAs for energy and RECs, the solicitation process and the resulting PPAs can send appropriate locational and operational signals to renewable generators compatible with incentives to facilitating financing of new LSR.

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122 For example, through 2013, 83% of the wind generation capacity constructed in the United States is owned by independent power producers, most of which has been financed and built based on the revenue certainty created by long-term contracts with electric utilities as the buyers. (U.S. Department of Energy 2014)

Solicitations for utility PPAs will entail additional regulatory processes and new roles for the State's utilities regulated by the Commission. For the protection of both utility investors and ratepayers, the PPAs entered into by the utilities pursuant to solicitation should be subject to the approval of the Commission. The solicitations themselves (the design of the RFP and the evaluation framework) should also be subject to approval by the Commission.

There are limitations to the PPA-only utility solicitation approach. The utilities may be ambivalent about taking on the role of purchasers under PPAs with the costs, time, and the risks (albeit small) associated with it, without the prospects of any upside. This could affect their motivation and effectiveness. There is also the possibility of negative effects on utility credit ratings from S&P (unlikely from Moody's and Fitch), which could have implications on rates at some future time. These constraints can be mitigated by providing some degree of remuneration to utilities.

Administration of a PPA-only process presents issues of effectiveness, fairness, and efficiency. Allowing utility affiliates to bid will expand participation of competent and creditworthy generators but will require, at a minimum, independent oversight by state agencies or independent evaluators to assure that the evaluation and selection process is free of bias. There is also the possibility of bias due to the interest of some utilities in transmission expansions that may be associated with certain generation projects. State agency responsibility for RFP design, solicitation issuance, bid evaluation and selection would provide the strongest protections to assure fairness in the solicitation process.

There are a variety of options as to how utility PPA solicitations could be conducted. A centralized process involving a common RFP and a single bid evaluation process would be most administratively efficient. From a contractual standpoint, the purchase of energy and RECs could be allocated among the utilities based on their respective load shares or on some other basis.

10.1.4 State Entity as Solicitor; EDC as Renewable Energy Bundled PPA Buyer or Generation Owner: Open-Source Solicitation (Option 3b)

This assessment finds that an open-source competitive solicitation is the option most likely to deliver the largest quantity of LSR at the least cost. By creating competition between PPA and utility-ownership options, this policy is expected to attract the broadest range of projects in response to periodic solicitations, resulting in the greatest leverage for annual LSR planning budgets.

UOGs may have advantages with respect to terminal value ordinarily not present under PPAs where the generation owner owns a project's terminal value (which may be positive or negative, but is likely to be positive). Solicitations may be structured to incorporate terminal value in the evaluation and encourage PPA bidders to offer proposals which provide terminal value (through options to extend the PPA term at specified prices and/or options to purchase the generator).

Open-source solicitations may significantly alter the value proposition for utilities. Utilities would have the opportunity to acquire new renewable generation projects pursuant to bid contracts and earn a regulated rate of return on the investment if the bid projects have competitive merit. On the other hand, they would be purchasers under PPAs if PPAs are determined to have competitive merit. In this overall context, any justification for remuneration for utilities entering into PPAs is substantially reduced.

In terms of limitations, open-source solicitations present issues of comparability and potential bias in evaluation and selection. These issues can be mitigated by State agency direction of the solicitation design, evaluation and selection. Particular issues involving risk transfer to ratepayers associated with most UOG proposals, particularly involving forecasts of energy production and long-term operation and maintenance expenses can be addressed through retention of experts to aid in the bid evaluation and imposing quality standards on bidder production forecasts.

Allowing utilities to compete as buyers of LSR assets presents issues of vertical market power and whether existing restrictions on utility generation asset ownership should be modified, both of which will need to be revisited by the Commission.

Finally, open-source solicitations will produce substantial administrative complexity in the design and implementation of solicitations that is incremental to PPA-only solicitations. The complexity and associated timing and cost impacts are due primarily to the need to review estimates of energy output and operation and maintenance and capital replacement costs for UOG projects as well as evaluating terminal value, all in a fair, unbiased manner. Another factor adding to complexity is the allocation of UOG and PPA contracts to utilities assuming a centralized procurement approach is used. With the utilities participating as both PPA buyers and UOG buyers, however, open-source solicitations should be less complex to implement with utilities as PPA counterparties than in the model where a State entity is the PPA counterparty and the soliciting entity but the regulated utilities are the potential asset buyers.

Despite the added complexity, open-source utility solicitations are feasible to design and implement, and the increased competition and available structural options may produce benefits in terms of increased renewable generation at lower costs that outweigh the effects of incremental complexity.

10.2 Securitization Offers Low-Cost Debt and Enables Project Financing

As evaluated in Chapter 7 and quantified in Chapter 8, lowering the interest rate on project-based debt can have a meaningful impact on LCOE and cost premium to ratepayers. Project-level debt is uncommon in today's LSR market because of the uncertainty many projects face with respect to energy revenue, REC revenue, or both – as well as the complexity of attempting to layer project debt on top of tax equity investment, which requires priority returns. State-backed, securitized debt has the potential to stimulate borrowing at the project level and can be paired with any of the LSR policy options evaluated. As demonstrated in Chapter 8, securitized debt can reduce the otherwise applicable market premium by $1 to $5 per MWh.[123]

10.3 Legacy LSR Considerations

Under the Main Tier RPS procurement, 2,035 MW of renewable resources in New York have been placed under New York RPS Main Tier contracts to deliver RPS Attributes to NYSERDA. The vast majority of these contracts are for 10 years in duration and will come to an end as soon as January 2016, yet many have substantial remaining life. For purposes of this discussion, these generators are referred to as Legacy RPS Renewable Resources (Legacy LSR).

