



**PRELIMINARY REVIEW OF ALTERNATIVES
FOR TRANSITIONING THE NEW JERSEY SOLAR MARKET
FROM REBATES TO MARKET-BASED INCENTIVES**

Prepared for:
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Agency Note:

The Board of Public Utilities' Office of Clean Energy has indicated that as part of its review of a draft of this report issues were raised regarding whether the Board of Public Utilities currently has the legal authority to implement the tariff or hybrid-tariff models discussed in this report. The Office of Clean Energy has indicated that the Board will consider this issue as part of its review of the options discussed in this report as part of its ongoing proceeding. The purpose of the analysis was to review a range of options for renewable incentives in New Jersey for comparative purposes.

LIST OF ACRONYMS

| | |
|--|--|
| ACP: alternative compliance payment | MACRS: Modified Accelerated Cost Recovery System (Accelerated Depreciation) |
| BE: Business Enhancement rider | MSEIA: Mid-Atlantic Solar Energy Industry Association |
| BGS: basic generation service | MW or MWh: megawatt or megawatt-hour |
| BPU: Board of Public Utilities | NJCEP: New Jersey Clean Energy Program |
| BTM: behind-the-meter | OCE: Office of Clean Energy |
| CORE: Customer On-Site Renewable Energy Program | PBI: performance-based incentives |
| CPI: consumer price index | PSEG: Public Service Electric & Gas |
| DG: distributed generation | PTC: Production Tax Credit |
| EDA: Economic Development Authority | PV: solar photovoltaic |
| EDC: electric distribution company | RE: renewable energy |
| EDECA: Electric Discount and Energy Competition Act | REC: renewable energy certificate |
| EIS: PJM Environmental Information Services | RGGI: Regional Greenhouse Gas Initiative |
| EY: energy year | ROI: return on investment |
| GATS: PJM Generation Attribute Trading Systems | RPS: renewable portfolio standard |
| GHG: greenhouse gases | SACP: solar alternative compliance payment |
| IBI: investment-based incentive | SBC: Societal Benefits Charge |
| IRR: internal rate of return | SREC: solar renewable energy certificate |
| ITC: investment tax credit | |
| kWh: kilowatt-hour | |
| LBNL: Lawrence Berkeley National Laboratory | |
| LSE: load-serving entity | |

EXECUTIVE SUMMARY

This executive summary highlights the key findings and recommendations from an independent assessment of potential strategies for transitioning the New Jersey solar PV market from its current dependence on up-front rebates to a more market-based structure in which solar renewable energy certificate (SREC) revenues will play an increasing role in project finance. This report is an interim deliverable, provided to provide near term feedback to the Office of Clean Energy, state policy makers, and solar industry stakeholders as they consider the relative merits of various market transition strategies.

Summit Blue Consulting and its partner, the Rocky Mountain Institute, (together referred to as the “Summit Blue Team”) prepared this report as part of a larger Renewable Energy Market Assessment being conducted for the New Jersey Board of Public Utilities’ Office of Clean Energy (OCE). The goal of the report was to provide OCE with objective and timely feedback on the range of options available for the solar market transition. Given the time-sensitive nature of the decision-making process for setting an Alternative Compliance Payment (ACP) level for Energy Year 2008, OCE requested this feedback by December 15, 2006. The draft version of this report was provided for review at that time. Given these time constraints, the Summit Blue team has prepared a screening-level analysis of seven potential options.

The Summit Blue team has discussed with OCE and the Governor’s Office the importance of providing a more rigorous analysis of a narrower set of transition options. One key objective of this initial report is to provide the information and analyses necessary to narrow the scope of options that will undergo more detailed quantitative analysis as part of a separate assignment.

Background

The immediate need for a market transition is clear. The Customer Onsite Renewable Energy (CORE) Program has approximately \$200 million in rebate funds available to disburse through 2008, the end of the current funding period.¹ However, requests from projects waiting in the Program queue currently exceed that budget. The current funding situation—along with the lack of clarity regarding the future of incentives in New Jersey—have caused a serious slow-down in the process of bringing new solar projects into the development pipeline. The solar industry reports that current market conditions are placing serious financial strains on many solar-related businesses in the State.²

While the CORE Program has been incredibly successful since its inception in 2001, and has enabled New Jersey to be heralded as a national leader in solar energy development, funding all the PV systems that will be required to meet the RPS requirements at current rebate levels is not an economically favorable approach. Furthermore, as specified in the Electric Discount and Energy Competition Act (N.J.S.A. 48:3-61), the New Jersey legislature seeks to develop Clean Energy Programs that can operate without rebates. Therefore, as New Jersey decides how to support solar project development in the next funding cycle, there is great emphasis on transitioning away from the current rebate-centered solar incentive structure to one that is more focused on market-based mechanisms.³

¹ Based on CORE program records dated December 5, 2006.

² Clearly one of the ongoing issues with the early years of solar the RPS in New Jersey will be keeping a balance between the number of installers hoping to make a living there, and the number of systems that are needed in any given year to meet the RPS. Over time, as the industry grows larger and more flexible, this issue should become less critical.

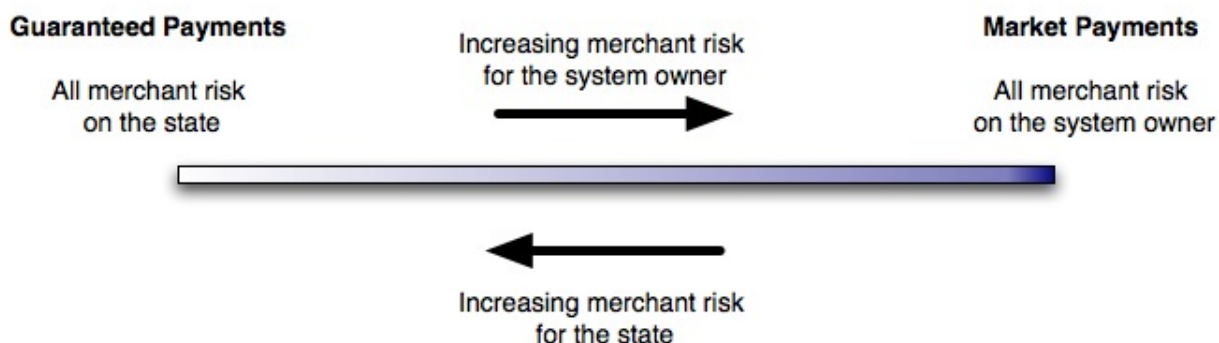
³ Market-based cap and trade systems have been used successfully in several situations in recent years, most notably for control of NO_x and SO_x emissions from stationary sources. This success is now being extended to greenhouse gases in the Northeast and California.

The OCE has worked closely with stakeholders from the solar industry to identify potential transition strategies that will balance the need to stimulate the rapid rate of project development that is necessary to keep pace with RPS requirements, while minimizing potential costs and risks borne by ratepayers. Members of New Jersey’s RPS Transition Working Group and other solar market stakeholders highlight the fact that if, in a post-rebate market environment, the risk profile of projects were to shift dramatically, it would be much more difficult to secure capital to finance projects.

REC markets are still very new and relatively immature. A number of risks make the solar market a difficult investment environment. The most notable is merchant risk, or uncertainty about SREC sales revenues from the project. A major subset of merchant risk is regulatory risk, the potential for the BPU or the Legislature to take actions that effectively reduce the value of the SRECs in the market. Industry representatives argue that moving to a high merchant risk environment is unfavorable for the ratepayers since the associated higher financing costs will result in higher SREC costs and/or Solar Alternative Compliance Payments (SACPs).

Given these factors, the issue of risk allocation is a key element in the market transition decision-making process. A graphic illustration of the spectrum of potential risk profiles associated with varying levels of revenue certainty is shown in Figure E-1. Currently in New Jersey, system owners receive a rebate based on the rated capacity of the system they install and then payments for the SRECs that they generate. When combined with the Federal incentives, the rebates eliminate much of the merchant risk to the system owner.⁴ At the same time, because the regulatory risk is high and is entirely under the control of the State, it seems clear that the State should carry some of the risk, at least until the market matures, and the regulatory risk declines.

Figure E-1. The allocation spectrum of merchant risk in the NJ SREC market



As a means of providing alternatives for mitigating the risks associated with market uncertainty, members of the RPS Transition Working Group presented four formal proposals, each of which offers some mechanism for providing PV system investors with a level of revenue certainty in the post-rebate market. Two of those proposals, the “Underwriter” and “Commodity Market Model” proposals, are centered around using the existing SREC market as a dynamic medium for setting SREC prices, while providing PV investors with a measure of revenue certainty in the form of a floor price for SRECs.

⁴ That is, under the current system of rebates, the system owner receives most, or all, of his system price regardless of the price of SRECs. This is particularly true for larger systems (e.g. ≥ 100 kW, see Table 3-1), but even for smaller systems the combined Federal and State rebates are substantial. For example, the combined New Jersey rebate and Federal tax incentive for a 1 kW system and a 10 kW system would represent 80% and 55%, respectively, of their capital cost under the current system.

The other two proposals are distinct in that one, the “Tariff Model” (which is referred to hereafter as the “Hybrid Tariff Model”) would involve having system owners receive guaranteed performance-based (i.e., on a per kWh basis) payments/credits. The fourth proposal presented by the RPS Working Group, the “Auction-Set Pricing and Standard Contract Model,” involves having market clearing prices set through an annual auction in which some portion of the market would be matched with buyers, and the rest of the market would receive SREC pricing based on the auction-set price. The other key feature of this proposal is that projects’ economic lifetime would be compressed to five years – the term of a standardized, required contract.

Review Methodology

The Summit Blue Team conducted a criteria-based assessment of the four proposals described above, as well as three additional potential market frameworks: 1) OCE’s Solar REC-only pilot transition program, 2) a “Full-Tariff Model” and 3) a Continued Rebates / Baseline Model.⁵ Under the OCE Solar REC-only pilot program, PV systems would have to be supported entirely by the SREC market with no revenue certainty mechanisms in place. The full-tariff model was not submitted as a formal proposal, but is included here because a) through interviews, we learned that this model is being seriously considered by several stakeholders, and b) it provides a useful “benchmark” of risk allocation for comparison to the formal proposals. The full-tariff model differs from the hybrid-tariff option presented in the white paper series in that it would be designed to provide PV system owners with their full incentive in the form of a tariff (i.e., a payment from the utility based on energy production), rather than a system in which revenues flow from both the tariff and from SREC sales (i.e., the hybrid-tariff approach).

The six potential transition strategies, as well as the continued rebates/baseline strategy were evaluated using evaluative criteria which are introduced in Section 4 of the report. The major categories of evaluative criteria include:

- Sustained orderly development
- Transaction costs
- Ratepayer impact
- Support for other policy goals

Key strengths and weaknesses of each potential strategy were identified, and the potential impacts of various future market scenarios were examined as they might play out under each of the proposed models. Through this process, none of the proposals emerged as presenting the obvious “winning” strategy. Thus, the strategies recommended for further review include a combination of features from the proposals that seem most likely to provide the flexibility to stimulate entrepreneurship and innovation and adapt to in response to changes in market conditions, while still providing enough stability to appeal to investors and lenders.

Recommendations

A key feature of the proposals was that the merchant risk for the systems needed to be shared between the State and the system owner. This feature ultimately focused attention on two possible approaches, the

⁵ The baseline / continued rebates model was only included in the Section 5 of this report, the qualitative criteria-based review of potential market transition strategies. Sections 6 and 7 of this report did not include discussion of the baseline / continued rebates option.

Hybrid-Tariff, and the *Underwriter*,⁶ as these models represent the best combination of primary and secondary elements that offer the flexibility, revenue stability, and market forces desired by regulators and market players. While the underlying mechanism in these two models is the same as in that offered in the originally proposed transition models, in each case the recommended features of these models vary in significant ways from the original proposals.

Both models recommended for *further review* involve a substantial reliance on the SREC market and include provisions for making that market as transparent, liquid, and stable as possible. In order to balance the risk allocation, both systems provide revenue support in the early years of the market. However, the share of the risk assumed by the system owners/developers will increase as the market matures and the regulatory risk decreases. For this reason, both of the systems recommended for further review include a declining level of financial support as time goes by. The preliminary analysis contained in this report indicates that either of these approaches has the potential to accomplish OCE's goals to fulfill the RPS requirements while minimizing ratepayer impacts. A more detailed analysis of potential ratepayer impacts of these two transition strategies will be conducted in the spring of 2007 and will include a comparison with the option of continuing the current rebate structure. This review, along with the broader review of New Jersey renewable energy markets, will provide additional feedback to inform a planned stakeholder review process and OCE market transition decisions.

New Jersey has the potential to maintain its position as a national leader by both surpassing other states in its per-capita development of solar capacity and introducing a successful model for large-scale solar market development. By pursuing a gradual reduction in the State's current level of financial incentives, and a sustained, orderly transition to a financing structure in which the only form of ratepayer support would be through SREC revenues, New Jersey will be well-positioned to fulfill its goal of achieving its aggressive RPS targets while minimizing ratepayer impacts.

⁶ Note that the underwriter concept was included in both the Underwriter and Commodity Market Model proposals submitted by RPS Working Group members.

1. INTRODUCTION

Summit Blue Consulting and its partner, the Rocky Mountain Institute, (together referred to as the “Summit Blue Team”) are pleased to submit this report as part of the Renewable Energy Market Assessment being conducted for the New Jersey Board of Public Utilities’ Office of Clean Energy (OCE). This interim report has been prepared with the goal of providing OCE with timely assistance in its efforts to rapidly transition the New Jersey solar market from a dependence on rebates to a market-based structure in which Solar Renewable Energy Certificate (SREC)⁷-based project financing can play a greater role in supporting the level of market growth necessary to meet the State’s RPS requirements. The report is intended to be reviewed by the public and to inform discussion among stakeholders during the hearing process that will follow issuance of a January 2007 Board Order. The analysis contained herein will be supplemented by additional analysis of ratepayer impacts of proposed transition strategies, and of the New Jersey renewable energy market, for a final project report to be delivered in May 2007.

The content and views expressed in this report represent an independent evaluation of the options proposed to OCE. The criteria used to evaluate the transition options is founded on the guiding principles that OCE has set forth for the transition process,⁸ as well as key elements of success identified through research into the activities of other leading clean energy markets, both domestic and international. The primary criteria are:

- Sustained orderly market development
- Transaction costs
- Ratepayer impacts
- Support for other policy goals

The report includes an evaluation of each of the four full transition proposals presented by representatives of New Jersey’s RPS Transition Working Group, as well as a “Full-Tariff” model and an “SREC-Only” model that were deemed relevant through discussions with OCE staff and stakeholders. In addition, for baseline comparison purposes, the Team included a qualitative review of a “Continued Rebate / Baseline Model” which, as the name implies, represents a continuation of existing CORE Program rebates.

While the Summit Blue Team has conducted a significant amount of primary and secondary research into the transition options available to New Jersey, given that the Team is still in the early stages of its schedule for the overall market assessment assignment, the Team has not yet completed the full scope of primary research that is planned for the overall assessment of renewable energy markets. Any additional findings that emerge pertaining to the rebate transition will be presented in the comprehensive Market Assessment Services Report to be submitted to OCE in May 2007.

1.1 Report Objectives and Methods

The Summit Blue Team has prepared this report to provide OCE with unbiased and timely feedback on the range of options available to transition the New Jersey solar market from one that is heavily dependent on rebates to one that relies more heavily on market-based project finance. Given the time-sensitive nature of

⁷ The New Jersey Renewable Portfolio Standard Rules (N.J.A.C. 14:8-2.2) define a Solar REC as “a type of REC, as defined in this section, issued by the Board or its designee, which represents the environmental benefits or attributes of one megawatt-hour of solar electricity generation, as defined in N.J.A.C. 14:8-1.2.”

⁸ The OCE’s guiding principles are discussed in more detail in Section 4.

the decision-making process for setting an Alternative Compliance Payment (ACP) level for Energy Year 2008, OCE requested that this screening level analysis be completed in time to inform public comment on the topic in early 2007. Given the time constraints, the Summit Blue Team prepared a comprehensive screening-level evaluation of the available options. The Summit Blue Team has discussed with OCE and the Governor's Office the importance of providing a more rigorous analysis of a narrower set of transition options. One key objective of this initial report is to provide the information and analysis necessary to refine the scope of options that will undergo more detailed quantitative analysis as part of a separate assignment to model ratepayer impacts of the leading market transition options.

The analysis and findings presented in this report are based on the results of both primary and secondary data collection activities. The Team conducted interviews with over 20 individuals including policy experts, representatives from other states' renewable energy programs; members of BPU staff, members of the investment community, representatives from the New Jersey Governor's Office, and authors of the market transition proposals. An email survey of BPU's Renewable Energy Committee was also conducted to gather feedback on the variety of potential market transition options. Twenty responses to the survey were received. The Summit Blue Team also reviewed a wealth of literature characterizing renewable energy policy initiatives in effect in other states and nations.

The Summit Blue Team's assessment included both qualitative and quantitative components. The Team conducted a qualitative evaluation of seven potential market models using a set of criteria that was developed based on the OCE guiding principles.⁹ Six *transition* strategies were reviewed including four proposals submitted to the BPU by members of New Jersey's RPS Transition Working Group, as well as a two additional models deemed relevant to the analysis because they represent additional alternatives being discussed by market stakeholder and they expand the spectrum of risk/reward scenarios examined in the report. For comparison purposes, the Team also reviewed a "Continued Rebates / Baseline Model." The strategies reviewed are listed below.

Models proposed by RPS Transition Working Group:

- Underwriter Proposal
- Commodity Market Proposal
- Auction-Set Pricing / Standard Contract Proposal
- Tariff Proposal (referred to throughout the report as "Hybrid-tariff" model)

Additional Models Reviewed:

- Full-Tariff Model
- Solar REC-only Model
- Continued Rebates / Baseline Model

Each of the seven market strategies was reviewed according to its strengths with regard to the evaluative criteria. The Team's qualitative, criteria-based review reflects insights and knowledge gained through the interviews, survey results and market research described above.

The Team also adapted economic models prepared by authors of the market transition strategies to conduct a preliminary examination of the financial implications of the various proposals from the perspective of

⁹ A list of OCE's guiding principles is provided in Section 4.

ratepayers, project developers, and the investment community.¹⁰ The goal of this first-phase quantitative analysis was to compare likely ratepayer impacts and market outcomes associated with various strategies using a consistent set of assumptions. This preliminary economic analysis is valuable in that it places all the strategies on a level playing field. However, the impacts associated with the various strategies are heavily dependent on program design details (i.e., the level of guarantee provided and associated administrative costs) as well as potential market scenarios (i.e., equipment cost trends over the next decade, and the possible roll-out of a large-scale PSEG PV program). Therefore, the quantitative analysis was effectively an initial screening exercise, and its results must be viewed accordingly.

Recognizing that each proposal includes a variety of elements, and that some elements may have merits independent of the full proposal within which they were originally presented, the Summit Blue Team reviewed the strengths and weaknesses of both the primary and secondary elements of the six transition strategies. Taking into consideration the state of solar market maturity in New Jersey, and drawing on the strongest elements of each transition strategy reviewed, the Team prepared a set of potential alternative market transition models that it recommends for further review. The two alternative models recommended for further consideration represent a combination of the strongest elements from the seven market models reviewed in the report, as well as additional success factors identified by the Team through primary and secondary research conducted as part of the assignment. The recommendations section is intended to narrow the field of transition options that will undergo more rigorous evaluation as part of a second-phase review.

1.2 Organization of Report

The remainder of this report is organized as follows:

Section 2 provides background on the New Jersey solar market and the unique challenges BPU faces in its efforts to identify a transition strategy that balances the goals of fulfilling RPS requirements while minimizing ratepayer impacts. This section includes an overview of New Jersey's RPS requirements and the status of incentive programs which support renewable energy development. This section also provides context by comparing New Jersey's solar RPS requirements, PV development incentives, and other market characteristics with those in other states considered on the cutting edge in developing renewable energy initiatives. Finally, Section 2 identifies the factors that bring the New Jersey solar market to the current turning point, warranting consideration and review of transition strategies.

Section 3 focuses on the solar project development process and the policy decisions necessary to establish an effective market transition path for New Jersey. Background is provided on the basics of PV project economics and the various types of risks in the market. Thus, the focus of this section is on providing context for the assessment of transition options presented in Sections 5 through 7.

Section 4 describes the criteria used to evaluate the market transition options.

Section 5 provides summaries of each market transition strategy as well as a detailed discussion of strengths and weaknesses of each strategy as they relate to the evaluative criteria.

¹⁰ Economic models prepared by Lyle Rawlings (Advanced Solar Products, Inc.) and Mark Warner (Sun Farm Network) were adapted for use in preparing the summary-level quantitative assessment presented in this report. A more detailed analysis of ratepayer impacts is anticipated in Spring 2007.

Section 6 focuses specifically on the *financial and ratepayer impacts* associated with the seven strategies included in the review. This section presents results of the preliminary quantitative assessment of the models and identifies the key features of each strategy which drive the potential outcomes.

Section 7 presents the results of the email survey of members of BPU's Renewable Energy Committee. This section also includes discussion of how each of the transition strategies reviewed in Section 5 might fare under a variety of potential scenarios.

Section 8 summarizes the analyses and presents the Team's recommendations for the models to undergo further review and analysis. This section includes a description of two additional potential transition strategies developed by the Team based on insights from the review of the seven market models which were the focus of the report.

2. NEW JERSEY RENEWABLE ENERGY MARKET BACKGROUND AND POLICY CONTEXT

This section describes the policies and programs that shape the New Jersey renewable energy market and the factors which necessitate the current examination of potential market transition strategies. It includes an overview of New Jersey's RPS requirements and the incentive programs which support renewable energy development in the State. The discussion also puts the challenges faced by New Jersey solar market transition in context by considering the lessons learned from renewable energy policy successes and shortcomings in the U.S. and abroad. It also includes a comparison of New Jersey's PV-related policies and incentives with those of other states that have ambitious renewable energy initiatives.

2.1 Overview of OCE Renewable Energy Programs

An interim Renewable Portfolio Standard (RPS) was defined in the Electric Discount and Energy Competition Act (EDECA), which passed in New Jersey in 1999. The RPS was revised by BPU via a public stakeholder process in 2003, and changes to the RPS went into effect in early 2004. The revised version of the RPS included innovations such as a solar-specific requirement, and the use of RECs or Alternative Compliance Payments (ACPs) to demonstrate compliance. It was at this point that the New Jersey solar market began its rapid growth trajectory. Passage of EDECA and the revised RPS laid the foundation for the launch of New Jersey's Clean Energy Program administered by the OCE. The programs and initiatives that OCE currently supports are summarized in Table 2-1 on the following page.

Table 2-1. OCE Renewable Energy Program Summary

| Program | Market Actors Served | Requirements | Technologies | Method of Support |
|---|---|---|--|---|
| Renewable Energy Project Grants and Financing | Municipal utility authorities Large C&I users Large-scale renewable developers | Supply or offset a minimum of 1 MW of power | Wind, PV, Landfill gas, Digester gas, Methane from sustainable biomass | Competitive solicitation Grants and long-term financing |
| Customer On-Site Renewable Energy (CORE) | Residential customers Public entities Commercial and industrial customers RE installers & manufacturers | RE system to be installed on customer's side of the meter < 2MW Rated capacity must be < 100 % of annual electric use | Wind, Sustainable biomass, Fuel cells using renewable fuels, Solar electric | Rebate program Amounts vary with technologies (\$/Watt) and size of installation Incentives for wind and biomass are capped as a % of eligible costs |
| SREC/REC Market Infrastructure and Trading Platform | Sellers: anyone with a solar electric system net metered and inter-connected to the local distribution system serving NJ Buyers: electricity suppliers, private investors, RE brokers, and individuals | Grid-connected solar electric system Inspected by NJBPU All metered kWh are eligible | SRECs = solar renewable energy certificates REC = certificates from other renewable energy technologies eligible to meet NJ RPS requirements. ¹¹ | Trading platform designed to facilitate transactions that motivate investments in customer-sited renewables, and to enable compliance by regulated entities with the RPS intended to serve behind-the-meter generators in New Jersey. |
| Renewable Energy Business Venture Financing | Businesses that market RE technologies and develop new technologies. | Must be conducting research, business development, RE commercialization and/or technology demonstrations. | PV, Wind, Fuel cells, Wave and tidal, RE-generated hydrogen, Sustainable biomass | Direct funding |
| Manufacturing Incentive | Not yet developed. | | | |

¹¹ As specified in the Electric Discount and Energy Competition Act at N.J.S.A. 48:3-61, the New Jersey legislature seeks to develop Clean Energy Programs that can operate without rebates. In accordance with this goal, the OCE Board intends to gradually transition to the use of long-term REC purchase agreements to finance renewable energy projects. Currently, NJCEP includes a Solar REC (SREC) program which consists of a trading platform, a list of registered brokers and aggregators, and reports on trading statistics.

New Jersey has established one of the most aggressive RPS policies in the country, and it is one of only a few such policies which includes specific requirements for solar. In order to meet New Jersey's solar RPS requirements, the state will need to have at least 1,500 MW of solar capacity in place by 2021.¹²

This document is focused exclusively on the CORE (Customer On-site Renewable Energy) program, which is designed to encourage installation of solar systems to meet the RPS targets.

2.2 Renewable Energy Program Funding

OCE's renewable energy programs are funded through revenues from the Societal Benefits Charge (SBC), a non-bypassable charge imposed on all customers of New Jersey's seven Investor-Owned Utilities (IOUs). The SBC fund took effect in 1999 and is managed by the BPU. A total of \$745 million will be collected during the 2005-2008 time period, with at least 25% spent on Class I renewable energy and 75% spent on energy efficiency. The funds are held in a Clean Energy Trust Fund.¹³

In an effort to keep pace with the solar-set aside in New Jersey's RPS rules, the state has allocated a substantial portion of its overall Clean Energy Program funding to support solar development. Table 2-2 below shows the allocation of renewable energy funds spent in 2005. During 2005, over 84% of the Clean Energy Program funds were spent on the CORE Program.¹⁴ Within the CORE Program, over 91% of rebate expenditures in 2005 supported solar project development.¹⁵

Table 2-2. 2005 OCE Renewable Energy Program Expenses

| Program | Budget (000) | Actual Expenses (000) | Committed Expenses (000) |
|---|------------------|-----------------------|--------------------------|
| Customer On-Site Renewable Energy (CORE) | \$85,700 | \$29,850 | \$136,514 |
| CleanPower Choice | \$3,000 | \$2,729 | |
| EDA Programs | | | |
| NJBPU Grid | \$2,000 | \$6 | \$2,000 |
| Manufacturing Incentive* | \$2,000 | \$6 | |
| Public Entity Financing | \$2,500 | \$8 | |
| Clean Energy Financing for Businesses | \$3,000 | \$9 | \$446 |
| Renewable Energy Project Grants and Financing | \$14,000 | \$557 | |
| Renewable Energy Business Venture Financing | \$8,000 | \$2,358 | \$81 |
| Total Renewable Energy Programs | \$120,200 | \$35,523 | \$139,041 |

* A 2005 budget for this program was established by the BPU but the program was not implemented in 2005. Expenses for this program were for program development.

Source: New Jersey's Clean Energy Program 2005 Annual Report, New Jersey Board of Public Utilities, OCE, p. 25.

¹² The projected solar capacity requirement is based on the assumption that the average PV system installed in New Jersey will annually produce 1,200 kWh per kW of installed capacity (AC), as well as an assumed annual load growth rate of 1%. Recent trends indicate that both of these assumptions may require adjustment. First, data from metered PV systems (which are predominantly flat-roofed systems which perform more poorly than pitch-mounted systems) show an annual production rate that is closer to 1,000 kWh per kW of installed capacity. Also, according to OCE, electricity load in has grown, on average, by 1.4% annually over the last ten years, and 2.12% over the last five years. Both of these factors indicate that the 1,500 MW projected PV capacity goal should be adjusted.

¹³ Database of State Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NJ04R&state=NJ&CurrentPageID=1&RE=1&EE=0.

¹⁴ New Jersey's Clean Energy Program 2005 Annual Report, New Jersey Board of Public Utilities, Office of Clean Energy, p. 25: Of the total \$35,523,000 in Clean Energy Program expenditures \$29,850,000 was spent on the CORE Program.

¹⁵ Calculated based on New Jersey Office of Clean Energy program records.

The legislative act that introduced the SBC (N.J. Stat. § 48:3-60) stipulates that after the eighth year in which the SBC fund takes effect, BPU is required to work collaboratively with the Department of Environmental Protection to determine, based on the results of a comprehensive resource assessment, the appropriate level of funding to support Class I Renewable Energy resources in the years following. The act states:

“The board shall make these determinations taking into consideration existing market barriers and environmental benefits, with the objective of transforming markets, capturing lost opportunities, making energy services more affordable for low income customers and eliminating subsidies for programs that can be delivered in the marketplace without electric public utility and gas public utility customer funding.”¹⁶

This declaration and other statements by the BPU establish New Jersey’s intent to transition away from the use of SBC funds when the market is ready for such a transition.

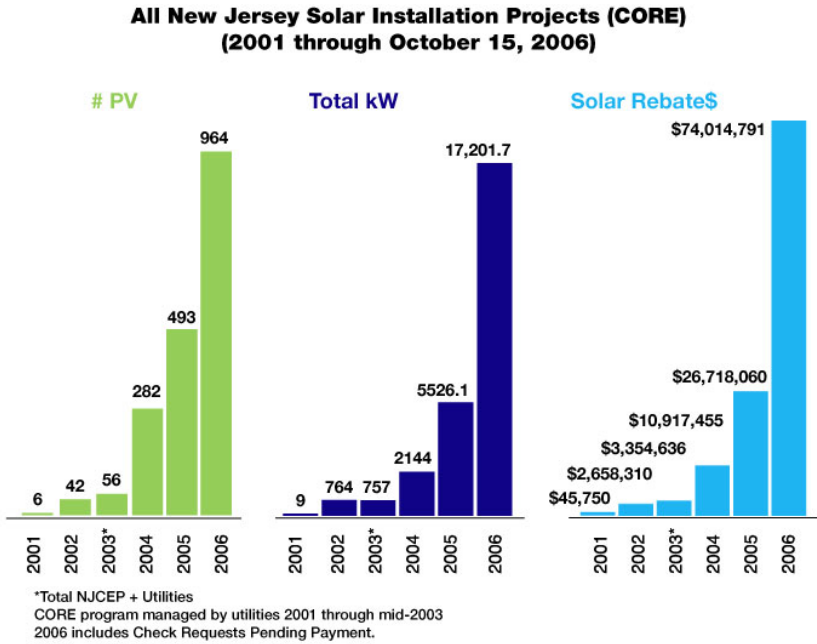
2.3 CORE Program Status and the Need for Immediate Action

From the launch of OCE’s Clean Energy Program in 2001 through the end of 2006, OCE incentives had resulted in the installation of over 31 MW of solar capacity in New Jersey. This PV system capacity represents 1,957 customer-sited solar installations.¹⁷ This rapid pace of project development will need to continue, as New Jersey must draw on the resources of over 90 MW of solar capacity in order to meet its RPS solar requirement for the 2008 RPS compliance year, and over 1,500 MW of solar capacity will be needed to meet solar RPS requirements for 2020.

¹⁶ 48:3-60. Societal benefits charge by public utility; Universal Service Fund.

¹⁷ Based on CORE Program records as of December 5, 2006.

Figure 2-1. New Jersey CORE Program Solar Installations, Annual Figures through October, 15, 2006



Source: OCE website¹⁸

Figure 2-2. CORE Program Solar Installations by Year

| New Jersey Solar Installation Projects (CORE) by Year (2001 through October 15, 2006) | | | |
|--|--------------|-----------------|----------------------|
| | #Projects | Total kW | Total Rebate\$ |
| 2006 | 964 | 17,201.7 | \$74,014,791 |
| 2005 | 493 | 5526.1 | \$26,718,060 |
| 2004 | 282 | 2144.1 | \$10,917,455 |
| 2003* | 56 | 757.0 | \$3,354,636 |
| 2002 | 42 | 764.0 | \$2,658,310 |
| 2001 | 6 | 9.0 | \$45,750 |
| Total: | 1,843 | 26,401.9 | \$117,709,002 |

*Total NJCEP + Utilities
CORE program managed by utilities 2001 through 2003
2006 includes Check Requests Pending Payment.
Source: OCE website¹⁹

¹⁸ The graph shows annual figures that are detailed in the table that follows. Available at http://www.njcep.com/html/res-installed/renew_ener_sys_instll.html.

