White Paper Series: New Jersey's Solar Market
Transition to a Market-based REC Financing System

The following series of White Papers were prepared by stakeholders and members of New Jersey's Clean Energy Council (CEC), Renewable Energy Committee who advise the New Jersey Board of Public Utilities in the design and implementation of New Jersey's Clean Energy Program including the Customer On-site Renewable Energy rebate program. In April 2006, the New Jersey Board of Public Utilities approved an expanded Renewable Portfolio Standard (RPS) which calls for 20% Class I Renewables by 2020 and includes a minimum requirement of 2% New Jersey solar. In May 2006, Members of the CEC Renewable Energy Committee formed an RPS Transition Working Group, to consider various financing models to support the continued growth and expansion of New Jersey's solar market. The principles and models being considered by the RPS Transition Working Group are outlined in the following series of White Papers, which were first discussed as part of the ***Roundtable Discussion on New Jersey's Solar Market,*** *held at the 2006 New Jersey Clean Energy Conference & Leadership Awards (September 18, 2006).*

The RPS Transition Working Group is soliciting further comment on the White Paper Series: New Jersey's Solar Market. Please submit comments or questions to info@njcep.com *with 'Solar Market Transition' in the Subject line.*

White Paper Series: New Jersey's Solar Market

New Jersey's Solar Market:
Transition to a Market-based REC Financing System

A White Paper

Revision: September 22, 2006

Prepared By:
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in consultation with the Members Of The RPS Transition Working Group, a Sub-Committee Of The Renewable Energy Committee

FOR DISCUSSION PURPOSES ONLY
White Paper – Establishing a Market-based REC Financing System

With the newly adapted Renewable Energy Portfolio Standards (RPS) New Jersey will require at minimum 19,102,500 MWhs of Class I renewable energy. This estimate is based on a conservative 1% annual electric energy growth rate. Over the last 10 years, electric energy has increased by 1.4% and over the last 5 years by 2.1%. This 19,102,500 MWh of Class I renewable energy is approximately 4,400 MW of renewable energy capacity. In addition, the newly adopted RPS will require 2.12 % Solar set aside as part of the Class I renewable energy RPS. The Solar set aside within the Class I RPS is 1,800,000 MWhs or approximately 1,500 MW. Given these numbers, it is clear NJ cannot simply provide rebates or grants to construct this capacity. If we did, this cost would be in the billions of dollars and would require an annually funding level of approximately $500,000,000. The rate impact of this funding level could be approximately 5 to 7 percent. Clearly it is not an option to simply "buy" our way to the RPS goals.

A more cost effective option is to convert the renewable energy rebate/grant program to a market-based Renewable Energy Certificate (REC) financing program. Currently, an upfront rebate or grant is provided for a set percentage of the capital cost of the renewable energy system. The remaining capital cost is financed based on the avoided electricity costs. In addition, currently RECs, provide an annual additional value to reduce the overall payback period. For solar, this is managed to provide a 10 year payback or a 10% ROI.

As an example, a 10 kW PV system cost $77,500. With a NJCEP rebate of $43,500 and a federal tax credit of $3,000, the remaining cost is $31,000. The avoided annual electric cost of this system is approximately $1,200 and REC value is approximately $1,800. This results in a 10 year simple payback (Figure 1).

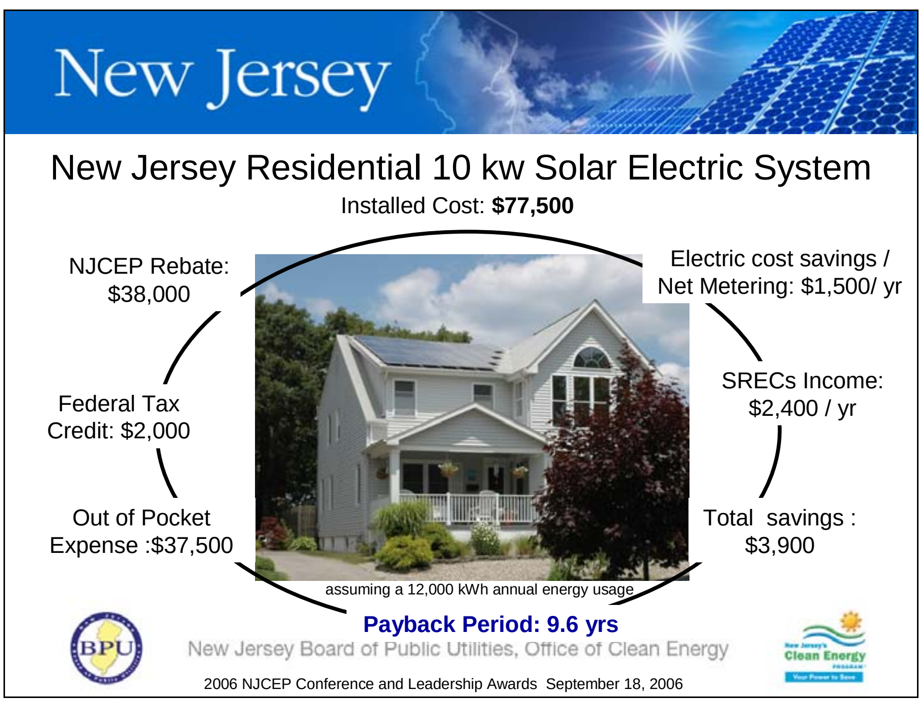

Figure 1: New Jersey Solar Financing Model for 10 yr Payback Period

By increasing the REC value, the rebate amount can be significantly reduced or eliminated and the rate payers' annual impact can be significantly less than managing a rebate/grant program. However, for the market-based REC financing system to work it must be verifiable, traded freely on an open market, provide some degree of price certainty and allow for dating the REC to establish a vintage for REC retirement.

1. ***Verifiable*** – The REC system must be able to report actual data for all REC generation. This could be a real time metering system or a system that records REC generation on a set timeframe – weekly or monthly. Buyers must have confidence in the quality of the system to produce actual REC generation. While engineering calculation are fine for a small tracking and trading system, if the REC system is to expand to be relied on by the financial markets it must run more efficiently and effectively – recording generation for more accurate trading.

2. ***Trade freely on the open market. –*** More and more challenges are being made by and against state economic development policies that favor in state businesses as contrary to interstate commerce. The REC system must be able to be bought and sold on the interstate market within acceptable limits. One obvious boundary is that RECs should be traded within the same market in which the electricity that the renewable energy systems are bought and sold. Expanding on this market would be by agreement between the parties that establish REC systems.

   How to establish a market based REC financing system if all states that participate in the REC market do not have the same system. Creating such a system that increases the price of REC would cause an imbalance in the REC market with all the REC in the interstate market trading from states with lower REC value to states with higher REC values. An option might be to establish a baseline REC that is bought or sold freely between states but that states could layer on top of the baseline REC different additional values. In this manner, State A that participates in market-based REC financing system with higher REC values, can still trade with State B that does not participate in the market-based REC financing without upsetting the market balance. State B can add additional value to the baseline REC that is traded between States A & B to cover the addition of the increased value or price of the REC. An example of how this already works is with fuel cell RECs in Connecticut or the waste coal RECs in Pennsylvania. These RECs have no value in other states – a null REC but have value added by the state in which they trade. In this same way a REC that has the same value in interstate trading can be used as the baseline REC value with additional value added on top of this interstate REC price to cover the additional financing costs.

3. ***Certainty*** – The REC system currently provides an upper limit – an ACP. The ACP is the price above which the REC value does not exceed. In order to allow for a market-based system, the BPU will need to set the floor price below which all buyers must pay a certain price and no lower. In between the floor price and the ACP, the market on an annual basis will provide the value of the REC depending on supply and demand.

4. ***Vintage*** – At some point after the renewable energy system that is "paid for" by the market-based REC financing system, the REC generated by that specific system must be reduced or fully eliminated. The market-based REC financing system should not be expected to pay the higher REC value after the debt is recovered. The market based REC financing system must be able to track the vintage of the renewable energy system. After it records a certain value the REC have generated by the specific system the vintage of that specific systems REC would be reduced or have no value.

The following criteria for evaluating alternative models for transitioning from a rebate-centric financial model to REC-based model were developed during a series of Renewable Energy Committee working group meetings.

Guiding Principles

The ideal REC based initiative should be able to:

- 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

EXAMPLES OF DIFFERENT SREC PROGRAM MODELS

	1	2	3	4	5	6
Model	**R.E. Tariff**	**Central Admin./ Power Authority Admin.-determined Price**	**Central Admin./ Power Authority RFP→Clearing Price**	**Central Admin. RFP**	**Commodity Market w. BPU-determined term & life**	**Commodity Market**
Similarity to other models	Germany, Spain, other European countries, Ontario, Washington State (pilot), China (proposed)	New York/ NYSERDA	Pennsylvania (proposed, but w.o. Power Authority)	Colorado (proposed), Massachusetts		New Jersey, Nevada
How price is determined	BPU proceeding (yearly?)	Periodic analysis by BPU/ Administrator determines cost plus fixed return (e.g., 10% after-tax return based on prevailing cost of systems)	Periodic RFP for SRECs (e.g., 2/year). Administrator uses results of RFP to set market clearing price. Special structure & price for small systems.	Periodic RFP for SRECs (e.g., 2/year). Clearing price set for small systems.	Commodity market	Commodity market
How term is determined	BPU sets fixed term	BPU/Administrator sets fixed term	BPU/Administrator sets fixed term	BPU/Administrator sets fixed term	BPU sets fixed term	Commodity market (SBC or ACP funds may be used to pay for longer-term contract insurance)
Price is re-set	Yearly (a schedule may be set over several years, e.g., 2 years)	Yearly	Twice per year	Twice per year	NA	NA
Life of plant for NJ SREC creation	BPU sets life of plant for SREC creation	BPU/Administrator sets life of plant	BPU/Administrator sets life of plant	BPU/Administrator sets life of plant	BPU sets life of plant	Unlimited
Parties involved in buying/selling	Utility ←→ generator (all sizes)	Utility ←→ Power Authority (all sizes)	Utility ←→ Power Authority (all sizes)	Utility ←→generator for large systems. Utility ←→ Aggregator or Utility ←→ Power Authority for small systems	Utility ←→ generators, aggregators, resellers.	Utility ←→ generators, aggregators, resellers.

A white paper regarding establishing a market-based REC financing system that was prepared by the OCE (summarized above) was circulated for review and discussed at the REC Working Group meeting scheduled for June 20, 2006.