RPS contracts with Legacy LSR projects have already led to investment in putting "steel in the ground," with its associated economic benefits. However, under these contracts New York has no residual post-contract rights to RPS Attributes. It is inevitable that in the absence of a New York policy stimulating demand that creates sufficient value for Legacy LSR RECs, the energy and RECs from some or all of these resources are likely to leave the market. This departure would impact New York's ability to claim

[123] Benefits on the higher end of this spectrum are secured when securitized debt displaces conventional project-level debt.

that renewable energy supply toward RPS goals, as the right to make such claims accrues to the rightful purchasers of the associated RECs.[124] It could also impact New York's method for compliance with Clean Air Act Section 111(d) targets, either directly (based on accounting procedures) or indirectly (because exported energy would need to be replaced by increased energy production from fossil-fueled generators).

If New York State wishes to retain Legacy LSR production in-State to support fulfillment of its policy objectives or federal requirements, there is a tension between this desire and the need to do so at minimum cost to ratepayers. Most potential features of procurement options for Legacy LSR mirror those for new renewables. If desired, procurement could be accomplished together with, or separately from, new renewables, with selection by a central procurement entity, EDCs (jointly or independently), or an independent evaluator. An assessment of market dynamics and options focusing on the potential attractiveness of revenue stability to Legacy LSRs, the risks to ratepayers of combining procurement of new and Legacy LSRs, and changing conditions over time, suggest preferable approaches for consideration.

10.4 Voluntary Market Considerations

One of the State's leading policy objectives is to increase participation, liquidity, and innovation in the voluntary renewable market. Over time, the New York voluntary market has not realized its anticipated breadth and depth. Nationwide, most competitive markets experienced voluntary penetration of well below 1%. Recently, however, an increasing number of large, sophisticated, end users have engaged in meaningful purchases that have contributed to the financing and construction of new renewable energy generators.

According to the Rocky Mountain Institute (Rocky Mountain Institute 2015), corporate renewable energy procurement totaled approximately 1,000 MW nationwide in 2014; and contracts in excess of 700 MW have been announced thus far in 2015. Entities such as Google, Kaiser Permanente and Mars have leveraged their significant demands and strong credit to entered 20-year bundled PPAs for hundreds of MWs based purely on economics. This represents a potentially significant trend and opportunity. These purchases are not easily replicated in New York, however, for two reasons. First, current voluntary market participants have thus far been unable to aggregate enough demand, demonstrate sufficient credit, and obtain approval for contract durations long enough to enable project financing. In addition, the

[124] Renewable energy-related claims pertaining to energy without RECs have triggered Federal Trade Commission violations.

majority of the transactions noted above involved wind projects in superior wind resource locations maximum economies of scale, reduced cost and complexity of both permitting and construction, and all captured the now-expired Federal PTC. In short, the economics of these transactions provided corporate buyers with bundled purchases of energy and RECs at near parity to wholesale market prices, an economic outcome that may be challenging to replicate in the near-term. Additional policy instruments will be necessary to advance the voluntary market in New York, and prepare it for further expansion as cost premiums shrink in the future.

Like the retail market itself, end-user motivations for voluntarily purchasing renewable energy are not uniform. Nonetheless, an analysis of the history of end-user purchases demonstrates three recurring motivations (which vary in priority from buyer to buyer):

- Meet internal renewable energy goals.
- Reduce greenhouse gas emissions.
- Increase goodwill with customers and the public.

Looking forward, however, a fourth motivating factor for voluntary purchases is emerging with increasing frequency – the desire to stabilize, and possibly reduce, electricity costs through hedging. In today's voluntary market, participants are actively exploring whether brown power hedges can provide new opportunities for end users to achieve cost-effective, long-term budget certainty.

To secure financing, renewable energy projects must secure the sale of the majority of output under long-term contracts backed by an investment grade credit rating. This paper identifies ways to integrate voluntary participation into policy-driven renewable energy procurement models, which can enable the voluntary market to make incremental REC commitments and/or enter brown power hedges by instituting a first-of-its-kind, market-making structure that could be integrated into the procurement model to address some of the barriers and support voluntary market activity in New York. To this end, the State can take the initial, long-term position, and sells shorter term strips of RECs and/or brown power hedges to end users.

If voluntary participation increases, leverage can be created for the State's budget-limited LSR procurement under certain circumstances. When the State resells portions of its long-term purchases as short-term bundled or REC-only strips to the voluntary market, the revenue produced can be circulated back into the LSR procurement cycle. This revenue can be used to stimulate the financing of additional LSR facilities. This effect is based on the premise that the sales include RECs and that short-term re-sales are priced at a premium to the State's long-term purchase. Where the State resells portions of its long-term purchases as brown power hedges to end users, the revenue is circulated back into the procurement cycle but no incremental demand for renewables can be claimed because the RECs remain with the State. Further, there is only a net financial benefit to the State if the price of the brown power hedge is greater than the State would have received through liquidation of energy into the NYISO spot market.