The dramatic burst in the construction of solar projects over the last five years has led well over 100 businesses to become active in the New Jersey solar market as aggregators, brokers, installers, or other equipment or service providers. These businesses, which include 60 solar installers, comprise both large corporate entities with presence on the national and international markets, as well as small businesses active only in the New Jersey marketplace.

Table 2-3. Registered SREC Account Holders, as of June 30, 2006

| | |
|--------------------------|------|
| Solar Facility Owners: | 1053 |
| Wind Facility Owners: | 1 |
| Biomass Facility Owners: | 6 |
| REC Brokers: | 34 |
| REC Aggregators: | 53 |
| LSE: | 35 |
| Others: | 58 |

Source: OCE Solar Market Update, September, 2006²⁰

While OCE's other renewable energy programs also provide financial incentives to renewable energy market participants, OCE is focusing its immediate market transition efforts on the CORE program and the solar industry. This is largely due to the fact that the Program's current year budget is fully committed. There is a queue of nearly 1,600 project applications, representing over 63 MW of potential PV capacity at some stage in the application process. If all of these projects move forward, the dollars required for rebates would substantially exceed the resources available in the annual program budget.²¹ On November 9th, the BPU approved the allocation of \$29.5 million of the 2007 CORE budget for use in granting additional rebate commitments to be paid in 2007. These funds will be allocated to queued projects in the private sector that are greater than 10 kW.

While the additional funding approval will help get projects moving out of the queue, it does not solve the larger issue of uncertainty among developers and the financial community about the future of CORE program funding. Since no plan exists for the disbursement of financial incentives beyond OCE's current funding cycle ending on December 31, 2008, and given the fact that solar systems can only qualify to produce SRECs if they register in the SREC program (a process that is currently dependent on participation in the CORE program), the solar industry indicates difficulty in selling new projects.

The uncertainty about the future direction of New Jersey's solar market is placing strain on the local solar industry. Industry representatives report that layoffs are beginning to occur, and that at least one company has gone out of business as a result of the current market conditions. As the New Jersey solar market proceeds through this transitional phase, and as solar markets expand and contract in other states, changes in the roster of industry players in New Jersey can be expected. It is important to monitor both market entry and exits, and to compare the status of the industry against that which is necessary to fulfill the RPS requirements.

¹⁹ Available at http://www.njcep.com/html/res-installed/renew_ener_sys_instll.html.

²⁰ Available at http://www.njcep.com/media/Solar_Market_Update_Sept_06.pdf.

²¹ Data is sourced from OCE program records as of December 5, 2006.

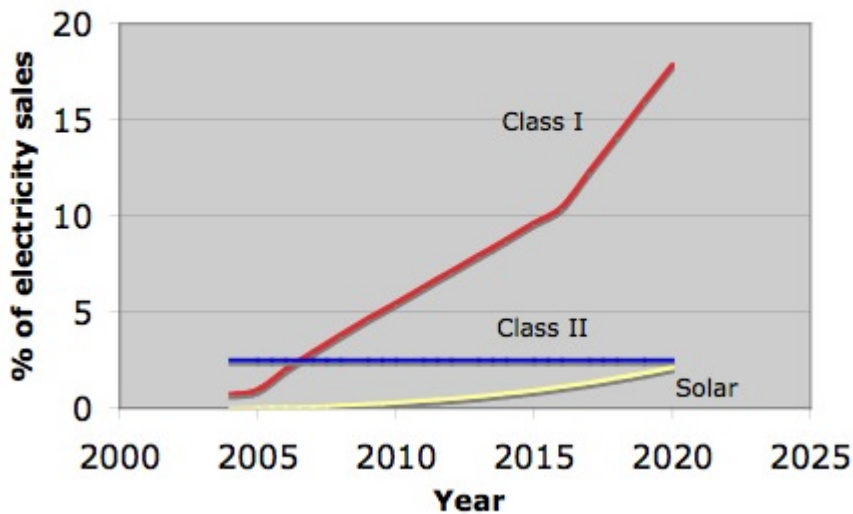
2.4 Key Elements of the New Jersey Renewable Energy Market

2.4.1 Renewable Portfolio Standard (RPS) Goals

New Jersey's RPS (originally passed in 1999 and revised in 2004) is one of the most aggressive policies of its type in the country, requiring 22.5% of the State's electricity to be sourced from renewables by 2021. As a subset of that total requirement, 2.12% of the State's electricity usage must be sourced from solar (equivalent to over 1500 MW of solar installed capacity) by 2021. The Board has stated that it intends to adopt additional RPS requirements for 2022 and beyond that will be equal to or greater than the already established percentages.²²

The RPS applies to electric power suppliers. The NJ RPS has a tiered system, including two resource classes, and an explicit solar energy requirement:²³ Figure 2-3 shows New Jersey's steadily increasing RPS requirements.

Figure 2-3. New Jersey RPS Requirements by Category



Source: Based on RPS requirements detailed in tables on pages 56-57, RPS Rules Adoptions N.J.A.C. 14:8-2, NJBPU, April 14, 2006.

A more detailed summary of the New Jersey RPS requirements is provided in Appendix A.

²² RPS Rules Adoptions N.J.A.C. 14:8-2, NJBPU, April 14, 2006. N.J.A.C. 14:8-2.3 (b), page 57.

²³ To qualify as Class I or II energy, the energy must be generated in, or delivered to the PJM region. Energy is delivered to the PJM region if it complies with the energy delivery rules established by PJM Interconnection. If the energy is generated outside of the PJM region and delivered into the PJM region, the energy can be used to meet the RPS if it was generated at a facility that commenced construction on or after January 01, 2003.

The New Jersey RPS includes a separate solar standard because the BPU believes that solar provides unique and important benefits to the New Jersey electric distribution system. BPU cites the following key reasons for establishing the solar set-aside:

- The specific solar requirement will promote market transformation of solar in NJ and *insulate ratepayers against rising fossil fuel prices, and fossil fuel fluctuations*;
- Decentralized, customer sited photovoltaic installations will provide *localized distributed generation that will delay the need for system upgrades to meet dispersed load growth*; and
- Solar electricity generation *coincides with annual peak demands* required to meet summer cooling loads. Solar has the capability to decrease conventional power plant use during peak times, reducing the amount of ground level ozone in NJ.²⁴

2.4.2 RPS Compliance: SRECs, RECs, ACP, SACP

Electric power suppliers must comply with the RPS through the acquisition of Renewable Energy Credits (REC) and Solar Renewable Energy Credits (SREC), or by making Alternative Compliance Payments (ACP) and Solar Alternative Compliance Payments (SACP). A REC represents the environmental attributes of one megawatt-hour (MWh) of renewable energy generation from an eligible facility and a SREC represents the environmental attributes of one MWh of solar generation from an eligible facility. SRECs are issued by the Board of Public Utilities, and are transacted through New Jersey's own SREC trading platform. The SREC trading platform is intended to handle transactions of "behind the meter" (BTM) renewable energy systems. While these systems could technically be traded through the PJM Generation Attribute Trading System (GATS), that system was not in place when New Jersey's RPS went into effect with its REC-based compliance system. GATS has been deemed too complex by some to support SREC trades since such trades often involve parties with little or no technical background. In order to qualify for the issuance of an SREC, electric generation must occur at a facility that is interconnected to a grid that supplies New Jersey.

The BPU or its designee will issue all SREC and Class I RECs that are based on electricity generated on a customer-generator's premises. Customer-generators (including all solar projects) must be eligible for net metering (< 2MW in capacity) to fulfill the requirement that electric generation come from a grid that supplies New Jersey. PJM-Environmental Information Services (EIS) issues Class I RECs from utility-scale projects (over the 2 MW net metering limit) and all Class II RECs. PJM-EIS formed the Generation Attribute Tracking System (GATS) to provide the environmental and emissions attributes reporting and tracking services for states in the PJM region.

2.4.3 Alternative Compliance Payment (ACP)

Alternative Compliance Payment (ACP) and Solar ACP (SACP) levels were established in New Jersey through a 2003 Board Order as a tool to:

“provide(s) a ‘back-stop’ mechanism that protects suppliers, as well as consumers, from the cost implications of excessive market risk. The ACP and SACP set an upper limit for the cost of RPS compliance; remove the risk of unknown financial penalties for any renewable energy shortfalls; provide protection against the possibility of market power

²⁴ Renewable Portfolio Standards (RPS) Rules Adoption. N.J.A.C. 14:8-2, New Jersey Board of Public Utilities, 13 April 2006; p 19-20, BPU response to Comments 21 and 23. A future, detailed analysis of distribution system cost deferral impacts associated with the PV capacity growth in New Jersey is recommended by the Team as well.

exertion and unforeseen scarcity of renewable energy and REC shortages; and gives suppliers some flexibility in complying with RPS requirements.”²⁵

The RPS regulations stipulate that the BPU must review the ACP and SACP levels at least annually in collaboration with an ACP Advisory Board.²⁶

The ACP and the SACP have remained at their original 2004 levels—\$50/MWh ACP, \$300/MWh SACP (about \$80 more than the current average SRECs trading value)—and will continue to remain at that level through Energy Year 2007 (ending May 31, 2007). The last NJ BPU review of ACP and SACP levels was in February 2006, and another review is currently underway to establish the ACP and SACP levels for the 2008 Energy Year.

There is a great deal of scrutiny over the level at which the ACP and SACP levels are set. Some stakeholders feel that ACP levels should be set at levels double the REC trading values to ensure that they provide a sufficient incentive to participate in the marketplace and, ideally, enter into long-term contracts with generators. However, an additional purpose of the ACP is to limit ratepayer exposure to risk in the event of a supply shortage in which LSEs would be dependent on ACPs to meet RPS requirements. The BPU and its ACP Advisory Board recognize these competing goals of setting the ACP and SACP levels.

The incentive structure that takes shape in a post-rebate New Jersey solar market will have a dramatic impact on determining an appropriate range for ACP and SACP levels. In the absence of rebates or any other form of guaranteed financial support, solar project economics will require a much greater SREC revenue stream than projects in other states and regions where rebates or other financial incentives reduce a project’s financial risk.

As discussed in later sections of this report, the solar industry anticipates SREC trading values in the range of \$650 per MWh in a post-rebate market, assuming no other form of revenue guarantee. For perspective, as noted above, the current SACP in New Jersey is set at \$300 per MWh, and several other states’ ACPs are set in the range of \$50 per MWh. Table 2-4, on the following page, shows ACP levels in other states.

²⁵ December 18, 2003 NJBPU Order.

²⁶ New Jersey RPS Rules: N.J.A.C. 14:4-8.10 (b) and (c)

Table 2-4. Comparison of ACP Levels in Northeastern U.S.

| State | ACP / Compliance Penalty |
|---------------|---|
| Connecticut | \$55/MWh |
| DC | \$25/MWh Tier 1 \$10/MWh Tier 2 \$300/MWh Solar |
| Maine | Not defined |
| Maryland | \$20/MWh Tier 1 \$15/MWh Tier 2 |
| Delaware | \$25/MWh, up to \$50/MWh |
| Massachusetts | \$55.13/MWh (adjusted by CPI) |
| New Jersey | \$50/MWh non-solar \$300/MWh solar |
| Pennsylvania | \$45/MWh 200% of average market value of solar credits sold during the reporting period of solar 200% of market price for solar |
| Rhode Island | \$50/MWh (adjusted by CPI) |

Source: Clean Energy State Alliance, Northeast Compliance Markets: An Examination of Opportunities to Advance REC Trading, October 12, 2005.

One issue in assessing potential market transition strategies for New Jersey is the impact of a potential imbalance between SREC values in New Jersey and other nearby states. A geographic imbalance would decrease the liquidity of SRECs making it difficult for New Jersey SRECs to trade in markets outside of New Jersey. Therefore, New Jersey ratepayers would be the only candidates available to purchase SRECs from New Jersey solar projects. In addition, high SREC values in New Jersey will entice solar generators from other states to seek the opportunity to sell into the New Jersey market. This could lead to challenges that RECs from solar projects outside the state should be allowed to be used for compliance in New Jersey, a change that would certainly put downward pressure on SREC values.

2.4.4 RPS Solar Set-Aside

New Jersey's solar development targets are the largest in the country on a per capita basis. As a result of the solar set-aside in its RPS, New Jersey possesses additional, unique challenges in meeting its RPS targets. In order to achieve the rapid and substantial level of solar project development necessary to fulfill the solar RPS requirements, New Jersey must overcome *barriers* that have inhibited solar market development for years. A critical hurdle to overcome is project economics; the solar value proposition must appeal to mainstream consumers who use mainstream criteria to evaluate investment decisions.

Unlike the innovators and early adopters of solar technology, whose values and commitment to the environment drive their decision to invest in a solar project, mainstream consumers will not invest in solar

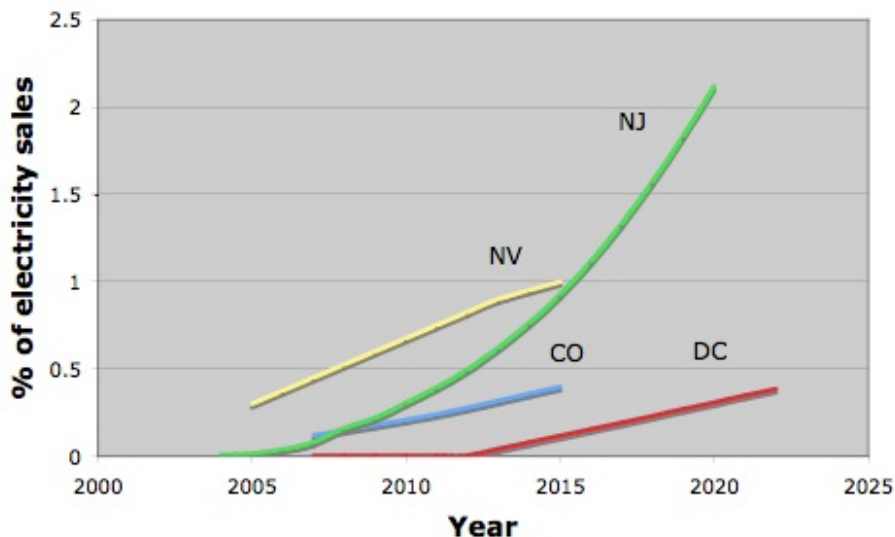
unless it makes financial sense when compared to other long term investments. The solar market must be financially viable for developers, installers, aggregators, brokers, third-party investors and other potential participants in order to stimulate the level of market activity necessary to achieve RPS goals.²⁷ In New Jersey, due to the substantial RPS requirements, the PV value proposition must be strong enough to appeal to the early majority in a shorter period of time than in most other PV markets.

As noted in Section 3, defining the necessary and/or appropriate investment criteria (simple payback and/or ROI thresholds) for solar market participants is a fundamental step in establishing the solar market transition path.

Since New Jersey is one of only a few states possessing a solar set-aside, there is little experience on which to draw in determining potential impacts on the broader RPS market and identifying strategies for fulfilling the solar goals in the most cost-efficient manner. Three other states (District of Columbia, Nevada and Colorado) have specific solar set-asides in their RPS requirements, and a few other states have tiered structures, or structures that allow for weighted credit for certain technologies.²⁸

DC and New Jersey both have tiers/classes in their RPS rules and both include a separate solar requirement. Colorado and Nevada require that a percentage of the annual RPS requirement be fulfilled with solar (5% for Nevada, 4% for Colorado). It is important to note that in Nevada's RPS, PV resources receives a 2.4 multiplier for compliance purposes, and customer-sited PV may receive an additional 1.05 multiplier. Figure 2-4 shows a summary of solar set-asides in place in other states.

Figure 2-4. RPS Solar Set-Asides by State



Source: Clean Energy State Alliance, Northeast Compliance Markets: An Examination of Opportunities to Advance REC Trading, October 12, 2005.

²⁷ Note that the market structure chosen by New Jersey will affect the number and type of market actors that will emerge in the future. For example, if the "auction-set pricing and standard contract" proposal is selected, there would be much less need for aggregator and broker services than under the proposed "commodity market" structure.

²⁸ For example, Maryland offers a 200% credit for RECs from solar resources. In New Mexico, every 1 kWh of solar produced counts as 3 kWh for the New Mexico RPS.

Another state with a notable solar target is California. In 2006, the California Public Utility Commission set forth a goal of achieving 3,000 MW of installed PV capacity in the state by 2017.²⁹ While unprecedented among U.S. states in its magnitude, California's target is similar to New Jersey's in the challenge that it represents because California has a much larger geographic territory and population, as well as a greater solar resource than New Jersey.

Some elements of California's Solar Initiative, as well as details of RPS compliance in California are still under negotiation. See Appendix B for a more detailed summary of solar policies and programs in California. We have also included a summary of key details of solar set-aside provisions in other states in Appendix C.

2.4.5 Poor Climate for Negotiating Long-Term Contracts

Since New Jersey's rebates, combined with the Federal tax incentives, have historically reduced the upfront cost of solar projects by between 50 and 100 percent, the portion of project investment supported by third-party financing has been much smaller than what would be necessary in a post-rebate solar market.³⁰ As an increasing percentage of solar project investment is supported through third-party financing arrangements, long-term contracting will become increasingly important. This is due to the fact that the investment community seeks certainty in project revenue streams. Given the dynamic nature of REC markets, SREC revenues will inherently vary over time. Without the revenue certainty provided by long-term contracts or other means, the financial community will, according to solar industry representatives, discount the value of the revenue stream by 50% to 90%.³¹ This discounting of future revenue streams makes project financing both more difficult to secure and more expensive (i.e., higher interest rates).

Renewable energy project developers everywhere share in the challenge of addressing investor concerns over the inherent variability in REC values over time. The most common strategy pursued by renewable energy project developers to address concerns about revenue uncertainty is to secure long-term contracting for energy and/or RECs.³²

A key factor making it difficult for New Jersey solar projects to secure long-term contracts is the three-year contract term for the State's Basic Generation Service (BGS), the default electricity supply option. New Jersey's Electric Distribution Companies (EDCs)³³ procure their BGS supply through an auction process every year. Each year the EDCs procure one third of their load for a three-year period. The winning bidders become BGS suppliers and have to meet all the requirements of being a PJM Load Serving Entity (LSE), including satisfying the RPS requirements. However, because the term of the BGS contracts is only three years, BGS suppliers are typically unwilling to sign contracts for SRECs that are longer than three years.³⁴

²⁹ This goal is not included in the state's RPS goals.

³⁰ According to the OCE, a wide variety of project financing arrangements have existed under the current rebate incentive system in New Jersey. Finance arrangements have included payment with cash and credit cards, home equity and other forms of equity, power purchase agreements, secured and unsecured loans, government borrowing, and DEP financed infrastructure trust financing.

³¹ Chris O'Brien and Lyle Rawlings (authors of the Auction Set Pricing / Standard Contract Model) note that in the limited cases when lenders support projects that depend on future streams of revenue from the spot market, they discount the expected revenue by 70-90% - effectively nullifying the expected revenue for purposes of lowering the cost of capital. These values were verified through an interview with one member of the financial community who chose to remain anonymous. Other representatives from the industry have echoed this concern over the devaluation of RECs when their values are not secured.

³² Since all solar projects in New Jersey are net-metered, long-term contracting for energy is not necessary.

³³ New Jersey's EDCs include PSEG, Atlantic City Electric Company, Jersey Central P&L, and Rockland Electric Company.

³⁴ More information on the BGS auction process can be found at <http://www.bgs-auction.com/bgs.auction.overview.asp>.

Market uncertainty also contributes to the difficulty of securing long-term contracts for solar projects in New Jersey. The two most fundamental elements of uncertainty in the New Jersey SREC market include:

1. New Jersey has not yet defined a clear path for supporting solar market development in a post-CORE program rebate environment.
2. New Jersey's RPS rules are subject to change. Under Executive Order 66 (1978),³⁵ the BPU is required to re-evaluate its rules every five years. In addition, if the Board determines that the RPS is dysfunctional or placing an undue burden on ratepayers, it is within the Board's authority to go through a standard rulemaking process to change the RPS rules.

2.5 Comparison of New Jersey's Renewable Energy Programs to those of Other States

Given its marginal solar resource when compared to states like California, Arizona and Florida, and given the immature state of the its solar market prior to the launch of the CORE program, New Jersey was not an obvious candidate for becoming a national leader in solar installations. However, the early successes of the CORE program demonstrates that the market will respond to a favorable solar value proposition, consumers have shown a great interest in participating in the solar market, and the solar industry has proven that it is capable of responding quickly to market opportunities.

There are a number of states offering economic incentives to spur the growth of the PV industry and encourage system installation. Overall, investment in PV systems is growing at a steady pace.³⁶ In states whose solar incentive programs offer less favorable economics to solar project investors, program participation has primarily been limited to the small subset of the market willing to invest in solar to support their values, even if they can't receive a Return on Investment (ROI) that competes with other possible investment opportunities. However, as a result of the substantial financial incentives offered through New Jersey's CORE program, industry participants report that middle class homeowners and public entities have been able to participate in the solar market alongside the solar program early adopters. A summary of other states' renewable energy policies and incentive programs is provided in Table 2-5.

³⁵ Executive Order 66, issued in 1978 by Governor Brendan Byrne, requires all regulations issued after 1978 to sunset five years after adoption of the regulation.

³⁶ *Photovoltaic Incentive Design Handbook*, prepared by Thomas Hoff, Clean Power Research, for NREL, September 15, 2006.

Table 2-5. Summary of PV Market Incentive Elements for Select U.S. States

| State | PV Incentive | Renewable Portfolio Standard (RPS) | RPS Solar Set-Aside | Alternative Compliance Payment |
|--|--|--|---|--|
| California (first two are existing rebate programs that will be replaced by CA Solar Initiative) | | 20% by 2010; goal of 33% by 2020. | CPUC set goal to reach 3,000 MW installed capacity by 2017, but no solar-specific provision currently in RPS rules. | |
| 1. <i>Emerging Renewables Program</i> | \$2.60/watt; PV performance-based incentive option is \$0.50/kWh for 3 years. | | | |
| 2. <i>Self Generation Incentive Program (SGIP)</i> | Through 2006 - \$1.00/watt to \$4.50/watt for renewables, depending on technology | | | |
| 3. <i>California Solar Initiative (Performance Based Incentive Program)</i> | Declining schedule of incentives starting at \$0.39/kWh and ending at \$0.03/kWh for systems >100kW; and an upfront incentive (calculated on performance projection) starting at \$2.50/watt and ending at \$0.20/watt. | | | |
| Colorado | \$2/watt DC plus REC payment of up to \$2.50/watt for systems up to 10 kW | 3% by 2007; 6% by 2011; 10% by 2015 | 0.4% by 2015 | No ACP, but there is a requirement that the average residential retail rate may not be impacted more than \$0.50 per month. |
| Connecticut | \$5/watt | 10% Class I and Class II by 1/1/2010; 4% Class III resources by 1/1/2010 | | \$55 per MWh |
| Delaware | 50% of project cost | 10% by 2019 | | \$25 per MWh |
| District of Columbia | | 11% by 2022 | 0.386% by 2022 | \$25 per MWh for "tier one" resources, \$10 per MWh for "tier two" resources, and \$300 per kWh of required solar resources. |
| Massachusetts | \$2/watt to \$6.75/watt depending on project | 4% by 2009 (plus 1% each year after 2009) | | \$55.13 per MWh |
| Nevada | \$3/W AC for residential and small business; \$5/W AC for schools and public buildings | 6% in 2005, rising to 20% by 2015 (can be met by both renewable energy sources and energy efficiency) | 1% by 2015 | |
| New Jersey | \$0.15 - \$5.00/watt DC (varies by technology, capacity and applicant type). Res <10kW systems: \$3.80/watt effective 9/06 | 22.5% by 2021 (2.12% from solar) | 2.12% by 2021 | \$300 per MWh for solar, \$50/MWh for non-solar |
| New York | \$4/watt to \$4.50/watt | 24% by 2013 | | |
| Pennsylvania | \$4/watt up to \$20,000; then \$1/kWh produced in first year of production up to \$5,000 | 18% by 2021 (8% Tier I and 10% Tier II) | | \$45 per MWh; separate ACP for solar PV at "200% of average market value" of the solar credits sold during the reporting period. |
| Texas (Austin Energy only) | \$4/watt AC; Nonprofit organizations: \$4.50/watt AC; Equipment manufactured in Austin: \$6.25/watt AC | Statewide RPS: 2,280 MW by 1/1/2007, increasing to 5,880 MW by 1/1/2015. Austin Energy only: 5% by 12/31/04; 20% by 1/1/20 | | The lesser of \$50 per MWh or 200% of the average cost of credits traded during the year. |
| Washington | Statewide production incentive: \$0.15/kWh, multiplied by a factor dependent on technology type and where equipment was manufactured. Puget Sound Energy rebate: \$525/kW DC to \$600/kW DC. Orcas Power & Light rebate: \$1.50/watt AC. Franklin County PUD: \$500/kW DC. | 15% renewables by 2020 and cost-effective conservation | | \$50/MWh |

Source: Database of Statewide Incentives for Renewable Energy, <http://www.dsireusa.org/index.cfm?EE=0&RE=1>.

2.6 Background on Renewable Energy Incentives

Since the 1970s, policy-makers in the U.S. and around the world have been struggling with how to use public policy to encourage the growth of self-sustaining markets for renewable energy technology.

Early attempts focused on incentive structures that essentially rewarded investment in installed systems (investment-based incentive, “IBI”). For example, in the early 1980’s the federal government offered investment tax credits for solar hot water systems up to a cost of \$10,000. This provoked a dramatic surge in the installation of systems with project prices typically pegged at the \$10,000 threshold allowed by the incentive.

Since then, capacity-based (\$/kW) incentives or subsidies have become very popular, especially for photovoltaic (PV) technology. However, these subsidies are essentially another flavor of IBI. Furthermore, as these programs become successful and more and more systems are built every year, the direct payment of cash to the investors brings into sharp focus the apparent cost of the programs to the taxpayers or ratepayers. Typically, attempts to phase out the subsidies have been met with dramatic declines in sales, as new customers ask themselves why the price that they are being asked to pay is higher than the price paid by those who purchased their systems earlier. And, fundamentally, the investment of capital in a system is a relatively poor proxy for the production of renewable energy.

From past experience the renewables community (both governmental and private) has learned that, in essence, all incentives distort the very markets that they are trying to encourage. The trick is to find incentives that do the most good while doing the least damage.

In the early 1990s, Congress introduced a performance-based incentive (PBI) in the form of the Production Tax Credit (PTC) for corporate investments in wind and certain bioenergy projects.³⁷ This incentive focuses on the *production of electricity* from renewable energy facilities, rather than on the *investment* in the renewable energy generating facilities. While the PTC eventually became available to landfill gas, geothermal and other renewable energy technologies, wind project development, in particular, has become largely dependent on the PTC. One of the interesting things about the PTC is that the primary market-distortion (other than the acceleration of wind installations) has been the development of unique equity ownership structures and project financing schemes. Overall, PBIs are clearly a much more direct approach to encouraging the production of renewable energy. Barring fraud, PBIs should encourage the installation of the best performing systems at the lowest cost. This will help to mature the technology and should encourage economic efficiency in the industry. Furthermore, spreading incentive payments out over a number of years reduces the net present value of the total incentive paid, thus decreasing ratepayer impacts.

Having said that, PBIs also have a number of disadvantages from a policy point of view. For example, use of PBIs requires the measurement (or at least some estimation) of the performance of the system. This, combined with the requirement to make periodic payments based on the performance, requires more administrative effort and oversight of the systems over a longer period of time. And PBIs fail to solve two key issues: 1) how to prevent the overall cost of the program from becoming excessive as more systems are installed; and 2) how to transition away from government-supported financial returns at the end of the program.

³⁷ Information obtained from the Database of State Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=federal¤tpageid=1&ee=0&re=1, and the Union of Concerned Scientists, http://www.ucsusa.org/clean_energy/clean_energy_policies/production-tax-credit-for-renewable-energy.html.

The transition from IBIs to PBIs can be difficult, as players accustomed to one type of revenue stream try to adapt their sales and business models to another. However, it will almost certainly be beneficial in the long-run. In fact, it is probably important to do it now while the solar market is still quite small, and the overall scope of the CORE-based PV systems is still tiny. It also will be important not to appear to penalize early-adopters during the transition, even if it creates some perception of double-dipping.

The California Solar Initiative

With a goal of installing 3,000 MW of solar electric capacity by 2017, the California Solar Initiative (CSI) has the highest solar installed capacity target of any State in the U.S. The CSI is a performance-based incentive program, but it gets around some of the administrative burdens of monitoring and issuing incentive payments over time.

Systems under 100 kW can receive an upfront lump-sum incentive in the form of an “Estimated Performance Based Buydown” (EPBB). The EPBB amount is calculated based on the expected future performance of the system, taking into consideration performance factors such as location, orientation and shading.

All systems greater than 100 kW receive a Performance-Based Incentive (PBI), and systems under 100 kW can opt to receive their incentive through the PBI structure rather than receiving an up-front EPBB. Participating projects will receive monthly PBI payments, calculated on a \$/kWh basis, over a five-year period.

Incentive amounts will decline gradually over the next ten years at a rate of approximately seven percent per year. Residential, commercial, and government / non-profit entities each qualify for a different incentive level. For the EPBB approach, the incentives start in 2007 at \$2.50/W for residential and commercial entities, and \$3.25/W for government / non-profit entities. For the PBI structure, the incentives start at \$0.39/kWh for residential and commercial entities and \$0.50 for government / non-profit entities.

In a recent California Public Utilities Commission (CPUC) decision (Decision 07-01-018, January 11, 2007), it was determined that solar system owners would gain title to the RECs associated with electricity produced from their solar systems. Therefore, systems participating in the CSI can receive revenue both from REC sales and from their incentive payment(s).

Additional details pertaining to the CSI are included in Appendix B. Information on the CSI is also available at <http://www.gosolarcalifornia.ca.gov/>.

3. BACKGROUND FOR SOLAR MARKET TRANSITION DECISION-MAKING

In order to design an effective solar market development structure for New Jersey's post-rebate environment, it is necessary for people entering the debate to have a common language and understanding of the process of developing solar projects, as well as the key policy decisions that must be made to provide direction for the design of an appropriate and effective market transition plan. This section includes a brief introduction to solar policy decision-making. Topics discussed in this section include:

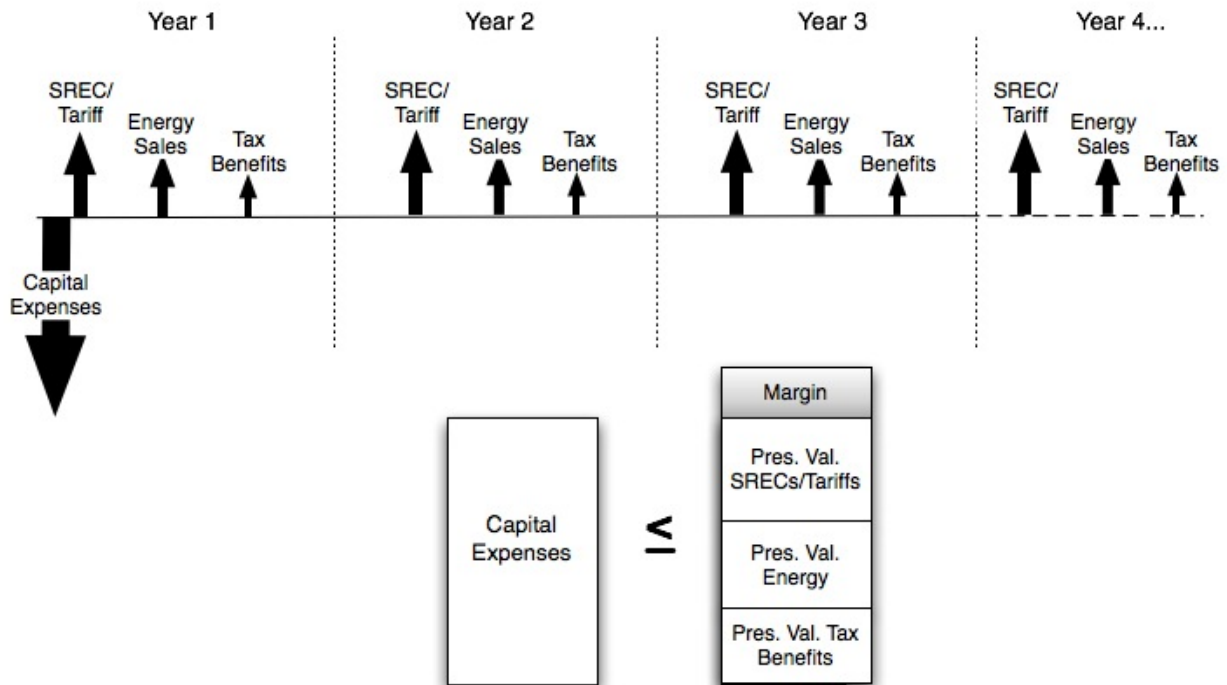
- PV project economics
- Risk allocation
- Return on investment thresholds
- Level of market intervention
- Market conditions necessary to facilitate RPS success

3.1 PV Project Economics

The process for developing solar projects depends heavily on the size of the project, the type of financing, and type of ownership structure. However, they all have certain elements in common. The projects are characterized by a large initial capital outlay that must then be recouped through a series of payments over many years.