Timeline for NJCEP to Transition to a Market-based REC Financing system from a Rebate Centric Incentive system

	Activity	Completion By:
1	**Develop written concept summaries with current stakeholder process**	**End Of July 2006**
2	**SMALL work group develops draft straw proposal of overall migration architecture and description of key elements**	**End of August 2006**
3	**Finalize migration proposal with full stakeholder group and public process**	**End of October 2006**
4	**NJBPU Develop, Submits for Board Approval and Publish in the NJ Register REC rule proposal (and related changes)**	**End of December 2006**
5	**REC rule proposal Public Hearing and Public Comment Period**	**Jan 07 thru End Of Feb 07**
6	**REC rule Comment/Response Document, Submit Final Rule for Board Approval and Publish Adoption in NJ Register**	**End Of May 2007**
7	**Start NJCEP Rebate Transition Period**	**June 2007**
8	**Fully Implement NJCEP REC Based Financing system**	**Jan 2008**

Note: overall architecture, description of key program elements, and required implementation actions (and timetable) defined as of the end of 2006. Any changes that require BPU rule making (or similar regulatory action) complete over the following six months. There may be other aspects implementing the transition – not specifically regulatory in nature – could also be started in Jan 2007.

Underwriting Solar Investments In New Jersey:
Achieving Scale In An RPS-Dominated Environment

A White Paper

Originally Published: August 15, 2006
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Introduction

The renewable energy market in New Jersey is currently supported by a two part incentive structure: rebates and long term renewable energy value from the Renewable Portfolio Standard (RPS). The New Jersey Board Of Public Utilities (BPU) has established a strategy of evolving from an incentive environment dominated by up-front rebates to greater focus on the sale of Solar Renewable Energy Certificates (SRECs) over time. This transition allows a more market-oriented approach to economic development, and reduces dependence on the programs needed to provide rebates. The resulting SREC-based environment will result in performance based economics, enhanced market growth and elimination of current growth barriers, and cost improvements through scale.

But the migration from rebates to an RPS-focused environment will be challenging, and it is essential to maintain current industry momentum during the transition. An RPS-based program is profoundly different than one based on rebates since projects will be required to take on significant project debt to enable the installation. *The RPS-based market will only succeed if the capital markets have the confidence necessary to secure project investment, in volumes sufficient to meet the aggressive RPS goals.*

This document focuses on a proposal to introduce underwriting as a way to encourage the emergence of project finance resources equitably across the market and minimize rate-payer costs. The following summary provides a brief overview and is probably sufficient for most readers. The remaining sections provide a more detailed discussion of implementation mechanics, with a focus on financial considerations.

Proposal Summary

An RPS-dominated market will depend heavily on traditional project finance: the approximately $4/watt available from rebates today will have to be directly replaced by $4/watt of project debt (plus cost of capital) for most projects. Without this investment support, the projects simply won't happen in any but the most affluent segments.

The primary financing challenge is that solar project investments must amortize over an extended term (10-15 years at least) to be cost competitive with utility supply (since traditional plants typically finance over decades). In addition solar investments face significant regulatory, technology, and market risks that those investments might be stranded. Combined with the relatively small scale of both the industry and individual projects and the emerging nature of the market, it is clear that the availability of capital resources will be heavily dependent on creating revenue confidence in the SREC revenue stream, with an associated policy commitment to minimizing stranded investments.

The fastest way to create this long term revenue confidence is through underwriting. This approach is particularly relevant given that the solar RPS goal represents over 1.5GW of solar power plant construction. Underwriting is a proven mechanism that has been used successfully in a variety of other environments, and it is particularly prevalent in the energy industry. Implementing an underwriter for the NJ solar market would provide the same kind of financial assurances that typical power plant developers enjoy, and result in a similar ability to attract private capital, create scale, and reduce cost of capital expenses that are ultimately carried by the rate payer. The proposed underwriting mechanism could be used with any of the market models being proposed, but is especially well suited to the commodity market proposal.

There are a variety of ways to implement an underwriter, but this proposal is based on the following approach:

- Create a solar underwriting program within the NJ-EDA. The underwriter must be vested with enough long term stability to allow debt security confidence by the market.

- The underwriting program being proposed should require minimal direct funding in the nominal case, other than perhaps initial administrative and start up costs. In cases where the market is approximately in balance, payouts made by the underwriting agent will be funded in-year through Alternative Compliance Payments (ACP[1]). This in-year funding mechanism, building on the availability ACP revenues already existing within the market, is essential to the underwriting entity being proposed.

- Prior to construction, any solar project can secure an underwriting commitment, similar to the way rebate reservations are made today. ALL types of projects – including small projects and projects with third party ownership structures – can apply for underwriting support. This commitment will promise to buy any unsold SRECs from the project over 15 years, if the project is unable to sell them on the open market. The price will be set for the term, at a specified fraction of the then current ACP, with the underwriting discount set by the ACP board. The underwriting discount must be sufficient to support realistic cost of capital for project debt. With this guarantee in hand, the project then has a minimum revenue stream commitment, at a fixed price over a 15 year term, which can be used as security for the project debt. In a given year, the project will try (and probably in most cases succeed) to sell their SRECs on the open market for a price higher than the underwriting guarantee. Any SRECs that are "left over" at the end of the year are then bought by the underwriting agent, at the previously agreed upon price, and retired. These purchases, when needed, are intended to be funded IN-YEAR by ACP payments made by the LSEs.

- The expectation is that most projects will sell most of their SRECs on the market, success of which may vary from year to year (depending on long term contracting and spot market conditions). The underwriting guarantee is only exercised in the event that SRECs can't be sold through the market as desired**. The underwriting program therefore serves as a backstop to natural market mechanisms, providing minimum revenue guarantees without disrupting market based transactions as the preferred vehicle**. Project developers are motivated to sell on the market since

[1] The Alternative Compliance Payment (ACP) is an alternative method for satisfying an entities RPS obligation other than buying (and retiring) SRECs. The ACP cost is set by the ACP board every year, and is currently $300/MWHR of RPS obligation.

their ROI would be higher, and LSEs are still motivated to buy on the market to avoid the maximum costs associated with the ACP.

With underwriting in place, appropriate project finance could emerge *for projects of all sizes* even if long term SREC purchase agreements (by LSEs or other parties) are not realized. Furthermore, the underwriting function can help the transition happen *more quickly*, given that natural market mechanisms cannot be made to develop on a specific schedule. The introduction of an underwriting vehicle could help sustain project development even if rebates have been reduced but long term SREC revenue confidence has not yet matured. But as those mechanisms emerge, dependence on the underwriting vehicle will naturally reduce and it may eventually become unnecessary.

Support For Transition Goals

Mike Winka published a summary paper that outlined goals for the RPS transition, and asked that all proposals specifically address the extent to which transition proposals address these objectives. The underwriter proposal is only part of an overall transition plan, and could be combined with any one of several possible market approaches. But assuming underwriting is implemented as proposed, as part of a market-oriented "commodity market" approach as detailed in other documents, we believe the stated goals are addressed as follows:

1. **Verifiable**: The underwriter program is intended to operate in parallel with a natural SREC market, building on the SREC market already in place today. This underwriter proposal therefore recommends no specific changes in how SRECs are recorded and certified. Underwriting can function equally well in the current environment (where <10KW systems are estimated, and >10KW are reported), or in a changed environment where all systems report production directly.

2. **Free Trading**: As noted, the underwriting mechanism is intended to function in parallel with natural market trading, and to be as minimally disruptive on that trading mechanism as possible. Underwriting support – as something separate from actual trading – could be made eligible only to systems physically in the state of NJ. This might be a way encouraging in-state development without restricting regional market development. On a related note, the underwriter proposal is based on enabling 15-year economic lives for the installations, which brings the required SREC prices down. Compared with some other proposals – 5-yr SREC life, for example – lower SREC prices facilitate regional market development. Put another way, any NJ model that forces SREC prices up (like high risk factors, or shorter terms), will make NJ a SREC magnet in the regional market, to the disadvantage of the NJ rate-payers.

3. **Certainty**: The underwriter is a way to provide the "floor pricing" suggested as a goal, and is a book-end to the price ceiling currently implemented by the ACP. Of all proposals currently on the table, we believe the underwriting proposal provides a flexible mechanism for establishing floor-pricing most directly.

4. **Vintage**: The underwriter model does not address vintage, or related questions about legacy systems, directly. There is some "vintage impact" from the proposed

underwriter mechanism, however, in that systems from a given year are each supported with a unique floor price and procurement guarantee term. As outlined in the commodity proposal, however, we believe that introducing vintage constraints adds considerable complexity to the market, and should be avoided in the SREC mechanism itself. We also believe that legacy systems should not be stranded in the transition to the REC-only market. The reason is that the new market will depend heavily on participants taking long term positions in SREC. Considerable damage could be done to creation of this market if participants that have *already* taken such long term positions (based on rules that were in effect at the time they made their project commitments, which included no term or other vintage constraints) are stranded.

5. **Timeline**: We believe that the underwriter proposal, implemented through a commodity approach to the market, is the fastest way to make the transition. We are not able to judge the regulatory actions needed for implementation, but we believe that only two actions need to be taken to implement the proposed transition: a) raise the ACP to the appropriate level immediately, and b) implement underwriting. We think the only regulatory action required to implement underwriting is authorization to apply ACP payments to "first use" by the underwriter. Pending further definition of regulatory actions required, we believe these two actions could be taken MUCH FASTER than the timeline originally proposed.

Several additional goals for the program were identified at the August 22 Renewable Energy Committee, and the underwriter proposal (in concert with the commodity market proposal) address these additional criteria as follows:

1. **RPS Goal Compliance**: market results for the last several years demonstrate conclusively that a) there is strong market (customer) demand for solar, and b) the industry can respond to fulfill this demand assuming project economics work. Current estimates are that the industry has met, and perhaps exceeded, the RPS goals for the last two years. As we transition to the SREC only market, the *primary* gate on whether this momentum can be sustained – and whether RPS goals can continue to be met – is whether project financing materializes. The best way to ensure the RPS goals are met is to ensure that a) project economics continue to be attractive to customers and b) make sure that project finance resources are available. The underwriter proposal is a direct response to this need, and we believe the introduction of an underwriter is the fastest and highest confidence mechanism for securing long term revenue and attracting capital.

2. **Lowest Possible Cost**: The underwriter model works in parallel with natural SREC trading, which we believe is the best mechanism for achieving lowest possible SREC cost. In addition, the introduction of an underwriter should facilitate lower capital costs through reduced risk – cheap solar will require cheap money. Lastly, to the extent underwriting enables strong capital support, supply will better fulfill RPS requirements thereby minimizing SREC shortfall and ACP burden for the ratepayer.

3. **Open Process**: As noted above, the underwriter augments commodity market trading, which should incorporate mechanisms for auditable, trackable transactions. The underwriter proposal neither helps nor hinders attainment of this program goal.