10.5 Wholesale Competitive Market Option

A final option for supporting LSR resources would involve reforming wholesale market rules. Projected revenue streams from the NYISO competitive markets alone have been unable to incent the development of LSR resources. With gas prices projected to remain at low levels, the competitive market energy revenues are expected to be low relative to the level needed to finance new LSRs.

It is true that wholesale energy market prices do reflect the valuation of the cost of externalities (SO_x, NO_x and CO_2) to some extent although few would claim that the full external cost has been included. Unless natural gas prices increase considerably, wholesale competitive market energy revenues will not sufficiently drive entry of new merchant LSR resources. In addition, the capacity revenues from the market typically are a smaller segment of the revenue stream for variable renewable resources than for dispatchable resources.

In addition to externalities, NYISO wholesale market mechanisms do not explicitly recognize the value of certain other attributes of LSR. For example, FERC regulated LBMP, ICAP and ancillary service markets do not explicitly value fuel diversity benefits that a resource may bring to the electric system; leading to the concern that the system may become overly dependent on natural gas, as evidenced in the fact that the electric prices today are largely driven by the price of natural gas. These markets also do not explicitly recognize the value of price volatility reductions that resources such as wind can offer to the system. As natural gas prices can be volatile, especially during high gas demand periods, concomitant electric prices will also be volatile. While bilateral contracts for LSR are a place that such attributes can be valued by market participants, it does not appear such transactions are happening to facilitate new entry of those resources.

In a business-as-usual approach, the State would continue to provide incremental payments to renewable developers to facilitate new LSR resources by augmenting the revenues from the competitive wholesale market. Although this approach may work, some argue that competitive market mechanisms can more cheaply and effectively facilitate the entry of new resources that will provide the greatest benefits to the system.

That said, an option could be advanced to consider new market mechanisms to more explicitly reflect the value of the benefits of LSR resources (environmental, fuel diversity, price stability, fuel security etc.) and compensate those resources for those benefits. Such mechanisms could include modifications to existing NYISO market energy, capacity, and ancillary services market products or the creation of new market products. Any new proposal should also discuss whether any of these changes would be sufficient to scale the LSR sector independently, or whether an additional LSR procurement mechanism would be necessary to drive scale, whether the proposal would lead to overall lower cost to consumers compared to other procurement options discussed in this paper, and what federal and state legal issues might arise with respect to state actions influencing wholesale market prices.

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Appendix A: Financial Modeling Approach, Metrics, and Cases Analyzed

A.1 Description of Financial Modeling Approach

The Climate Policy Initiative's (CPI) financial model uses a representative wind project's technical, policy, and financial characteristics to estimate the revenue required for a project to meet investor financial requirements, including that of developers (a targeted after-tax internal rate of return [IRR][125]), outside equity investors (targeted after-tax IRR, common tax equity structures and constraints, fees), and debt providers (minimum debt-service coverage ratio or DSCR[126] requirements and average lender fees).[127]

The model uses three interconnected modules:

1. **A pro-forma project cash flow model:** This model uses key project inputs - costs, revenue, financing, and policy parameters - to generate expected tax and cash flows over the development, construction, and operation of the project. In particular, the model estimates cash and tax flows to and from investors, debt providers, ratepayers, and government stakeholders.
2. **A leveled cost of energy (LCOE) model that incorporates tax equity and debt optimization:** The leveled cost of energy model uses the cash and tax flows generated by the pro forma cash flow model to solve[128] for the minimum additional revenues or incentives needed to simultaneously meet the requirements of all project financing sources and maximize the amount of debt. The resulting financial structures and additional revenues or incentives are then used to complete the cash-flow model of the project (and to check that all financial requirements are indeed met).[129]
3. **Scenario and sensitivity analysis:** The scenario analysis worksheet facilitates the analysis of a large number of project cases, along with different policy and financing scenarios, using the pro forma cash flow model and/or the levelized cost of energy model.

125 The IRR is the discount rate at which the net present value of all cash flows to and from a given investor is zero.

126 The debt service coverage ratio in any given period is the ratio of cash available for debt service (that is, revenues net any operating expenses) to the scheduled debt service payment due in that period. So a minimum DSCR requirement of 1.20x means that a project is required to have cash available at any given time that exceeds any required debt payment due by at least 20%.

127 For more information about CPI's model, see Varadarajan et al. (2012).

128 Since the additional revenues or incentives and the optimization of financing structure affect the cash flows, a solution is often only possible through iteration.

129 Note that the impact of uncertainty in cash flows on debt size is modeled in part through the use of annual P90 revenues available for debt service for the purposes of debt optimization. The annual P90 revenues are a conservative estimate, representing the level of revenues that one might expect to exceed in 9 of 10 years. P90 revenues are estimated based on historic market price volatility (if appropriate) and expected wind resource variability.

The CPI model is designed to allow a high degree of differentiation among capital providers – particularly with respect to financing parameters and constraints, and the associated impact on project cash flows. The analysis focuses on the relationship between contracting approaches, required debt coverage ratios, and equity return requirements. Through this capability, the model provided insight into the relationship between contracting approaches, developer risks, bid prices and estimated cost of electricity or revenue requirements.

A.2 Financing Terms and Metrics

The financing terms and risk premiums used as inputs to the model are expected to vary based on differences in procurement model, available contract type, length, counterparty and other factors. Table A-1 provides the baseline financing assumptions for different sources of capital, and for each of the base options.