Figure 3-1 provides a cash-flow schematic. Here we see the initial capital cost on the left, and a series of revenue streams from the incentive or tariff payments, the energy payments (or retail electricity payments offset, in the case of net-metered systems), and the tax advantages accruing to the owner over a period of years.

Figure 3-1. PV System Project Economics



The bottom of the figure illustrates that for the project to be successful, the present value of all of the revenue streams—including the incentives—must be larger than the initial capital outlay.³⁸ The project developer must be able to recover enough revenue from the project quickly enough to make it profitable, or at least economically viable. This is problematic for PV projects, where the system is both expensive and the required payback period is typically for 20 years or more. Furthermore, since the market for SRECs is new and thinly traded, the potential revenues available from SRECs in the out-years are seen as uncertain. Therefore, these future SREC revenue streams are greatly devalued by the investment community.

Project economics vary significantly across the range of prospective owners. For example, corporate entities with large tax burdens are capable of taking advantage of the Modified Accelerated Cost Recovery System (MACRS) and Corporate Tax Credit, which together can dramatically reduce the effective cost of a PV system.³⁹ Residential PV system owners can also benefit from a tax credit, representing 30% of the system cost up to \$2000.⁴⁰ However, public entities that are tax-free are normally unable to benefit from

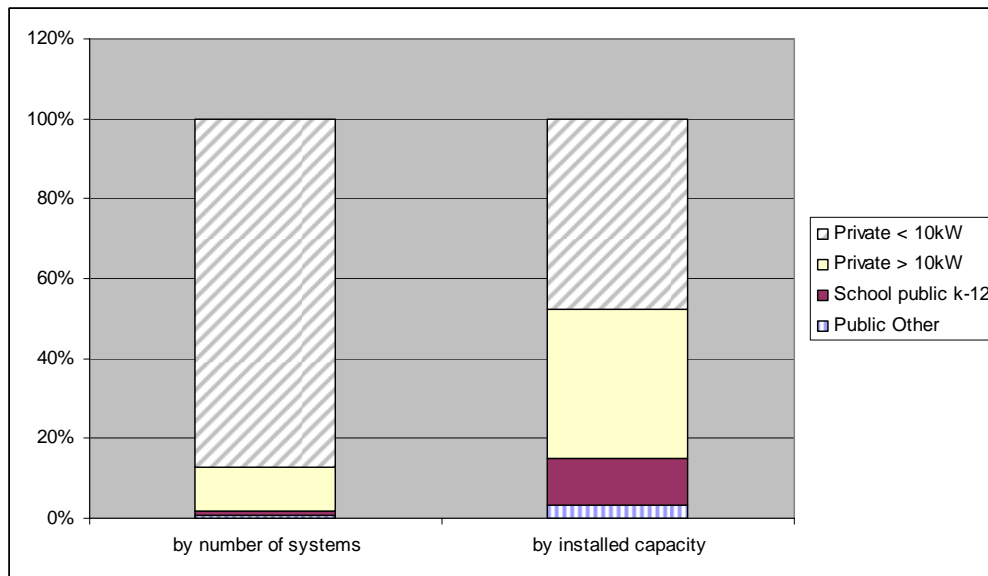
³⁸ For the sake of simplicity—and because they are arguably not a huge part of the system economics—we have here ignored the O&M costs of the system.

³⁹ The MACRS enables corporate entities to recover solar investments through an accelerated 5-year depreciation schedule. The Business Energy Tax Credit also provides commercial and industrial solar project owners with a 30% tax credit. This incentive would have expired at the end of 2007, but was recently extended through 2008 by Section 207 of the [Tax Relief and Health Care Act of 2006 \(H.R. 6111\)](#). Further information on federal tax incentives is available through the Database of State Incentives for Renewable Energy, <http://www.dsireusa.org/library/includes/genericfederal.cfm?currentpageid=1&search=federal&state=US&RE=1&EE=0>. Or see next footnote.

⁴⁰ SEIA guide to Federal Tax Incentives for Solar Energy, Version 1.2, May26, 2006. <http://www.seia.org/manualdownload.php>

any tax incentives.⁴¹ Similarly, the cost per kW of PV systems decreases as the size of the system increases. Because of these variations, each class of project needs to be examined individually. As shown in Figure 3-2, the majority of systems receiving rebates are private systems under 10 kW. Many of these systems are likely to be owned by residential customer or small business owners with a relatively low tax burden. Therefore, these smaller projects see less benefit from the Federal tax incentives than do larger systems, and they are in greater need of the rebate funds.

Figure 3-2 Distribution of CORE Program rebates by project type (mid-2003 through mid-2006)



Probably the simplest project example is a **residential** installation. In this case, the homeowner will typically self-finance the system either with personal savings or through a home-equity loan. Notice that in either case, it is not the value of the solar system that is securing the investment. For this reason, homeowners are able to be more patient about the returns on their investment. Given New Jersey’s net-metering rules, any electricity generated by the PV system would result in a reduction on the homeowner’s electricity bill.⁴² All of the risk for performance of the system that is not covered by warranty, and all the merchant risk fall on the homeowner. In the same way, all of the risk associated with any kind of performance-based incentive—whether SRECs or tariffs—would also fall on the homeowner.

The next level of complexity is an **owner-financed commercial system**. In this case, the system size is larger, but the owner (either an individual or a company) is still able to self-finance the system. Again, the financing for the project is either carried on the owner’s balance sheet or is secured by some other asset. As with the homeowner, any performance risk or risk for the revenues falls on the owner.

The most general form of ownership is the **project-financed**, or non-recourse financed, deal. In this case, the project capital cost is assembled from a variety of sources. For large power plants (e.g., wind farms), there can be many sources of funding, but for solar projects (and for the sake of simplicity) we will focus here on only two – debt and equity. The equity investors in a project take on the highest risk, but also have

⁴¹ However, public projects can benefit from tax incentives if they negotiate creative ownership arrangements or purchase power agreements with third-party entities.

⁴² This net-metering benefit has substantial value since each kWh is offset at the retail electricity rate, including any associated fees that are charged on a per kWh basis.

the largest upside potential. They get repaid only when the debt has been satisfied, but if the project is producing more revenue than is needed for the debt, they receive all of the excess.

The lenders that service the project finance market essentially lend their money against the revenues that the project will produce.⁴³ For this reason, they examine the revenue prospects of the deal very closely. They look closely at the various risks that the project will fail to produce the claimed revenue streams. For net-metered PV projects the electricity “sales” revenue stream presents a low level of risk revenue.

However, the level of risk associated with the incentives that make the solar project financially successful depends a great deal on the type of incentive program in place. As discussed in the next section, there is great variability in the level of risk borne by the project owner(s) vs. that borne by the entity providing the incentive. The lender must evaluate the creditworthiness of the entity providing incentive revenues as well as the loan recipient, and then discount the value of the expected incentive revenues in calculating funds available for repayment of the loan. Typically, poor creditworthiness will result in a lower debt to equity ratio, which for solar systems means that the project developer or system owner must provide more upfront capital. This dilutes their earnings relative to their risk exposure and may result in an unacceptable situation from their point of view. Obviously if the project is to be built, some resolution must be found.

Table 3-1 illustrates examples of current project economics for various project types (varying by size and ability to benefit from tax incentives). Under the current situation, with Federal tax credits for both commercial and residential systems, as well as New Jersey’s rebates, the incentive packages for the various system sizes covers roughly 50% to 100% of projects’ installed costs.⁴⁴ The remainder of the investment in these latter cases must be recovered with revenues from power and SREC sales.

Table 3-1. Example New Jersey Solar Project Economics

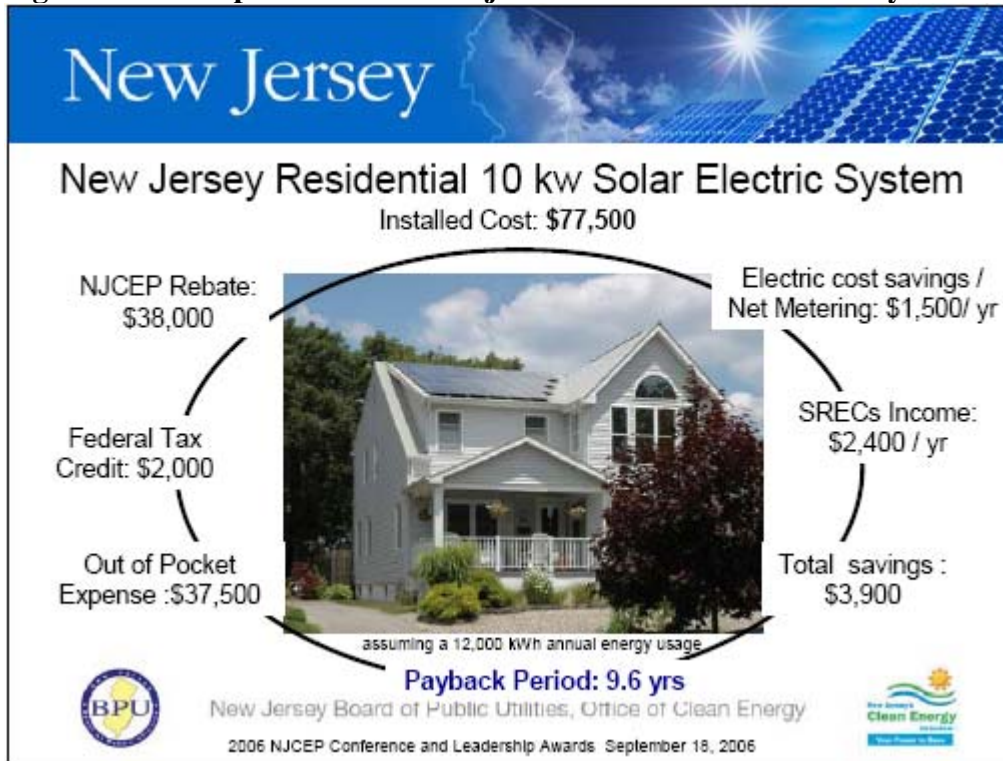
| System Size | 100 kW - Commercial | | 10 kW - Residential | | 1 kW - Residential | |
|-----------------------------|---------------------|---------------------|---------------------|---------------------|--------------------|---------------------|
| | Cost or Incentive | % of Installed Cost | Cost or Incentive | % of Installed Cost | Cost or Incentive | % of Installed Cost |
| Total Installed Cost | \$(725,000) | | \$ (77,500) | | \$ (7,250) | |
| NJ Rebate | \$ 270,000 | 35% | \$ 38,000 | 49% | \$ 3,800 | 49% |
| Federal ITC | \$ 232,500 | 30% | \$ 2,000 | 3% | \$ 1,185 | 15% |
| NPV of MACRS Deduc. at 10% | \$ 300,591 | 39% | \$ - | 0% | \$ - | 0% |
| Total | | 104% | | 52% | | 64% |

Figure 3-3 is an OCE graphic illustrating the situation for a 10 kW residential system. It shows that with the current rebate, and Federal tax incentive, the system owner sees about a nine year payback. For a 20-year system life, this is equivalent to an IRR of 10%.

⁴³ The lenders are also secured by the plant itself of course, but as with most foreclosures that is an undesirable last option.

⁴⁴ The MACRS accelerated depreciation is described in a footnote earlier in this section. The \$2000 cap on the Federal Investment tax credit for residential systems creates a situation in which smaller residential systems (say ≤ 2 kW) are rewarded more handsomely than larger ones.

Figure 3-3 Example of Current Project Economics for New Jersey Residential PV System



Source: White Paper Series: New Jersey’s Solar Market Transition to a Market-based REC Financing System, p. 3.

3.2 Risk Allocation

Risk allocation is one of the more important elements of project finance. It is an axiom of modern non-recourse financing that risk should be allocated to the party best able to manage it. So, for example, risk of construction delays would be assigned to the general contractor, and risks associated with equipment failure or design would be assigned to the equipment supplier.

In the case of photovoltaic systems, there are three primary categories of risk involved. These categories are summarized in Table 3-2 and described in the following paragraphs.

Table 3-2. Project Risk Categories

| Risk Categories | Description of Potential Risks |
|-------------------------|--|
| Equipment Risk | <ul style="list-style-type: none"> • Poor quality equipment • Poor-quality installation |
| Performance Risk | <ul style="list-style-type: none"> • A “bad” solar year (low insolation level) • Shading • Insufficient cleaning of modules |
| Merchant Risk | <ul style="list-style-type: none"> • Volatility in SREC market pricing • Exposure to spot-market pricing • Regulatory risk (a sub-category of merchant risk) resulting from the uncertainty created by the possibility of changes to rules governing market. |

The first category is **equipment risk**. This is the potential for the equipment to not function as designed or to be mis-installed in such a way that it can't function correctly. This is normally covered by warranties offered by the installer and/or the manufacturer. The State should consider carefully the warranties it is requiring on the systems it is incentivizing, especially for residential systems that are more likely to go to less sophisticated buyers.⁴⁵

The second major class of risk is **performance risk**. This is a heading for a number of related causes that prevent the system from delivering the expected amount of energy. The most obvious one, of course, is insolation level. In a "bad" solar year the system will not produce as much energy as planned, and the revenues will be lower than modeled. Other examples of performance-lowering factors might be tree limbs or other greenery that begins to shade the solar panels for part of the day or failure to clean the panels regularly. This class of risk is naturally borne by the system owner, since s/he is best positioned to manage them.

The third class of risk is **merchant risk**. This is a term that describes the salability of the output of the system—power and SRECs—into the market. For net-metered PV systems, sale of the power is generally not considered an issue.⁴⁶ However, the sale of SRECs may be a larger and more important stream of revenue, and it is exposed to a variety of merchant risks. For example, new markets like the NJ SREC market are typically small and thinly traded. As a result, SREC values can be subject to rather wild volatility created by seemingly small disturbances. For example, the system owner may be forced to sell into a "down" market that would negatively impact the revenue stream.

A major factor affecting the merchant risk of SRECs is **regulatory risk**. The entire market for SRECs has been created artificially by the state government creating the RPS. Any changes to the RPS goals, or the rules for buying and selling SRECs could result in a major dislocation in the SREC market. For example, any decision by the NJ BPU must be renewed by the succeeding BPU members.⁴⁷ This is not a reassuring scenario for lenders being asked to finance systems with economic lives of 20 years. Regulatory risk is going to be very difficult to eliminate in New Jersey. Therefore, it is important to explore strategies for managing this type of risk.

Another factor creating merchant risk is the term of the contract for SRECs. Ideally, lenders would like to see iron-clad, long-term contracts for the SREC output. However, the entities that need SRECs to satisfy the RPS, the LSEs, are not typically interested in entering into a contract longer than three years since that is the contract term for the current BGS auction system. *This inability to secure long-term contracts creates uncertainty in the market and discomfort for lenders.*

One of the reasons that risk is so important is the effect that it has on financing. Lenders like to see that their money is well-shielded from risks over which they have no control. As the risk level rises, loans become both more difficult to find and significantly more expensive.

This factor is more evident for large systems where the loans are substantial and the lenders are likely to be more sophisticated about issues of risk. However, it is not absent for smaller and residential systems. Research has confirmed that some residential systems are being funded by home equity loans. In this case,

⁴⁵ For a discussion of the importance of warranties in PV incentive programs, see "Designing PV Incentive Programs to Promote Performance: A Review of Current Practice," Galen Barbose, Ryan Wisner, and Mark Bolinger, LBNL and CESA, LBNL-61643, October 2006.

⁴⁶ Although, like other policies and market rules upon which solar investments depend, net metering policies are potentially subject to change during the investment time horizon for a PV system.

⁴⁷ Executive Order 66 (1978).

the value of the home is used to secure the loan and the lender is indifferent to the associated revenues. However, it is important to note that now the homeowner is shouldering both the performance and the market risk for the PV system.⁴⁸ It seems clear that the State has a role to play in trying to ensure that individuals that enter into these arrangements don't become victims of the risks that they have assumed.

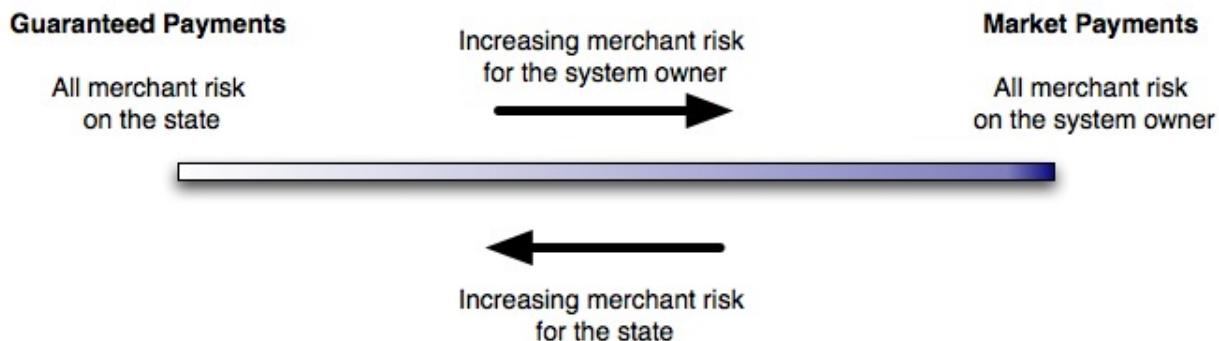
New Jersey Risk Allocation

Under the CORE program as it has existed to date, the up-front rebate offered by the state has reduced a great deal of the financial risk associated with solar projects. Table 3-1 above (in previous section) shows that after the current New Jersey and Federal rebates and tax benefits, commercial and industrial system owners with an appropriate tax appetite can roughly break even without ever producing energy, while residential system owners can recover roughly 50% to 64% of the capital cost of the system in the first year.⁴⁹

This limited risk profile has enabled rapid industry and market growth. However, in a post-rebate environment, the risk profile of projects is likely to shift dramatically. Project investors will need to absorb more of the project's financial and performance risk. A number of industry experts agree that the financial community is ready and willing to serve the needs of solar project investors, but they note that this absorption of risk by the financial community will come at a very high cost.

In fact, this question of merchant risk is not an "either/or" issue, but rather one that exists on a spectrum, as illustrated in Figure 3-4 below. In Section 6 it becomes clear that the different transition options that have been proposed possess very different risk allocation portfolios. Although some of the transition models that have been offered focus the risk on one end of the spectrum or the other, there are a number of models that provide a more balanced risk allocation. A determination about the appropriate allocation of risk will have a significant bearing on the framing of a suitable transition strategy for the State.

Figure 3-4. Merchant Risk Spectrum



3.3 Return on Investment Thresholds

A project's risk is intimately tied to its return on investment. If New Jersey investors are to accept the level of risk offered by the New Jersey solar markets, they must see an acceptable level of return on investment. This requirement speaks to a variety of policy decisions, ranging from the structure of the incentive

⁴⁸ As well as the equipment risk, if s/he doesn't have a strong warranty.

⁴⁹ Original pro forma on which this analysis was based courtesy of Mark Warner of Sun Farm Ventures.

program itself, to the setting of ACP levels. Anything that reduces the investors' upside, or increases their risk, will reduce their willingness to invest.

Current CORE Program rebate levels were designed with the goal of providing projects with a 10-year simple payback.⁵⁰ Under this current Program structure, up-front rebates reduce the risks to project investors, and thus, investors may be willing to accept lower levels of return on investment or longer loan terms. Based on feedback from the solar industry, this payback threshold is insufficient to stimulate the level of development necessary to meet RPS goals in a post-rebate environment.

As with the earlier discussion around project risk and finance, different classes of investors have different risk/return appetites. Solar industry experts report that residential consumers are most concerned with the simple payback period for their solar investment and that to attract interest beyond the subset of early adopters, it is important to show simple payback in the range of five to seven years.⁵¹ These are equivalent to an internal rate of return (IRR) of 19% and 13% respectively, assuming a 20-year economic life.⁵²

By contrast, the larger—and more sophisticated—system owners are likely to accept returns on the lower end of that range for roughly the same level of risk. This may be especially true if they are planning to capture additional value from the solar investment as part of an overall sustainability campaign for their company. As described above, the project finance investors will need to see returns large enough to support their debt service and an upside potential that will justify the risk.

3.4 Level of Market Intervention

Another critical decision for policy-makers is to determine the extent to which they are able to turn the market loose and let it function through the inevitable gyrations that new markets normally go through. Obviously, perceptions of either very high or very low prices for SRECs will engender substantial outcry for market intervention. This appears to be an inevitable part of market-based systems in our society.

However, regulatory or legislative action in response to price fluctuations has a poor history of success. In the case of markets for SRECs in New Jersey, once the market has been defined, and the rules for trading are established, there is a strong case to be made for a certain level of “benign neglect.” This is because regulatory risk, defined as the vulnerability to potential changes in policies and market rules, is overwhelmingly the predominant risk that market participants fear.

For this reason, it seems advisable to approach this transition carefully and with a great deal of thought. Once the new system is set up and running it will be difficult and “expensive” (in terms of damage to market confidence) to change it.

⁵⁰ Or roughly a 9-10% IRR for a 20-year system life.

⁵¹ At the time this report was completed, the Summit Blue Team had not yet collected data from residential CORE participants. Therefore, these data are based on data provided by the solar industry.

⁵² Misunderstanding of the relationship between rate of return and simple payback periods is fairly rampant in this industry. Although simple payback is the easiest to calculate (capital cost divided by annual revenues produced), it does not provide a measure that allows comparability to other investment opportunities, which are typically expressed in percentage returns. By contrast the IRR (internal rate of return) calculates the rate of return that exactly accounts for all of the costs and revenues over the expected life of the system. For example, it is not uncommon for unsophisticated customers to ask for simple paybacks of 2 or 3 years, which would provide IRRs (50% and 33%) much larger than nearly any other investment with a comparable level of risk.

3.5 Market Conditions Necessary to Facilitate RPS Success

The New Jersey RPS reflects the State’s leadership and commitment to building a thriving renewable energy market, and it provides a solid foundation upon which to build that market. However, as evidenced by the current inability of installers to initiate new solar projects, a number of other conditions must exist in order for the market to deliver the renewable energy supply required by the RPS. According to a Lawrence Berkeley National Laboratory (LBNL) report, in states with RPS requirements, the following criteria must be met in order to facilitate achievement of RPS targets:

1. The presence of creditworthy long-term power (SREC) purchasers.⁵³
2. Stable political and regulatory support.
3. Adequate and accessible developable resource potential.

The New Jersey marketplace has substantial weaknesses in the first two criteria. These two criteria are of particular importance in New Jersey since the State’s renewable energy resources, while sufficient, are not particularly strong compared to other states. As noted above, and as addressed in all of the RPS Transition Working Group proposals, the current challenges associated with securing long-term REC purchase contracts are a major barrier in the New Jersey marketplace. In addition, functional barriers in existing programs, and uncertainty about New Jersey’s renewable energy market structure going forward present market participants with a great deal of regulatory risk.

⁵³ Wiser, Ryan, Kevin Porter and Bob Grace. (2004) “Evaluating Experience with Renewable Portfolio Standards in the United States.” Lawrence Berkeley National Laboratory, LBNL-54439. While not specifically stated in the LBNL report, given that RECs/SRECs are the medium for demonstrating compliance with the RPS, an ability to enter into long-term REC/SREC contracts is of equal importance to project developers.

4. ASSESSMENT CRITERIA FOR TRANSITION OPTIONS

A variety of solar market transition options are available to OCE, each possessing its own set of strengths and weaknesses. In order to objectively evaluate the merits of these options, each must be reviewed using a consistent set of criteria that reflect the priorities of OCE and market stakeholders, and that are consistent with elements present in the most successful solar markets. OCE's guiding principles for the market transition (see text box) formed the primary basis for developing the list of criteria used in this report. Based on findings from primary and secondary research, the Summit Blue Team adapted these guiding principles and a few additional relevant criteria. The Team then grouped these criteria into categories that represent the most fundamental areas of interest in assessing the merits of each strategy. The primary categories include:

- Sustained orderly development
- Transaction costs
- Ratepayer impact
- Support for other policy goals

These primary criteria, and the associated secondary criteria, are described briefly below. These criteria are applied in Sections 5 and 7 as the framework for evaluating each of the six potential transition strategies included in this analysis.

4.1 Sustained, Orderly Market Development

As mentioned above, the overall goal of the RPS, and of the OCE incentive structure, is to develop a robust and sustainable market for renewable energy in New Jersey. This requires a clearly established plan for market growth. Such a plan will build investor confidence while still allowing the market to grow rapidly enough to meet the aggressive RPS goals.

1. Facilitate rapid growth (to meet RPS targets)

The incentive program needs to be able to manage the rapid growth rates mandated by the annual RPS goals. A market transition strategy that requires a long ramp-up period, or that doesn't provide a sufficient level of financial support to stimulate PV development among classes of consumers that extend beyond the early adopters would not rate well for this criteria.

OCE Guiding Principles for Solar Market Transition:

- Achieve the rapid growth that is needed to meet the RPS goals. Facilitate project development and sales of systems. Ensure that closing a sale is simple and quick. Ensure that projects can be financed. Allow growth to be accelerated or slowed when needed.
- Achieve the lowest possible cost to ratepayers for a given amount of effective capacity and the lowest possible transaction costs.
- Ensure an efficient, transparent, and auditable process that can provide tools for policy goals, such as opportunity for different sizes and types of projects (large & small, private & public, etc.).
- For utilities, suppliers, and other market participants, minimizes regulatory risk, as appropriate, minimizes the administrative burden, and maximizes investor confidence in the market place.
- Ensure compatibility with regional markets and insuring adequate sources of supply.
- Allow all interested parties to participate.
- Support congestion relief.
- Support New Jersey's State Development and Redevelopment Plan.
- Require low implementation costs.
- Minimize the regulatory risk of investments in renewable energy systems.

Source: White Paper Series: New Jersey's Solar Market Transition to a Market-based REC Financing System, p. 5.

2. Program readily adaptable to changing market conditions

Ideally, the natural mechanisms in the market would facilitate a rough balance between supply and demand, but since any incentive program will introduce some level of market distortion, it is critical that the program possess elements of flexibility that will enable it to adapt in response to changing market conditions. Changing market conditions might include an under- or over-supply of SRECs, or a dramatic breakthrough in technology or price. Examples of ways that an incentive program can adapt to changing market conditions include conducting a periodic review of the appropriateness of incentive levels, or tying incentive levels to some market index.

This criteria is closely related to that of economic efficiency, and both are of critical importance to the effectiveness of an incentive program. In both cases, the goal is to ensure that incentive levels coincide with the level of support necessary to stimulate the amount of development required of the RPS goals. Structuring a program to adapt to changing market conditions is one way to ensure that projects are not over or under-subsidized.

3. Compatible with regional markets

Stability of the market for RECs will be tied to its size and liquidity. Compatibility and fungibility of RECs across regional (and eventually possibly national) markets will add stability to the New Jersey market. It will also force New Jersey prices in line with regional prices.

New Jersey's RPS rules currently stipulate that only PV systems interconnected with a distribution system that supplies the State can create SRECs eligible for New Jersey RPS compliance.⁵⁴ Therefore, discussion of trading RECs from PV systems located outside New Jersey into the State is essentially irrelevant. However, to the extent that New Jersey SREC trading values can fall within the range of those in the surrounding region and other parts of the country, this will increase the liquidity of the New Jersey SREC market.

4. Maximize investor confidence

One of the most essential elements of building a successful market is developing investor confidence in the revenue stream that is servicing the load. A high level of investor confidence results in cheaper financing, and this in turn produces: greater availability of money, lower interest rates, longer contract terms and reduced discounting of future revenue streams. In the case of the New Jersey REC market, investor confidence seems to be focused on the merchant risk that systems face. As discussed in Section 3.2 **merchant risk** is driven by:

- a. **regulatory risk**—the risk that either the BPU or the legislature will reverse or amend an existing regulation or statute,⁵⁵ and
- b. **price risk**—the risk that an over-supply of solar energy in any given period would cause the prices for SRECs to fall.

Any program design elements that can increase the certainty of projected future revenue streams and make the market more predictable will enhance investor confidence. Some program design elements that may enhance investor confidence include:

⁵⁴ New Jersey RPS Rules: N.J.A.C. 14:8-2.9 (d).

⁵⁵ In fact, regulations passed by NJ BPU need to be revisited every 5 years. This does not create an atmosphere of certainty among commercial lenders. Executive Order 66 (1978).

- Design a program that includes a well-defined structure and long-term plan.
- Attempt to establish contractual commitments that would withstand future changes in policies or market rules.
- Reduce the long-term economic time horizon of projects by means such as providing one-time upfront rebates, offering short-term incentive payment periods that enable projects to quickly recover their investment, or front-loading incentive payments so that projects will recover the majority of the investment over a shorter period than they otherwise would. Of course, this method has deficiencies in other areas since it will concentrate the impact on ratepayers.

5. Facilitates self-sustaining market

Ideally, the market mechanisms would allow the government influence to be subtle enough to create minimal distortion, and to permit the government role to gradually diminish without disrupting the ongoing trades. Historically, investment- or capacity-based incentive systems have not had much success in promoting sustainable markets. For this reason, more attention today is placed on production-based incentive systems, which encourage technical and economic efficiency in both the system design and in the financial structures.

4.2 Transaction costs

1. Ensure transparent, auditable process

Any successful market needs to have mechanisms that prevent fraud and misbehavior on the part of the traders. In the case of the SREC market, these would include transparent pricing and fully auditable processes, along with verified production. Either the SREC trading system or the PJM GATS would fulfill the need to provide auditable SREC transactions. However, in some market transition proposals, elements exist that would require monitoring and are less readily audited than the SREC transactions themselves. Also, there are clear differences among the proposals in the area of price transparency, since the SREC trading system provides price transparency but PJM GATS does not. To the extent that a proposal recommends using one system versus another, the issue of price transparency must be considered.

2. Program design encourages simple efficient project logistics

One of the primary functions of any trading mechanism is to bring together willing sellers and buyers and allow them to consummate their transaction efficiently. The more effectively this process works, the more liquid the market becomes. An ideal market structure would not require complex ownership structures or contractual arrangements in order for projects to take advantage of incentives. Furthermore, it would be flexible in nature to enable future innovations to take effect.

3. Low administrative burden

This criteria pertains to the overall administrative burden or “hassle factor” imposed on market participants such as project owners, installers, and administrative entities. While some level of administrative costs is essential for any effective, well-monitored program, program designers should strive to keep administrative elements to a minimum and to look for opportunities to maximize administrative efficiency (i.e., automatic tracking of all system production data would

minimize administrative burdens both for project owners and for program administrators). In general, minimizing paperwork and approval processes associated with an incentive structure is important in that it enables a greater amount of funds to be spent on actual system construction.

4.3 Ratepayer impact

1. Economically efficient (no over- or under-subsidization)

In order to use the ratepayer monies most efficiently, the program should provide only the incentive level required to keep the market supply and demand in balance. An ideal market structure will include mechanisms to enable incentive outlays to change in response to the dynamic economic needs of market participants. This criteria is particularly important given the fact that certain project types (i.e., commercial projects in which the owner possesses a large tax burden) can quickly achieve a positive cash flow in the absence of incentives, while the viability of other projects (i.e., residential and many public projects with less ability to take advantage of tax incentives) is much more dependent on the availability of state incentives.

2. Minimize regulatory risk

As described above, minimizing regulatory risk is closely related to improving investor confidence. Reducing regulatory risk will reduce financing costs and thus, the incentives required to stimulate project development. Eliminating regulatory risk in New Jersey would be impossible. However, certain program design elements can make the market more predictable and appealing for investors (see examples listed under “minimizing regulatory risk”).