4. **Maximize Investor Confidence**: the underwriter proposal is specifically designed to address investor needs for long term revenue security. The administrative burden for the program is projected to be relatively minimal, essentially a one-time transaction at the point of underwriting commitment, and then payouts (if any) for stranded SREC purchases annually.

5. **Regional Market Compatibility**: as noted above, enabling longer payback terms (15 years), with reduced revenue risk (through underwriting), allows SREC prices to stay relatively low compared with some other options (such as forcing a 5-yr term). Maintaining "reasonable" SREC prices, compared with regional pricing, is critical for even market development across the region and avoidance of NJ becoming a SREC magnet due to inflated SREC value. We also believe that the underwriting model could be expanded on a regional (and potentially national) basis, thereby making this NJ program a leadership example for solar market development elsewhere. Also as noted above, enabling capital support (through reduced revenue risk) is one of the best ways to ensure sufficient supply.

6. **Market Equality**: the proposed underwriter would be available for ALL projects, regardless of project size or ownership structure. It therefore "levels the playing field", and makes it possible for investment resources to be available more equitably across all segments. Absent a mechanism like underwriting (or some similar risk reduction system), it will be extremely difficult for smaller projects to get funded through traditional (and scalable) sources.

7. **Congestion Relief**: the underwriting proposal supports all projects, regardless of where they are. It therefore neither helps nor hinders congestion relief goals other than by facilitating smaller (more distributed) projects that otherwise might not happen.

8. **State Development Plans**: we are not aware of those goals, and cannot comment on how this proposal applies.

9. **Low Implementation Costs**: the full costs for an underwriting program are not yet known, especially given that an execution vehicle (NJ-EDA, or something else) has not yet been identified. As proposed, however, the underwriter is expected to be relatively lean administratively, easily managed by several qualified staff. The broader financing issue is whether a backstop fund, in addition to expected revenues from the ACP, might be required. If it is, funding of that reserve could be substantial.

10. **Minimize Regulatory Risk**: see response #4 (maximize investor confidence) above.

Detailed Program Description

Motivation

It is possible that simply increasing SREC value is sufficient to attain the confidence needed for project financing, at least for larger scale projects. But it may NOT be sufficient, or it may not result in the emergence of necessary market conditions fast enough, or with enough coverage across all segments (including smaller projects). The underwriting concept is proposed as a mechanism to address these market transition risks.

This additional market facilitation is needed since there are good reasons why desired long term SREC contracting may not happen fast enough. In particular, LSEs have expressed considerable resistance to making SREC purchase agreements from facilities that are not yet constructed. Yet this is exactly the sort of agreement that a project developer needs to secure project financing in advance of construction. In addition, LSEs are likely to distribute the risk in their SREC purchase portfolio, and will satisfy their RPS obligation through a combination of spot market, mid-term, and long term purchases. There are good "risk allocation" reasons why all of the SREC market may not be purchased through the long term agreements needed. Finally, there is less financing available for smaller projects – especially projects under 100KW – where transaction cost barriers may limit both long term SREC purchase agreements and project financing support.

The underwriting mechanism is proposed to address these risk since it is a proven and well understood approach, can be primarily funded from structures already defined (the ACP), and can be equally beneficial to projects of all size and in all application sectors. It therefore is a relatively easy way to "level the playing field" regarding project financing in an emerging market where risk factors are unproven and the potential for stranded investments are significant.

Implementation

The underwriting entity can be structured a variety of ways: either as a product from an existing financial services company, as a not-for-profit set up specifically for the purpose, as a Non-Governmental-Organization (NGO), or under the umbrella of a state agency. Ideally private financial markets would create the needed product, leveraging similar products already available. It is likely, however, that the initial risk profile is too high and the industry scale is still too small. We therefore believe that a separate entity under the NJ Economic Development Authority is the most appropriate basis short term.

Initial discussions with NJ-EDA indicates that it is consistent with their charter and operational capabilities, assuming they are charged to implement the program and it is appropriately funded. This underwriting proposal is based on the expectation that it could be implemented relatively quickly under the NJ-EDA, with minimal new regulatory action required to create the necessary authority.

The entity needs only three things to fulfill its purpose: a) the operational ability to process applications and payouts (when needed), b) long term sustainability, sufficient to meet financing party needs for security, and c) privileged access to ACP revenues in-year. The BPU would need to create the latter (assignment of the ACP) through regulatory action.

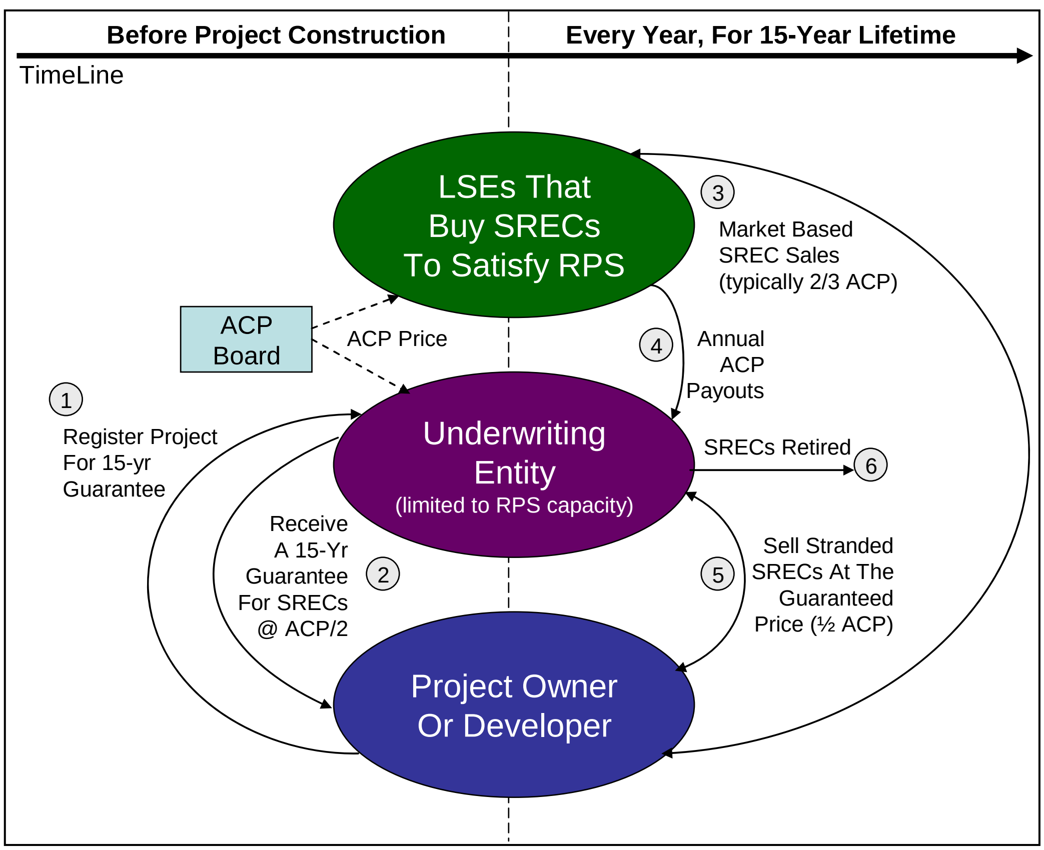
There may be the need for initial start-up funding and initial coverage of basic administrative costs. Once the program is operating, however, a nominal administrative fee could be extracted by the entity from the ACP stream. Cost to the rate-payer will be minimized if the underwriting entity were not-for-profit, or administered through the NJ-EDA as proposed. Depending on how the program is structured and where it resides, it may be appropriate to require a modest application fee for underwriting to help cover administrative costs, as long as it is modest and scaled with project size properly.

We propose that the underwriting function be implemented immediately, with the goal of issuing the first project commitments in January of 2007.

Program Operation

The underwriting entity being proposed acts in parallel with natural SREC market activity between willing parties, and is funded in-year through ACP flows that are already defined. The following diagram summarizes the transactions that would take place between a project developer, the SREC buyers, and the underwriting entity.

Underwriter Transaction Model



The underwriting process, as illustrated in the diagram above, functions as follows:

1) The underwriting entity can accept new project underwriting commitments up to, but not greater than, what the RPS market will require. This limit should take into consideration the total amount of capacity installed at the end of the previous energy year (all projects, not just the underwritten ones). This operating constraint will make it highly UN-likely that there will be more SRECs than RPS-demand, since it is relatively rate that in this environment projects would get financed without underwriting (at least in the early years).

2) Project developers/customers can apply for an underwriting guarantee at the time they are arranging financing for a proposed project. The underwriter will issue a written commitment to buy any stranded SRECs from the project at a fixed fraction of the CURRENT ACP for 15 years. This amount remains constant over the term, although could potentially be ramped to reduce exposures in the out years. The underwriting fraction would be set by the ACP board every year, but financial modeling indicates that the underwriting price should be approximately 60% of the ACP. The project developers can use the underwriting commitment to secure the required project debt, which should also result in lower debt costs.

3) Once project construction is complete, the facility owner (or designated broker/aggregator) can sell the system's SRECs on the open market in whatever way they want. LSEs can only acquire SRECs through the market; they can not get them from the underwriter in any way. As in today's market, we would expect SRECs to naturally trade at about 65% to 90% of the ACP, which is HIGHER than the underwriting guarantee. Projects are therefore motivated to sell SRECs in the market since their profit will typically be higher. The underwriting function is therefore not a replacement for direct SREC transactions between willing parties, and the underwriting fraction is set low enough to motivate use of the market. Given an appropriate balance of pricing points in the market by the ACP board, it is expected that most SRECs will be sold through the market, preferably through long term contracts.

4) ACP payments made at the end of the energy year are paid to the underwriting fund, up to the amount needed to cover payouts (if any) plus administrative costs. As long as a) the RPS demand is greater than the number of SRECs available, b) future ACP prices are not driven too far below previous year underwriting commitments, and c) LSEs can only buy SRECs from the market, there should always be enough ACP funding to cover any payouts made by the underwriter, with a little room left over to cover the underwriter's administrative costs. See the financial section below for more details on the funding mechanism. Basic regulation mechanisms are proposed along with this underwriting function, to ensure that the needed market balance is maintained and underwriter liability can be bounded.

5) At the end of an energy year, a project can exercise their underwriting guarantee to get paid for any SRECs they were unable to sell. Any <u>SRECs the underwriter purchases are retired.</u> This condition is critical since otherwise the underwriter becomes a short-circuit for the entire market, and natural market transactions will be limited since the

LSEs would benefit from doing a single transaction with the underwriter rather than participate in the market.