The developer return targets and the long-term equity return targets for the Utility-Backed PPA and NYSERDA REC contract cases are after-tax IRRs based upon ranges shown in Figure 3-2 of Mintz-Levin (2012), which reflect terms prevalent from 2010-2012. As interest rates over that period were comparable to the range of forward interest rates in 2017, these return targets are used without adjustment as estimates for return target ranges in 2017.[130] For the developer IRR, the midpoint of the range for wind sponsor equity (development) was used. The long-term equity target IRRs were based on the range for wind sponsor equity (long-term). As the bulk of projects built in the U.S. over that period had long-term power purchase agreements, the target for Utility-Backed PPA was taken to be 50 basis points (bp) below the midpoint of the range for wind and the target for the Reference Case was taken to be 125 basis points above the midpoint. YieldCo equity costs for Utility-Backed PPAs are conservatively taken to be a further 75 basis points lower based on implied hurdle rates from recently disclosed YieldCo transactions.[131]

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130 Specifically, note that between 2010 and 2012, 20-year treasury yields ranged between 2.6-4.7%, roughly consistent with the 2.5-4.0% range of implied forward 20-year treasury yields for 2017 based on the treasury yield curves since the beginning of 2014.

131 For example, TerraForm Power's recent acquisition of 521 MW of wind plants from Atlantic Power suggests an unlevered cash-on-cash yield of 9% (http://ir.terraform.com/phoenix.zhtml?c=253464&p=irol-newsArticle&ID=2031429), or an implied unlevered IRR of roughly 5.7%. Even with 60% leverage at the YieldCo level, this suggests a levered hurdle IRR of under 8%.

As noted in Section 8.2.2, levered tax equity structures (i.e., with both tax equity and project debt) were used to model financing with the PTC in the case in which the sponsor does not have the tax liabilities to utilize the project's tax benefits. Based on discussion in Chadbourne & Parke (2014), recent transactions suggest unlevered tax equity hurdle rates remain roughly at or slightly below 8%, while tax equity investors demand a 400-600 bp premium for levered transactions. The midpoint of this range is used and a 500 bp premium for a 13% tax equity hurdle rate for a Utility-Backed PPA is assumed. As the sponsor equity is highly levered in these transactions, a similar premium is assumed for sponsor equity leading to a sponsor hurdle rate of 15%. Again, as most transactions are for fully contracted assets, a 175 bp spread was assumed between the hurdle rates for the Utility-Backed PPA and the Reference Case.

The debt term for both Utility-Backed PPAs and for the Reference case was taken to be two years less than the duration of revenue support, based on common practice. The utility debt cost was estimated based on the implied forward 20-year treasury yield in 2017 (calculated as the average of the implied forward 20-year treasury yields in 2017 calculated using the daily treasury yield curves from January 1, 2014 to April 17, 2015) of 3.25% and a projected spread for A-rated utility bonds of 150 bp based on recent historical spread data provided by the DPS. The equity cost for Utility-Owned Generation is also based on implied forward treasury yields in 2017 as well as an estimated equity premium and current New York utility betas, also based on data provided by the DPS. Assumptions underlying other debt costs and spreads for all options are described in greater detail in the notes under Table A-1, and were also generated in part using spread data provided by the DPS.

The budgetary analysis in Section 8.4 required projections of capital costs through 2028. Data on historical spread, yield, and equity premium sensitivities to interest rate were used to project debt and equity costs over that period. Projections of interest rates were based on implied forward 20-year treasury yields from 2017-2025 calculated using average daily treasury yield curves in 2014 and 2015, and using the compound average growth rate (CAGR) over that period to extend to 2028 (Table A-2).

Table A-1. Key financial metrics for each base option

Financial Metrics	Reference (NYSERDA 20-yr REC)	Utility-Backed PPA	Utility-Owned Generation (UOG)
Equity Return Targets[a]			
Developer Target IRR	12.75%	12.75%	12.75%
Long Term Equity Target IRR	10.50%	8.75%	9.00%
YieldCo Target Equity IRR	n/a	8.00%	n/a
Tax Equity Sponsor IRR	16.75%	15.00%	n/a
Tax Equity YieldCo Sponsor IRR	n/a	14.00%	n/a
Tax Equity Investor IRR	14.75%	13.00%	n/a
Debt Financial Metrics			
Maximum Leverage	n/a	n/a	52%
Debt Term	18	18	20
Debt Costs / Fees	2.00%	2.00%	n/a
Debt Minimum DSCR (P90)[b]	1.25x	1.20x	n/a
Utility Debt Cost[c]	n/a	n/a	4.75%
RBB Securitized Debt Cost[d]	4.40%	4.40%	4.40%
YieldCo Corporate Debt Cost[e]	n/a	5.50%	n/a
Project Debt Cost[f]	6.25%	6.25%	n/a

[a] Equity and tax equity return targets are based on ranges in Mintz-Levin (2012).

[b] Minimum DSCR requirements are applied on annual P90 cash flows – that is, they are calculated using annual revenues that are expected to be exceeded in 9 out of 10 years.