3. Low program implementation costs

This criteria is related to “low administrative burden” but pertains more broadly to the overall implementation costs associated with various program alternatives. Drivers of implementation costs include incentive levels, and the amount of necessary program implementation infrastructure (i.e., monitoring systems and/or staff support). While administrative and implementation costs could not be assessed within the scope of this assignment, certain assumptions were made regarding the relative magnitude of program implementation costs. This criteria is important because all of the money spent on creating program infrastructure or administering an incentive program is money that cannot be used to support actual PV project development.

4.4 Support for other policy goals

1. Equity of opportunity to participate (i.e., system size)

A well-designed incentive program will offer appropriate types and levels of incentives to serve the needs of a wide variety of system sizes, participant types (i.e., residential, commercial, etc.), and ownership structures. Low-income and small business participants should be included in this diversity of needs served, as these ratepayers contribute to rebate program funding, but typically do not possess the means install PV.

2. Ability to encourage development by target categories

An ideal program will stimulate PV development among customer classes which represent various policy goals by providing greater incentives to those customers.

3. Congestion relief

One of the benefits of distributed generation is the relief of transmission and distribution system congestion. Ideally, the program incentives would particularly encourage development of systems in locations where the grid support is weakest.

5. MARKET TRANSITION OPTIONS

Members of New Jersey's RPS Transition Working Group have presented a variety of proposals outlining strategies for transitioning to a non-rebate funded solar market. Two of those proposals, the ***Underwriter*** and ***Commodity Market Model*** proposals, are centered around using the existing SREC market as a dynamic medium for setting SREC prices, while providing PV investors with a minimum level of revenue certainty in the form of an "underwriter commitment". This effectively sets a floor price for SREC sales.

The other two proposals are distinct in that one, the ***Tariff Model*** (which is referred to hereafter as the ***Hybrid-tariff*** model) would involve having PV system owners receive guaranteed payments/credits on a per kWh basis through their monthly electric bill to cover a portion of their investment. The remainder of their investment would be recovered through avoidance of retail electricity rates for the portion of their electricity demand provided by the PV system. PV system owners could also obtain SREC revenues.

The fourth proposal presented by the RPS Working Group, the ***Auction-Set Pricing and Standard Contract Model***, involves having market clearing prices set through an annual auction in which some portion of the market would be matched with buyers, and the rest of the market would receive pricing based on the auction-set price. The other key feature of that proposal is that the economic lifetime of projects would be compressed to five years- the term of a standard, required contract.

In addition to the proposals submitted by the RPS Transition Working Group, the Summit Blue Team assessed: 1) a ***Full-Tariff*** model, 2) an ***SREC-Only*** model, and 3) a reviewed the concept of a ***Continued Rebates / Baseline*** model. The additional models were included in the analysis because they represent a broader spectrum of possibilities than were reflected in the Transition Working Group's proposals. Furthermore, the continued rebates / baseline model enables the reader to compare the other six market models to the conditions associated with existing rebate-based market structure.

The ***full-tariff model*** differs from the ***hybrid-tariff option*** presented in the white paper series in that it would be designed to provide PV system owners with their full incentive in the form of a tariff, rather than a system in which revenues flow from both the tariff and from SREC sales (the hybrid-tariff approach). It is representative of an approach that has been used in Europe's largest renewable energy markets and has recently been introduced in Ontario and some U.S. states. Some New Jersey stakeholders have begun developing their own models to further examine the approach.

The ***Solar REC-Only model*** is included because it represents the opposite end of the project risk spectrum from the full-tariff approach. Furthermore, it is consistent with the Pilot Program that will soon be implemented in New Jersey. The Pilot Program is intended as an interim measure to enable projects to bypass the CORE Program and be built based solely on the financial benefits provided by SREC revenues and federal tax incentives. The Pilot Program will provide no revenue certainty mechanisms.

The seven market models were evaluated using the evaluative criteria introduced in Section 4. This section starts with a summary table of the key strengths and weaknesses of all of the six potential transition strategies. Then each of the strategies is discussed in detail as it relates to the evaluative criteria. The section concludes with a description of a proposal from PSEG that would involve the utility partnering with municipalities to install over 500 MW of solar on public buildings. While that proposed program would have a dramatic impact on the solar market outlook, it has been treated separately from the other transition strategies since the program would not apply to the whole New Jersey solar market.

5.1 Distinct Elements of the Potential Transition Strategies

This section identifies and notes the primary strengths and weaknesses associated with each of the distinct elements of the potential transition strategies. Most elements addressed are taken from the formal proposals submitted by the RPS Working Group or from the SREC-Only OCE Pilot Program. However, a few additional elements that were identified as having significant relevance to the discussion have also been included. These additional elements have been identified with an asterisk.

Table 5-1. Key Strengths and Weaknesses of Proposed Market Transition Strategies

| Elements | Strengths | Weaknesses |
|--|---|---|
| Primary Elements | | |
| <p>Underwriter</p> <p><i>Related Market Transition Strategies: Underwriter Model and Commodity Market Model</i></p> | <ul style="list-style-type: none"> • Provides revenue certainty, improving investor confidence • Increased access to capital • Provides growth opportunity for market infrastructure • Provides some level of ability of “market forces” to determine SREC pricing within boundaries of floor and ceiling values | <ul style="list-style-type: none"> • As proposed, reliance on ACP as funding mechanism would present significant risks, although an alternative funding mechanism (i.e., SBC funds) could be used • Difficult to identify willing / appropriate underwriter entity • Potential for unfavorable decisions to lead to market conditions that would “break” the system financially and expose ratepayers to substantial risk • Risks associated with underwriter system may limit investor confidence, thus reducing the intended value of revenue certainty offered by the program • Does not address upfront project cost barrier |
| <p>SREC-only market, no minimum revenue guarantees</p> <p><i>Related Market Transition Strategy: SREC-Only Model</i></p> | <ul style="list-style-type: none"> • Provides projects possessing the most favorable economic attributes with an opportunity to get built • Fosters growth of “market maker” infrastructure (i.e., aggregators and brokers), which facilitates the development of a self-sustaining market | <ul style="list-style-type: none"> • Limits equity of opportunity for small and public projects • Difficult for most projects to obtain financing • Many installers focused on serving smaller systems would go out of business • Added costs to ratepayers associated with higher financing costs, greater use of ACPs, and aggregator and broker services • Does not address upfront project cost barrier |
| <p>Auction-Set Pricing</p> <p><i>Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model</i></p> | <ul style="list-style-type: none"> • Allows market-forces to determine SREC pricing • Provides transparency in SREC market pricing | <ul style="list-style-type: none"> • Annual occurrence eliminates ability for dynamic market corrections between auction events • SREC pricing likely to be driven by largest, most sophisticated players making resulting SREC pricing insufficient for small project owners • Substantial administrative burden • Potential for gaming • Does not address upfront project cost barrier |
| <p>Mandatory Standard Contract</p> <p><i>Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model</i></p> | <ul style="list-style-type: none"> • Reduces transaction costs for buyers and sellers, resulting in lower costs of compliance for ratepayers • Increases transparency of transactions | <ul style="list-style-type: none"> • Limits flexibility of contractual relationships • Administratively burdensome to enforce compliance • OCE costs of developing and updating to keep pace with changing market needs |
| <p>Hybrid-tariff</p> <p><i>(tariff + SREC revenue streams, tariff level set to make up ROI not expected to be provided by SREC revenues)</i></p> <p><i>Related Market Transition Strategy:</i></p> | <ul style="list-style-type: none"> • Provides revenue certainty, improving investor confidence • Enables SREC market activity to continue, building market infrastructure that will eventually be needed for a self-sustaining market when no incentives are in place • Lowers SREC trading values making NJ SRECs better- aligned with regional solar REC values • Can be tailored to match the needs of different project types, and to provide added incentives for development of projects that advance | <ul style="list-style-type: none"> • May still be difficult to obtain project financing if program’s limited revenue certainty fails to sufficiently boost investor confidence • Results in both administrative costs of tariff, as well as middleman costs to facilitate SREC trades • May limit third-party owner arrangements • Requires BPU action to re-set tariff level periodically and to monitor dynamic supply / demand balance to determine when to cease new tariff commitments |

| Elements | Strengths | Weaknesses |
|---|---|---|
| <i>Hybrid-tariff Model</i> | <ul style="list-style-type: none"> specific policy goals Provides simple solution to limit “windfall profits” of past rebate-funded projects | <ul style="list-style-type: none"> Does not address upfront project cost barrier |
| Full-tariff* <i>(tariff revenues only, tariff level set to provide full project ROI)</i> <i>Related Market Transition Strategy: Full-tariff Model</i> | <ul style="list-style-type: none"> Provides projects with certainty that full target ROI will be achieved Reduces transaction costs by supplying LSEs with SRECs directly from tariff-funded projects Can be tailored to match the needs of different project types, and to provide added incentives for development of projects that advance specific policy goals Provides simple solution to limit “windfall profits” of past rebate-funded projects | <ul style="list-style-type: none"> Limits development of infrastructure (i.e., brokers / aggregators) necessary to sustain market once program expires May limit third-party owner arrangements Requires BPU action to re-set tariff level periodically and to monitor dynamic supply / demand balance to determine when to cease new tariff commitments. Does not address upfront project cost barrier |
| Secondary Elements | | |
| Continuation of Rebates for Small Systems <i>Related Market Transition Strategies: Commodity Market Model</i> | <ul style="list-style-type: none"> Administratively simple Provides project owners with upfront capital which enables more projects to be built, and may enable self-finance of projects Lower upfront and finance costs should result in lower SREC trading values | <ul style="list-style-type: none"> Not performance-based, therefore, may result in inefficient use of funds Reduces the project investment amount used as the basis for calculating the value of the federal tax credit for a given project.⁵⁶ |
| Compressing Project Economics (i.e. to 5 years) <i>Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model</i> | <ul style="list-style-type: none"> Increases investor confidence Reduces financing costs | <ul style="list-style-type: none"> Requires SREC values dramatically higher than those in any other market, thus producing “rate shock” Requires adjustments in RPS requirements, further weakening regulatory certainty of the market as a whole |
| 2-Year SREC Trading Life <i>Related Market Transition Strategies: Commodity Market Model</i> | <ul style="list-style-type: none"> Increases flexibility of market Provides better planning time horizon for SRECs created toward the end of the Energy Year | <ul style="list-style-type: none"> Would increase complexity of market monitoring to manage supply / demand balance |
| Allow Large-Scale (>2MW) PV Systems to Generate SRECS <i>Related Market Transition Strategies: Commodity Market Model</i> | <ul style="list-style-type: none"> Improves ability to achieve RPS requirements in an efficient manner May reduce overall cost of RPS compliance by putting downward pressure on SREC prices Improves potential to attract development of PV industry manufacturing facility | <ul style="list-style-type: none"> In absence of other mechanisms to support smaller systems, lower SREC prices could limit ability of SREC market to provide necessary ROI for small systems Would not provide same level of distributed generation benefits as would a larger number of smaller systems |
| Use of PJM GATS as Trading Platform | <ul style="list-style-type: none"> Decreases ratepayer expenditures in support of SREC trading platform Increases ability to trade SRECs with other states in PJM region | <ul style="list-style-type: none"> Provides no transparency of SREC trading values Not user-friendly for most users, therefore, requires services of an aggregator, broker or other project representative |

⁵⁶ Both the personal and corporate federal tax credits are applied to the project investment amount after subtracting the value of any “subsidized energy financing.” This certainly includes state-funded rebates, and thus, is shown here as a weakness of upfront rebates. It is unclear how a production-based incentive would be treated for the purposes of calculating the value of the federal tax credit for a given project. Therefore, it is not clear whether this weakness would be shared by production-based incentive structures such as the hybrid or full tariff models.

| Elements | Strengths | Weaknesses |
|---|---|--|
| <i>Related Market Transition Strategies: SREC-Only Model</i> | | |
| Limits on Creation / Sale of SRECs for Rebate-Funded Systems* ⁵⁷ <i>Related Market Transition Strategies: Underwriter and Commodity Market Models</i> | <ul style="list-style-type: none"> • Reduces “over-subsidization” / “windfall profits” of projects that already received rebates • Avoids excessive ratepayer impacts | <ul style="list-style-type: none"> • Erodes investor confidence by setting precedent for changing rules • Reduces ability of early adopters to be rewarded for stepping forward and setting a model for other investors • Increases complexity of state’s market rules resulting in increased administrative burden and decreasing appeal to investment community |
| Template Standard Contract* <i>Related Market Transition Strategies: N/A</i> | <ul style="list-style-type: none"> • Reduces transaction costs for buyers and sellers, resulting in lower costs of compliance for ratepayers • Maintains flexibility of market actors to enter into unique contractual arrangements | <ul style="list-style-type: none"> • OCE costs of developing and updating to keep pace with changing market needs |

* Asterisk represents elements not incorporated in formal proposals, but identified as relevant by the Summit Blue Team.

⁵⁷ Though this element was not included in any formal proposal, it is being discussed by OCE and market stakeholders as an option for avoiding having rebate-funded systems receive windfall profits in a post-rebate environment in which SREC values will likely be much higher than they are today.

5.2 Proposals Submitted by RPS Transition Working Group

5.2.1 Underwriter Model

Summary

The proposed underwriter program would provide a mechanism for projects to receive a 15-year commitment from an underwriting entity (proposed to be the NJ-Economic Development Authority) to purchase unsold SRECs from the projects at a pre-determined value (effectively setting a “floor” price). This commitment provides SREC price certainty (eliminating some investment risk) and can help projects secure financing.

Key Functional Components of the Proposed Approach

1. Create Underwriting Program within NJ-Economic Development Authority (EDA): The author explains that, “The underwriter must be vested with enough long term stability to allow debt security confidence by the market.” The author also notes the fact that EDA is a non-profit, which should help keep ratepayer costs low because the entity won’t require a high ROI.
2. Establish Underwriting Commitments: Prior to construction, any type of solar project (small, public, large, etc.) could secure an underwriting commitment. The underwriter commits to buy any SRECs not sold into the market at a set price that would be based on some fraction of the ACP (referred to in the paper as the “underwriter discount”). To maintain balance between supply and demand, the underwriter would limit its commitments to the amount of capacity necessary to meet RPS requirements.
3. Alternative Compliance Payments (ACP) as Funding Mechanism: When payments to system owners are necessary, they would be funded through in-year ACP revenue. Therefore, the authors argue, the approach would require little direct funding (i.e., only for start up and initial administrative expenses). At the end of each RPS compliance year, ACP payments would be made to the underwriter to cover necessary payouts plus administrative costs.
4. ACP Board Sets Floor Price: The underwriter price would be set by the ACP Board. It would need to be high enough to enable the project to recover the cost of capital. Authors say that financial modeling indicates that the underwriting price should be about 60% of the ACP. They note that in today’s market, SRECs are trading at 65% to 90% of ACP value. The underwriter discount/value would be set far enough below the ACP that the project owner would still have an incentive to go out to the open market to sell the SRECs. Only the unsold portion of SRECs would be purchased by the underwriter.
5. 15-Year Commitment Helps Secure Project Debt: The underwriter agreement would have a 15-year term and would function as a long-term revenue stream commitment for the project, which could help secure project debt.
6. Retire SRECs Purchased by Underwriter: The author says that it’s important that LSEs can only buy SRECs from the market, so they don’t short-circuit the markets by always going directly to the underwriter to buy SRECs.

7. Underwriter System in Place for 10 Years: The author proposes that the underwriting system be in place for 10 years, with an option to continue at end of term (i.e., in each of the ten years during which the program is operational, new 15-year commitments would be issued to projects).
8. No Limits on SREC Value Based on Project Vintage: The authors explain that limiting the value of SRECs from existing systems that received rebate funding would add unnecessary complexity to the market. Further, the authors argue that constraints on SREC values for rebate-funded systems would “strand” the investments made by existing system owners who made project investments at a time when there were no term limits on SREC values.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

The author argues that the proposed system would provide the fastest transition of any of the proposals, as it would only require: 1) raising the ACP immediately and 2) implementing the underwriting system. The author suggested that underwriting commitments could be made in January 2007, just four months after the proposal was submitted. Summit Blue disagrees with the author’s assumption that the underwriter model could be adopted and implemented in such a short timeframe. It seems clear that identifying and establishing activity by an appropriate underwriting entity, obtaining authority to direct ACP funds to the underwriter, and establishing an underwriting price commitment (“ACP discount”) would require a timeline substantially longer than the one suggested by the author.

After an underwriter system is established, and assuming it boosts investor confidence as intended, the market should respond rapidly, thus facilitating development at the pace necessary to meet RPS requirements.

2. Enables scale-up or scale-back of growth as needed

Under the proposed underwriter system, the underwriting entity would keep track of the amount of PV generation that is expected to be generated from systems with underwriter commitments. The entity would only issue underwriting commitments for the amount of capacity necessary to meet RPS requirements. This would limit the likelihood that an SREC over-supply situation would occur, thus providing a level of protection to SREC values.

In addition, since the system relies on market forces, and it proposes using the SREC system, which provides market transparency, it would facilitate the ability of the market to respond to potential over-supply or under-supply conditions.

3. Compatible with regional markets

Under the underwriter system, New Jersey would be in the unique position of both: 1) possessing the most substantial RPS-based solar set-aside in the country and 2) relying completely on SREC revenues to fulfill projects’ economic needs. As a result, New Jersey’s SREC market values would be substantially higher than REC values anywhere else in the PJM region and in the country as a whole. In the absence of any other form of financial support for PV systems, SREC values would need to be in the range of \$650/MWh in order to provide projects with an ROI at a level that would

stimulate enough project development to meet RPS requirements.⁵⁸ Therefore, while SRECs would not be restricted from being sold to other states or regions, trade of New Jersey SRECS outside the State would be highly unlikely, making the SREC market less liquid.

The author also believes that PJM's GATS and other regions will likely adopt New Jersey's SREC trading system. It should be noted that Pennsylvania is working out the details of a solar set-aside program and has retained Clean Power Markets, the same company that runs New Jersey's SREC program, to provide customer services that will facilitate SREC trade through the PJM GATS. It is not yet clear whether Pennsylvania SRECs would be of comparable value to New Jersey SRECs under a commodity market scenario in which SREC revenues are the only form of financial support for projects.⁵⁹

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

The proposed underwriter model offers a conceptually viable framework for providing projects with much-needed revenue certainty. From the perspective of potential project owners and investors, the underwriter system provides confidence in that it would place boundaries around their risk exposure. Further, by providing a floor value, the system would enable SRECs to be valued by financial entities at a significantly higher level than they otherwise would be in a market with no mechanisms to enhance revenue certainty. This would lower the project owners' cost of capital.

The author correctly points out that in a post-rebate New Jersey solar market, current rebate funding levels will need to be replaced by an equivalent amount of project debt, plus the cost of securing capital. The author further notes: "The RPS-based market will only succeed if the capital markets have the confidence necessary to secure project investment in volumes sufficient to meet aggressive RPS goals."⁶⁰ As discussed in Section 2.4.5, the uncertainty present in the New Jersey marketplace, coupled with the financial community's lack of familiarity with and confidence in REC markets in general, would make it challenging for projects to secure financing in a post-rebate environment unless some form of securitization of future revenue streams exists.

In addition to improving *access* to capital, the security provided by an underwriter system would also help lower the cost of capital. In the absence of any form of revenue securitization, those financial entities that *are* willing to support projects will dramatically discount the value of REC venue streams, resulting in higher risk premiums.

The author also explains that avoiding any **vintage constraints** on the SREC values of rebate-funded systems helps build investor confidence. Summit Blue agrees with the author that vintage constraints would introduce unnecessary market complexity and administrative costs, and would reduce investor confidence in the market. It is true that PV owners who received large rebates under the CORE program will not require nearly the level of SREC revenues that a non-rebate

⁵⁸ A financial model prepared by the author demonstrates that SREC revenues of \$650/MWh would produce a project ROI of 8.4% if the underwriter commitment lasted for ten years.

⁵⁹ California also possesses a rigorous solar development goal, though it is unclear how this will affect REC values in that state since the issue of REC ownership is currently unresolved. Through SB1, the California Public Utilities Commission set a 3,000 MW solar development target which is approximately double that of New Jersey's. However, California has a much larger population and geographic territory, as well as a much greater solar resource than New Jersey. Therefore, New Jersey's solar targets could still be viewed as the most rigorous in the country.

⁶⁰ White Paper Series: New Jersey's Solar Market Transition to a Market-based REC Financing System, p. 9.

funded project would in order to recover their project investment. However, those early adopters and, in some cases the investors that backed them, made their investment based on the assumption that the systems would create SRECs that could be sold into the open market for the life of the system. Changing these rules now would send a signal to investors that the New Jersey market is unstable and would exacerbate the existing issues associated with regulatory uncertainty in the state.

In summary, the proposed system would clearly result in greater investor confidence than would a no-revenue securitization approach. However, it is not clear that the proposed system would reduce issues of uncertainty to a level that will enable the program to have its intended effect. Regulatory uncertainty which, according to industry representatives, is currently the greatest factor limiting investor confidence in the New Jersey market, would still be a problem under the underwriter system. However, given that New Jersey's regulations must be "re-adopted" every five years, and given the BPU's authority to initiate processes to change RPS rules as it deems necessary, no transition strategy will be able to eliminate regulatory risk.⁶¹

5. Program readily adaptable to changing market conditions

This proposed program would be fairly adaptable to changing market conditions. First, the authors propose that the underwriting entity limit the issuance of underwriter commitments once enough have been executed to facilitate the quantity of development necessary to meet RPS goals. Further, within the boundaries of the floor and ceiling prices, market forces would be at work to provide adjustments to market pricing.

6. Facilitates self-sustaining market

The proposed system does facilitate the development of a self-sustaining market in that it simultaneously: 1) provides the revenue certainty that is so important to facilitate project development given the current state of market maturity in New Jersey and 2) relies on market forces to set actual SREC prices. This effect is enhanced by the fact that the underwriter system would encourage the development of "market making" participants such as aggregators and brokers who would be necessary to facilitate market transactions in the absence of state-supported programs.

Transaction Costs

1. Ensure transparent, auditable process

The author recommends using the SREC trading system already in place in New Jersey. Summit Blue agrees that the existing SREC system would provide sufficient verifiability.

On the issue of metering to provide real data on system performance, the author explains that the system would work equally well under the current SREC system policies (where production for systems <10 kW is estimated), or if all systems were metered to report actual production.

⁶¹ Under Executive Order 66 (1978), New Jersey's regulations must be re-evaluated every five years. In addition, as noted by BPU in the RPS Rules Adoption document, BPU has the authority to initiate a rulemaking process at any time to adjust existing rules as it deems appropriate.

Given the plans for a smart metering initiative in New Jersey, it would make sense to meter all PV systems as part of this process so that actual system performance data can be collected in an efficient manner.

2. Program design encourages simple efficient project logistics

The proposed system relies on dynamic market forces to facilitate SREC transactions. Under a market system, it is important for “market making” participants such as aggregators and brokers to participate in the market to reduce the “hassle factor” for small systems and to match up buyers and sellers in an efficient manner. Since several aggregators and brokers are already active in the New Jersey market, the proposed system should allow for simple, efficient project logistics.

3. Low administrative burden

The program would require significant administrative capacity. At a minimum, the underwriting entity would need to certify new projects, monitor the issuance of new commitments to ensure that they do not exceed the level necessary to meet RPS targets, monitor the needs and performance of existing commitments, and administer funds to those projects that make “calls.” These administrative tasks would come at a cost. It would also take time to establish the necessary policies and procedures for managing the underwriter commitments.

The program would result in additional administrative burdens for BPU in that it would require the “underwriter price” to be set periodically. The proposal suggests that this be the responsibility of the ACP Advisory Board. The process of setting the ACP is already fraught with challenges. The ACP Advisory Board must attempt to set the ACP level high enough to provide LSEs with an incentive to participate in the REC market rather than making ACPs. At the same time, the Board must be conscious of the potential ratepayer impacts if the REC market were to fail and ratepayers were to bear the cost of a significant use of ACPs for RPS compliance. Introducing the added challenge of setting a REC floor value would only make the ACP Advisory Board’s job more challenging and controversial.

Ratepayer Impact

1. Low overall cost of compliance

By providing a minimum guaranteed revenue stream for projects, an underwriter program would likely reduce the cost of capital for projects. As a result, the projects could accept lower SREC values, which would translate into lower RPS compliance costs for ratepayers. Furthermore, extending the underwriter commitment over a 15 year period would enable REC values to be lower than under a scenario in which projects were expected to recover their investment over a shorter period of time (i.e., the auction-set pricing proposal).

However, certain aspects of the underwriter proposal pose risks that could have negative ratepayer impacts. First, as noted in the proposal, if the REC market’s floor and ceiling values were not set appropriately, or if the underwriter were to issue too many underwriting commitments and a surplus situation were to occur, the underwriting entity could be exposed to great financial risk. If a public-sector entity is functioning as the underwriter, the financial losses associated with a “broken” underwriter system would be passed along to ratepayers. If a private-sector entity were chosen as the underwriter, the risk of a negative program outcome would result in a high risk

premium that may take the form of very high administrative costs.⁶² In either case (public or private-entity underwriter), the potential for poor regulatory decision-making to “break” the underwriter system poses a substantial risk for ratepayers.

A second possible risk for ratepayers is that the underwriter program’s administrative expenses, together with higher SREC values associated with a post-rebate marketplace could result in ratepayer costs (on a \$/MWh of solar generation basis) that are comparable to those of the existing rebate system. Financial considerations and potential ratepayer impacts associated with the underwriter proposal are discussed further in Section 5.

A third source of risk for ratepayers pertains to using ACP revenues as the program’s primary sustaining funding source. The author states, “As long as the maximum ACP payments exceed the maximum underwriter exposure (and assuming banking of receivables across years), the underwriter is economically viable.”⁶³ However, beyond maintaining a balance between program revenues and expenses, it would be necessary to ensure a high enough volume of revenue to provide the funding necessary to support the underwriter’s substantial administrative functions. Assuming functional market conditions (i.e., ACP levels are set high enough to provide LSEs with an incentive to procure their RECs in the marketplace rather than making ACPs, and market supply and demand are relatively balanced), there should be minimal ACP revenues, and this could result in a lack of sufficient funds to support the program. General uncertainty about the level of ACP revenues would also limit investor confidence and, therefore, make ACP revenues a poor source of funds on which to depend for program support.

In addition, on principle, a transition strategy dependent on ACP revenues seems poorly aligned with ratepayer interests since ACPs are, by nature, the compliance mechanism with the highest cost to ratepayers. Instead, the state should seek ways to limit the use of ACPs.

2. Economically efficient (no over- or under-subsidization)

The proposed model is fairly economically efficient in that it only provides support to projects if they are unable to find SREC value in the marketplace. In contrast to rebates or tariff systems which would provide financial support to a project regardless of market conditions, since the underwriter program provides projects with a resource of “last resort,” it is possible that ratepayers would see very little cost associated with pay-outs for the program if the market were functioning effectively.

However, an element of economic inefficiency exists in the proposal in that imposing constraints both on the floor and ceiling values for RECs limits the ability of market dynamics to play out. Regardless of how diligent a decision-making body is in evaluating the appropriate levels at which to set the floor and ceiling values, the process will never be able to predict future changes in the market that could dramatically reduce or increase project costs to levels that would, in the absence of price floors and ceiling, have resulted in REC pricing at below the floor value or above the ceiling value. This weakness can be managed through periodic reviews of the appropriateness of

⁶² The author notes that a government entity, such as the Economic Development Authority (EDA), would be the ideal candidate to play the role of underwriter. However, it is not clear that the EDA would be interested in serving this function. If EDA did agree to manage an underwriter program, it is possible that the Authority would outsource actual program administration.

⁶³ White Paper Series: New Jersey’s Solar Market Transition to a Market-based REC Financing System, p. 18.

floor and ceiling levels, but the existence of these reviews also present uncertainty in the market, as changes in the floor and ceiling values could greatly affect project economics.

While it is not discussed in the proposal, one way to make the system more economically efficient would be to use a “contract for differences” approach in which the underwriter price would vary depending on changes in retail electricity rates. This would reflect the fact that revenues necessary from the SREC market (to produce a target ROI) would vary depending on changing energy market conditions. This approach may result in added administrative costs. An alternative means of avoiding over-subsidization of projects would be to decrease the underwriter price during the later years of the contract to reflect the likelihood that SREC prices will decrease over time. This would increase the chances that committed projects will continue to be able to find more competitive SREC values from the market than they can from the underwriter commitment, thus limiting the risk exposure of the underwriter.

3. Low program implementation costs

As noted above, the implementation costs of the underwriter program have not yet been determined. It is clear that the system would require substantial administrative capacity and that a number of important decisions would need to be made to facilitate an underwriter program. It would also take a significant amount of time and effort on the part of BPU staff to identify and contract with an underwriting entity, to obtain authority to direct ACP funds to the underwriter, and to facilitate the process of establishing an underwriting price.

Support for Other Policy Goals

1. Equity of opportunity to participate

The proposed structure is equitable to some extent in that *it allows both small and large systems to participate* in the market. However, the proposed model is inequitable in some respects as well. First, in the absence of any rebate funds, it would be necessary for small systems to obtain financing, and the need to take on debt could limit interest among potential residential and small business owners. This could raise equity concerns of cross-subsidizing across rate class and customer segment. In addition, the proposed program would not allow large-scale (>2 MW) systems to generate SRECs.

2. Ability to encourage development by target categories

The underwriter proposal provides no specific mechanisms for encouraging development by customer categories that would advance various policy goals.

3. Congestion relief

The proposed program does not provide any unique benefits in the area of promoting congestion relief.

5.2.2 Commodity Market Proposal

Summary

The author proposes a market-based system relying on the current SREC trading platform, as well as adoption of the proposed underwriter model discussed above. Therefore, the ACP Board would set floor

(underwriter price) and ceiling (ACP) prices. This proposal is distinct from the underwriter proposal in that it supports: 1) the temporary continuation of rebates for small systems; 2) extending trading lifetime of RECs to 2 years; and 3) enabling large scale (>2MW) solar facilities to generate SRECs.

Key Functional Components of the Proposed Approach

1. Continue Use of SREC Trading System to Set SREC Market Prices: SREC prices would be set by market forces resulting from the negotiation of bilateral transactions between project owners and LSEs.
2. Raise Solar ACP to at least \$650/MWh: The author proposes to raise the ACP and maintain it at a level that would: 1) replace the current economic value of rebates and 2) sustain the pace of project development necessary to fulfill RPS goals.
3. No Limits on SREC Value Based on Project Vintage: There would be a single class of SRECs with no constraints on SREC value based on the year the system entered into operation.
4. Complete CORE Projects in Queue: Fulfill all current rebate commitments, but allow projects to opt-out of the rebate if they prefer the underwriter form of support.
5. Continue Rebates for Smaller Projects: Once SBC funds already earmarked for the CORE rebate program through 2008 are exhausted, renew SBC funds and continue providing some rebate funding to small projects (<100 kW) on a declining schedule through 2011.
6. Make 10-15 Year Underwriter Commitments. The author proposes adoption of the Underwriter Model as proposed by Mark Warner.
7. Extend REC Trading Life to 2 Years: The goal of this proposed measure is to provide greater flexibility in trading timelines.
8. Allow Grid-Supply Systems (>2MW) to Generate SRECs: (i.e., systems too large to qualify for net-metering): Given the aggressive solar goals in the RPS, the author argues that larger systems will be essential to achieving the goals in a cost-efficient manner.

Strengths and Weaknesses According to Evaluative Criteria

Note that because the proposed Commodity Market Model advocates adoption of the proposed Underwriter Model discussed in Section 5.2.1, there is significant overlap in our criteria-based assessment of the two proposals. Therefore, the reader is referred to the underwriter proposal discussion for all but the points highlighted below, which are unique to the commodity market proposal.

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

Given that the model would enable large-scale (>2MW) systems to generate SRECs, it would facilitate more a more rapid rate of PV capacity growth.

2. Enables scale-up or scale-back of growth as needed

See underwriter proposal discussion.