6) We propose that the underwriting program be defined for 10 years, with an option to continue if conditions merit at that time. The proposed life of the commitment is 15 years, so in year 11 the program stops issuing new underwriting commitments, but continues to make payouts (based on ACP receipts) as needed. Depending on how market conditions develop, it may be appropriate to reduce the underwriting term in the out years (from its initial 15 years), which also serves to minimize longer term liability exposure.

Once established, the underwriter may become a natural home for other market stimulation activities, including additional "market assurance" measures. In particular, there are variety of methods that could help stimulate long term SREC contracting. These concepts, as potential expansions of the essential underwriting concept, are explored in Appendix A.

Financial Considerations

The proposed solar program has something to build on that most underwriter programs don't: the ACP revenue streams already defined in the current market. The critical requirement to making this underwriting entity viable is confidence in the year-by-year ACP funding mechanism, which potentially avoids the need for a large backstop fund. As long as there are not significantly more SRECs in the market than RPS demand, and future ACP prices are not set dramatically below earlier year floor prices, the ACP mechanism can be assured to work. Even outside these boundaries, the system is relatively robust as long as some ACP flows continue.

A financial model has been developed to explore the cashflows and financial exposures of the proposed mechanism. This model is provided along with this white paper to allow evaluation. Input parameters include ACP prices year by year, ACP discount factors, solar deployment rates, and relative market adoption factors (how many SRECs are traded through the market, and how many result in underwriting calls). Given these inputs, the model predicts worse case financial exposures and a year by year cashflow. This model accounts for the fact that underwriter payouts in a given year are based on a range of underwriting floor prices from previous years. It does not account for any administrative or overhead costs, although they are expected to be minimal compared with the cashflow of the program overall. **Please note: this model is an initial version focused on modeling basic flows. Further modeling is warranted, pending broader review and stakeholder input.**

Based on inputs provided, the model projects "worst case" conditions under extreme deviation, and yearly cashflows that would actually result from more realistic scenarios. Note that the worst case estimates are extremely unlikely to be realized in practice, since they represent conditions of profound breakdown in the function of the market. But they are provided to estimate the degree of exposure possible for the underwriting entity. The estimate of "Maximum Underwriter Exposure" shows the payments that would have to be made if ALL installed solar capacity is underwritten (even above the RPS limit), and if ALL SRECs have to be bought by the underwriter every year (no sales through the market). The estimate of "Maximum ACP Flow" projects the maximum ACP payments that might be made by the LSEs, assuming they didn't buy any SRECs from the market. These cashflows go somewhat hand-in-hand, since except for scenarios of extreme oversupply, SRECs that are bought by the underwriter are always accompanied by ACP payments. As long as the maximum ACP payments exceed the maximum underwriter exposure (and assuming banking of receivables across years), the underwriter is economically viable. The model has been used to examine a variety of cases, and in all but the most extreme oversupply or ACP depression conditions, ACP collections should exceed underwriter payout obligations.

Beyond worst case boundary conditions, this model is useful for exploring relatively realistic market scenarios and determining sensitivity to entity liability as market conditions vary. Key conclusions from the model include:

1. The proposed ACP mechanism works in many cases, in that likely underwriter calls are more than covered by ACP flows under realistic conditions. As expected, extreme swings in the market will result in uncovered calls, but the model demonstrates that the ACP board should have the ability to prevent such conditions from emerging, and will have significant flexibility in handling underwriter commitments <u>as long as at least some ACP flows are available</u>.

2. A nominal market case has been defined, based on a) an initial year ACP of $650/SREC, b) an underwriting price at 60% of the ACP ($390/SREC in the first year), c) an annual ACP decline of 10%, and d) an annual solar deployment growth rate of 20% every year. This solar deployment rate was chosen because it tracks the RPS goal relatively consistently, and results in approximately 1500MW installed by 2020. The ACP decline rate results in an ACP that approaches non-solar REC commodity prices by the end of the program. Under this nominal case, the model predicts several key results:

    a. In a "properly functioning" case where most SRECs are sold on the market, and only 5% make underwriting calls, the ACP revenues exceed underwriting payouts every year of the program. In fact, the program (assuming it banks unused ACP collections) generates a $916M excess over its lifetime.

    b. In an extreme case, where 100% of the SRECs are not sold through the market and ALL generated SRECs result in underwriting calls, the underwriter is cashflow positive every year, and accrues banked net proceeds of $794M.

    c. Looking further at the extreme "100% of SRECs make calls" case, and forcing oversupply conditions, the market mechanism is robust enough to remain financial viable even with modest levels of oversupply. If the solar growth rate is set to 27% per annum, the program is cashflow positive for the first 10 years, and the net collected over the lifetime is positive (i.e., excess ACP collections banked in early years cover shortfalls in latter years). <u>Note that this is an extreme oversupply condition, resulting in almost DOUBLE the required RPS capacity in 2020</u>, but even in this case the underwriter is fully funded. This condition should never emerge, since the underwriter being proposed would limit underwriting commitments when oversupply conditions materialize.

d. In another important extreme case (assuming 100% of SRECs make calls, none sold through the market), the model indicates that the ACP board will have considerable freedom to drop ACP prices without creating underwriter liability. Assuming the solar deployment is at 20% per year (approximately on track with the RPS trajectory), and the ACP decreases 25% per year (dramatic reductions every year), the program remains cashflow positive and accumulates about a $35M excess over its 15-yr lifetime. This conclusion is critical, since it implies that as long as there are ACP flows for at least some period of time, the ACP board will have flexibility in managing future ACP prices downward in response to market price improvements without creating significant liability. This includes the ability to drop the future ACP below previous year floor prices.

3. The model can be used to explore cases where the ACP-funding mechanism does not work. The primary failure case is when there is significant oversupply and there are no ACP payments but numerous underwriting calls. Looking at a possible scenario, assume massive deployment in the early years (25MW in 07/08, and 50MW in 08/09), followed by a consistent 20% solar growth rate. This results in five years of slight undersupply, followed by oversupply the remainder of the period. In this case, the underwriter builds up a base of underwritten commitments during the first five years (since the oversupply limit has not been triggered), but is left with no ACP flows for the next 10 years to fund the underwriting calls. Once the oversupply situation emerges, however, no further new underwriting commitments are made, so the maximum obligation is based on the first five years. Further assuming only a modest ACP reduction rate is applied (20%), the total unmet obligation over the lifetime is approximately $486M. Note that this is a slightly nonsensical case, since if significant oversupply emerged, the ACP should be dropped more aggressively (than the 20% assumed), in which case the degree of oversupply should reduce and the associated shortfall would reduce. The methodology outlined in this example, however, can be used to identify maximum exposures under cases of no-ACP payments. In all of these cases, the size of the liability scales with the size of the base of underwriting commitments, which is dependent on the number of years the program operates before the oversupply limit is triggered. Under all these scenarios, it is assumed that one (or more) of the regulation mechanisms defined below would be employed. Note that the oversupply scenario described in this case results in almost DOUBLE the RPS requirement, which presumably would trigger regulation mechanisms that prevent (or at least limit) underwriter liability.

4. As expected, extreme scenarios can be created which break the underwriter. If solar growth outstrips the RPS trajectory significantly, or the ACP is set too low by the ACP board in future years, significant liabilities emerge. Sensitivity analysis indicates that these breakdown cases are extraordinarily extreme, and only occur in cases where the ACP board sets conditions that are in direct violation of policy goals. Example include a) increasing the ACP even when oversupply exists, b) continuing to

make underwriting commitments when there is oversupply, or c) dropping the ACP dramatically even when there is a capacity shortfall.

5. Based on this initial financial modeling, and resulting sensitivity analysis, we believe there is merit in the concept of funding an underwriting mechanism from in-year ACP flows. Most importantly, initial assessment indicates that the ACP board will have the ABILITY, within reasonably wide market variations, to set conditions so as to avoid (or at least minimize) underwriter liability. The primary breakdown scenario is oversupply that eliminates ACP flows even thought underwriter calls continue to be made. The combination of controls through ACP price setting, with the regulation mechanisms proposed below, are expected to be sufficient to maintain market balance.

Regulation Mechanisms

As noted in the above analysis, the proposed ACP funding mechanism appears to be robust enough to allow ACP management within a reasonable range of market conditions without creating underwriter liabilities. Given that state liability is involved, however, is may be appropriate to ensure further governance mechanisms to ensure that the liability is manageable. Assuming the ACP board doesn't drop the future ACP far below previous underwriter commitments, the issue of ensuring underwriter financial integrity reduces primarily to the problem of assuring that there is not excessive SREC oversupply in the market.

Several actions can be taken to ensure this balance:

1. Limit underwriting commitments based on annual assessments of total installed capacity. Each year, the underwriter only issues underwriting commitments up to the RPS limit. In this way, the underwriting entity provides an indirect regulation function that can help ensure that the oversupply condition does not emerge.

2. Couple this underwriting proposal with other ideas for a "circuit breaker". In this case, if significant oversupply emerges, the RPS profile could be increased to match supply capability, thereby reducing the oversupply risk and underwriter vulnerability.

3. As a final, somewhat extreme option, the BPU could restrict NEW (not yet built) projects from participating in the SREC market, thereby preventing the oversupply situation from threatening the underwriter's solvency.

This multi-step sequence of oversupply limits should be sufficient to ensure viability of the ACP funding mechanism. If further financial security it needed, however, it may be appropriate to have modest backstop funding on reserve to cover calls – perhaps on the order of one year of exposure. If that is required, it may be appropriate to apply some funding from the Societal Benefit Fund to establish that fund, and/or to exercise state bonding facilities for this purpose.

In any event, we believe that the combination of a) preferred access to ACP revenues, b) sound decisions by the future ACP board, c) multiple regulation mechanisms to ensure oversupply is minimal, and d) if needed, a MODEST backstop fund are sufficient to secure the proposed underwriting entity. Note that in cases where these regulation mechanisms are exercised, the market will be demonstrating the reduced need for underwriting and the program can begin to be phased out.

In considering the underwriter proposal, many are concerned about the "worst case" scenario where future prices drop dramatically, and the ACP board would like to drop the ACP price accordingly. In this situation, particularly if there are also oversupply conditions also emerging, the financial viability of the underwriter would be stressed. It is important to note that this market condition could emerge **WHETHER THE UNDERWRITER IS IMPLEMENTED OR NOT**. The risks of this condition are not the result of the underwriter, but a general risk of the proposed RPS-only market. The underwriter mechanism makes this risk more obvious, however, since it shares the burden for such conditions between the state and private investors. If there were no underwriting mechanism, and the feared "low price/oversupply" condition develops, it is the early project investors that are left absorbing the economic consequences. Fear about that condition, and the fact that investors have NO ABILITY to affect or minimize the emergence of such conditions, are what limit capital investment today. A primary advantage of the underwriter model is that it creates a strong feedback linkage between actions taken to affect market conditions (by the BPU and the ACP board) and state-borne consequences. Initial financial modeling demonstrates that the ACP board will have the ability to ensure underwriter integrity (i.e., prevent financial liability), assuming they adopt underwriter solvency as a goal. The underwriting proposal is based on establishing a policy goal of preventing stranded investments if future ACP-drop/oversupply conditions develop.