[c] The utility debt cost was estimated based on the implied forward 20-year treasury yield in 2017 (calculated as the average of the implied forward 20-year treasury yields in 2017 calculated using the daily treasury yield curves from 1/1/2014-4/17/2015) of 3.25% and a projected spread for A-rated utility bonds of 150bp based on recent historical spread data.

[d] RBB Securitized debt costs were estimated as AAA corporate bond yields, and calculated using utility debt costs and historical spreads between AAA and A rated corporate bonds – on average, 35 bp.

[e] YieldCo corporate debt costs were estimated as BBB corporate bond yields, and calculated using utility debt costs and recent historical spreads between A rated corporate bonds and BBB rated bonds – on average 75bp.

[f] Project debt costs were calculated using BBB corporate bond yields and adding 75bp, reflecting their illiquidity and the fact that they are often structured to be just marginally investment grade.

Table A-2. Debt and equity cost projections for budgetary analysis

Financial Metric	Base Case 2017	High Case 2017	2017	2018	2019	2020	2024	2028
Project Debt Rate	6.25%	6.90%	6.25%	6.32%	6.36%	6.39%	6.50%	6.64%
Utility Debt Rate	4.75%	5.40%	4.75%	4.82%	4.86%	4.89%	5.00%	5.14%
Utility Equity Rate	9.00%	9.50%	9.00%	9.05%	9.08%	9.11%	9.19%	9.30%
IPP Equity PPA IRR	8.75%	9.25%	8.75%	8.80%	8.83%	8.86%	8.94%	9.05%
IPP Equity REC IRR	10.50%	11.00%	10.50%	10.55%	10.58%	10.61%	10.69%	10.80%
Developer Equity IRR	12.75%	13.25%	12.75%	12.80%	12.83%	12.86%	12.94%	13.05%

A.3 Financing Metrics, Capital Structure, and WACC for All Cases

The concept of procurement model-specific risk premiums is combined with the baseline financial return requirement metrics to yield the option (and variant / sensitivity)-specific capital structures and costs shown in Table A-3. Specifically, key variants that impact capital structures and costs include the use of YieldCo equity and RBB Securitization. Important sensitivities that also affect capital structures and costs include extension of the PTC (both with and without the need for tax equity) and higher or lower future interest rates. As the capital structure is optimized by the financial model, Table A-3 also provides the percentage of debt and equity in each option as well as the resulting WACC (which was calculated as the after-tax IRR for all financing activity). Finally, because all the non-tax-equity cases involve an assumed sale of the asset by the developer to the long-term equity investor, the effective developer fee implicit in the sale price needed to meet developer equity returns is also shown.

Table A-3. Financial metrics, capital structure, and WACC for base options and key variants / sensitivities

Scenario Financial Metrics	PTC	Tax Equity	RBB Securitized Debt	Yield Co	Int. Rates	Debt	Long Term Equity	Dev. Equity[a]	Cost of Debt	Senior Debt DSCR	Long-Term Investor Return	Dev. Equity Return	Dev. Fee[b]	WACC
Reference (NYSERDA 20-year REC Contracts)	No	No	No	No	Base	51%	49%	-	6.25%	1.25	10.50%	12.75%	6.7%	8.45%
	No	No	Yes	No	Base	52%	48%	-	4.40%	1.25	10.50%	12.75%	6.7%	7.38%
	Yes	Yes	No	No	Base	46%	45%	9.6%	6.25%	1.25	14.75%	16.75%	-	11.43%
	Yes	No	No	No	Base	29%	71%	-	6.25%	1.25	10.50%	12.75%	6.6%	9.26%
	No	No	No	No	Low	50%	50%	-	5.60%	1.25	10.00%	12.25%	6.4%	7.90%
	No	No	No	No	High	51%	49%	-	6.90%	1.25	11.00%	13.25%	6.9%	9.02%
Utility-Backed PPA	No	No	No	No	Base	66%	34%	-	6.25%	1.20	8.75%	12.75%	6.7%	7.29%
	No	No	Yes	No	Base	68%	32%	-	4.40%	1.20	8.75%	12.75%	6.7%	5.77%
	No	No	No	Yes	Base	66%	34%	-	5.50%	1.20	8.00%	12.75%	6.7%	6.55%
	No	No	Yes	Yes	Base	68%	32%	-	4.40%	1.20	8.00%	12.75%	6.7%	5.66%
	Yes	Yes	No	No	Base	54%	44%	1.7%	6.25%	1.20	13.00%	15.00%	-	9.43%
	Yes	Yes	Yes	No	Base	56%	43%	1.1%	4.40%	1.20	13.00%	15.00%	-	8.20%
	Yes	Yes	Yes	Yes	Base	55%	43%	1.6%	4.40%	1.20	13.00%	14.00%	-	8.11%
	Yes	No	No	No	Base	42%	58%	-	6.25%	1.20	8.75%	12.75%	6.6%	7.84%
	No	No	No	No	Low	67%	33%	-	5.60%	1.20	8.25%	12.25%	6.5%	6.65%
	No	No	No	No	High	66%	34%	-	6.90%	1.20	9.25%	13.25%	7.0%	7.92%
Utility-Owned Generation	No[c]	No	No	No	Base	52%	48%	-	4.75%	-	9.00%	12.75%	6.5%	5.38%
	No	No	Yes	No	Base	52%	48%	-	4.40%	-	9.00%	12.75%	6.5%	5.28%
	No	No	No	No	Base	52%	48%	-	4.75%	-	9.00%	9.00%	4.6%	5.20%
	No	No	No	No	Low	52%	48%	-	4.10%	-	8.50%	12.25%	6.2%	4.97%
	No	No	No	No	High	52%	48%	-	5.40%	-	9.50%	13.25%	6.7%	5.79%

[a] In all cases except for the tax equity cases, the developer is assumed to sell the project at the start of operations to the long-term equity investor. If tax equity is used, the developer is assumed to retain a small equity stake in the project.