3. Compatible with regional markets

The commodity market proposal advocates **extending the SREC trading lifetime to two years**. The author of the proposal, and a number of other industry representatives support the extension of the SREC trading life as a means of increasing market flexibility. Summit Blue agrees that added flexibility in application of RECs makes sense as a means of protecting investments, and for logistical reasons, and that it is compatible with regional markets. From the perspective of regional market compatibility, three other states (jurisdictions) in the PJM region already have three-year REC lifetimes (D.C., Maryland, and Delaware), and Pennsylvania has a compliance banking provision that provides some protection in the case of an over-supply situation in a given year.⁶⁴ The standard PJM schedule includes an annual settlement period in which any unsettled certificates are transferred to “residual mix” for retirement. However, to accommodate states that allow extended REC trading lifetimes, PJM GATS Operating Rules include a special provision that allows continued trade of RECs that otherwise would have been retired.⁶⁵

From a logistical perspective, the rationale for an extended REC-trading life is sound as well. Since both the PJM GATS and SREC systems are structured such that SRECs are created on a monthly basis throughout the Energy Year and that there is a three-month true-up period following the close of the Energy Year, there is less flexibility in planning for those SRECs generated toward the end of the Energy Year. Through conversations with the SREC administrator, it appears that there can be some timing issues associated with actually generating the end-of-year SRECs in time to be traded before the end of the true-up period. While issues associated with the timing SREC creation will be minimized once an automatic metering system is eventually in place, the fact remains that the planning horizon for late-year SRECs is relatively short. A two-year SREC trading life would provide a cushion to protect generators’ SREC revenue in the case of slight over-supply scenario.

On principle, while there is a strong national precedent for keeping REC trade generally consistent with the period in which the associate energy was created, even the Center for Resource Solutions, a highly reputed organization active in setting standards for the voluntary REC market, is supportive of the 2-year REC trading lifetime.⁶⁶

Further investigation is necessary to determine the extent to which a two-year REC trading lifetime would be compatible with New Jersey’s information disclosure standards.

⁶⁴ Brooks, Cameron, David Bogomolny, Scott Weiner and Michael Winka, “Northeast RPS Compliance Markets: An Examination of Opportunities to Advance REC Trading.” NJ Office of Clean Energy, Rutgers University Center for Energy, Economic and Environmental Policy, and Clean Energy States Alliance, October 12, 2005. Note that in New England, both Massachusetts and Rhode Island also allow up to 30% of a given year’s RPS requirements to be met through early compliance.

⁶⁵ This extended REC trade is facilitated through the use of “Clean Energy Portfolio Standard (CEPS) Subaccounts.” PJM Environmental Information System, “Generation Attribute Tracking System (GATS) Operating Rules” Revision 4, may 10, 2006, p. 33.

⁶⁶ Jan Hamrin, president of CRS, explained that, in the voluntary green power market it is important to match the period of generation with the REC lifetime for the purposes of consistency with customer expectations. However, she believes that for REC compliance purposes, greater flexibility is appropriate. Interview with Jan Hamrin, President, Center for Resource Solutions, December 1, 2006.

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

See underwriter proposal discussion.

5. Program readily adaptable to changing market conditions

See underwriter proposal discussion.

6. Facilitates self-sustaining market

See underwriter proposal discussion.

Transaction Costs

1. Ensure transparent, auditable process

See underwriter proposal discussion.

2. Program design encourages simple efficient project logistics

For owners of smaller systems owners, for whom project logistics can be a significant deterrent, the proposed system would simplify the installation and financing processes by maintaining a rebate program. The lower effective upfront project cost associated with a rebate program would making it easier for small system owners to self-finance their projects.

By allowing large grid supply systems to generate SRECs, the proposed system would also facilitate economies of scale and the development of cost-efficient projects.

Also, as noted in the underwriter proposal discussion, the proposed system relies on dynamic market forces to facilitate SREC transactions. Under a market system, it is important for “market making” participants such as aggregators and brokers to participate in the market to reduce the “hassle factor” for small systems and to match up buyers and sellers in an efficient manner. Since several aggregators and brokers are already active in the New Jersey market, the proposed system should allow for simple, efficient project logistics.

3. Low administrative burden

See underwriter proposal discussion.

Ratepayer Impact

1. Low overall cost of compliance

See underwriter proposal discussion. Note that the approach proposed in the commodity market model has elements that could both increase and decrease ratepayer costs relative to the underwriter proposal. On the one hand, allowing grid-supply projects to generate SRECs should lower costs to ratepayers since SRECs from these projects would put downward pressure on SREC values. On the other hand, providing rebates to small systems would represent an additional ratepayer cost. It can be assumed that the impacts of these two factors would, to some extent,

cancel each other out. However, a more thorough analysis would be necessary to determine the net effects.

2. Economically efficient (no over or under-subsidization)

By allowing grid supply PV systems to participate in the market, the proposed model facilitates economies of scale associated with building large-scale PV systems. This has the potential to reduce SREC costs and thus relieve ratepayer impacts. The system is efficient in that it limits the more expensive form of support (rebates) to only those systems that need this type of support.

3. Low program implementation costs

In addition to the implementation costs discussed under the underwriter proposal section, there would be additional implementation costs associated with the commodity market proposal since it advocates the continuation of rebates for small systems.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

The proposed structure is equitable in that it provides opportunities for both very small and very large systems to participate in the market.

2. Ability to encourage development by target categories

To the extent that participation by small customers is a goal of OCE, the commodity market model would further this goal by providing rebates for that customer class.

3. Congestion relief

Since systems >2MW would be built in New Jersey, this could potentially detract somewhat from the DG benefits that would result from having a greater number of smaller systems distributed throughout the grid. However, the introduction of grid-scale PV systems should, in general, reduce the need to import power from out of state which should help relieve congestion problems.

5.2.3 Hybrid-Tariff Model (*Tariff Revenue Plus SREC Revenue*)⁶⁷

Summary

The proposed model would provide projects with a stable, long-term revenue source by having Electric Distribution Companies (EDCs) issue premium payments/credits to solar project owners on a per kWh basis. It would be an energy-only tariff, but would be a companion to the separate SREC revenues that project owners would receive from participation in the SREC market (which this model proposes to leave

⁶⁷ While this proposal was referred to as the “Tariff Model” in the whitepaper series, we refer to it here as the “Hybrid Tariff” to distinguish it from the “Full Tariff Model” that is also being discussed as an alternative in New Jersey, though no formal whitepaper proposal was submitted in support of the full tariff concept.

untouched). The author proposes a system that could be modeled after New Jersey’s existing Business Enhancement (BE) rider.

This model is essentially a PBI administered by a utility. Conceptually, it bears significant similarities to the California Solar Initiative. The model proposed by the author would provide solar projects with revenue both from the PBI payments and from SRECs.⁶⁸

Key Functional Components of the Proposed Approach

1. **Implement a Renewable Energy Tariff:** Systems that meet certain criteria could apply to receive a premium (above retail rate) payment/credit for each kWh of energy produced. This revenue would be in addition to the net metering benefit, and SREC revenues.⁶⁹
2. **10-Year Tariff Contract Between EDC and PV System Owner:** Eligible PV system owners would enter into a 10-year agreement with their EDC to be served by the PV Tariff program. A tariff rate (either fixed or declining) would be pre-established for the term of the agreement. The tariff level applied to each new 10-year contract issued during the following year would be set annually at a level that provides potential project owners with a target ROI, making certain assumptions about the market value of SRECs (i.e., $ROI = \text{tariff revenues} + \text{SREC revenues} - \text{system upfront cost}$).
3. **PV System Owner Maintains Ownership of SRECs:** Since SREC revenues would remain a fundamental resource for providing PV system owners with a reasonable ROI, they would retain title to SRECs.
4. **Only New Systems Eligible for Tariff:** This would keep systems that already received rebates from receiving more than their “fair share” of incentives.
5. **Dedicated Meter to Track System Production:** A separate meter would be necessary to measure total

Who Administers the PBI?

The Hybrid-tariff plan assessed here proposes that the EDCs be responsible for making tariff payments / credits through the monthly electric bill, and that the program funds be collected through rate recovery. A primary benefit of this approach is that it leverages EDCs’ metering and billing capacity to increase administrative efficiency. However, EDCs are not the only entities that can administer a PBI.

Another option worthy of consideration is to have OCE or its “market manager” (program administrator) administer the program. PBI payments would come from SBC funds instead of being rate-based.

This arrangement would avoid any need for buy-in from the EDCs, and would appear to be a good use for the SBC funds.

Although the analysis here focuses exclusively on involving the EDCs, it’s important to remember that this is NOT the only choice.

⁶⁸ The key distinction between the terms “tariff” and “performance-based incentive” (PBI) is that a tariff typically refers to a rate structure administered by a utility-type entity (in this case, the EDC), whereas the term PBI is not necessarily administered by a utility. In the case of the California Solar Initiative, the incentive program is managed by the California Energy Commission (which manages only the New Solar Homes Partnership component of the Initiative) and the California Public Utilities Commission. However, the incentives are actually issued through program administrators, the utilities. Another distinction that has been made between PBIs and tariffs is that tariff programs, as implemented in Europe, do not involve any net-metering benefit or REC benefits. Rather, they are structured to provide system owners with full recovery of their project investment over 15-20 years. For additional information on the tariff v. PBI distinction, see Appendix D.

⁶⁹ The author explains that the renewable energy tariff could take the form of a rider applied to standard operating tariffs, following the model of JCP&L’s Business Enhancement rider designed to promote economic development.

kWh production from each system. System owners would receive revenue based on system performance.

6. Issue Electric Bill Credits: Premium energy payments would be delivered to system owners in the form of a credit on their electric bills.
7. Rate Recovery as Funding Mechanism: EDCs would recover tariff payments and administrative fees through rate increases.
8. Limit Tariff Payments as Needed to Maintain Market Balance: Annual limits to tariff payments could be established to avoid over-supply conditions (i.e., once target # of MW are registered in tariff program, a waiting list could be started for the following year until there is a need to encourage additional supply to meet rising RPS goals). This would function as a “circuit breaker” for both the cost of the tariff program and maintaining supply/demand balance.
9. Vary Tariff Rate Across Market Segments / System Sizes to Support Various Policy Objectives: Tariff rates would vary across market segments/system sizes so that greater incentives could be offered for residential projects, projects in transmission/distribution constrained areas, etc.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

The proposed model does not possess any unique elements that would enable it to facilitate more rapid growth than other models. Like all of the other proposed models, this model would likely require a rate proceeding. If the proposed system were to gain necessary support from EDCs, it has the potential to be implemented rather quickly since it could leverage the existing billing capacity of the EDCs to facilitate tariff system operations. However, it is important to recognize that the success of this model is dependent on buy-in from EDCs, and it is unclear at this stage whether EDCs would support the model. The Summit Blue Team was unable to gauge EDC support for such a model given the limited timeframe within which this report was prepared.

Once implemented, the hybrid-tariff approach should provide sufficient support to facilitate the pace of development necessary to meet RPS requirements.

2. Enables scale-up or scale-back of growth as needed

As the author points out, tariff commitments could be limited so that they are only issued to the number of systems that are anticipated to be necessary to fulfill RPS requirements. This feature of the program would function as a “circuit breaker” tool to help keep supply and demand in balance in the market.

4. Compatible with regional markets

The author suggests continued generation of SRECs from PV projects and continued use of the SREC system for trading SRECs. Since project owners would receive revenue from the hybrid-tariff program in addition to SREC market, this would enable lower SREC values to exist. Lower SREC values would be more compatible with REC values in other parts of the region and the

nation, thus improving the ability of New Jersey SRECs to be traded to out of state entities in an over-supply situation.

5. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

By providing system owners with a guaranteed stream of revenue for a fixed period, the proposed system could substantially improve investor confidence in project economics. The tariff structure may also enhance investor confidence and improve project economics by enabling some projects to take advantage of greater tax benefits than they would if they received a rebate.⁷⁰

Since funds used for tariff payments would be rate-based, these funds would likely be considered more secure than an underwriter program depended on ACP revenue. Yet, since the guaranteed revenue stream would only cover a portion of the project's debt, revenue certainty would still be a problem for the portion of project debt that is expected to be recovered from SREC revenues.

Given the inherent uncertainty in New Jersey's regulatory system (i.e., the five year sunset requirement resulting from Executive Order 66), it is impossible for this or any other strategy to solve the problem of regulatory risk.

6. Program readily adaptable to changing market conditions

The author notes that a variety of options would be available to ensure that tariff levels adapt to reflect changing market conditions. For example, a tariff schedule could be established in which tariff levels would automatically decrease gradually over time, or a set of criteria could be established and used as the basis for periodically re-evaluating the appropriate tariff level. The author also points out that for the portion of project revenue provided by SRECs, natural market adjustments would be reflected in changing SREC prices.

7. Facilitates self-sustaining market

Since this model would involve a continuation of SREC trading activity, it has the potential to facilitate gradual and consistent market maturity that could be self-sustaining upon the program's expiration. The proposed model provides projects with revenue certainty at a time when this type of support is of critical importance in the market. Therefore, the proposed approach should provide the market with the support it needs to gradually transition to a state of self-sufficiency. However, it should be noted that aggregators and brokers would be less likely to thrive than they might under a market scenario in which the bulk of a project's ROI is dependent on SREC revenues. This is because SREC values, and subsequently the cumulative value of the "middleman markup," would be less than under a fully market-based approach.

Transaction Costs

1. Ensure transparent, auditable process

The author recommends using the SREC trading system already in place in New Jersey. Summit Blue agrees that the existing SREC system would provide sufficient verifiability.

⁷⁰ See Wisner, Ryan and Mark Bolinger. (2006) "Federal Tax Incentives for PV: Potential Implications for Program Design." Lawrence Berkeley National Laboratory, San Francisco, CA.

2. Program design encourages simple efficient project logistics

The tariff system would make project logistics somewhat more complex than under other proposed transition strategies. As with the underwriter and commodity market models, potential system owners would need to secure upfront capital as well as a buyer for their SRECs (whether by negotiating with an aggregator or identifying an individual SREC buyer).⁷¹ However, since there would be no guaranteed revenue stream to cover the portion of projects debt dependent on recovery through SREC revenues, the revenue certainty benefits of the approach would be limited. This could make it more difficult for projects to obtain financing than under a system that provided more substantial revenue certainty, such as the full-tariff model discussed later.

An additional logistical challenge of the tariff program is that it could limit the ability of projects to participate in innovative ownership structures. For example, one unique ownership structure in place in the New Jersey market today involves having the developer absorb the upfront cost of the system and letting the project host buy the system in installments over time. Since tariff revenues/credits would accrue to the metered electricity customer through their monthly electricity billing, rather than being paid directly to the developer, this may limit the appeal to developers of pursuing such innovative investment/ownership approaches.

3. Low administrative burden

The tariff program would place an administrative burden on EDCs, as they would be expected to administer the program. However, the necessary administrative functions should require minimal staff training or capital investment since the EDCs are already positioned to provide customers with various billing options and rates. Furthermore, automated metering that would likely be installed on all new systems under “smart metering” efforts that are already in the planning stages would improve administrative efficiency and reduce the cost of implementing a tariff program.

From the perspective of the project owner, the hybrid-tariff program would result in a level of administration comparable to that of an underwriter program since they would need to find SREC buyers.

From the perspective of the state, the program should require a fairly low administrative burden. The largest administrative tasks would be setting the annual tariff level and monitoring capacity growth to determine when tariff commitments should stop being issued in order to maintain a balance between supply and demand.

Ratepayer Impact

1. Low overall cost of compliance

The author explains that, *assuming* hybrid-tariff payment of 15 cents per kWh paid out over 10 years, the gross costs of a hybrid-tariff incentive program for ratepayers would be half compared to a rebate program (assuming a rebate value of three dollars per watt of installed capacity).⁷² This is

⁷¹ Though it should be noted that for smaller systems, the Commodity Market Model would provide somewhat more streamline project logistics since they would receive rebates.

⁷² The author uses an 8 MW system as an example and shows that a three dollar per watt rebate would cost ratepayers \$24,000,000 in one lump sum, whereas a tariff payment of 15 cents per kWh paid out over 10 years would cost ratepayers \$13,200,000, paid out

due to the fact that under the rebate program, the incentive is paid in one lump sum upfront, whereas with the tariff program the incentive is paid out incrementally over time.

One must also consider the administrative costs associated with tracking system performance and issuing incentive payments over the term of the tariff commitment. While EDCs are well-positioned to perform the administrative functions associated with a tariff program, the cost of EDC administrative efforts will still be passed through to the ratepayers.

The proposed structure would limit participation to only new systems that have not already received rebates. One can assume that the existence of this proposed tariff program would lead to lower SREC trading values since project owners would not be as dependent on SREC revenues to recover their investment. Therefore, unlike the other proposed models, rebate-funded systems could continue deriving value from participation in the SREC market without ending up with windfall profits. The simplicity of this mechanism for limiting potential windfall profits for rebate-funded systems is an important benefit of the tariff proposal.

Since the proposed program employs a combination of incentive types (tariff and RECs) the author explains that it would “diversify the risk of volatility of any one incentive.”⁷³ This diversification of regulatory risk could have some benefits. However, as discussed earlier, the hybrid-nature of the proposed system means that the benefits associated with each incentive type cannot be maximized.

2. Economically efficient (no over or under-subsidization)

The proposed model is economically efficient because it distributes funds on a performance basis; it rewards high quality and well-maintained PV installations and avoids wasting funds on projects that are poorly sited or installed.

Furthermore, tariff levels could vary based on the needs of different market segments so that the incentive matches the needs of the project owner and over-subsidization or “free-ridership” is minimized.

As noted in the section above pertaining to the mechanism’s adaptability to changing market conditions, periodically adjusting the tariff levels set forth in new tariff commitments would enhance economic efficiency of the program. The level of economic efficiency could potentially be further enhanced by structuring the tariff commitments on a “contract for differences” basis, ensuring that project owners only receive the level of incentive needed to achieve a target ROI. However, administrative costs of a “contract for differences” approach should be further evaluated to determine whether they would outweigh the likely ratepayer benefits.

3. Low program implementation costs

Given the need for BPU to set tariff levels annually and to monitor the supply / demand balance, as well as the EDCs need to track system production and manage payments / credits, it is clear that the tariff program would carry substantial implementation costs. However, these costs would likely be comparable to or lower than the costs associated with an underwriter or auction-set pricing / standard contract approach.

over 10 years. This calculation is consistent with an assumed annual kWh production rate of 1,100 kWh per kW of installed capacity, or a capacity factor of roughly 13%, both of which are realistic assumptions for New Jersey solar projects.

⁷³ White Paper Series: New Jersey’s Solar Market Transition to a Market-based REC Financing System, p. 58.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

The proposed program is described by the author as “allowing all ratepayers to participate fully.” The accessibility of the program to all customer-sited generators, coupled with the author’s proposal to adjust tariff rates to meet the needs of different project owners (i.e., residential and public entities) would make the tariff program an equitable one.

2. Ability to encourage development by target categories

As the author explains, the program could be structured to distribute incentives where they are most needed, such as congested areas of the distribution system, public buildings, “smart growth” areas, etc. This could be done by establishing a base-level tariff and applying a multiplier to increase the incentive for target participants. This ability to tailor the incentive to reflect both policy priorities, as well as the varying economic needs of different market segments, is one of the greatest strengths of this proposed transition strategy.

3. Congestion relief

See comments above.

5.2.4 Auction-Set Pricing, Standard Contract Model

Summary

SREC prices would be set in an annual auction in which approximately 25% of the SRECs required to fulfill RPS goals for the following compliance year would be auctioned to LSEs. The authors note that the auction would be similar to that which currently occurs annually for Basic Generation Service (BGS). In an effort to reduce transaction costs and make it easier for LSEs to enter into SREC contracts, BPU would develop a standard contract for all LSEs to use for SREC purchases. LSEs would only be held responsible for RPS compliance shortages via the ACP if they chose not to participate in the auction-set pricing / standard contract system. PV systems in New Jersey would only be eligible to produce SRECs during their first five years of operation. This would require systems to receive higher SREC prices during their short economic lifetimes than they would if system costs were amortized over a longer period (such as the 10-15 year economic time horizon applied under other proposed strategies).

Key Functional Components of the Proposed Approach

1. Standard Contract Terms: BPU would develop a standard contract so terms would be consistent for all transactions. The contract would be developed by an administrator through a stakeholder process and would require a five-year term.
2. Annual Auction: In an annual auction, 25% of the SRECs LSEs are projected to need to meet RPS requirements would be put up for auction. Bidders would specify the SREC price they’re willing to pay under a five-year standard contract. Winning auction participants would be eligible to sell

SRECs for a price equal to the highest qualifying bid price (“Dutch Auction”) for the specified SREC volume. If less than 25% of RPS-required supply participates in the auction, BPU could cancel the auction and retain the market clearing price (MCP) from the prior auction.

3. Auction Price becomes Market Clearing Price: After the auction, BPU would post the auction results and the highest qualifying bid would become the Market Clearing Price for the following year.
4. Contract Execution: The BPU or administrator would allocate SREC bids among the LSEs and LSEs will have 60 days to execute SREC contracts.
5. Market Clearing Price (MCP): Pricing set during the auction would function as the basis for all SREC pricing during the following year. Until the next auction, and for SREC volume up to the state’s RPS requirement, solar owners who weren’t winning bidders could negotiate SREC sales contracts under the following conditions:
 - a. > 30 kW PV system owners could sell SRECs for 95% of MCP and
 - b. < 30 KW PV system owners could sell SRECs for 105% of MCP.
6. Limited Role for Alternative Compliance Payment (ACP): ACP would only apply if LSEs refuse or fail to participate in the program. However, since the ACP mechanism would remain in place as a penalty, the ACP Advisory Board would still need to adjust the ACP periodically.
7. Five-Year Economic Life of Systems: Systems would be limited to creating / receiving payment for SRECs during the first five years of operation as a means of limiting financial risk associated with a longer-term economic life, thus lowering the cost of capital.
8. RPS Target Adjustments to Accommodate Five-Year Economic Life of Systems: To account for the fact that systems would be restricted to creating SRECs for only first five years of their operation, RPS requirements would be adjusted. The basic adjustment described would shift the timing of RPS requirements but would ensure that, by 2020, the overall solar generation requirements would be consistent with the overall amounts required in the RPS rule.
9. Potential Additional RPS Target Adjustments to Counter Likely Price Spikes: To minimize ratepayer impacts from higher SREC prices that will result after rebates are eliminated, the authors suggest RPS targets could be adjusted further to weight the requirements toward the latter years of the RPS compliance schedule. The authors note that the need for early target adjustments would be reduced if transition away from rebates occurred gradually rather than abruptly.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

With regard to facilitating rapid growth in PV system development, it is not clear that this proposal possesses any particular benefits relative to the other proposals. The authors claim that the system could be fully implemented within six months. Summit Blue disagrees with this assumption; implementation of the plan would require a great deal of decision-making and preparation. At a minimum, the proposed system could not be implemented in time to affect the coming Energy Year, as the BGS auction for the coming Energy Year is scheduled to occur in February.

2. Enables scale-up or scale-back of growth as needed

The authors propose to limit the ability of market participants to enter into REC contracts, once the projected amount of SRECs necessary to fulfill the RPS target in a given year has been put under contract. Based on analyses, Summit Blue Team thinks this is a poor strategy for managing the supply / demand balance in the market, due to the standard contract requirement of the proposed model this “circuit breaker” strategy would essentially *prohibit* projects from being built over and above that deemed necessary to meet the RPS targets. This does not allow any flexibility to build supply to meet the potential needs of the voluntary market.

The authors also offer two potential approaches for adjusting details of the RPS to fit the market conditions that would result from implementing the auction system. Under the first approach, RPS targets are adjusted to account for the fact that SREC production is limited to the first five years of operation in such a way as to maintain the total generation of solar power required by the RPS rule. The authors also describe an approach in which real reductions would be made in RPS solar requirements as a means of reducing the “rate shock” that would result from compressing the projects’ economic lifetime to five years.

Adjusting RPS compliance details, even if it only amounts to shifting the years associated with compliance levels, is an unfavorable approach that could further weaken regulatory certainty and thus, investor confidence, in the New Jersey market. Credible and consistent RPS rules must form the foundation of the New Jersey renewable energy market if it is expected to sustain itself over time.

3. Compatible with regional markets

While the proposed model would allow the sale of SRECs to out of state entities, it would effectively prohibit such trade from happening, as SREC values would rise to such high levels in order to facilitate a five year economic time horizon for projects. The authors note that Pennsylvania is considering an auction system for PV, and that if it does, the two states could be compatible. However, it is not clear that Pennsylvania will adopt such an approach, and there are no indications that other states in the region are considering such an approach.

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

The authors explain that the proposed approach would maximize investor confidence by compressing the economic life of systems to a five year period that corresponds with the lifetime of regulations in New Jersey under Executive Order 66. It appears that the proposed measure to limit the period of SREC production for PV projects to five years would face significant hurdles, particularly due to the likely “rate shock” that would result from the required higher SREC values. However, assuming acceptance of a five year SREC production provision, this shortened economic time horizon could, in fact, boost investor confidence *at the project level*.

At the market level, the auction system would likely detract from investor confidence. First, it would involve changes to RPS requirements that would send a signal that the existing rules are negotiable and subject to change. The auction system could also produce vastly different market clearing prices from one year to the next and is vulnerable to gaming. Finally, under an auction system in which prices are set only once per year, it is hard for investors to plan for projects in the pipeline and expected to come online in the following year. For these reasons, it appears that the

auction approach would not succeed at providing the investment community with broad confidence in the New Jersey marketplace.

5. Program readily adaptable to changing market conditions

On an annual basis, the proposed auction system would adapt to changing market conditions by producing different market clearing prices in different years. However, the system would limit the potential for minor market corrections and adjustments in the prices to take place during the course of each year. In addition, by requiring all market participants to use the same standard contract, the proposed system would limit innovation and would restrict the possible emergence of new contract terms to address evolving market conditions.

6. Facilitates self-sustaining market

The authors of the proposed model take a decidedly “command and control” approach to facilitating a market-based system. The proposed approach would, by its nature, eliminate the role of middlemen in the marketplace. Therefore, the market would remain dependent on the auction system unless and until the solar market reaches a point of economic parity with conventional electricity generations, at which time SREC revenues and SREC trading would no longer be necessary to facilitate growth in the solar energy market.

Transaction Costs

1. Ensure transparent, auditable process

The auction-set pricing system would ensure transparency, in that pricing (as it relates to the market clearing price) and contract terms of all deals would be centrally determined. Presumably, mechanisms in the SREC system would prohibit SRECs from being traded if the parties to the transaction could not demonstrate that they used standard contract and pricing provisions.

2. Program design encourages simple efficient project logistics

The simplicity and administrative efficiency of SREC negotiations under the auction/standard contract approach would, indeed, be superior to all other transition proposals. However, it is not clear that it would be easy to get projects built under the proposed system. The authors explain that projects would likely participate in the auction at a point when they have secured a contract but have not yet been built. Prior to the auction event, potential project owners would likely sign contracts for which execution would be contingent on the outcome of the auction. Having project development be contingent on the outcome of an auction is problematic. First, since the auction system would produce only one market pricing data point per year, it would be difficult for market participants to project and plan for project economics. Furthermore, with many contracts contingent on the outcome of the auction, it could produce a surge of project construction activity following the auction event, which could be unmanageable for installers, manufacturers, inspectors, EDCs approving net metering contracts, and other entities who play an essential role in getting projects up and running.

3. Low administrative burden

The proposed model would come with high administrative costs. The process of organizing and facilitating the auction event would be administratively intensive. Management and administration of the auction process would also likely be highly scrutinized, as gaming is a real possibility when

only a fraction of the market (i.e., 25%) would participate in the actual auction event. Further, administrative activity would be required to monitor adherence to the market rules (i.e., determining who is allowed to get what pricing based on their role in the market- small versus large, winning versus losing auction participant, etc.) to track the status of contracts administered relative to RPS requirements (the administrator would restrict further contracts from being executed once the amount of supply necessary to meet the RPS requirements had been met), and to plan for the following year's auction event (i.e., determining whether there is enough supply in the pipeline to warrant holding an auction in that year, etc.).

The authors explain that ACP issues would not need to be dealt with under this system. However, since it is still proposed to be used as a penalty for LSEs that don't participate in the auction system, the ACP Advisory Board would still need to go through the process of setting an ACP, and administrative capacity would need to exist to deal with the possible flow of ACPs.

Ratepayer Impact

1. Low overall cost of compliance

The authors' economic analysis shows that ratepayer impacts of the auction approach are over 60% lower than the commodity market approach on a future value basis and that they are 27% lower on a present value basis. The authors explain that rate impacts would be even lower in a supply shortage situation, since under the auction model, participating LSEs only pay for RPS compliance associated with supply that's available in the marketplace.

2. Economically efficient (no over or under-subsidization)

The proposed model would provide a significant level of economic efficiency in that it would employ market forces to set REC pricing, but would not include any of the middleman "markups" that typically exist in a more freely functioning market. The proposed model also employs economically efficient tactics by applying multipliers to the market clearing price to set contract pricing that rewards auction participation and provides different pricing for small versus large systems.

3. Low program implementation costs

While transaction costs associated with the auction model would be quite low, administrative costs would be as high, if not higher than they would be under any other proposed strategy. It is not clear to what extent the low transaction costs would offset the administrative costs of the program.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

All types of projects would be eligible to participate in the auction, as participants would be accepted on a first come, first serve basis. However, it is highly unlikely that small-scale projects would possess the knowledge or interest to participate in the auction process. Therefore, large systems with the most favorable project economics would likely drive the market clearing price. While this is positive from the ratepayer perspective, it is not favorable for the owners of small systems. Though small system owners (<30kW) would benefit by receiving 105% of the market clearing price.

2. Ability to encourage development by target categories

As noted above, while all project types would be eligible to participate in the auction, large, sophisticated projects will most likely result in a market clearing price that is substantially lower than what would be necessary to support development of smaller projects or projects that are unable to take advantage of the full benefits of federal tax incentives. The authors do, however, suggest that multipliers could be applied to the MCP to provide incentives for development of project types encouraged by particular policies.

3. Congestion relief

There are no mechanisms included in the proposal to indicate that this approach would provide any congestion relief benefits beyond those provided by the other proposed strategies.

5.3 Alternative Proposals / Transition Options

5.3.1 SREC-Only Model (OCE Pilot Program)

Summary

OCE is in the process of introducing a Pilot Program intended to: 1) facilitate project development that will limit the projected RPS shortfall for EY 2009, and 2) “evaluate several factors of market based financing for solar PV installations.”⁷⁴ The Pilot also clarifies the framework within which PV projects can be constructed now that the current CORE rebate budget is fully committed.

As discussed in Section 2.3, PV project sales activity is virtually at a standstill in New Jersey right now. This is due in part to the uncertainty about what sort of incentive or revenue securitization scheme might be offered by OCE in place of the CORE program rebates. Furthermore, on a logistical level, getting a project registered in the SREC system is currently dependent on the procedures embedded in CORE program participation. While the lack of new sales activity in the industry right now is a problem for a number of reasons, it is particularly important for commercial projects to be able to take advantage of federal tax incentives that are scheduled to expire at the end of 2007.

The Pilot Program lays out a system in which projects would be fully dependent on SREC sales revenue (plus avoided electricity costs and federal tax incentives) to recover the cost of their solar investment. Project owners would be required to register with the OCE, demonstrate that the project is already under contract, and share the project’s financial pro forma with OCE.

While the SREC-Only Pilot Program is not intended to provide a comprehensive transition strategy for the whole market, it is relevant to this discussion since it will function as the framework within which new projects are financed over the short-term. In concept the SREC-Only model represents the opposite end of the financial risk spectrum. Therefore, playing out the scenario of how an SREC-only model would stack up against the evaluative criteria provides valuable insights and perspective on the range of potential market transition strategies. For the purposes of highlighting the differences between different alternative transition strategies, the discussion below refers to a “SREC-only model,” which is based on a hypothetical

⁷⁴ Quotation taken from NJ BPU, “Solar Pilot, Straw for Phase 1” circulated November 21, 2006. The Pilot Program was authorized through a BPU recommendation developed in late December, and approved by Board Order on January 19, 2007.

scenario in which OCE's SREC-only Pilot Program design would be applied to the whole New Jersey solar market as a comprehensive market transition strategy.