Pros and Cons

Benefits

1. This program can be implemented relatively quickly, with minimal regulatory action. This advantage is critical, given the urgent need to accelerate the RPS market migration. The underwriter can be implemented outside of the BPU (perhaps in the NJ-EDA), the diversification of which reduces regulatory risk and enhances market confidence.

2. The underwriting program results in minimal disruption of natural SREC market trading, and therefore is a way to *facilitate* private investment without constraining the innovation and efficiency that market mechanisms allow.

3. It is based on a widely understood mechanism that has been used successfully in other markets. It is well understood by the financial community, and there is considerable evidence that the existence of underwriting commitments will stimulate massive investment in NJ solar by private capital. Of all the models being discussed, underwriting is the most *proven* mechanism for encouraging investment, especially in the energy industry. In essence, this underwriting proposal puts solar plant

investment on a similar footing with the assurances that traditional power plant investments receive.

4. It provides the long term revenue confidence needed, without disrupting direct market participation by buyers and sellers as exists in the market already. Creating an underwriter function leverages the SREC market that already exists in NJ without discouraging further growth of that market.

5. If natural market mechanisms emerge, so that underwriting is not needed, a) that will become quickly apparent, and b) the program can be discontinued easily (while honoring outstanding commitments). Underwriting is therefore an effective way to stimulate early market development, without limiting options for future migration to an unassisted market. This model is also fairly flexible, since the ACP board can modify various factors (including ACP price, underwriting discount, underwriting limits, variations on term, etc) that can be adjusted to respond to changing market conditions.

6. Underwriting can be applied to all of the market models under consideration, although it fits particularly well with the commodity trading model.

7. The introduction of a strong and ubiquitous underwriting program – especially if it serves all market segments well – eliminates the need for other market facilitators (such as multipliers, enforced contracting terms, etc). It therefore allows a simpler and more efficient market. In addition, the underwriter levels the playing field across all market segments, and reduces the potential that some systems (particularly smaller residential systems) are disadvantaged in the new RPS environment.

8. The underwriting structure establishes a strong and appropriate linkage between policy makers that can affect market conditions (the BPU and the ACP board) and accountability held by the state. Such a linkage creates a natural feedback mechanism between decisions and consequences that other models lack.

9. Initial modeling indicates that most, if not all, of the underwriting system can be funded from mechanisms that are already defined in the RPS program (the ACPs).

10. This mechanism is exportable to the region and other markets. If successful, it could serve as a model for promoting solar investments nationally (assuming a similar national RPS mechanism with an ACP component).

Costs, Risks, and Disadvantages

1. The underwriting entity needs to be created, which will require a focused effort and senior policy support.

2. Although the primary exposure for payments is expected to be covered by ACP flows, some initial funding (as a modest backstop, and to cover startup and initial

administrative expenses) may be required. The magnitude of these expenses are not yet known.

3. The proper functioning of the market, and the underwriter in particular, depends heavily on sound decision making by the ACP board. Flawed ACP board decisions could either disrupt underwriter function or create a significant financial liability.

4. If the planned management and governance systems proposed for the underwriter fail, the state could end up with a significant financial liability. In particular, the underwriter depends (if implemented in the NJ-EDA or similar state authority) on state willingness to make significant long term commitments to avoid the stranding of project investments, not unlike commitments made to other public policy priorities.

5. If abused, or if the underwriter floor is set too high, the underwriter could short-circuit the natural market mechanisms and essentially default to a centralized buyer at maximum (ACP level) rate payer expense.

Appendix A: Underwriter Support For Long Term Contracts

The primary objective of the proposed underwriter is to create long term revenue confidence and enable project investments. Once an underwriter is established, however, it may be able to provide a further facilitation role that reduces other risks. The following additional ideas are offered as possible optional enhancements to the core underwriter proposal.

One of the biggest disincentives any market faces with long term contracts is the increased risk associated with the term. Simply put, the likelihood of some unforseen event occurring that prevents a party from fulfilling their contractual obligations increases with time. So a shorter contract is generally viewed as less risky than a contract of the same subject matter that is in place for a longer term. Longer term economic lifetimes are necessary for solar projects, however, to make solar electricity competitive with utility supply.

To encourage longer term contracts, the underwriter could offer to take some of the risks from each party if they were willing to enter into a contract of at least ten years (or more) duration. For the LSE (buyer) the underwriter could assume the risk that the solar developer will not perform or that by regulatory fiat, the S-RECs they have purchased are no longer useful. In each case, with the backing of the BPU and the State, the proposed underwriter can take this risk.

In the first case where the underwriter is called upon to make good on a failure of the solar developer to provide S-RECs (with no contributing fault from the LSE buyer -- for example the solar generator is destroyed by a force majuere event), the BPU can issue to the underwriter at no or minimal cost the S-RECs needed to make the LSE whole and keep them in compliance with the RPS regulations. Alternatively, they could forgive the fraction of that contract's SREC inventory from the RPS obligation.

In the other case, assisting the solar developer, the underwriter could take the risk that the LSE will exit the market or refusse to pay for the S-RECs. In the case where the market has fallen and the spot price is less than the contract price, the underwriter can step in and cover the difference. The aspect of the underwriter's risk will have some cost associated with it and the underwriter will need to be compensated for taking this risk. The risk would be mitigated by the underwriter's ability to enforce the original contract price if it can locate the original contracting LSE party and if that LSE is not in bankruptcy.

As another element, the underwriter could look into taking part of the price risk from the LSE should the LSE decide to leave the New Jersey market and not be able to re-sell its obligation under the long term contract except at a loss. This too would have an underwriting cost associated with the risk but is another element the State could support to encourage long term contracts.

In each of the above cases, the underwriter is supporting a contract that is otherwise negotiated among an LSE and solar developer. Of course the underwriter would want to see specific terms in any underwritten contract but provided those terms were included by the parties and it was of at least ten years duration, this removal of risk could be a strong incentive for parties to enter into long term agreements.

As with all underwriter proposals, there is a strong linkage between regulatory action and state liabilities, which represents a tangible policy commitment to limit stranded investments. Where the State is a party to the underwriter's contract, that relationship will be a very strong disincentive for the State to change the regulatory rules that would undermine the validity of the S-REC market. Because the underwriter would take that risk in a long term contract, it would seek to be reimbursed for its losses from the State.

COMMODITY MARKET-BASED TRANSITION TO A LARGE SCALE SUSTAINABLE SOLAR MARKET

MOVING THE NEW JERSEY SOLAR PROGRAM FROM REBATES TO RECS

A White Paper

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COMMODITY MARKET-BASED TRANSITION TO A LARGE SCALE SUSTAINABLE SOLAR MARKET

MOVING THE NEW JERSEY SOLAR PROGRAM FROM REBATES TO RECS

A WHITE PAPER

The solar energy market in New Jersey is planning a transition from a system dominated by public rebate incentives to a focus on recurring production revenues derived from the Renewable Portfolio Standard. This approach has the advantage of reducing current market caps and enabling significantly larger scale, but it depends heavily on support from private capital for project financing. In short, the support currently provided by the rebates has to be replaced by equivalent project investment based on confidence in the RPS revenues over time.

We believe that commodity market based mechanisms are the preferred option for this new environment, since we think it is the most likely to capture the support of the capital markets. Fortunately, the environment that has been created in NJ is already heavily market focused, and the existing momentum can be leveraged – with some modest facilitation – into a larger scale environment. The primary challenge is creating the revenue confidence needed to secure project debt without restricting natural market mechanisms that allow innovation and efficiency. This document proposes several specific actions that can be taken to facilitate the emergence of this market.

I. SUMMARY OF COMMODITY MARKET BASED MODEL/PLAN

- Continue to register, trade and retire SRECs using the existing trading system. Market participants will continue to establish REC prices through bilateral transactions. Maintain the simplicity inherent in the current SREC market structure, including a single class of SRECs with no vintage constraints.
- Raise the solar ACP immediately, and maintain it at levels needed to replace the current economic value of the rebates and sustain project volume consistent with the RPS goals.
- Complete projects in the queue to the extent that CORE funding is available but allow projects that opt out of rebates to use a REC only structure.
- Fully utilize the existing CORE budgets through 2008, then renew the SBC and provide limited rebate funding for small project (<100 kW) systems through 2010. Projects larger than 100 kW that cannot be funded from the existing CORE budget will not receive a rebate.
- Establish an underwriting entity to issue 10-15 year floor contracts (see write-up on Underwriter for details).
- Extend REC life to two years
- Allow grid supply Solar-RECs
-

A primary goal of this proposal is a simple structure that can be highly efficient through natural market mechanisms, with minimal effort to accomplish the transition. Given that growth of the industry is currently being constrained by the CORE program budgets, the ability to adopt and implement this model quickly –with minimal regulatory action - is considered a primary benefit of this approach. Enhancing RPS value (through an ACP increase) and introduction of an underwriting program are the two most critical actions needed to start the market transition.

II. DETAILS OF MODEL/PLAN

- **Keep the SREC trading system in place**. Allow the market to establish SREC prices. The SREC market has been working well in New Jersey. LSEs for the most part have purchased and retired their SREC requirement. Although there was one major supplier that chose to pay the SACP rather than purchase SRECs last year, that party is now an active market participant. A number of solar developers have been able to negotiate and sign multi-year SREC delivery contracts with brokers, aggregators or LSE's. We believe the market will continue to improve as market participants become more comfortable with the stability of the trading system. We support the transition of the NJ SREC market to a regional platform over time, provided fees for participation remain reasonable. New Jersey rate-payers have already invested considerable funding to establish the current SREC market, now entering its third year of trading. This proposal leverages that progress, can be accomplished relatively quickly, and encourages the innovation and efficiency that market-based mechanisms enable. Most importantly, we believe that market-based mechanisms are the most likely to attract the capital investments needed to make an REC-only market function.