[b] The developer fee is calculated as the premium relative to costs incurred in development and construction required to meet developer targeted returns.

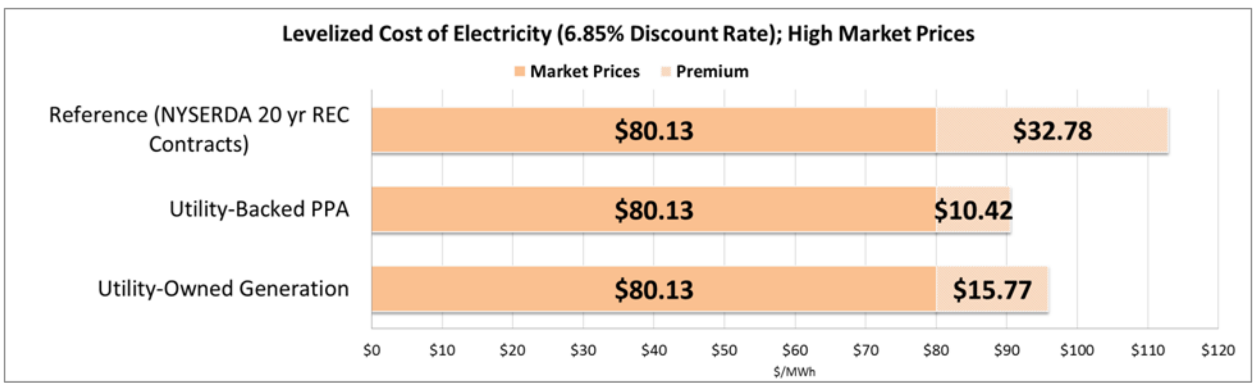
[c] Note that we did not assume any change in capital costs for a utility with or without the PTC, the same financial metrics apply in cases with the PTC.

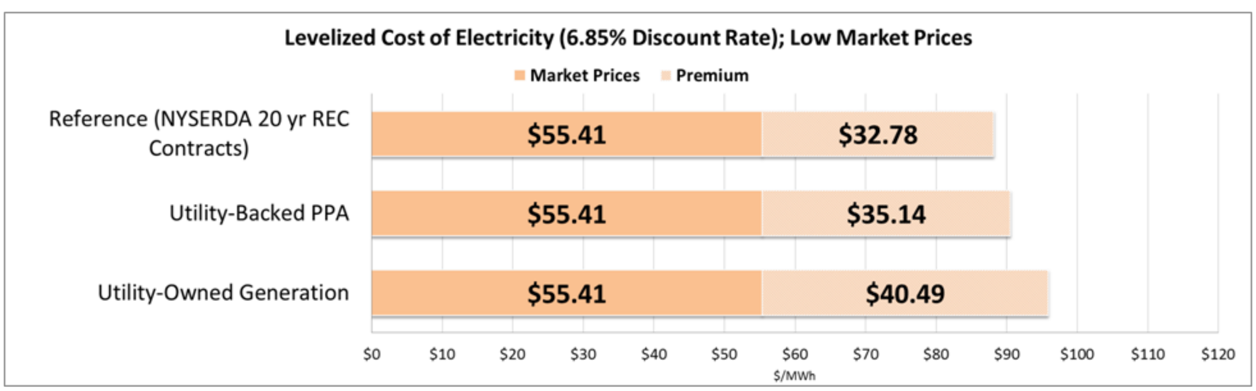
Appendix B: Key Financial Modeling Sensitivities

This appendix presents the results of financial modeling to assess the sensitivity of the results in Chapter 8 to market price, interest rate, and discount rate assumptions.

The realized benefits of Utility-Backed PPAs and UOG relative to the Reference Case depend sensitively on the trajectory of future market prices. If market prices end up being much higher than expected, ratepayers could see enhanced benefits from the fixed prices they are paying either through a PPA or UOG. However, if market prices are actually lower than anticipated, the REC-financed assets could end up being less costly (Figure B-1). Of course, as expectations adjust, one expects that the REC contract bids for future projects would adjust accordingly, thereby reducing the size of this effect over time.