Key Functional Components of Approach⁷⁵

1. Eligibility and Application Review and Approval Process. The process for accepting applications will be an open competitive solicitation for a set period of time. NJBPU Solar pilot projects will not receive any NJBPU rebates and must certificate to this fact.
2. Procedural Requirements and Administrative Responsibilities for Participants:
 - a. Participants must certify to the fact that a contract exists, or for public projects, that a contract will be executed within certain number of days. Participants must also provide a schedule for project completion. These measure are intended to ensure that projects that are part of the Pilot will be completed.
 - b. Participating projects will be financed through the current REC market and must certificate to this fact.
 - c. Participating projects must be constructed, installed and operated consistent with existing NJBPU Polices and Procedures for the CORE Program.
 - d. Participating projects can utilize any other funding such as federal tax credits, federal grants, any other state agency grants or any other grant/rebate funding (except NJBPU grant, rebate or other incentives) and must disclose all funding sources.
 - e. All NJBPU Solar pilot projects must provide a detailed pro forma financial statement to document project financing.
3. Target Distribution of Participants:
 - a. Private Less Than or Equal to 10 kW (residential) – 10%
 - b. Private Greater Than 10 kW (C&I) – 50 %
 - c. Public - 40%
 - i. Local Governments – 40%
 - ii. Public Schools – 40%
 - iii. State Facilities – 20%
4. Metering Requirement: All NJBPU Solar pilot projects must be able to be remotely monitored and communicate the energy generated to the REC tracking system at a minimum on a monthly basis or for each MWh generated. All NJBPU Solar pilot projects must be able to accurately meter the energy generated by the system at minimum on a monthly basis or each MWh generated.
5. PJM GATS Participation Requirement: All NJBPU Solar pilot projects must be registered with PJM-EIS Generator Attributes Tracking System (GATS). All Solar RECs generated by NJBPU Solar pilot project system can only be traded within PJM-EIS GATS.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. **Facilitates rapid growth (to meet RPS targets)**

⁷⁵ The language below has been adapted from the "NJBPU Solar Pilot" pilot proposal circulated by OCE on November 21, 2006.

Based on interviews with installers and developers, it is clear that some potential commercial and industrial project owners are ready to build projects based on an uncertain future stream of SREC revenues. This is largely due to the fact that current federal tax incentives are so favorable.⁷⁶ However, the majority of stakeholders in the market believe that, given current PV system costs, without providing potential project owners with some form of revenue certainty, only a limited number of projects will be able to secure financing for construction. In the coming years, project economics could change dramatically in the event of a major breakthrough in PV technology or a dramatic increase in the cost of electricity. These circumstances would tip the scales in favor of PV investment and lead to rapid growth in PV installation without the assistance of any subsidies. However, assuming the continuation of current PV system economics and data gathered through interviews with industry representatives and policy experts, it does not appear that the SREC-only structure would result in the level of PV system development necessary to meet New Jersey's RPS solar goals in the coming years.

Transitioning to an SREC-only market would also result in the closure of many small solar businesses that serve the needs of residential and small commercial customers since potential "small system" PV owners would not likely be interested in taking on the upfront cost or debt burden necessary to install PV in an SREC-only environment. In addition to being a major step backwards in terms of economic development and job creation in New Jersey, loss of these skilled PV workers to other sectors of the economy would make it even more challenging to meet the PV system development needs associated with the increasing RPS requirements in the coming years.

2. Enables scale-up or scale-back of growth as needed

The SREC-only model would create a structure in which market forces would be the major driver of SREC prices. Assuming a functioning market in which the industry is capable of responding to growing demand with increased supply, the market would theoretically be able to scale itself up or down to respond to demand. However, in the absence of any form of revenue certainty for project owners, it does not appear that the market is mature enough to respond to the demand set forth in the RPS.

3. Compatible with regional markets

SREC-only market structure would be compatible with regional markets from a functional perspective in that certificates from pilot PV systems would be traded through the PJM GATS. However, from a practical perspective, New Jersey SREC prices would need to rise to such high levels under the SREC-only market that they would be cost-prohibitive for all buyers other than New Jersey LSEs that possess RPS compliance obligations.

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

An SREC-only system would do nothing to enhance investor confidence in an already uncertain marketplace. As discussed earlier, it is clear that REC markets are not well-enough established for the financial community to trust in them as a source of revenue in general and that New Jersey in particular possesses a high level of regulatory risk due to its five year regulatory time horizon.

⁷⁶ Current Federal Tax code allows owners of a solar PV system to deduct a 30% Investment Tax Credit, and then to depreciate the solar system asset on an accelerated 5-year schedule. As demonstrated in Section 3 above, with the right ownership structure these can represent a significant source of revenue for the project.

Given the financial community's lack of confidence in the SREC market, and the fact that an SREC-only market structure would place all of the project risk on the shoulders of the project owner, projects would likely have great difficulty getting projects financed.

5. Program readily adaptable to changing market conditions

Since the SREC-only structure would be market based, it would be dependent on market forces to adapt to changing conditions. However, as noted above, it is not clear that the market is mature enough to function effectively.

It is important to note that, given the pilot nature of the program, BPU could respond to poor early performance by adding incentives back at a later time. However, this perspective could be risky given budget allocation cycles. The opportunity to allocate funds may be closed by the time the pilot demonstrates that additional support is necessary. The resulting ebb and flow of financial support for PV systems would send a confusing signal to the investment community and could diminish confidence in the market.

6. Facilitates self-sustaining market

An SREC-only market structure, if applied as comprehensive transition strategy for the New Jersey solar market as a whole, would effectively thrust the market into a "sink or swim" scenario. All indications are that the market is not yet ready to sustain itself at the level necessary to fulfill New Jersey's solar RPS goals.

Transaction Costs

1. Ensure transparent, auditable process

A key benefit of the current SREC trading platform in New Jersey is that all SREC trading values are recorded and cumulative data is publicly reported on a regular basis. With PV systems trading certificates through the PJM GATS rather than through the SREC system currently, as proposed in the OCE Pilot Program, and in the hypothetical SREC-only model, transactions would be auditable, but there would be little transparency in SREC pricing. The pilot proposal includes provisions for providing OCE with project information, including copies of project pro formas. It is not clear whether or how this information would be shared with the market to affect SREC pricing, or to send a signal to the market regarding the status of capacity growth relative to RPS targets.

2. Program design encourages simple efficient project logistics

In an SREC-only market, solar will be a much more difficult "sell" to potential customers, and to the financial community that will be necessary to fund the projects. The industry will likely need to pass along the added costs of this longer sales cycle in the form of higher project costs. The need for brokers and aggregators would grow substantially, and these market players should be able to efficiently match buyers with sellers. However, these services would come at a cost to ratepayers in the form of higher SREC costs.

3. Low administrative burden

The proposed structure places a high administrative burden on project owners/developers given the fact that they would receive, in return, no guarantee of recovering any portion of their project investment. One administrative cost that is not yet well understood is that of participating in the

PJM GATS. While the GATS operating rules allow for behind the meter generators to register their attributes in the system, and there are currently no fees associated with participation, it is possible that if enough PV systems began using the system and demanding administrative resources, PJM stakeholders may institute a fee in the future. Also, GATS is structured for use by those familiar with the energy industry and project owners would likely need the assistance of some representative (i.e., an aggregator, broker or developer) to facilitate their GATS participation.

From the perspective of OCE, the administrative burden is small in comparison to the other models. However, there would still be substantial administrative tasks associated with managing the certifications and project information required of program participants.

Ratepayer Impact

1. Economically efficient (no over or under-subsidization)

If the market were currently at a mature state, this model would demonstrate many attributes of economic efficiency; projects would receive a performance-based SREC revenue stream, and those with more favorable economics (i.e., larger systems and those eligible for the most substantial federal tax incentives) would receive a more favorable return on their investment.

However, as discussed earlier, transition to an SREC-only market would be a major blow for small businesses that have emerged to serve the needs of the growing New Jersey solar market to date. This would diminish the impact of past ratepayer funds that have facilitated small business development in the New Jersey PV industry, and may require additional resources to be spent to rebuild the industry in the coming years when the RPS solar requirements increase steadily.

2. Low overall Cost to Ratepayers

This model is likely to result in a higher cost to ratepayers than other models due to the following: 1) a lack of revenue certainty for project owners would make it more difficult to gain access to financing, meaning an increased likelihood of LSEs needing to rely on ACPs to comply with RPS requirements; 2) those projects that do get financed would pay high risk premiums which would be passed on to ratepayers in the form of higher SREC costs; and 3) the market would be highly dependent on the services of middlemen such as brokers, which may result in added costs.

3. Low program implementation costs

As noted above, the administrative costs to pilot program participants would be fairly high given that the only benefit they gain in return is the right to generate SRECs in an uncertain marketplace.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

The proposed pilot program would not provide equity of opportunity. Based on reports from industry representatives, residential PV system owners are averse to taking on debt to pay for their systems. Project economics are much less favorable for this class of customers than for commercial and industrial customers who can benefit from economies of scale and hefty federal tax incentives. Therefore, when the upfront cost of PV increases (in the absence of a rebate), and there is no form of revenue certainty for potential project owners, there will be a very weak business case for

servicing this customer class. As a result, residential PV system installation rates would decline severely.

The public sector class may also suffer under a structure that is heavily dependent on project financing because they cannot take advantage of tax incentives. Of course, the public sector entities can always participate by signing power purchase agreements with private developers.⁷⁷

2. Congestion relief

The pilot program would not provide any particular benefits in the area of congestion relief, as there would be no means by which to drive development toward the most heavily burdened areas of the distribution system.

5.3.2 **Full-Tariff System (Tariff Revenue but no SREC Revenue)**

Summary

While not submitted as a formal proposal, through interviews with industry stakeholders, the Summit Blue Team learned that a full-tariff system is also being discussed as a market transition option. The fundamental distinction between a full-tariff system and the tariff model proposed by Cassandra Kling (referred to above as the “Hybrid-tariff Model”) is that tariff payments under the full-tariff system would be large enough so that systems would not also require SREC revenues in order to be economically viable. Since no formal proposal was submitted, it is not clear what proponents of a full-tariff program would envision as the future role of the SREC program. For the purposes of this discussion, the Summit Blue Team assumes that under a full-tariff system, PV system owners would turn their SRECs over to their LSE in exchange for receiving the tariff support. After the term of the tariff commitment is over, project owners would reclaim access to their attributes for sale either into the New Jersey SREC market or elsewhere. For the purposes of this discussion, we also assume that all net-metered systems would have access to the tariff rate structure, but that different tariff rates would be paid to small versus large systems.

Key Functional Components of Approach

1. **Implement a Renewable Energy Tariff:** Systems that meet certain criteria could apply to receive a premium (above retail rate) payment/credit for each kWh of energy produced. Projects would also receive a net-metering benefit, offsetting retail electricity rates. However, in contrast to the hybrid-tariff model, under the full-tariff model, projects would not receive any SREC revenue.
2. **10-Year Tariff Contract Between EDC and PV System Owner:** Eligible PV system owners would enter a 10-year agreement with their EDC to be served by the PV Tariff program. A tariff rate (either fixed or declining) would be pre-established for the term of the agreement. The tariff level applied to each new 10-year contract issued during the following year would be set annually at a level that provides potential project owners with a target ROI, making certain assumptions about future retail electricity rates that would relate to project financing in the form of avoided electricity costs.

⁷⁷ If PSEG is successful in pursuing its “Green Towns” program, that would represent another option for public sector development. However, in principle the Green Town program benefits could be implemented in conjunction with any of the proposals.

3. SRECs Transferred to LSEs for Duration of Tariff Commitment: In exchange for receiving financial support from ratepayer funds, at the end of each Energy Year during the period of the tariff commitment, system owners would transfer ownership of their SRECs to the LSE by which they are currently served.
4. Only New Systems Eligible for Tariff: This would keep systems that already received rebates from receiving more than their “fair share” of incentives.
5. Dedicated Meter to Track System Production: A separate meter would be necessary to measure total kWh production from each system. System owners would receive revenue based on system performance.
6. Issue Electric Bill Credits: Premium energy payments would be delivered to system owners in the form of a credit on their electric bills. In cases where tariff payments exceed the amount of the monthly electric bill over an extended period, payments would be issued to customers either bi-annually or quarterly.
7. SBC Funds Support Program: The tariff payments and administrative expenses would be sourced from SBC funds to avoid disrupting the EDC’s cash flow.
8. Limit Tariff Payments as Needed to Maintain Market Balance: Annual limits to tariff payments could be determined to avoid over-supply conditions (i.e., once the target number of MW are registered in tariff program, the EDC could start a waiting list for the following year, or until there is a need to encourage additional supply to meet rising RPS requirements). This would function as a “circuit breaker” for both the cost of the tariff program and maintaining the supply/demand balance.
9. Vary Tariff Rate Across Market Segments / System Sizes to Support Various Policy Objectives: It would be fairly easy to offer slightly different rates to different system types to offer greater incentives as appropriate, i.e., to non-profits or residential system owners.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

The level of certainty provided by a full-tariff program should facilitate project financing and, in turn, sustain the pace of development necessary to meet RPS targets.⁷⁸ Like all of the other proposed models, this model would require a rate proceeding. If the proposed system were to gain necessary support from EDCs, it has the potential to be implemented rather quickly since it could leverage the existing billing capacity of the EDCs to facilitate tariff system operations.

As discussed in the review of the hybrid-tariff model, it is important to recognize that the success of this model is dependent on buy-in from EDCs, and it is unclear whether EDCs would support

⁷⁸ Regulatory certainty issues would still exist. See comments on the “maximize investor confidence” criteria for discussion on this topic.

the model. The Summit Blue Team was unable to gauge EDC support for such a model given the limited timeframe within which this report was prepared.

2. Enables scale-up or scale-back of growth as needed

Tariff commitments could be limited so that they are only issued to the number of systems that are anticipated to be necessary to fulfill RPS requirements. This feature of the program would function as a “circuit breaker” tool to help keep supply and demand in balance in the market.

3. Compatible with regional markets

SRECs produced by systems under tariff commitments would go directly to LSEs. Therefore, the only SRECs trading in the open market would be: 1) those that had already received rebates; 2) those produced by systems not funded through the tariff program (i.e., if there is enough demand from the voluntary market to cause systems to be developed even after new tariff commitments are no longer being issued in a given year); and 3) systems whose tariff commitments have expired, but wish to continue participating in the SREC market. Since demand for SRECs trading in the open market would be fairly low, SREC values for New Jersey PV systems trading on the open market should be closer to the REC trading values in other states and regions.

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

By providing PV owners with a guaranteed stream of revenues designed to deliver a reasonable ROI, the proposed system should boost investor confidence substantially. Investor confidence in commercial and industrial sector projects should increase even more than for other sectors, as this sector will gain the ability to take advantage of tax benefits that they would not qualify for if they received a rebate.

Since funds used for tariff payments would be rate-based, these funds may be considered more secure than funding for an underwriter program that depended on ACP revenues.

Given the inherent uncertainty in New Jersey’s regulatory system (i.e., the five-year sunset requirement resulting from Executive Order 66), it is impossible for this or any other strategy to solve the problem of regulatory uncertainty.

5. Program readily adaptable to changing market conditions

For tariff commitments commencing in each new Energy Year, a new tariff schedule could be set at a level deemed appropriate given typical project economics at that point in time.⁷⁹ As a means of tracking changing market conditions, the level could be indexed to retail electricity prices (i.e., a contract for differences) so that the tariff payments would only provide as much revenue as is needed to achieve a pre-established “strike price” necessary to deliver a target ROI for the project.

6. Facilitates self-sustaining market

⁷⁹ As an alternative, an overall declining schedule of tariff levels could be set at the program outset to provide the industry with the ability to plan for a gradual decline in subsidy.

The program would work within the SREC-trading structure (whether it be through the existing SREC trading system, or through the PJM GATS), as SRECs from tariff-funded systems would still be used by LSEs to demonstrate RPS compliance. The SREC system would remain active as a mechanism for setting market prices as well; it would be used by rebate-funded systems looking to sell SRECs to LSEs, as well as non-state supported systems looking to sell into the voluntary market. The need for “market making” entities such as aggregators and brokers would be much less than under the commodity market or OCE proposed systems. However, there would be a need for such entities to play a limited role in the market, thus sustaining the infrastructure necessary to make a market functional at the point when state support is no longer available.

In addition, the tariff system would facilitate the development of a self-sustaining market by enabling the existing installer base to mature and gain a greater capacity to withstand potential future market challenges.

Transaction Costs

1. Ensure transparent, auditable process

Virtually all aspects of the tariff system would be transparent and auditable. The process of setting tariff levels would presumably be the responsibility of the Board, and therefore, would be subject to public comment. Assuming that SRECs would still be used for RPS compliance, and that the SREC trading system, or PJM GATS, would be responsible for managing the transfer of those SRECs (or “certificates,” in the case of GATS), the process of tracking attributes should be transparent and auditable. Issuing and tracking tariff payments should also be transparent and auditable since these functions would be managed through the EDC’s billing systems.

The only aspect of the program that would not be readily transparent is the administrative costs incurred by the EDCs. OCE would need to depend on EDCs to pursue efficient administrative strategies to ensure an efficient use of ratepayer funds.

2. Program design encourages simple efficient project logistics

The full-tariff system would make project logistics fairly simple. While potential system owners would need to secure upfront capital to get the project built, this process should be fairly straightforward since there would be a guaranteed revenue source for the project. Since SRECs for participating projects would go directly to LSEs, both LSEs and PV system owners would experience a lower “hassle factor” than they would under alternative proposed scenarios.

A significant logistical challenge of the tariff program is that it could limit the ability of projects to participate in innovative ownership structures. For example, one ownership structure in place in the New Jersey market today involves having the developer absorb the upfront cost of the system and letting the project host buy the system in installments over time. If the developer were not able to directly receive the tariff revenues from the project, this may limit the application of such innovative investment approaches in an already difficult investment environment.

3. Low administrative burden

See discussion from hybrid-tariff proposal above.

From the perspective of the project owner, the full-tariff program would result in a particularly low administrative burden since project owners would not need to deal with finding an SREC buyer for the duration of their tariff commitment.

Ratepayer Impact

1. Economically efficient (no over or under-subsidization)

The proposed model possesses several elements that enhance economic efficiency. First, it distributes funds on a performance basis, thus rewarding high quality PV installations and avoiding wasting funds on projects that are poorly sited or installed. Tariff levels also would vary by year to reflect changes in project economics and by market segment to reflect differences in the needs of different types of project owners. An additional benefit of the full-tariff model is that it limits the role of middlemen whose services may increase the cost of SRECs, and thus the cost of RPS compliance.

It is true that annually-set tariff levels based on the inherently imperfect assumptions of the Board will never be as accurate at setting “efficient” prices as a functional market, but it is not clear that the market is yet mature enough to function efficiently. Therefore, a full-tariff system would provide an appropriate level of economic efficiency given the status of the market.

2. Overall Cost to Ratepayers

Since the project incentive would be paid out incrementally over time, as opposed to being paid in one lump-sum upfront, the present value of the incentive payments would be lower, thus having a lower impact on ratepayers than a rebate system. Ratepayers should also benefit by the direct nature of the buyer-seller relationship between project owners and LSEs, as it will limit the markup associated with the services of market middlemen.

A full-tariff program should lead to lower SREC trading values for those entities that do depend on market-set pricing (as opposed to fixed tariff payment levels). These lower SREC values will benefit ratepayers by resulting in a lower cost of RPS compliance. Also, unlike the other proposed models, rebate-funded systems could continue deriving value from participation in the SREC market without ending up with windfall profits. This feature of the tariff program delivers ratepayer benefits, and the simplicity of this “vintage” solution is an important benefit of either the hybrid or full-tariff options.

One must also consider the administrative costs associated with tracking system performance and issuing incentive payments over the term of the tariff commitment. While EDCs are well-positioned to perform the administrative functions associated with a tariff program, the cost of EDC administrative efforts will still be passed through to the ratepayers.

3. Low program implementation costs

Given the need for BPU to set tariff levels annually and to monitor the supply / demand balance, as well as the EDCs’ need to track system production and manage payments / credits, it is clear that the tariff program would carry substantial implementation costs. However, these costs would likely be comparable to or lower than the costs associated with an underwriter or auction-set pricing / standard contract approach.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

See discussion for hybrid-tariff model.

2. Ability to encourage development by target categories

See discussion for hybrid-tariff model.

3. Congestion relief

See discussion for hybrid-tariff model.

5.3.3 Continued Rebates / Baseline Model

Summary

This model would involve an extension of SBC-funded up-front rebates for PV owners, and a continuation of the SREC market as it exists today (i.e., no changes in ACP). Rebate levels may be periodically adjusted over time, but would maintain the current goal of providing projects with a 10-year simple payback.

The New Jersey legislature has declared that the State should pursue market-based incentives,⁸⁰ and the public debate regarding next steps for the PV market in New Jersey has focused on strategies for transitioning away from a rebate-focused incentive system. However, for the purposes of characterizing a baseline against which other market models can be compared, and to expand the range of alternatives considered, a limited review of a rebate model has been included in this analysis.

Key Functional Components of Approach

1. Continuation of Up-front Capacity-Based Rebates: Rebates would continue to be issued to PV system owners according to the same program rules and procedures in place today.
2. Levels Adjusted Periodically: Levels would start within the range of those currently being offered through the CORE Program, but may be adjust periodically to maintain the Program's goal of providing projects with a 10-year simple payback.

Strengths and Weaknesses According to Evaluative Criteria

Sustained Orderly Market Development

1. Facilitates rapid growth (to meet RPS targets)

Since the CORE Program structure is already in place and the industry has even established an extensive waiting list, extending the current rebate-based market would facilitate rapid continued

⁸⁰ As specified in the Electric Discount and Energy Competition Act at N.J.S.A. 48:3-61, the New Jersey legislature seeks to develop Clean Energy Programs that can operate without rebates.

development of projects in the near-term. However, even if SBC funding could be approved at the levels necessary for rebates to be issued to all PV systems required to meet RPS goals through 2021, it is not clear that this would provide a compelling enough value proposition to stimulate the level of development necessary to meet the long-term RPS goals. While the rate of PV system installation that has occurred through the CORE Program to date has been impressive, and installations have been completed by a diverse set of businesses and individuals, it is likely that the “low hanging fruit” among potential New Jersey PV customers (those most inclined to take advantage of PV system incentives) has already invested, or will soon invest in a PV system. As time passes and RPS goals increase, it will be necessary to market PV to those for which the technology will be a “harder sell.” As the industry begins to face these more challenging sales, the 10-year payback may become a significant hurdle to achieving the RPS goals.

2. Enables scale-up or scale-back of growth as needed

Rebate levels could fairly easily be adjusted over time to reflect the changing needs of the marketplace. Also, when Program funds become fully committed, as they are currently, the Program could begin a waiting list. In order to maintain a rough balance between supply and RPS demand, Program budgets could be set based on the projected amounts necessary to fund enough capacity to meet RPS demand.

3. Compatible with regional markets

An extended rebate market would result in SREC trading values that are more compatible with regional markets than would the underwriter, commodity or auction models since a smaller fraction of the project investment would need to be recovered through SREC revenues. However, since ACPs (including for solar) in other states are primarily in the range of \$50/MWh, except in D.C. (where the SACP is \$300/MWh) and Pennsylvania (where the SACP is set at a level 200% higher than the market trading value), New Jersey SREC values are currently higher than they are in other states in the region.

Assuming that a 10-year payback remains the basis for establishing rebate levels in the future, as the PV industry begins to face customers who demand a higher return on investment, this may put upward pressure on SREC values which will make New Jersey SRECs even less compatible with others other states in the region. Since New Jersey has a higher RPS solar set-aside than surrounding states, it is unlikely that other states in the region, with the possible exception of D.C. and Pennsylvania, will see trading values in the range of future New Jersey SRECs.

4. Maximize investor confidence (related to regulatory certainty, risk allocation, revenue certainty)

Since rebates offer funding in one lump sum at the time of project installation, they reduce project financial risk substantially, and this enhances investor confidence. Under the current rebate system, project financial risk has been reduced enough to attract investment from a diversity of sources. As the RPS requirement increases over time and demand for PV system investment increases as well, it is possible that investors will demand a higher risk: return ratio than is currently provided by the rebate system.

5. Program readily adaptable to changing market conditions

As noted above, the rebate levels and the number of rebate funding commitments made each year could be adjusted through a regular review process to help the Program remain in synch with the

changing needs of the market. Since the Program would be supported with SBC funds which are allocated in multi-year budget cycles, if it turns out the Program ends up needing more resources than were planned for at the beginning of the funding cycle, program managers would likely need to wait until the next funding cycle to increase funding levels.

6. Facilitates self-sustaining market

Since many projects would still require SREC revenues in order to recover their upfront investment, the SREC market infrastructure would remain intact. As the RPS goals increase and more PV systems are built over time, the SREC market infrastructure would mature as a higher volume of SRECs are traded in the marketplace. This growth and maturity of the SREC market infrastructure will facilitate the development of a self-sustaining market.

Transaction Costs

1. Ensure transparent, auditable process

Using the SREC trading platform and existing rebate tracking systems, a continued rebate system should fulfill this criteria.

2. Program design encourages simple efficient project logistics

By providing a one-time up-front incentive, the rebate system simplifies project logistics. Further, logistics are simplified by the fact that PV developers have already developed product and service offering based on a rebate incentive format.

3. Low administrative burden

As with any other incentive program, an application process would be required, and system monitoring should be conducted to ensure that funded systems are performing as expected. However, the overall administrative burden associated with a rebate program is less than that of any other model discussed since the incentive is based on a very simple capacity-based calculation and is issued in a single payment.

Ratepayer Impact

1. Economically efficient (no over or under-subsidization)

This model is not very economically efficient since there are few distinctions between different rebate level categories and, as discussed in Section 3.1, project economics vary significantly for different types of PV system owners.

Another key weakness in the area of economic efficiency, and a key distinction between the rebate structure and all the other models discussed earlier, is that the rebate is not performance-based. The CORE Program does incorporate some quality assurance mechanism, like requiring that all systems be inspected prior to receiving a rebate. However, in cases where system components fail, modules are not cleaned periodically, or where tree growth begins to shade a PV system, poorly performing systems will have already received their full incentive and ratepayers will not receive the full value intended for the rebate investment (i.e., additional systems will need to be funded to make up for the shortfall in production resulting from poorly performing systems).

The economic efficiency of a rebate system could be enhanced by increasing the number of categories by which rebate levels would vary, so that rebates would be set to (as closely as possible) to meet and not exceed the needs of the projects they are funding. Different incentive levels are currently offered for projects in five different size categories and based on whether they are private or public / non-profit. If the Program continues, opportunities should be explored for tailoring rebate levels based on the tax burden of different projects since Federal tax incentives are the primary source of additional financial incentives available outside the rebate program. One basic distinction that could be made is between residential and commercial projects.

2. Overall Cost to Ratepayers

Theoretically, a rebate system will possess the highest cost to ratepayers on a net present value basis, as rebates are paid out in one lump-sum as opposed to being paid incrementally over time. It is likely that the added administrative costs of various PBIs would offset the loss in ratepayer value associated with making upfront payments. However, the specific administrative costs the various models have not been carefully examined as part of this assignment and thus, the tradeoff between the lower administrative costs and higher net present value of payments cannot be well-established.

Another factor that would increase the overall cost to ratepayers is that the rebates are not performance-based. Poorly performing systems would receive the same level of incentive as those with optimal performance characteristics. In addition, one could argue that the quality of systems installed through a rebate-funded program is likely to be lower in general than those installed under a PBI Program since there is no incentive to ensure that systems are operating at maximum output over the rated lifetime of the system. As a result, capacity-based rebates are likely to result in wasted ratepayer funds, and will require additional ratepayer funds in order to achieve RPS targets.

3. Low program implementation costs

The implementation costs associated with the program are relatively low compared to other models discussed since rebate payments follow a simple formula and are paid in one lump-sum.

Support for Other Policy Goals

1. Equity of opportunity to participate (e.g., system size)

Rebate levels currently vary by project size and depending on whether the project is private or public / non-profit, with higher rebate levels (\$/kW) being paid to smaller project and public / non-profit projects. This helps facilitate participation by all customer classes.

2. Ability to encourage development by target categories

Higher rebate levels are offered to smaller projects and public / non-profit projects, and the Program budget reflects a priority to allocate a set portion of the budget to public projects. Additional such designations could be made in the future to encourage development by target categories.

3. Congestion relief

It is not clear that any efforts are currently being made to direct rebate funds to constrained areas of the distribution. However, if OCE were to obtain information about the location of constrained areas, higher rebate levels could be offered for projects in those areas.

5.4 PSEG “Green Towns” Proposal

Public Service Energy Group (PSEG) has submitted an innovative proposal to OCE that would help alleviate the long-term contracting challenges described above. The proposed program is intended to provide a mechanism for achieving the State’s PV development goals that will: 1) minimize ratepayer costs through elements of efficiency and 2) spread the ratepayer impact more evenly over a longer period of time to avoid “rate shock” that might otherwise occur if all RPS compliance costs were recovered from ratepayers through SBC funds or BGS auction pricing. Under PSEG’s proposed “Green Towns” program, the distribution company would partner with municipalities to install 555 MW of PV system capacity on public buildings. This amount of PV capacity represents approximately one-third of New Jersey’s projected RPS-required solar development.

PSEG would own the PV generators and would locate them in places that would maximize societal benefits (i.e., public buildings serving low and middle-income families, smart growth areas, and buildings in congested areas of the distribution system). This arrangement would enable the utility to take advantage of substantial tax incentives, and to use its knowledge of grid congestion issues to play a role in siting PV systems in places on the grid that can benefit most from distributed generation. In addition, the proposed program would provide significant economies of scale in the areas of obtaining capital, procuring equipment and services, and managing project logistics. PSEG would work with the New Jersey solar industry to install and maintain the PV systems.

While EDCs are restricted from owning generation under the EDECA retail competition act, PSEG would view the PV systems like they were a transmission and distribution investment, rather than viewing them as “generation” resources. Representatives at PSEG liken the potential PV investments to purchasing a new transformer; the investment would be made for the purpose of improving the distribution system reliability and performance. It would be depreciated over a long-term period of 25 years, and the costs (presumably, net of any tax benefits to PSEG) would be borne by the ratepayers through long-term rate recovery.

Under the proposed program structure, electricity cost savings resulting from electricity generated by the PV systems would accrue to the municipal buildings that host the equipment, and SRECs created by the systems would be provided to LSEs serving PSEG’s BGS customers. According to PSEG, the program’s unique structure would dramatically reduce the ratepayer impacts associated with achieving RPS compliance when compared to using a rebate program for supporting PV development. PSEG calculated that the present value costs to ratepayers associated with the current solar offering under the CORE rebate program are \$11,000,000 per MW (including rebates, RECs, and customer contribution), and that under the Green Towns plan the ratepayer impact would be \$7,000,000 per MW, yielding a \$4,000,000 benefit to ratepayers.

Table 5-2 below shows the program timeline envisioned by PSEG.

Table 5-2. Projected Schedule for Green Towns Program

| Phase | MW Goal | Date |
|-------|---------|--|
| 1 | 45 | Preparations would begin immediately upon approval, but system installations would not likely occur until 12-24 months after program approval. |
| 2 | 80 | 2012 |

| | | |
|-------|-----|------|
| 3 | 430 | 2020 |
| Total | 555 | |

While the concept possesses numerous elements of efficiency that have great potential to benefit ratepayers while dramatically improving the chances that New Jersey will meet its overall PV development targets, there are a few potential drawbacks worthy of attention. First, with guaranteed rate recovery for program costs, the utility would not be under any pressure to minimize program costs. Given that market forces would not be at work to keep costs in check for the large volume of PV system development associated with the program, it would be critical for competitive procurement of equipment and services to take place. Still, it would be difficult to keep a check on the administrative costs of the program, which could be quite high given the challenges associated with development on public buildings (i.e., educating decision-makers, approval timelines, coordinating with operations and maintenance staff, etc.). In particular, legal expenses could be significant given the unique utility ownership / municipal host relationship being proposed.

The proposed program would also have significant impacts on the portion of the solar market depending on SREC revenue and outside investment. Since SRECs generated from Green Town PV systems would be automatically allocated to LSEs, the program would effectively remove approximately one-third of the RPS demand from the SREC marketplace. The resulting decrease in market prices will improve the regional compatibility of New Jersey SRECs. However, the lower prices may also deter development among the portion of the market depending on SREC revenues to recover their PV system investment.

Finally, the project timeline could likely require a redistribution of RPS requirements. It would take approximately 12-24 months after program approval to begin installing projects under the proposed program. If no subsidies are in place to stimulate the development of market-based systems during the incubation period for the Green Towns program, it would be difficult to meet existing RPS requirements that will ramp up substantially over the next few years. Changing RPS rules would reduce regulatory certainty and could make it more difficult for the non-Green Town solar projects to secure capital.

Since the PSEG Green Towns proposal would only address a portion of New Jersey's solar market needs, we have included it as a scenario in Section 7 and shown how it may affect the likely outcome of the full market transition structures proposed.