- **Maintain A Simple Market Structure, And Protect Legacy Systems**. A commodity market is most effective when it is simple and homogeneous. We strongly recommend that the existing simple market structure be maintained, without economic life limits, system vintages, or other trading constraints. In particular, existing legacy systems must be allowed to participate in the new SREC market without undue constraint. Although we recognize the issues associated with perceived windfall benefits for older systems, this impact is very small compared with the overall program, and the impacts of constraints intended to minimize these factors would have a profound negative impact on this emerging market. Most importantly, the future of an REC-only market depends heavily on investors having the confidence to take long term positions on SREC value. If constraints are implemented retroactively on existing systems – who had to assume SREC value over the long term to meet project ROI objectives, based on the RPS rules then in effect – there will be significant damage to the emergence of the new REC-only market. A commodity system depends heavily on a simple and efficient market, with fair protection of legacy systems and clear regulatory intent to avoid stranded project investments.

- **CRITICAL! Immediately raise the solar ACP:** The value that is currently captured through rebates must now be covered by increasing SREC prices. In order to allow the SREC price (determined by market forces) to reflect the reduction in rebate levels, the solar ACP must be raised. Solar ACP levels would continue to be set by the BPU, with advice from the ACP subcommittee of the Renewable Energy Committee (no change in current practice). The philosophy of the ACP subcommittee should continue to be one of setting a level high enough to provide motivation for suppliers to purchase SRECs rather than pay the solar ACP. Given a likely range of SREC trading values (based on industry models), we are recommending that the SACP be raised immediately from $300 today to at least $650/MWh The ACP should be raised <u>immediately</u> to a) offset planned rebate reductions set for September 06, b) allow the BGS auction planners to factor the new ACP prices into their bids, and c) send much needed signals to the financial community that the RPS-migration strategy is going to be a reality. The ACP Committee and the BPU should monitor industry conditions to ensure that the SACP is set at a sufficiently high level to motivate LSE's to participate in the SREC trading program and that project volume is sufficient to meet the RPS capacity goals.

- **Reduce rebates over time, but continue rebates for projects less than 100 kW**: The existing CORE budgets should be fully utilized, based on current policies and the queue structure though 2008. Once those budgets are exhausted, eliminate rebates for systems over 100 kW, but continue support for smaller projects with a slower ramp-down period. The following table shows our recommended rebate reduction schedule, based on the SACP levels shown. (Note, a lower ACP would require higher rebate levels to provide equivalent economics.) Continuation of modest rebates for smaller systems will allow that sector to develop the aggregation functions necessary for those segments to more fully participate in an REC-only environment. During the period when the existing CORE rebates are still being issued, any project should have the option to opt out of rebates and install as an REC-only project.

Year	SACP Level	Under 10 kW. (/w)	10-40 kW (/w)	41-100 kW (/w)	101-500 kW (/w)	501-700 kW (/w)
2006	$300	$3.80[1]/4.40[2]	$2.75/3.45	$2.50/2.80	$2.25/2.60	$2.00/2.05
2007	$650	$3.35/3.95	$2.20/2.90	$2.00/2.30	$0	$0
2008	TBD	$2.65/3.25	$1.50/2.20	$1.30/1.60	$0	$0
2009	TBD	$1.95/2.55	$0.80/1.50	$0	$0	$0
2010	TBD	$1.25	$	$0	$0	$0
2011	TBD	$.55	$0	$0	$0	$0
2012	TBD	$0	$0	$0	$0	$0
2013	TBD	$0	$0	$0	$0	$0

- **Establish an underwriting entity to create 10-15 year SREC revenue confidence**: Once the ACP has been increased, projects should be able to realize the economics necessary for adoption. Very large projects, especially with corporate customers that are funding the project themselves, could probably start deploying REC-only projects immediately. But for project flow to develop across all market segments and ensure a low-cost of capital for solar projects (which reduces costs for the rate payer), we recommend the introduction of an underwriting system. This approach provides a guaranteed purchase of stranded SRECs at a set price, but still allows projects to trade freely through the commodity market. The proposed underwriter is funded primarily through the ACP mechanisms already defined, and should require minimal incremental funding. Underwriting is a known and proven mechanism for encouraging investment in desired markets, and is the primary way to ensure a fast and efficient transition to a REC-only environment. We propose that the underwriting function be established under the NJ-EDA, although there are other implementation vehicles possible. See the separate document on the proposed Underwriter for additional details.

- **Extend SREC life to two years**: The current one year SREC life makes it difficult for LSEs to plan their annual purchases and for solar project owners to match SREC production with SREC supply contracts. Moreover, if there are any "excess" SRECs in the market they are worthless post expiration. This means everyone in the market will try to ensure there is no excess – i.e. the market will always strive to be slightly short. It is self evident that in a short market, commodity prices are higher than normal. Thus a perennial short market drives SREC prices higher than they would be if the market could accept some "overage". Allowing SRECs to have a two year life solves this problem and allows the market to accept excess SRECs. In such a market, prices will tend downwards as contrasted with the eternally short market. LSEs (and their consumers) will therefore see lower SREC prices if SREC life is extended to two years.

- **Allow grid supply RECs**: Current rules only allow net metered solar electric systems to create SRECs. Given the aggressive goals for solar energy embodied in the RPS rules, it will be necessary to encourage large systems as well as small systems in the State. Systems that supply solar electricity directly to the grid should be able to create SRECs as well as customer sized systems. By allowing the creativity of the industry to develop new business models for large system installations, consumers in New Jersey will pay less for SRECs since there will be more opportunities to increase SREC supply. Grid supply projects have the potential to deliver the most solar generation, to the most rate payers, at the least cost, and should be a supported component of the new REC-only market.

III. Support for Transition Goals

Mike Winka published a summary paper that outlined goals for the RPS transition, and asked that all proposals specifically address the extent to which transition proposals address these objectives. The proposal detailed herein, which combines a market –oriented commodity approach, with an underwriter concept (detailed in another document) addresses the stated goals as follows:

1. **Verifiable:** Our proposal builds on the existing SREC trading system. The decision of when to meter and verify small systems (under 10 KW.) can be made at any time. Systems over 10 KW. will continue to report metered results that ensure that the State has a auditable system that inspires confidence in its integrity.

2. **Free Trading:** The strength of the proposal lies in its use of free market forces to set prices of SRECs. Other than setting the ACP, there is no need for government or

regulatory intervention. This feature will lead to greater investor confidence that politics will play a lesser role in the determination of SREC prices.

3. **Certainty:** Since the proposal for a commodity market relies on the forces of supply and demand, there are no guarantees or certainty for future year prices. We have recognized this limitation of the commodity market approach by coupling that market design with the Underwriter concept detailed in another White Paper. With this combination, the advantages of free market efficiencies in setting short term prices can be married with the establishment of a "floor price" for future SRECs that can provide (in the early years of a new market like SRECs), some assurances to investors that long term investments are rational investments.

4. **Vintage**: Our proposal is based on the belief that a market based on freely traded SRECs that are easily understood in the market and represent a simple concept of "One SREC = One MWH of solar generation" will be more successful in attracting new financial resources than a more complicated market based on a variety of SRECs with different vintages and different prices. The KISS principle applies here, particularly since there is a need for additional market participants to expand the capital resources available to fund projects. The more market participants need to know about the regulatory vagaries of vintage SRECs, the less likely new participants will be to participate. Altering the SREC definition potentially strands investment made over the past few years by initial investors and may make other investors wary about entering a market where the definition of the basic tradable commodity can change. Since the market is in an early stage, the vast majority of SRECs have yet to be created. The "windfall" of legacy SREC owners will, in the end, have a minimal impact in total program costs between now and 2020. The introduction of "vintages" for various SRECs could end up being more expensive in the end as the perceived regulatory risk of investors is factored into higher SREC prices over the long term.

5. **Timeline**: We believe that the commodity approach to the market is the fastest way to make the transition from rebates to SRECs. The process can be started immediately by raising the ACP to an appropriate level. The development of the Underwriter can take place after this change has been implemented.

IV. Support of Additional Criteria

Several additional criteria of an ideal SREC system were identified at the August 22 Renewable Energy Committee, and our commodity market proposal (in concert with the underwriter proposal) addresses these criteria as follows**:**

1. **Achieve the RPS goals at the lowest possible price, and drive down the cost of PV:**
   - *Achieve the goals of the RPS-* Market results for the last several years demonstrate conclusively that a) there is strong market (customer) demand for solar, and b) the industry can respond to fulfill this demand assuming project economics work. Current estimates are that the industry has met, and perhaps exceeded, the RPS goals

for the last two years. The best way to ensure the RPS goals are met is to ensure that a) project economics continue to be attractive to customers and b) make sure that project finance resources are available. With the combination of an SREC based commodity market and an Underwriter to provide a floor price for future SRECs, there is every reason to believe that an RPS based market can deliver in the future.

- *Achieve the goals at the lowest possible price*- We believe a freely traded SREC commodity is the best mechanism for achieving a low SREC cost. As we transition to the SREC only market, the *primary* gate on whether this momentum can be sustained – and whether RPS goals can continue to be met – is whether project financing materializes. In an SREC only market, the ability to finance projects will come from an ACP that is sufficiently high to drive short term economics that allow project financing to proceed, or with a long term floor support mechanism (the Underwriter) in combination with ACP levels that are between current rebate-supported levels and the SREC only spot-market value. The underwriter proposal is a direct response to a desire to meet the RPS at a lower cost than an RPS only market without an Underwriter. We believe the introduction of an underwriter is the fastest and highest confidence mechanism for securing long term revenue and attracting capital, thus reducing total program costs over the long term.

- *Drive down the cost of PV*- The attached proposal will drive down the price of PV because it promotes the widest access to the RPS market and encourages solar developers to reduce the cost of their SRECs. Market designs that attempt to set long term prices will cause ratepayers to pay more than those where reducing PV prices bring immediate increased profitability. This proposal will unleash the creativity and innovation of the solar industry.

2. **Allow all players to compete fairly.**

- *Open Process:* An open, accessible market provides easy access to everyone on the same terms. The price of SRECs can be seen on the web site so there are no information advantages for large developers over smaller SREC owners.
- *Market Equality:* The SREC market is available to all sizes and types of solar projects. Our proposal attempts to level the playing field in the early years for smaller systems that have slightly higher installation costs. By providing a reduced level of rebate support for these SREC owners, they will be able to sell SRECs at comparable prices to those SRECs coming from larger projects. In the longer term, we support the development of SREC aggregators who will offer aggregation services to residential and small commercial SREC owners.

3. Allow the development of tools for implementing related policy goals, including:

Reduction of electric transmission in congested areas / Concentration of development and redevelopment in smart growth areas / Pair solar power with energy conservation / Foster small business creation and job growth / Encourage public projects.

- The open SREC market structure allows the Board to develop a range of programs and policies to support the achievement of these goals.

4. Facilitate implementation through:

- *Low implementation costs-* Much of the infrastructure investment to set up the SREC trading system has been made. Thus, the implementation costs of the commodity market proposal will be minimal.