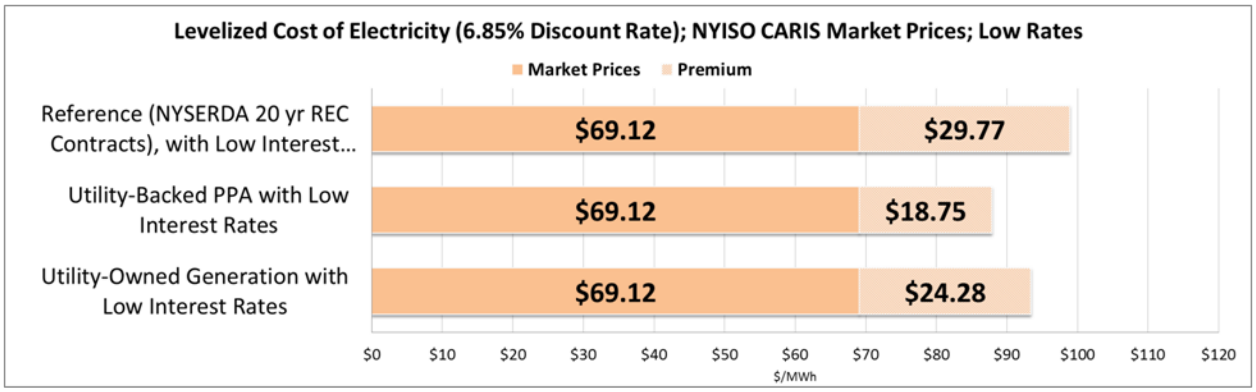
Figure B-1. Actual levelized cost of electricity for Representative 100 MW Wind Facility - base options (no PTC) if realized market prices are either higher or lower than anticipated

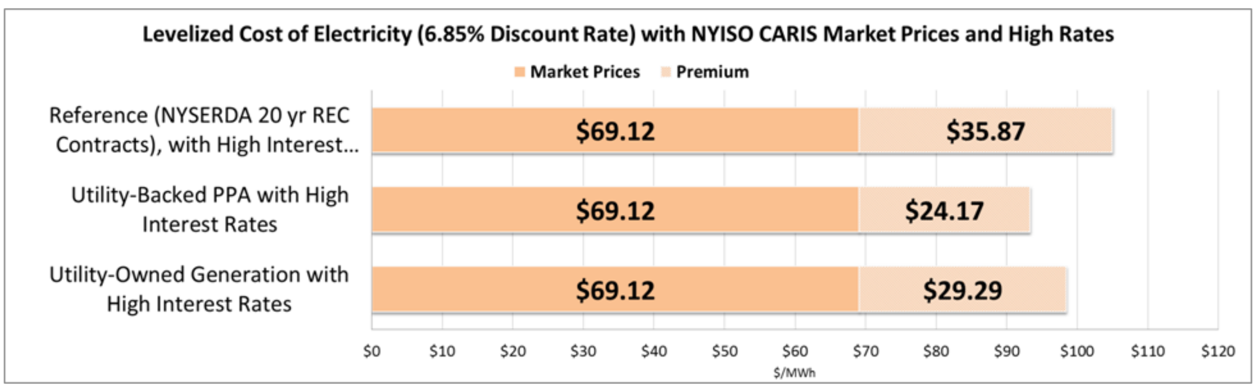




The relative benefits of PPAs and EDC ownership are robust to changes in interest rate expectations. Expectations regarding future interest rates have varied significantly over the last two years. For example, the range of implied 20-year treasury forward yields in early 2017 derived from daily treasury yield curves in 2014 and 2015 have varied from 4.00% early in 2014 to 2.50% currently. However, the analysis showed that the relative benefit of PPAs and EDC ownership is robust to these shifts (Figure B-2).

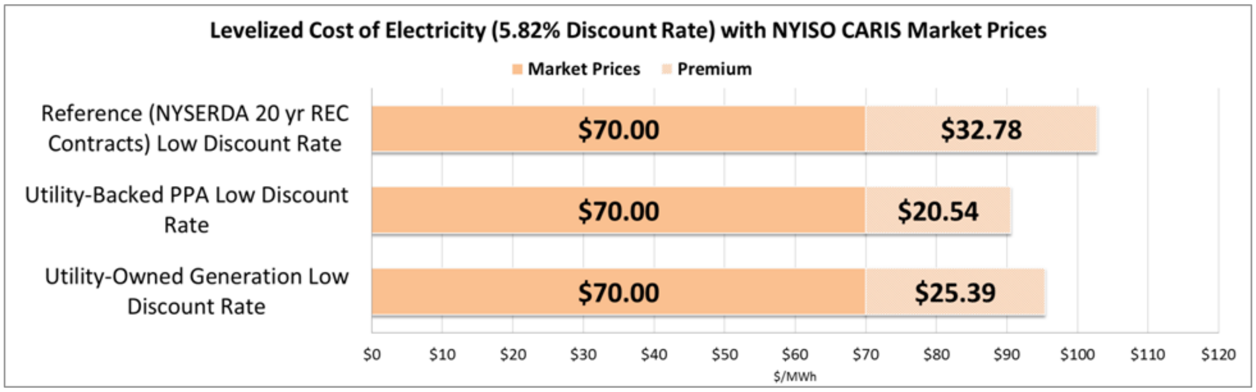
Figure B-2. Sensitivity of base options' cost of electricity to changes in interest rates





The relative benefits of PPAs and EDC ownership are also robust to changes in discount rate assumptions. The 6.85% discount rate used was calculated based on historical WACC for utilities from 2002-2007. We consider a lower discount rate scenario based on our base case projection for the utility cost of capital in 2017, as reflected in the leverage and cost of debt and equity assumptions used as our base case. This lower discount rate will tend to reduce the levelized cost of EDC ownership slightly due to its lower long-term cost profile (Figure B-3).

Figure B-3. Sensitivity of base options' cost of electricity to changes in discount rate



Appendix C: Early Stage LSR Market Opportunities: Offshore Wind

The financial analysis presented in this paper utilized a simplified base option assuming only land-based wind deployment over time. However, other LSR resources offer potential to New York State – most notably offshore wind (OSW) - which could materially contribute to New York's future policy goals.