6. FINANCIAL AND RATEPAYER IMPACT REVIEW

Meeting the RPS goals will require a substantial investment on the part of the ratepayers and taxpayers of New Jersey. There has been significant discussion of how this investment can be minimized and how it should be distributed. Although not all of the important features of an incentive program are directly expressed in costs, it is important to think through the ultimate cost equation that the State is facing. The fundamental goal is for the present value of all the present and future revenue streams to exceed the upfront capital cost of the system by a moderate margin.

$$\text{Capital cost} + \text{owner's margin} = \text{Present Value of (subsidy, power sales,}^{81} \text{ REC sales, tariffs, etc.)}$$

In essence, each of the strategies considered uses a different combination of revenue streams to try to make the economics of the installation work. Of course all of the models use the stream of revenue from the power sales as their basis. Beyond that, the models differ in their administrative costs, the source of the revenues, and correspondingly, who is carrying the various risks associated with the project.

Risk allocation is one of the more important elements of project finance. It is an axiom of modern non-recourse financing that risks should be allocated to the party best able to manage them. For example, the risk of construction delays would be assigned to the general contractor, and the risks associated with equipment failure or design would be assigned to the equipment supplier.

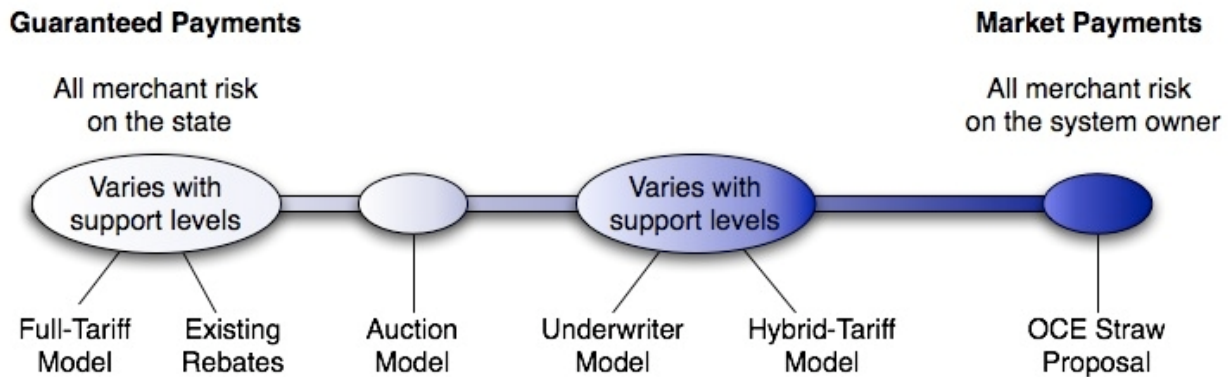
As discussed in Section 3, there are three primary categories of risk present in the PV market:

1. Equipment risk: the potential for the equipment to not function as designed or to be mis-installed in such a way that it can't function correctly.
2. Performance risk: the potential that the system will not perform as designed as the result of poor installation, maintenance, weather or other un-planned conditions.
3. Merchant risk: the salability of the output of the system—power and SRECs—into the market. A major subset of merchant risk is regulatory risk, or the potential that market rules or policies governing the REC pricing environment will change during the course of one's investment period.

Figure 6-1 illustrates how the various potential transition strategies allocate the merchant risk between the system owner and the State. The placement along the risk spectrum is intended to be indicative only—the levels set for various parameters have a substantial influence on the placement along the spectrum. Note that, while the Commodity Market Model is not shown in the following figure, the risk allocation for the *Commodity Market* model would be virtually the same as for the *Underwriter* model.

⁸¹ Note that in this case the term “power sales” represents both sales into the grid and avoided power costs.

Figure 6-1. Risk Spectrum for Solar Market Models⁸²



As discussed in Section 3, one of the reasons that risk is so important is the effect that it has on financing. Lenders must feel that their money is well-shielded from risks over which they have no control. As the risk level rises, loans become both more difficult to find and significantly more expensive.

Finally it is important to note that, in the absence of overt negative regulatory intervention, and with some time and maturation in the SREC market, this risk premium should start to drop. The key to this will be time in operation and comfort with the market mechanisms and the RPS targets.

The following section discusses the transition strategies from a financial perspective and explores issues of risk assignment.

6.1 Proposals Submitted by RPS Transition Working Group

6.1.1 Underwriter Model

Features: The underwriter model assumes that all of the revenue beyond the power sales will come from the sale of SRECs. Recognizing that the sale of an unknown commodity into a relatively new market is highly risky, the model authors also propose that the State provide a floor under the prices. The objective of this floor is to give the lenders a minimum revenue stream on which to base their loan calculations and thereby decrease the finance cost of satisfying the RPS.

In operation, the Underwriter would become a “buyer of last resort.” Sellers of SRECs would take them first to the open market, where they would presumably find a price that is higher than the floor value. Only when they could not find a buyer for their SRECs would they need to resort to the Underwriter.

The proposal postulates that the funds to pay for the Underwriter payments would come from the ACP payments. This funding mechanism supposes that there will be enough of an under-supply of SRECs that the ACP payments will more than cover the Underwriter payments. However, this plan begins to encounter trouble when there is an oversupply of SRECs. In that case, there are not likely to be any ACP payments, but there will be substantial claims for Underwriter payments. The authors propose to limit this risk by

⁸² Note that the level of risk associated with the existing rebate program varies depending on the tax appetite of the project. Corporate projects that can take advantage of the full benefits of all of the federal tax incentives have less dependence on SREC revenues to recover their investment.

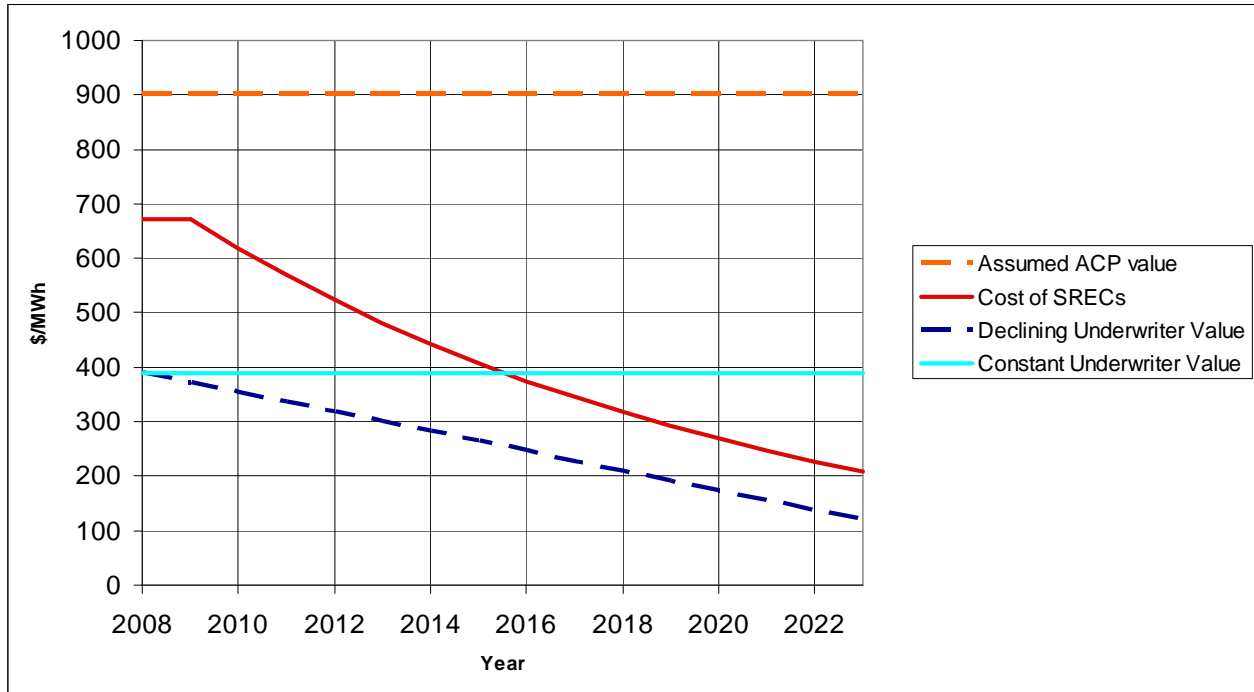
restricting the number of SRECs in any given year to the amount needed to meet the RPS goal for that year. However, it seems possible that if an over-supply were to develop anyway, and was serious enough, then owners of systems without the Underwriter coverage would be eager to unload their SRECs at any price, thereby meeting some significant fraction of the RPS. In that case, the Underwriter could end up liable for a significant payout in the same year that there are no ACP payments into the system. To prevent that situation from draining the Underwriter fund, the model authors propose seeding the fund with money from the SBC charges.

Deriving a firm cost to the ratepayers for this model is difficult because of the uncertainty associated with the market prices and potential payouts. However, it is possible to put a maximum value on the obligation undertaken by the Underwriter. This would be the case where in some unusual market condition the Underwriter would be forced to meet the entire RPS target of SRECs at the promised floor price. Obviously this is a “worst case” scenario, but not an impossible one.⁸³ This is the value reported as the “Underwriter Maximum Commitment” below.

Figure 6-2 illustrates the pricing assumptions used in modeling this proposal. Note that one concern with this approach is that a decline in the market price of the SRECs could drop their value below the guaranteed SREC price contracted by the Underwriter. This would mean that project owners would have no incentive to sell their SRECs into the market, and it would expose the underwriter to a great deal of risk that all existing underwriter-committed projects would make calls. An obvious solution to this concern is to develop a declining schedule of guaranteed prices as shown in the Figure.

⁸³ For example, if a new technology were introduced that substantially reduced the cost of photovoltaics systems and the market was flooded with new, dramatically lower cost systems, the legacy systems would be likely to file claims with the Underwriter. Similarly, if SRECs were to become regionally compatible, then a flood of cheaper SRECs from out-of-state would displace New Jersey SRECs and create drain on underwriter fund.

Figure 6-2. Assumed Costs Associated with Underwriter Model



Risk Allocation. The Underwriter model was designed to provide the revenue certainty to project stakeholders that is necessary to obtain project financing. By having what is essentially a hedge against a decline in the value of the SRECs, the lenders can focus on a well-defined revenue stream, presumably for the full term of the note. This should allow more favorable financing terms.

In essence, this mechanism passes most of the merchant risk for the SRECs to the Underwriter, who is providing a product very similar to insurance. Similar mechanisms exist in commercial markets of course, but in those cases, the Underwriter (e.g., insurance company) prices the product in a way that will cover that risk. In this case, the Underwriter must accumulate funds collected from the ACP to cover the risk. Unfortunately, it isn't clear that the inflow of funds from the ACP necessarily have a strong correlation with demands on the Underwriter. This could leave the Underwriter in danger of insolvency. The lenders, seeing this potential may not value the guarantee offered by the Underwriter at full value, and the borrower may not ultimately benefit much under the program.

6.1.2 Commodity Market Model

Features: The Commodity Market model is very similar to the Underwriter model in the sense that the primary incentive for the system owner is their ability to sell SRECs into the NJ market. (In fact, the authors cite the Underwriter model as part of their scheme.) The primary distinctions are: 1) the temporary continuation of rebates for small systems; 2) extending trading lifetime of RECs to 2 years; and 3) enabling large scale (>2MW) solar facilities to generate SRECs. A strong emphasis in this model is placed on raising the ACP with the notion that a higher ACP will lead to higher market prices for SRECs.

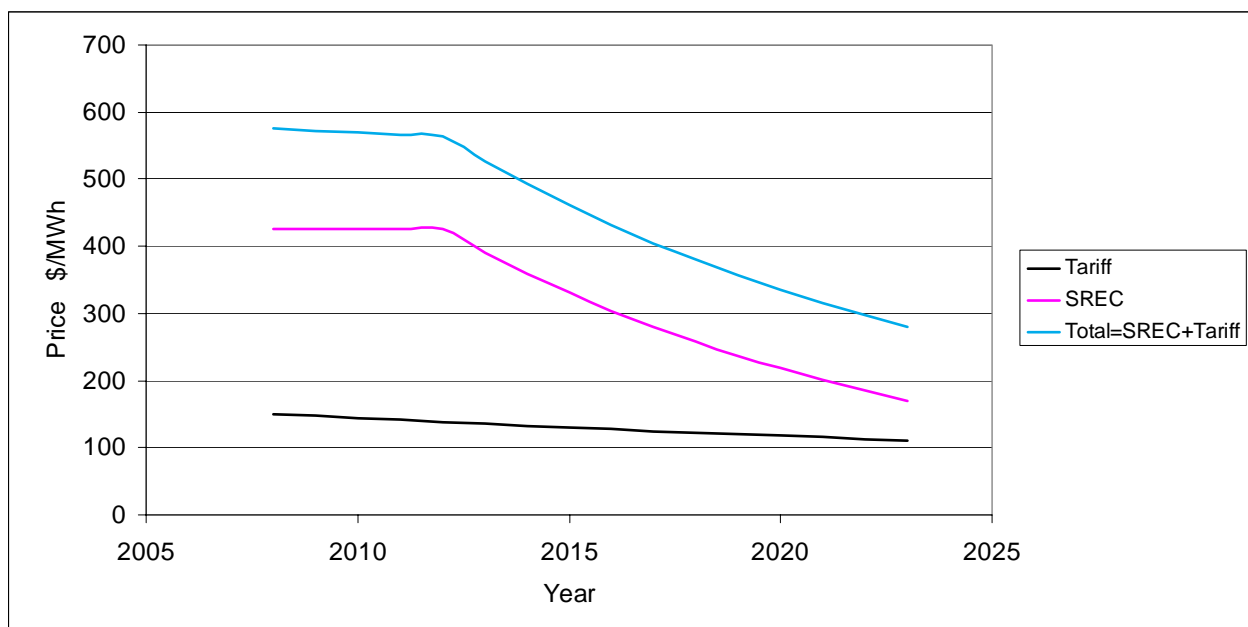
The Commodity Market Model uses the same SREC pricing assumptions that were used for the Underwriter model. These assumptions did not include the continuation of rebates.

Risk Allocation: The risk allocation in this model is very similar to that under the Underwriter model. Some of the merchant risk for the SREC price remains on the owner and, by extension, the lender. The smaller systems get a break with the continuation of rebates, which reduces their merchant risk. The extension of the SREC life to 2 years also reduces the merchant risk for all of the producers. However, the inclusion of the larger, grid-connected systems seems like it would be likely to reduce the cost of SRECs and could increase the merchant risk for the other, higher cost, producers in the market.

6.1.3 Hybrid-Tariff Model

Features: The Hybrid-Tariff model is a plan that includes revenue streams from both SRECs and Tariff payments. This approach would give system owners a mixture of the certainty created by the tariff payments (described in more detail below), while still allowing them to receive revenue (and capture any potential upside) in the SREC market. An interesting feature of this proposal is that the EDCs are proposed as the entities best able to manage the tariff payments, since they are more creditworthy than the LSE's and can rate-base the costs. Figure 6-3 shows the pricing assumptions used for this analysis.

Figure 6-3. Pricing Assumptions for Hybrid-tariff Model



Risk Allocation: The Hybrid-Tariff model splits the merchant risk between the system owner (for the SRECs) and the ratepayers (who pay the tariff). The degree of risk borne by each party is determined by the level of the tariff, which can be set by size of system, vintage of system, or a variety of other parameters.

6.1.4 Auction-set, Standard Contract Model

Features: This model involves holding an annual auction that would determine the market clearing price for SRECs, and then having all sellers and buyers use that price as the basis for determining SREC values under standardized five-year contract terms. In exchange for the certainty created by the market-clearing price, the projects would only be able to sell SRECS for those five years. Similarly, in exchange for agreeing to the five-year contract terms and participating in the auction system, the LSEs would be exempt from paying the ACP, whether or not they met the RPS targets.

Risk Allocation: The effects of this model are very similar to those of the Hybrid Tariff model described above in that the merchant risk is largely allocated to the ratepayer. The expectation is that the values bid for the clearing price will be relatively high, in order to provide the revenue streams needed to cover the service on a five-year debt.

6.2 Alternative Proposals / Transition Options

6.2.1 SREC-Only/OCE Pilot Proposal

Features: The OCE Pilot proposal is nearly a complete free market approach. The State does not provide any funding or backstop to the projects. They must receive their revenue from the PJM GATS program, and not through the New Jersey system. However, the system would ultimately involve a substantial increase in the SACP level, which would increase SREC trading values. LSEs would build the cost of RPS compliance into their retail rates, and thus, the higher SREC trading values would be felt by ratepayers in the form of higher electricity rates.

Risk Allocation: The merchant risk for this approach is clearly entirely on the system owner. In principle, trading the SRECS through the GATS system rather than New Jersey's existing SREC trading system should not increase the risk, as long as the transaction costs are not appreciably higher in one than the other.

6.2.2 Full-Tariff System (Tariff Revenue but no SREC Revenue)

Features: Full-Tariff systems (such as those in Europe) use a feed-in tariff based on the energy generated as the revenue stream to induce investment. The tariff would be set to provide a pre-determined benefit over a fixed period of time. This tariff stream would completely replace the revenue from the sale of SRECs. One of the key decisions in implementing the tariff model is the term over which the tariffs are to be guaranteed. The advantages of a short (i.e., five-year) period are that it closely matches the term of the financing available today, and therefore would cover the entire term of the loan. Unfortunately, this short term would also require fairly large tariff rates, which would likely produce political resistance.

To alleviate this problem, some industry stakeholders have discussed the possibility of tariff commitment periods of seven, ten and 15 years. These longer periods reduce the tariff rates, but since the term of most loans is still only five years, the lower rates won't guarantee that the project will generate enough revenue over the first five years to fully service the note.

Risk Allocation: The tariff model provides the lender with a solid guaranteed payment over the period of the program. In doing so, it shifts the merchant risk for the systems fully onto the ratepayer. However, if a shorter tariff commitment period were used, it should reduce the finance charges, and thus the overall cost to the ratepayers.

6.3 Overall Cost to Ratepayers

An attempt was made to capture the most salient features of each of the proposed transition models in order to predict their financial impact on the ratepayers.⁸⁴ A consistent set of assumptions was assembled and the financial modeling was constructed to reflect as closely as possible the actual differences between the proposals. This analysis includes some highly uncertain assumptions, and while the results are indicative of the relative costs of the proposed systems, the accuracy of the absolute numbers is less reliable. For

⁸⁴ The financial model used here was adapted from a spreadsheet started by Lyle Rawlings of Advanced Solar Products, Inc.

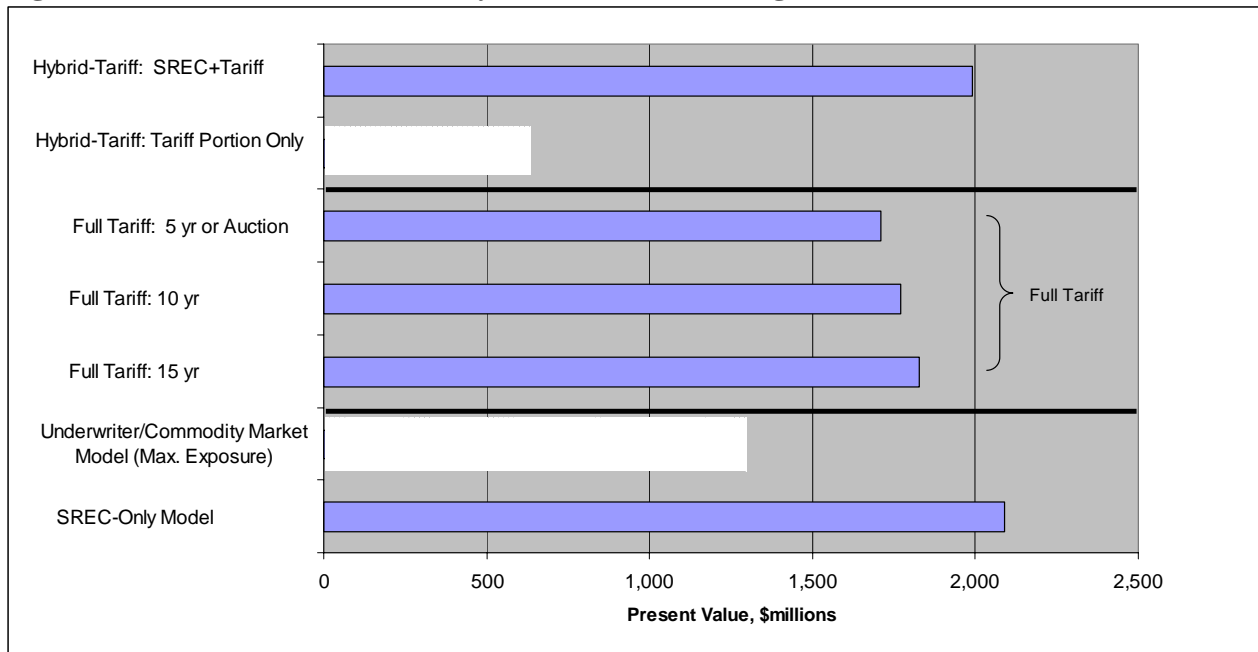
example, the cost of administering each of the programs is not included in any of the proposed systems, despite the fact that some will clearly cost more to implement than others. More detailed modeling of ratepayer impacts will occur in Spring 2007.

Figure 6-4 shows the estimates of the total cost to the ratepayers of the incentives offered under each of the proposed plans. The Net Present Value is calculated with a Discount Rate of 10%, and the values shown do not include estimates of administrative costs.

The Underwriter model is designed essentially as a backup to the SREC market. For this reason, the actual expenditures cannot be predicted with any precision. Therefore, the value shown in Figure 6-4 for the “Underwriter/Commodity Market Model (Max Exposure)” represents the maximum exposure of the Underwriter and Commodity Market models, should all of the SRECs required to meet the RPS file claims. The bar labeled “SREC-only Model” is a projection of the total cost of meeting the RPS with the SREC market (with projected prices above the Underwriter floor and below the ACP). In actual operation, the cost would depend on the functioning of the market and the value set for the Underwriter floor price. If the SREC market values are well above the floor price and the market is not oversupplied with SRECs, then the value would be closer to the “SREC-Only Model” bar. However, if for some reason the market became flooded with less expensive SRECs, the value could drop down to the “Underwriter/Commodity Market Model (Max Exposure)”. In other words, if the market produces an oversupply, the tax/ratepayers pay a lower value. Presumably this lower price for SRECS results is a slowdown in construction for a year or so until the RPS catches back up to the supply of SRECS.

The bar labeled “Hybrid-Tariff: SREC + Tariff” represents the combined value of the tariffs paid to the SREC producers plus the value they would receive from selling their SRECs in the market. By contrast, the bar labeled “Hybrid-Tariff: Tariff only” represents only the tariff portion of the total bar above it.

Figure 6-4. Present Value Summary of Transition Strategies



The three Tariff only models illustrated in Figure 6-4 show the relationship between the duration of the tariff and the overall cost to the tax/ratepayer. As the term of the tariff program is decreased, the finance

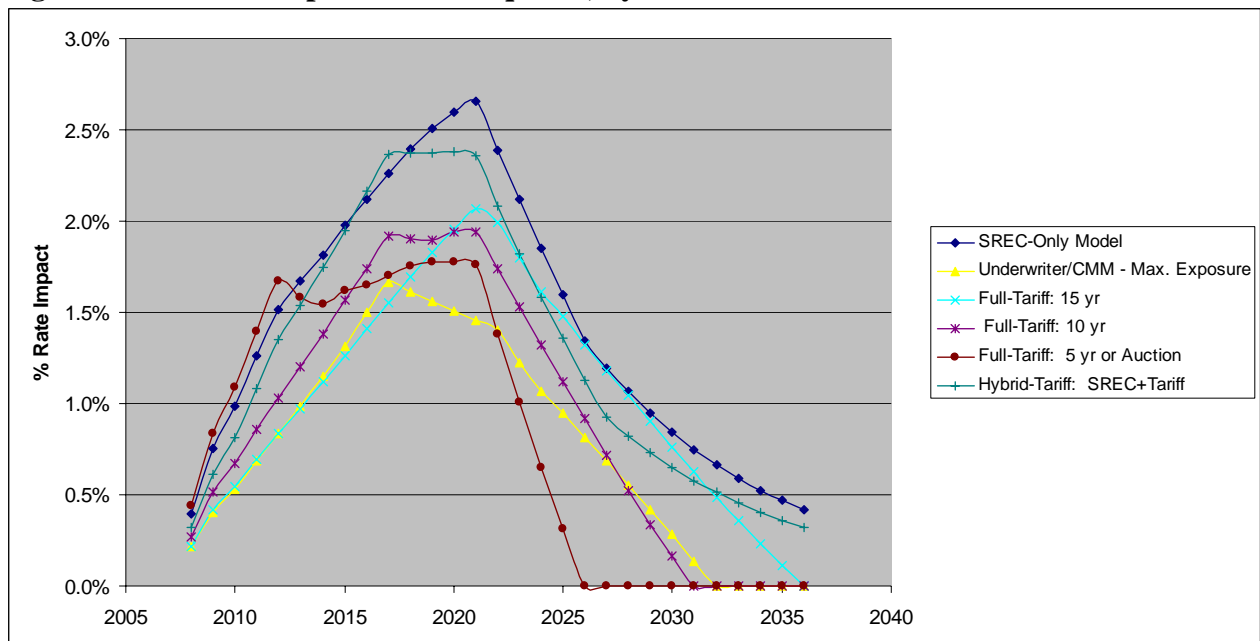
charges go down for two reasons: first, the rate charged for a lower risk investment may be lower, and second, with a shorter term the number of interest payments is decreased.

The SREC-Only model produces the highest total ratepayer expenditure, with an NPV of roughly \$2.1B. The overall cost for the Hybrid-Tariff model is very similar at essentially \$2B, of which the tariffs represent about \$500M. The various Full-Tariff program options (varying by length of tariff payment commitment) produce total costs in the range from \$1.7B to \$1.8B, directly related to the length of the guaranteed tariff.

As expected, because the SREC-Only model and the Hybrid-Tariff models have the highest risk and the longest periods, they each have the highest overall costs to the tax/ratepayer. Note however, that because of their extended period, these two plans also have the lowest SREC prices. However, on an NPV basis, the difference between the highest and the lowest cost options is less than 10%.

It is also interesting to look at the expenditures required on an annual basis, as shown in Figure 6-5 below. This figure shows the annual incentive expenditures normalized by the total statewide electric bills in the New Jersey system as a means of illustrating the impact of the various potential transition strategies on consumer electric bills. The two highest peak values shown here, between 2.25% and 3% are for the SREC-Only Model and the Hybrid-tariff model. The rest of the curves, for the Full-Tariff models and the Underwriter Maximum Commitment,⁸⁵ fall roughly in the 1.5% to 2.0% range. These represent a potential increase of \$1.50 to \$2.50 per \$100 on an electric bill.

Figure 6-5. Annual Expenditures Required, by Model



⁸⁵ Note, the value reported here is maximum possible exposure for the Underwriter model. As described above, this is an unlikely scenario.

7. COMPARATIVE ASSESSMENT OF TRANSITION OPTIONS

7.1 Results of Renewable Energy Committee Email Survey

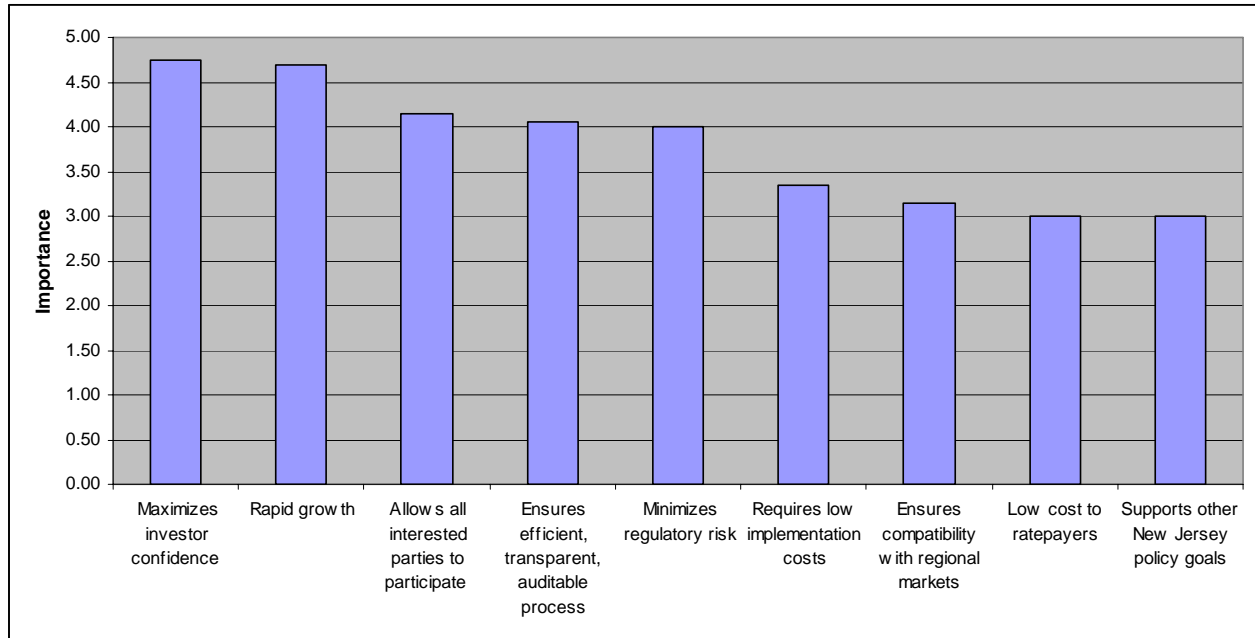
A Solar Market Transition Survey was distributed to members of the New Jersey Renewable Energy Committee and members of the Mid-Atlantic Solar Energy Industry Association (MSEIA).⁸⁶ Twenty respondents completed the survey and 60% of the respondents were Mid-Atlantic Solar Energy Industry Association (MSEIA) members. Of the total respondents, 95% indicated the type of company or organization they represent with 42% listed as installers, 16% as distributors, 11% as government entities, and 5% as manufacturers. Twenty-six percent listed themselves as “other” including ESCOs and systems integrators.

Given a variety of resource and logistical issues, and given the group’s familiarity with the range of potential market transition strategies, the New Jersey Renewable Energy Committee was deemed the most appropriate audience for responding to a survey focusing on solar market transition issues. The survey responses clearly reflect the views of the solar industry more than any other group of market stakeholders. While it is important to view the data summarized below with an awareness of the heavy representation of the solar industry, the results are still extremely valuable to the discussion of potential solar market transition strategies. Solar industry representatives possess hands-on experience dealing with the full range of solar market participants. Therefore, they are extremely knowledgeable about market barriers and the needs of potential customers. Furthermore, the group understands the intricacies of the various potential transition strategies. Possessing this critical knowledge and experience, the solar industry is uniquely qualified to provide feedback relevant for the market transition discussion.

In regards to evaluating the merits of the market transition options, maximizing investor confidence in the market place was the criteria of greatest importance, followed closely by the ability to achieve the rapid growth necessary to meet RPS goals. Respondents also placed much importance on allowing all interested parties to participate (i.e., providing opportunities for both large and small systems owners).