- *Ease of implementation-* Since the SREC market has been in operation for a number of years, our proposal is the easiest to implement. The only immediate need is to raise the solar ACP as rebates are reduced.

- *Short implementation period-* Since the SREC market has been in operation for a number of years, our proposal will have the shortest implementation period. The development of the Underwriter entity can be done after the new market structure is introduced.

5. Carry low regulatory risk

- The SREC program has been established and the rules written. The proposal herein will require very few additional regulatory proceedings. Our proposal only requires continued ACP setting on an annual basis. Other central administrator models require a higher level of regulatory involvement and thus have higher regulatory risks associated with their implementation.

6. Ensure compatibility with regional markets and ensure sources of supply

- Although regional SREC markets have not developed to a stage where the details of their structure are known, it is likely that they will utilize the SREC trading systems piloted in New Jersey (and probably adapted by the PJM GATS system). Continued use of the SREC trading platform will ensure that regional trading can be allowed if desired by the BPU.

V. NEEDED REGULATORY ACTIONS/ CHANGES

1. Convene the ACP Committee immediately and reset prices to start the market transition.
2. Publish a targeted rebate <100 kW schedule for reductions over the period 2006-2010. Allow non rebate systems to create and sell SRECs.
3. Renew the SBC funding for 2009-2012 to ensure minimal small system rebate dollars are available.
4. Create an Underwriting entity within NJ-EDA or another State agency or Authority.
5. [i]Amend the RPS rules to enable grid supply SRECs, extend the REC life to two years and give the BPU authority to create long term contract incentives for LSEs.[3]

VI. SCHEDULE FOR THE TRANSITION

ACTION	4th Q 2006	1st Q 2007	2nd Q 2007	3rd Q 2007	4th Q 2007	1st Q 2008
1.Convene the ACP Committee	**S/F**				**S/F**	
2. Publish a rebate schedule	**S----F**					
3. Renew the SBC funding	**S**	**------**	**F**			
4. Create the Underwriting entity	**S-----**	**------**	**-----F**			
5. Amend the RPS rule	**S----**	**------**	**F**			

S= Start F=Finish

In order to have a transition plan in place to avoid a program shutdown or a critical retraction of the market at the beginning of the 2007-2008 compliance year, it is imperative that a plan be adopted and implemented without delay.

VII. FINANCIAL IMPACTS (INCLUDING RATE IMPACTS)

Since this plan endorses the existing RPS model in the State, its financial impacts have been previously analyzed by the Staff of the Clean Energy Office and will serve as a baseline forecast

VIII. OPEN QUESTIONS AND CHALLENGES

Should the BGS suppliers with three year contracts get relief from any obligations as a result of the increase in the ACP?

IX. ADVANTAGES OVER OTHER MODELS

- Can be started immediately by raising the SACP
- Requires the fewest regulatory changes of the models being considered
- Can be phased in- if raising the SACP encourages sufficient development activity to meet RPS goals, no other changes may be required.
- Encourages efficiency in price setting- does not require a potentially contentious and time consuming legal/regulatory process to set prices. Such processes will be expensive and may place the nascent solar industry at a disadvantage compared to larger LSEs or LDCs.
- Fits in with the existing SREC market; maintaining the continuity of the market to inspire investor confidence. Other models that change the market may spook the financial community if they perceive other fundamental changes may follow.
- Because the proposed program relies almost exclusively on private parties, there is no administrative burden placed on the State. Nor is the State required to identify and contract with a private administrator to run the program. It runs itself.
- Promotes long term financial investments that can bring significant amounts of new private capital to the solar market.

- Minimizes the risk of political tinkering with the mechanics of the program that can occur with a tariff or centrally run auction model.
- This program has the highest likelihood of aligning the interests of the solar industry, the LSEs and the state's distribution utilities. The other models require suppliers or LDCs to either enter into long term contracts (auction model) or redefine the role of LDCs in the market (tariff model).

Footnotes:

[1] All Private Sector Solar PV Applications effective 09/01/06

[2] All Public and Non-profit Sector Solar PV Applications effective 09/01/06

[3] In the revised RPS rule, the BPU would be granted authority to put incentives in place to encourage 10-15 year supply contracts if the market does not respond sufficiently to the increase in SACP. An example of such an incentive structure follows: LSE's who enter into firm contracts of ten plus years with solar developers or aggregators are eligible to reduce their solar RPS obligation by 25%. If an LSE with an annual requirement to retire 1000 SRECs were to enter into a 10 year contract to purchase 100 SRECs each year, they would have their RPS obligation reduced by 25 SRECs so their new annual obligation for the term of the ten year contract would be 975 rather than 1000. At the end of the contract period, their obligation would return to 1000.

For the New Jersey Transition to an SREC-Only System for the Growth Of Solar Power in The RPS:

A DESCRIPTION OF AN AUCTION-SET PRICING, STANDARD CONTRACT MODEL WITH 5-YEAR SREC GENERATION

A White Paper

REVISION: August 22, 2006

Prepared By:

Chris O'Brien, SHARP Corporation and
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Members Of The RPS Transition Working Group
A Sub-Committee Of The Renewable Energy Committee

NEW JERSEY SREC TRANSITION

Auction-Set Pricing, Standard Contract Model

with 5-year SREC Generation

Summary

In this market-based model for New Jersey's SREC program, SREC prices are set in an annual auction, similar to the way the BPU currently holds auctions for Basic Generation Service. The BPU or a program administrator designated by the BPU conducts the auction and uses it to set market-clearing prices. The BPU or program administrator also develops a standard contract to be used by all LSE's to buy SREC's. As long as LSE's comply with the program, they are not subject to ACP payments; that is, they are not held responsible (nor are ratepayers) for the degree of success of the market in reaching the RPS requirements. With no administrative role in setting ACP prices or setting "floor" prices, this is a relatively "pure" market-based pricing model.

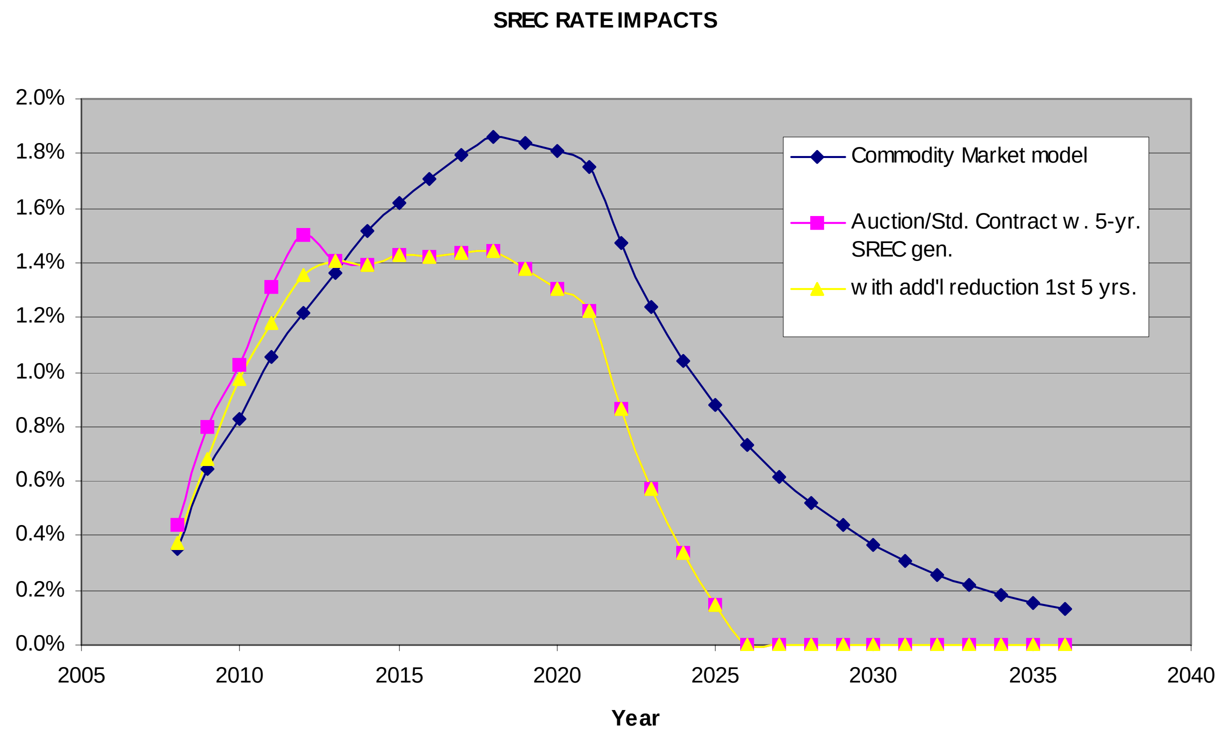
Solar power systems are allowed to generate SREC's only during their first 5 years of operation. Thus the need for contracts longer than 5 years is eliminated. Correspondingly, in order to maintain total solar generation at the levels set in the RPS Board order, SREC reporting requirements are reduced to a 5-year running total of new yearly requirements.

Because the 5-year measure could raise the short-term cost to ratepayers (the first 5 years), and because for a short period LSE's currently committed to 3-year BGS tranches will be affected by the transition away from rebates (with all SREC transition models), a real reduction in SREC requirements could be considered during the first 5 years (an "early sticker shock" reduction). However, a gradual decline in rebates could reduce the need for any such special reduction.