OSW presents unique long-term opportunities and benefits for New York State that warrant serious consideration and planning. This vast and vital resource is compelling, but also presents multifaceted challenges. Today, OSW costs are higher than many alternative LSR options and conventional energy options. As with most nascent markets, many unknowns still remain with regard to OSW development pathways and timelines in the U.S. and necessary development work involving many parties requires considerable time and effort to implement. New York State recognizes that OSW can be a critical component of its overall energy strategy and action will be necessary to ensure progress is made toward the cost-effective development of this resource.

OSW power projects have made significant progress in Europe with over 6,000 MW installed. In the U.S., there has been interest in opportunities for OSW projects along the Atlantic Coast, but no operational projects have been developed to date. Over the past decade, New York State has assembled important public information for proposed projects off Long Island, in Lakes Erie and Ontario, and in the Atlantic Ocean south of New York City and Long Island. This planning work has set the stage for the next phase of long-term development of this resource. NYPA, on behalf of a collaborative partnership with Consolidated Edison Company of New York and PSEG Long Island (PSEG LI), has applied for a lease from the federal Department of Interior's Bureau of Ocean Energy Management (BOEM) to assess a potential Atlantic Ocean OSW project site for its development potential. In addition, in 2013 the New York Department of State (DOS) published the Offshore Atlantic Ocean Study[132] which is aiding DOS's ongoing efforts with other New York State and federal government agencies to plan for potential OSW development activities, leading to the eventual establishment of Wind Energy Areas throughout the Mid-Atlantic Bight.

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[132] http://docs.dos.ny.gov/communitieswaterfronts/ocean_docs/NYSDOS_Offshore_Atlantic_Ocean_Study.pdf

Recently, the University of Delaware Special Initiative on Offshore Wind published a study (McClellan 2015) identifying potential strategies to drive further OSW cost reduction in New York. The University of Delaware study reviewed best practices; identified reductions in cost expected to result from advances in technology, supply chain and operations of OSW development experience in Europe; and identified interventions that New York can undertake to further reduce OSW costs. Several observations and findings are noteworthy from the report:

- OSW is currently more expensive than other renewable options, such as onshore wind and prospectively, solar electric. Project costs generally increase with distance from the coastline.
- OSW development is capital intensive, requiring financing solutions to raise the required capital and lower expected cost premiums. Long-term commitments from multiple credit-worthy buyers will be necessary.
- Long-term revenue certainty and market demand will provide a path for cost reduction.
- Interventions that increase available information will reduce uncertainty and costs, and create a more favorable environment for siting OSW by New York.
- Multistate collaboration delivering a market of scale could ease OSW barriers on cost, infrastructure, and regulations.

The report also includes key findings with regard to actions that can initiate to accelerate and realize the cost reduction potential for OSW:

- Anticipated global technological innovation, increased global competition in the OSW supply chain, industry-wide development and operational efficiencies driven by European market demand will reduce the LCOE for OSW projects in New York by 2020 roughly 20% lower than the costs for projects installed using today's turbine technology.
- Additional incremental LCOE improvements after global reductions are anticipated for New York OSW projects as U.S. industry learning develops with increased market development in Atlantic coast states.
- New York State itself can take direct steps to reduce NYS OSW project LCOEs by up to another 30% after global and U.S. learning. The New York-specific actions could focus on siting, pre-development activity, development of a series of projects over time, financing, developing operations and maintenance/infrastructure, and transmission and interconnection options.

Table C-1 summarizes the expected individual and aggregate impacts of these market trends and interventions as reflected in the University of Delaware study.

Table C-1. OSW Cost Reduction Pathway

Project	Financial Close Year	LCOE ($/MWh)	Cumulative % change
Base Project –(5 MW)	2020	291.5	N/A
Base Project –(8 MW advanced technology and global trends)	2020	226.5	-22%
NY Project (8 MW) plus global and U.S. trends	2022	202.5	-31%
NY Project (8 MW) plus global and U.S. trends, NYS interventions	2022	137.5	-53%

The LSR options presented in this paper could help advance OSW development and drive these cost reductions for New York State in several ways. First, it is expected that OSW would be eligible to compete with any other LSR in renewable resource procurement under the successor program to the Main-Tier RPS. Second, the innovative financing strategies proposed in this paper – such as creating low-cost debt financing through securitization combined with bundled energy and REC purchases - could help reduce the overall cost of capital of an OSW project and thereby drive LCOE toward lower levels; this could result in a material cost reduction for OSW. Lastly, the options proposed here for utility/private ownership of LSR projects has proven to be effective in European markets for early development of capital-intensive OSW projects.

In addition to the options identified in this LSR paper, with respect to financing and ownership, NYSERDA has identified critical early actions that could improve the value proposition of OSW and expedite responsible commercial deployment of this resource in a cost-effective manner. These actions include: establishing long-term revenue certainty and market demand to reduce cost, increasing available information to reduce uncertainty, creating a more favorable market for siting OSW in New York, and pursuing targeted improvements in federal policy to facilitate OSW development.

Work is underway in New York State on several of these fronts; the stakeholder process and ultimate determination of a path forward for LSR support and its applicability to OSW will be a critical component of New York's policy decision.

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