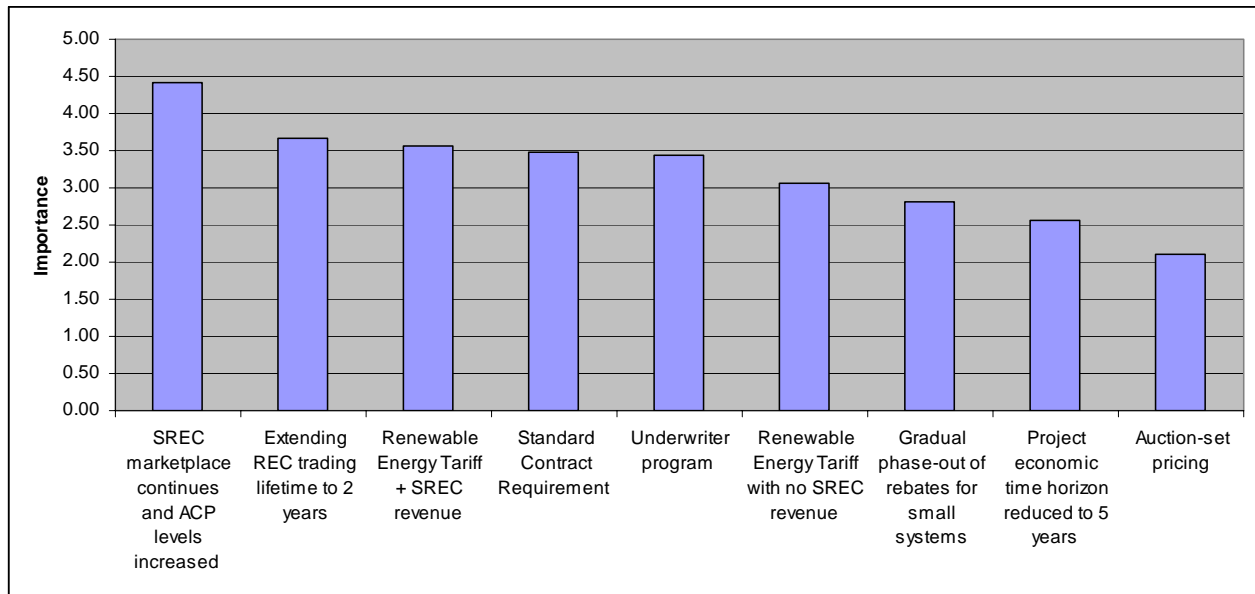
⁸⁶ The survey was initially circulated just to the New Jersey Renewable Energy Committee. The Mid-Atlantic Solar Energy Industry Association (MSEIA) offered to circulate the survey to its membership as well. Recognizing that the New Jersey Renewable Energy Committee membership is predominately made up of solar industry representatives, and therefore, that the survey results would primarily reflect industry perspectives regardless of whether it was distributed to MSEIA members or not, the Summit Blue Team decided to circulate the survey to the MSEIA membership in order to increase number of responses.

Figure 7-1. Importance of Market Transition Evaluative Criteria



Respondents were asked to rank the elements of a potential market transition strategy. “SREC market continues and ACP levels increased” emerged as the highest ranked element, with 70% of respondents scoring its level of importance as a four or five on a five-point scale. The average score for this element was 4.4. Extending the REC trading lifetime to two years received the next highest average ranking (3.7), and the hybrid-tariff (renewable energy tariff plus the SREC revenue) received the third highest average score (3.6). The average score for the underwriter program was 3.4. The two key elements of the auction-set/standard contract pricing program were split apart since they are so distinct. Auction-set pricing received an average score of 2.1, while “standard contract requirement” received a 3.5.

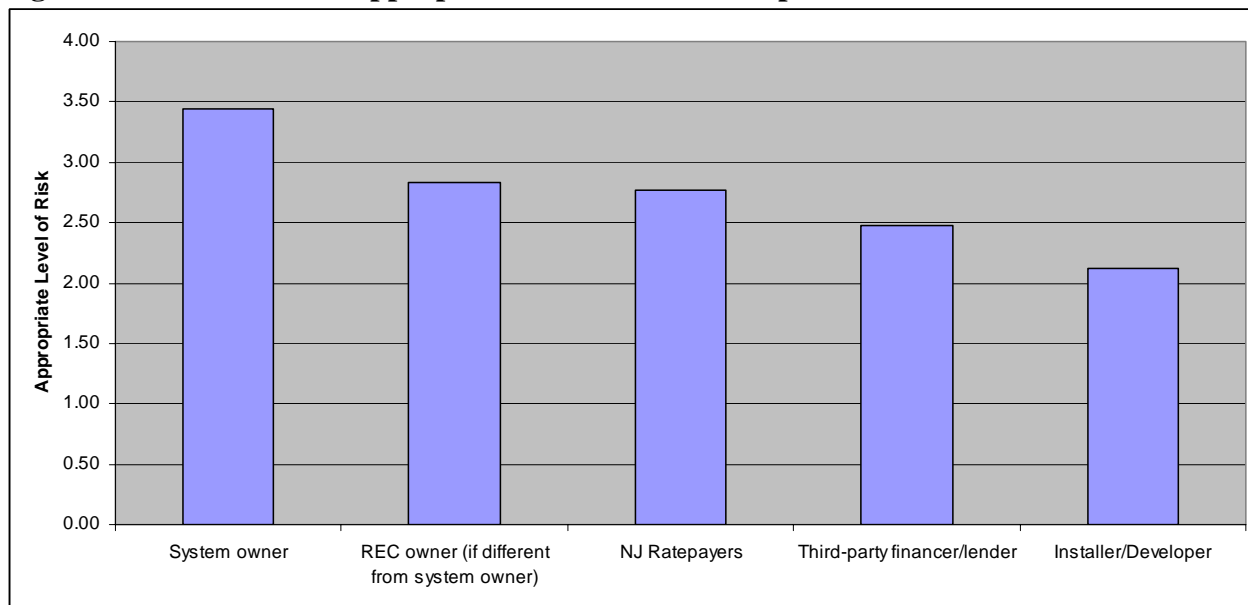
Figure 7-2. Importance of Transition Strategy Elements



The average simple payback threshold, or number of years to break even on an investment, reported by respondents as necessary for system owners to be willing to invest in a PV system was 7.7 years for residential systems and 5.4 years for both a small and large commercial systems.

On average, the respondents felt that in a post-rebate marketplace, the system owner should bear most of the financial risk, followed by the REC owner (if different from the system owner) and the New Jersey ratepayers (either through Systems-Benefit Fund supported programs or higher Alternative Compliance Payments). Respondents also believed that third-party financiers/lenders and installers/developers should also bear some level of risk.

Figure 7-3. Level of Risk Appropriate for Market Participants



For systems that have already received rebates, 53% of the respondents felt that they should be treated exactly the same way as new systems being installed in a post-rebate SREC market place in which ACP levels may be much higher than they are today. 37% of respondents felt that the number of years that a project can generate SRECs after project installation should be limited. 16% of respondents listed their reply in the “other” category. Many respondents commented that early movers who took a chance with their investment in a PV system when it was still new to the New Jersey market place should be rewarded for taking that risk by being able to receive SREC revenues for the entire life of their project.

Concerning the size of solar projects, 74% thought that large-scale (>2MW) solar projects should be allowed to generate SRECs in New Jersey. Of these same respondents, 63% thought that there should not be any variation in the treatment of small versus large (i.e., >2MW) systems in determining the SREC value they are able to receive from the market.

7.2 Potential Impacts of Future Market Scenarios

The various incentive models that have been proposed were examined in light of the various uncertainties that face New Jersey as it moves forward. These uncertainties were represented in the form of scenarios that describe events that have some real probability of occurring in the next decade or so. The scenarios examined and summaries of the likely impacts are discussed below.

Scenario 1: PV prices stay at current levels

In the first scenario, we examined the case where, for example, the generous subsidies offered around the world are sustained at their current high level. This would continue to support high demand for PV systems. However, if manufacturers are reluctant to make major investments in new production because of the regulatory risk associated with government subsidies, then we could see a period of sustained prices at or near current levels. Another potential scenario for current PV prices is a continued boom in microelectronics that keeps silicon expensive and in short supply for some period into the future. Obviously having the current price for PV systems, and thus SRECs, continue at their current level instead of falling, as in our current financial models, would be more expensive for the New Jersey ratepayer.

Scenario 2: PV prices drop dramatically

By contrast, the second scenario looks at what would happen if a sudden breakthrough in PV technology dramatically lowers the cost of PV systems. This technical breakthrough might be one of the non-silicon systems currently under development or some other totally unanticipated technical breakthrough. Since the panels represent roughly half of the current system prices, this sort of breakthrough could conceivably lower the overall system cost by 30-40%.

Clearly this would be good news for the New Jersey ratepayers. However, the benefit to the ratepayers would be muted in several of the models (Underwriter, and all of the Tariff models) by the long-term commitments that would have been made to the earlier, more expensive systems. Under the SREC-only, the Hybrid-tariff, and the Auction models, owners of early systems would see the value of their systems eroded as SREC prices fell.

Scenario 3: SREC markets expand dramatically

The third scenario focuses on the potential result of a Federal RPS.⁸⁷ In this case, the depth and liquidity of the SREC market would improve dramatically, and we would expect to see prices become more stable. This situation would presumably be viewed favorably by most lenders, and financing would become easier and cheaper, lowering the SREC price. The price decrease here is presumably less dramatic than in the scenario above and is balanced by the increased depth and reduced volatility of the overall market.

If the prices fell far enough, system owners under the Commodity and Underwriter systems would start making claims against the Underwriter agency, and its creditworthiness could decrease. Although there would likely be some initial discontinuities like this under the Commodity, Underwriter and Auction markets, in the long term the deeper markets and higher liquidity inherent in a regional or national trading platform should be a positive feature for most market-based models. On the other hand the relative paucity of New Jersey's resource base could prove a difficult barrier if local systems were forced to compete with systems located in better solar climates.

In this scenario the tariff models would face a somewhat jarring "second transition" into a more market-based system. A means would have to be devised to phase out the tariffs contracts that were already in place and move those earlier installed systems over to whatever new, larger SREC market emerged. New systems would presumably simply enter the larger market as they came on-line.

⁸⁷ The assumption here is that a Federal RPS would use some type of market-based mechanism such as RECs or SRECs to allow trading of renewable energy credits across state boundaries. Given the plethora of state RPS, set-asides, and incentive systems already in place, formulating a single Federal system would be a challenging undertaking.

Scenario 4: Over-supply of SRECs

This scenario primarily affects the SREC-only system. It is less likely for the models where there are fairly rigid controls on how many systems are allocated incentives, such as the Full-Tariff and the Auction models. In the Underwriter model and Hybrid-Tariff models, the question is similar but less clear-cut. Since the Underwriter and Hybrid-Tariff programs would only be allowed to contract for the number of SRECs required to meet the RPS, this should act as at least a partial inhibitor for wildly overrunning the RPS targets. However, as noted earlier, systems may get built without going through the Underwriter or Hybrid-Tariff programs, which would make this issue harder to manage.

In the case where the market becomes overheated, and too many SRECs are produced, prices fall and the Underwriter agency has to bail out many systems. In the OCE Straw proposal, as prices fall system owners see the value of their systems fall, and presumably this discourages installation of new systems for some time.

Scenario 5: Under-supply of SRECs

In the case where PV installations lag the RPS targets, demand for SRECs outstrips their availability. The LSE's presumably are forced to use the ACP to fulfill their RPS requirements. This situation creates an interesting conundrum around the ACP value. If the reason for the shortfall is related to the SREC prices and the ACP value is high enough, then it should encourage installation of more PV systems in the next year, hopefully catching up with the RPS requirements. However, if some other—non-price-related—barrier is creating the shortage and the market is unable to catch up to the RPS targets, then the ratepayers suffer the continued impacts of a higher ACP.

Scenario 6: PSEG Green Towns Program

As discussed in Section 5.4, the PSEG Green Towns program is a proposal to give the incumbent utility entry into the marketplace. The benefits to PSEG and the LSEs are substantial. PSEG would receive substantial tax incentives and public relations benefits. They would also have the opportunity to reduce grid congestion problems while incurring virtually no risk since program expenses would be rate based. The LSEs would avoid the transaction costs associated with securing SRECs to fulfill RPS compliance.

Relative to the other participants in the market, the utility has a) none of the merchant risks and b) access to lower cost money. Therefore, it seems likely that—at least in the short term—the regulated monopoly should be able to produce SRECs at a lower cost than the other firms in the market. This would clearly reduce the overall cost to ratepayers.

By contrast, the private companies that are competing for a piece of the market would suddenly see the overall market size reduced by 30% and the price of SRECs drop. This could make the development of a truly competitive SREC market in New Jersey more difficult.

8. SUMMARY AND RECOMMENDATIONS

In an ideal world, SREC prices would be set by pure market forces; a dynamic equilibrium between supply and demand would keep prices high enough to enable project investors to achieve a moderate return on their investment, while remaining below a reasonable threshold for ratepayer impact. Market rules would be clear and consistent, and market participants would have confidence in their longevity. SREC trading values would be made transparent, and brokers and aggregators would bring together willing buyers and sellers, providing benefits of efficiency, volume and liquidity to the market.

Some of these functional-market features are present in the New Jersey solar market. PV system buyers have demonstrated that they will respond to a favorable value proposition, and LSEs have become active participants in the SREC market, albeit by mandate. A variety of brokers and aggregators exist to bring together SREC buyers and sellers, and SREC trading prices are publicized on a website that receives a high volume of traffic. However, these features are all the result of government interventions that provide mandated demand, rebates, and information to stimulate the market, as well as a price ceiling to limit ratepayer costs.

If New Jersey were to remove the rebates and leave just the mandated demand and information, projects would likely continue to be developed by some businesses with a large tax appetite, and by innovators and early adopters who are willing to take risks and/or make purely value-based investments. However, residential and small commercial project development would decline dramatically, since the project economics for this class of project owners would be much less favorable. While opportunities would exist for public projects to obtain capital through bond initiatives and other means, substantial development by municipalities would likely depend on their ability to develop appropriate PPA agreements and the presence of State-funded technical support and education. If a significant decline in project development were to occur, many small businesses that have emerged to serve the existing market environment may face bankruptcy. A shortage in the solar capacity required to meet RPS goals would drive up SREC prices, and a significant portion of RPS requirements would be met through ACPs, resulting in negative ratepayer impacts.

In addition to being almost purely government-created, the New Jersey solar market is relatively new and subject to much regulatory uncertainty. As a result, there is little stability, and the financial community views it with skepticism. These conditions have led many industry and policy experts to conclude that, if the New Jersey RPS goals are to be met, efforts must be made to overcome current barriers to the execution of long-term SREC purchase contracts, and/or some type of revenue support or guarantee should be offered in a sustained, orderly manner over a number of years to provide project developers and potential system owners with the confidence they need to become active in the market place. The Summit Blue Team concurs with this assessment. Aside from the SREC-only model (OCE Pilot Program), which would provide no form of price certainty in the market other than a price ceiling, all of the potential market transition strategies evaluated as part of this assignment would provide a theoretically viable means of addressing revenue uncertainty concerns and providing other benefits to ratepayers. Furthermore, all of the proposals possess both strengths and weaknesses.

Through the criteria-based review of the seven market models, it became clear that the strongest features could be extracted from each of the proposals and combined to develop an alternative set of refined strategies. In the section below, the Summit Blue Team outlines two potential transition strategies that reflect the most favorable elements of the strategies reviewed in the report. Based on the Team's analysis, two refined potential strategies are most likely to provide the required market flexibility and to stimulate entrepreneurship and innovation, while still providing enough stability to appeal to investors and lenders. In

addition, the refined transition strategies would present conditions in which projects' merchant risk would be shared between the State and the system owner. The Summit Blue Team recommends that the two refined transition strategies outlined below undergo further review and analysis as part of New Jersey's efforts to determine an ideal market transition plan.

8.1 Transition Strategies Recommended for Further Analysis

The Summit Blue Team's recommended strategies for further review and analysis are designed to facilitate:

- **flexibility** to foster entrepreneurial market developments and to enable the incentive system to adapt to the meet the changing needs of the marketplace;
- **revenue stability** to facilitate continued steady installation activity while the market is still young;
- **market forces** to enable the development of the level of market infrastructure that will be necessary to sustain the market once incentives are no longer available.

The potential transition strategies reviewed in the report whose *primary elements* offered the desired combination of revenue certainty and conditions that will foster the development of a sustainable SREC market were the Hybrid-Tariff and Underwriter models (and by extension, the Commodity Market model since it incorporated the Underwriter model). Although these models use quite different mechanisms, each provides the combination of an assured revenue "floor," and some level of economic efficiency and responsiveness to market forces.

New Jersey seeks to develop an independent and robust SREC market, so the Summit Blue Team recommends that the State design the next phase of incentive programs to exist for a finite term and to offer declining levels of financial support. Incentives would gradually phase-out as experience with the market increases and investor confidence grows.

Incorporating the most favorable *secondary strategy* elements⁸⁸ with the primary elements of the Hybrid-tariff and Underwriter approaches, the Team developed proposed variations on both the proposed Hybrid-tariff and Underwriter models that, our analysis indicates, will better-serve the goals of the market than the versions of those strategies formally presented in the White Paper Series. Of course, a critical factor in determining the effectiveness and impacts of either of the potential strategies outlined below is the actual incentive level offered. The scope of this effort did not permit the depth of analysis required to determine an appropriate level of incentive or back-stop support to be offered under the proposed programs. However, the tools are at hand to do so, and the question is clearly critical to the next phase of decision-making.

⁸⁸ It is important to note the distinction between the Team's criteria-based discussion of the actual full proposals as submitted and the combination of the elements of those proposals recommended here. The full proposals that were submitted incorporated numerous details and, in some cases, some less-favorable details detracted from the merits of the overall proposal. Therefore, the discussion of the formal proposals may not immediately appear consistent with the recommendations. For a treatment of the proposed strategies that is broken out by the proposal's *primary and secondary elements*, the reader is referred to Table 5-1. That table is organized according to the primary and secondary elements of the proposed approaches, addressing the key strengths and weaknesses of each. Thus, the commentary in that table is more consistent with the recommendations presented here.

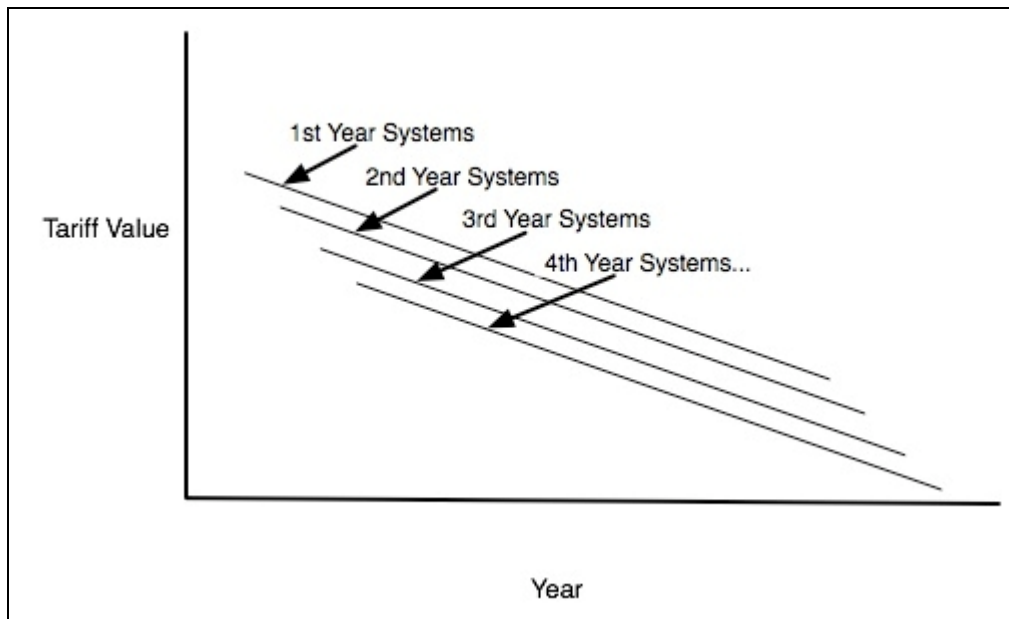
8.1.1 Features of Recommended Hybrid-Tariff Approach

The Summit Blue Team recommends further review and analysis of a hybrid-tariff approach which would look much like the performance based incentive system currently going into effect in California under the California Solar Initiative. Tariff levels would differ for small and large systems, and would decline along a predictable schedule over time. Under this declining schedule, the present value of the tariff revenue stream would be low-risk, but each year, as the tariff “price” decreases, the system owner will assume greater risk as a steadily increasing portion of revenues comes from the SREC market. A key component of this recommendation is to increase the SACP level so that it is high enough to encourage the LSEs to use the SREC market, and also high enough to not be a strong influence on the SREC trading values. The key features of the hybrid-tariff approach that are recommended for further review include:

1. **10-Year Tariff Commitments**: Under the recommended model, some entity in the state⁸⁹ would provide projects with premium credits/payments for solar electricity generated by their customers. The tariff schedules would be adjusted over time, but once a participant entered into a tariff commitment, they would be locked into the 10-year declining tariff schedule in effect for all tariff commitments commencing in that year.
2. **Gradually Declining, Two-Tiered Schedule for Tariff Levels**: To improve administrative efficiency and facilitate sustained orderly development, a gradually declining schedule of tariff levels would be set at the outset of the program. Two tariff level tiers would be set: Tier 1 would be for small systems (e.g., under 50 kW) and systems owned by government or non-profit entities; Tier 2 would be for larger systems (i.e. between 50 kW to 1 MW), and an annual funding cap would be set for participants in this tier. During the initial period of the program, tariff levels would be set with the goal of delivering a favorable target ROI to participating project owners (assuming revenues both from the tariff program as well as from the SREC market.) The gradual decline in the tariff levels should roughly track improvements in project economics resulting from solar technology and industry advancements, as well as increases in retail electricity rates. After an initial period of approximately five years, tariff levels would be reviewed and a determination would be made regarding whether the program should be extended (i.e., whether new tariff commitments should be made). Figure 8-1 shows how the tariffs might be set in practice. Declining tariffs provide firm revenue projections, while also promoting an increasing reliance on the SREC market.

⁸⁹ See the sidebar in Section 5.2.3 for more details. This entity could be either the EDCs, as proposed in the Hybrid-Tariff model, some other entity such as the OCE or the OCE’s program management company, or another entity entirely. See point 3 below.

Figure 8-1. Gradually Declining Tariffs



3. Program Funded with SBC Funds: A key feature of the tariff program is that the entity paying the tariffs must be creditworthy. This is an advantage of funding the tariffs with SBC funds. Since the value of the tariffs to be paid each year can be calculated in advance, the SBC funds would be collected upfront and the solvency of the paying entity should never be in question. An SBC funded program could be administered either by EDCs or by OCE or its Market Manager. EDCs would provide creditworthiness, they could leverage their existing billing functions, and EDCs would be well-positioned to track PV system production based on data provided through automatic metering devices. However, as noted earlier, this would be dependent on EDC buy-in, which may not exist.

8.1.2 Features of Recommended Underwriter Approach

As with the version of the underwriter approach presented in the White Paper Series, the Summit Blue Team recommends further analysis of a model in which the State would set up an underwriting entity, either in a state agency or potentially a private entity (this is a familiar function for insurance companies, for example). This entity would guarantee a minimum price for the SRECs for which it holds contracts. Key features of the underwriter approach that is recommended for further review include:

1. 10-Year Underwriting Commitments: The underwriting entity would sign contracts to support the negotiated “floor” for SREC prices for a 10-year period.
2. Gradually Declining SREC Minimum Price Levels: The minimum price levels under the contract would decline gradually at a predetermined rate. This will smooth the transition of the projects from a price-supported situation into one without price supports.
3. Underwriter Entity Independent, Transparent, and Funded with SBC Funds: The underwriter entity needs to be a creditworthy institution backed by sufficient funds to cover its potential exposure. Again, this is a familiar role for organizations like insurance companies. The funding to support the underwriting fund should come from the SBC. Each year, the amount paid into the fund will be

“trued up” to cover the claims paid in the previous year, and the exposure for the coming year. All transactions of the fund must be transparent and available to the market participants.

8.1.3 Features Common to Both Proposals

1. All Systems Metered and Provide Automatic Production Reports: This will improve program administrative efficiency and ensure accurate tracking of system performance.
2. System Owner Retains Ownership of SRECs: Under either model, the incentive level would be set based on the assumption that a portion of the project investment would be recovered through SREC revenues. While the SREC-dependent portion of the project debt would expose the project owner to risk, it also presents an upside potential. In addition, by forcing these SRECs to trade in the marketplace, the program facilitates steady development of market infrastructure while increasing investor confidence in the regulatory stability of the market.
3. Allow Grid-Supply PV Systems (>2MW) to Generate SRECs. This would increase the likelihood of achieving RPS requirements and would improve the economic efficiency of overall ratepayer spending to achieve RPS compliance.
4. Allow Existing Rebate-Funded Systems to Continue Participating in SREC Market: Although there is a perception of “double-dipping” associated with this, there are several good reasons to allow it: 1) relative to the amount of solar electric generation required to meet the 2021 RPS goals, the amount generated by rebate-funded systems is small, and allowing them to trade their SRECs will be an increasingly small factor in the market; 2) the extra administrative burden created by developing a second “vintage” or “tier” of SRECs simply isn’t justified by the small value they represent; 3) the systems in place now are the early adopters who built their systems in the face of the highest risk, and these citizens/ratepayers should not be prohibited from participating in the SREC market over the long-term; and 4) given that a portion of most new projects will recover a portion of their project debt through Tariff or Underwriter incentives, new systems would not command the extremely high SREC values that might exist under a system with no revenue certainty. These lower SREC values would decrease the “windfall” experienced by rebate-funded systems.
5. Template SREC Contract: OCE would develop a template contract that project owners could use to facilitate the trade of SRECs. This would help reduce transaction costs and educate project owners about the terms that they should look for in an SREC agreement.⁹⁰
6. SRECs would be traded through PJM GATS. This would increase compatibility with regional markets.
7. Transition Current SREC Program to Serve Function of Registry / Certifier: The current SREC program would transition to function as a registry and certifier of New Jersey SREC eligibility. In order to obtain certification as an RPS-eligible generator of SRECs (certification information will be required for PJM GATS certificates), PV project owners would agree to report the average annual SREC prices from their project as part of the annual RPS compliance reporting process. The functions of this registry/certifier entity would provide some level of market price transparency, while also monitoring progress toward fulfilling RPS requirements so that issuance of new tariff commitments can stop in the event of a potential over-supply situation. In addition, the SREC

⁹⁰ Note that OCE already provides a list of recommended contract terms on its website.

program administrator would provide customer service to those project owners needing assistance with their participation in PJM GATS.⁹¹

8. 2-Year SREC Trading Lifetime: This would provide generators with a longer planning timeframe and greater flexibility in trading SRECs, while simultaneously decreasing risk exposure for the underwriter entity. It is also consistent with the approach taken by other states in PJM and is permitted within the structure of PJM GATS.
9. Publish New System Registration Statistics: In the course of registering the systems for the SREC program, the BPU intrinsically gathers data on new systems under development. A system should be developed to report this data in a timely manner (say at least once a month) to an independent party (possibly a trade association) to publish for the industry. This should help to alleviate dramatic over- or under-building relative to the RPS targets.
10. Require Warranties for Registered Systems Smaller than 10 kW: These smaller systems should have protection against equipment or installation failures. As mentioned above, the system installers are the best positioned to manage this risk and should carry it. California has developed a set of PV warranty requirements that could likely be readily adapted for use in New Jersey.

8.1.4 Primary Advantages

In essence, both approaches share the merchant risk between the State and the system owners. Both of these plans force the system owners to take some of the downside risk of a fall in SREC prices, while still allowing them to retain the potential upside associated with a robust SREC market. Either the binding tariff or the underwriter contracts, in combination with the electric power revenues, will assure the system developers, owners, and their lenders of a significant revenue stream, albeit not enough by itself to provide substantial returns. In addition, of course, the project developers remain able to capitalize on any other Federal or State incentives such as tax credits or accelerated depreciation schedules.

From the ratepayers' point of view, both of these plans provide incentives for system developers and owners to build their systems as economically as possible, and to innovate wherever they can find either technical or financial competitive advantages. Each plan also gives the BPU a method to make required adjustments to the future commitments issued under the incentive program without wildly disrupting the whole market.

Either plan has the potential to be established and implemented with ease and efficiency. In order for the most cost-effective version of the Hybrid-Tariff model to be instituted, in which EDC's billing and metering-reading capacity would be leveraged, EDC buy-in would be necessary. This assumption requires further assessment. The Hybrid-tariff approach is clearly at an advantage in this area.

These proposed approaches promote the development of a market-like system that is likely to be compatible with any regional or national systems that are subsequently established. If, at some point in the future, some method is determined that will allow renewable energy credits to be incorporated into the RGGI GHG management scheme, this system is likely to be compatible.

⁹¹ Through an interview with Jan Pepper of Clean Power Markets (CPM), the SREC Program administrator, the Team learned that CPM will be playing this type of customer service / facilitator role for the state of Pennsylvania's solar projects.

8.1.5 Primary Disadvantages

As with all the models examined, these recommended approaches possess some shortcomings. For many developers, the principal drawback will be the lower level of guaranteed revenue to secure their financing relative to the current rebate program. Since both proposals are designed to split the merchant risk between the State and the system owner, the guarantee levels envisioned will likely not be enough to cover the full system cost.

As discussed earlier, there could be also be serious challenges associated with identifying a willing Underwriter entity, and there are some concerns about the risk premium that may be passed along if a private entity is selected to perform the Underwriter role.

Another potential problem is that there does not appear to be any pragmatic way of guaranteeing that future regulators do not tinker adversely with the market rules (i.e., any way to completely eliminate regulatory risk). The Hybrid-tariff model in particular does not provide direct negative (financial) feedback to the regulators for adverse tinkering with the market. However, this is a reality for investors in many policy-based markets and some level of regulatory risk is unavoidable. Furthermore, as mentioned above, the legal contracts that are signed for the tariff or underwriter amounts do provide a solid commitment for that portion of the revenue, and any action that seriously diminishes the rate of installation will be readily apparent to the public.

Neither of the recommended approaches offers any incentives to increase the prevalence of long-term SREC contracts. As described above, this is a desirable feature of the SREC market, but it is unlikely to become prevalent until the market has matured a bit more. In fact, the very reason the market transition strategies that incorporate revenue guarantees are recommended for further consideration is due to the fact that long-term contracts are hard to come by in current immature market.

8.2 Conclusions and Next Steps

New Jersey's CORE program has gotten off to a good start, but needs to transition to a more sustainable approach. Developing a new market from scratch is never easy, and many commercial entities that try it fail. The history of renewable energy development in the U.S. offers convincing evidence that it is no easier for governmental bodies, despite the potential advantages they possess in terms of regulatory power and scale.

The great challenge for governmental bodies is to establish mechanisms that provide development support within a framework that allows market forces to act, while not "poisoning" the waters. Historically, investment and capacity-based incentive rebate programs have not succeeded in fostering the development of sustainable markets. However, performance-based incentives hold great promise for fulfilling the financial needs of potential project owners while doing little damage to the ultimate goal of developing a market that will eventually be self-sustaining.

The two refined transition strategies recommended for further review and analysis are performance-based incentive systems. Both of the potential strategies would balance merchant risk between the State and the system owners (or SREC owners), and both possess the potential to accomplish OCE's goals to fulfill the RPS requirements while minimizing ratepayer impacts.

This review was undertaken in a very short time-frame and with limited resources. As a result, a comprehensive, in-depth analysis of the features and implications of the six potential transition strategies considered in the report was not feasible. A more detailed financial analysis of a sub-set of the potential

transition strategies will take place in early 2007 as a follow-up to this report. The Summit Blue Team recommends focusing that analysis on the two transition strategies described above, as they consist of a combination of the most favorable elements of the six potential transition strategies reviewed at the scoping level in this report.⁹²

During *the next stages of analysis* and decision-making leading to the development of an appropriate transition path for the New Jersey solar marketplace, OCE should continue to consider the following questions which were addressed at a scoping level in this report:

1. What is the necessary and appropriate target **return on investment** that incentive programs should seek to provide in order to stimulate the rate of development required by the RPS?
2. What program structure will provide **simplicity, economic efficiency and flexibility** so that it can both encourage a diversity of project-types, respond effectively to changing market conditions, and drive down system costs?
3. What is an appropriate **allocation of risk** across market participants?
4. How can New Jersey **minimize the perception of regulatory uncertainty**?

New Jersey has the potential to maintain its position as a national leader in solar electricity development by both continuing to surpass other states in its per-capita development of solar capacity, and introducing a successful model for large-scale solar market development. By pursuing a gradual reduction in the State's current level of financial incentives, and a sustained, orderly transition to a financing structure in which the only form of ratepayer support would be through SREC revenues, New Jersey will be well-positioned to fulfill its goal of achieving its aggressive RPS targets while minimizing ratepayer impacts.

⁹² To do this, the team plans to build a model system that starts with the project *pro forma* to establish the effect of the proposed incentives on the project financials. This information would then be used to inform a model of the ratepayer impact. By establishing probability functions for the key input variables and then using Monte Carlo techniques, it is possible to establish the performance of the incentive models under a wide variety of scenarios.

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| New Jersey Clean Energy Program | http://www.njcleanenergy.com/ | |
| U.S. D.O.E. Office of Energy Efficiency and Renewable Energy (EERE) | www.eere.energy.gov/femp/technologies/renewable_purchasepower.cfm | Federal Energy Management Program Green Power Purchasing Guidelines |
| EERE's Green Power Network | http://www.eere.energy.gov/greenpower/resources/publications.shtml | Library of publications on green power market |

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