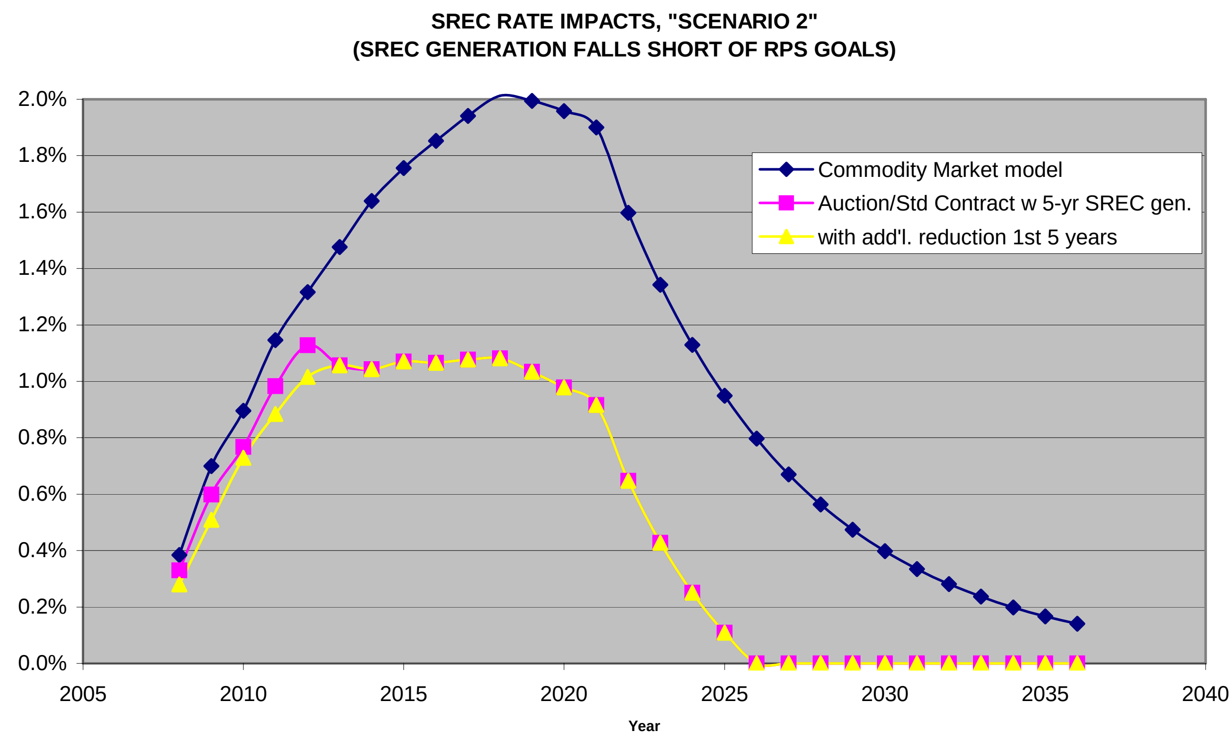
This model is expected to facilitate marketing and financing of solar projects, minimize the cost to ratepayers, and simplify the role of LSE's as well as reducing their risks. Transparent, stable pricing and low regulatory risk facilitate marketing. 5-year financing makes simple, traditional financing mechanisms feasible. Cost of capital is reduced. Minimizing premiums that must be paid for regulatory and market risk, and avoiding ACP payments, lowers the total cost to ratepayers.

Analysis of SREC pricing required under the Auction/Standard Contract model vs. the Commodity Market model shows that the price to produce a $3.25/watt present value under the Commodity Market model is estimated to be $630, and to produce the same present value under the Auction/Standard Contract model the price is

estimated to be $780. Analysis of resulting rate impacts shows that the total cost to ratepayers is substantially higher under the commodity market model – over 60% higher on a future value basis, and 27% on a present value basis – compared to the Auction/Standard Contract offer, as shown in the graph below from Appendix B.



Rate impacts may be even lower in the Auction/Standard Contract model if solar power construction falls short of the requirements, since ACP's will not be paid; ratepayers pay only for what actually gets built. Nevertheless, the Auction/Standard Contract model still provides better and more usable tools to help grow solar power toward the RPS goals. The graph below from Appendix B shows the rate impacts including the effect of no ACP payments if SREC generation falls short of the RPS goals by 25%



Introduction

- BPU has directed that the solar incentive program in NJ make a transition from a predominantly SBC-funded rebate program to an incentive program relying solely on the value of SREC's. The PV industry is working to develop recommended policy models for this transition. While there are many different models that have been outlined in PV industry discussions, these can be roughly categorized as follows:

    1. "Market based pricing, standard contract term" (this model) would feature standard contracts and a market based price (set at a level of market clearing price established through annual SREC auctions). This approach is similar to the model recommended by PV Now in Pennsylvania, and is described in more detail below. A feature of this description, a 5-year SREC life, can also be combined with other models.

    2. Market based pricing, market based contract terms ("Commodity Market") approach would not require long term SREC contracts or pre-determined SREC pricing, but might reply on other incentives to induce SREC market traders to enter into long term contracts. No further legislative changes would be required; however, would require BPU implementation of modified ACP schedule

3. "Feed in tariff" model would be modeled after programs in Germany, Spain, Ontario and elsewhere, whereby the State would provide long term guaranteed payments/kWh for energy and/or renewable attributes. This approach would be a departure from the current RPS. Current thinking among advocates is that the best approach for this type of a model would be to introduce a long term tariff schedule for energy production only ("super net metering"), not for SREC's

4. "Underwriter"model, whereby the State would provide security to SREC sellers by offering a 15 year put option guarantee at a strike price set at a fraction of the ACP, to be funded by actual ACP payments. Note that this option could be combined with #2 or #3.

- A key factor in developing a robust market for SREC's is the development of options for SREC's that produce reliable revenue, and that are readily accessible to both large and small solar customers. More on this point is included in Appendix A.

Key Objectives

- Provide market-based pricing through periodic (annual) auction process
- Provide standard contracts to SREC generators/sellers, both large and small
- Provide visibility to SREC contract prices for system developers and owners.
- Provide visibility to SREC contract prices for LSE's
- Minimize costs to ratepayers while providing the tools to accelerate project development.

Key Elements

- Standard Contract Terms, Other Than Price
    - Terms would be consistent for all transactions. A statewide standard contract form would be developed by the BPU, and the program administrator if there is one, with a stakeholder process to take into account the needs of the parties at interest. The standard contract will facilitate orderly, timely, and cost effective implementation.

- Annual SREC Auction

  - BPU or their designated Program Administrator (PA) will conduct an auction once per year for a share [25%] of SREC's required for the coming year. Bidders will specify the minimum SREC price they will accept under a 5 year standard contract (i.e. non-price terms are not negotiable). Winning auction participants will be eligible to sell SREC's for a price equal to the highest qualifying bid price ("Dutch Auction") for the specified SREC volume.

  - Following the auction, the BPU or PA will post the results of the auction, including the highest qualifying bid price. This will become the Market Clearing Price (MCP) for the period up to the subsequent auction.

  - The BPU or Program Administrator will allocate the SREC bids among the LSE's. LSE's will have [60] days to execute SREC contracts.

- Market Clearing Price (MCP)

  - For the period up to the next auction, and for SREC volume up to the level required under the RPS, SREC sellers will be able to market their SREC's to LSE's under the following conditions:

    - Owners of PV systems larger than [30kW] who were not winning bidders can sell SREC's for [95%] of MCP.

    - Owners of PV systems smaller than [30kW] can sell their SREC's for [105%] of MCP.

  - The BPU or PA will be responsible for maintaining an up-to-date database of SREC's sold, and the remaining RPS obligation for that period.

- Qualifying Bidders and SREC Sellers

  - All auction bids and standard contracts, whether above or below 30 kW, would carry reasonable project completion guarantees, in addition to being subject to uniform production verification and auditing requirements specified by the BPU/PA.

- Oversupply and Undersupply of SREC's

  - Auction under-supply. If the auction response is less than the target [25%] of total requirements for that period, the BPU or PA has the option to cancel the auction and maintain the MCP from prior auction until the next auction period.

  - Auction over-supply. If the auction response exceeds the target [25%] of total requirements for that period, the non-winning bidders (and non-participants) will be offered standard contracts at a price of [95%] of the value of the MCP, but the winning bidders will be offered standard contracts at a price of [100%] of the value of the MCP (for projects over 30kW).

  - Standard MCP contract over-supply. In the event that the volume of SREC's offered for sale through MCP-based standard contracts exceeds the SREC requirement for that period, then SREC contracts will be allocated on a first-come, first-served basis. PA will also maintain a waitlist in the event that winning SREC sellers do not finalize their contracts within the specified period of time.

  - Standard MCP contract under-supply. In the event that the volume of SREC's offered for sale through MCP-based standard contracts falls below the SREC requirements for that period under the RPS, then the shortfall volume will be carried forward to the following compliance period.

- The Alternative Compliance Payment would only apply in cases where an LSE refuses or fails to participate in the program.

- The generation of SREC's is limited to the first 5 years of operation for any solar power system. The RPS targets are adjusted to account for this change, in such a way as to maintain the total generation of solar power required in the RPS rule. This means that in any year after the fifth year this goes into effect, the RPS targets will be equal to the original target for that year minus the target for five years before that. This accounts for the fact that solar power systems built before that are still generating power, but no longer generating SREC's.

- Additional reductions in SREC requirements could be considered for the first five years. This would prevent a spike in ratepayer impacts during the first five years due to the higher SREC prices that would result, before the above reductions take effect. Such an additional reduction could also be used to reduce early impacts of the SREC transition on LSE's who currently have multi-year BGS contracts in place. The need for such real reductions over the first five years may be reduced if CORE rebates are reduced gradually, rather than being eliminated immediately.

Regulatory Changes Needed

1. Set up BPU or PA administration to conduct auction and implement standard contract

2. Change SREC creation period to 5 years and make corresponding adjustments to RPS targets.

Financial Projections and Rate Impacts

Prediction of SREC prices for this model and comparison with the Commodity Market model was done by finding the initial (2007-2008) SREC price that would produce a target present value, expressed as dollars per watt STC. The analysis and its results are shown in Appendix B. Key assumptions include:

Discount rate = 10%

Target present value = $3.25/watt(stc)

Average contract term in the Commodity Market model is 5 years

Financers discount the imputed value of post-contract revenue as shown in Appendix B (see also Appendix A, excerpt of PV NOW comments).

The market price of SREC's over time declines according to the schedule shown in Appendix B.

The predicted SREC price, in order to produce a $3.25/watt present value, is $630 for the Commodity Market model and $780 for the Auction/Standard Contract model with SREC generation limited to 5 years.

These initial prices were then used in an analysis of rate impacts (Appendix B). The initial prices were assumed to decline over time, according to an assumed schedule shown in Appendix B ("Calculations" sheet). Electric rates for a typical bill are assumed to increase by 3.5% per year on average.

The inclusion of a 5-year limitation on SREC generation necessitates a corresponding reduction in SREC reporting requirements in order to maintain the total solar power generation intended in the BPU's RPS order. These reductions are shown, as is additional reduction during the first 5 years to prevent temporary ratepayer impacts, and to reduce early impacts on LSE's.

The graph on sheet "Ratepayer Impacts" in Appendix B compares ratepayer impacts resulting from the above calculations for the Commodity Market model and the Auction/Standard Contract model with 5-year SREC generation, over the life of the program. Rate impacts are expressed as percent increase on a typical residential bill. For simplicity, it is assumed that after the year 2020 the requirements for solar power stop increasing. Costs after 2020 essentially are associated with paying off the solar power systems built in later years. The graph shows that ratepayers would pay significantly less over the life of the program with the Auction/Standard Contract model with 5-year SREC generation. The calculated total cost to ratepayers is approximately 50% higher for the Commodity Market case compared to the Auction/Standard Contract case. Ratepayer impacts may be even lower for the Auction/Standard contract case if the pace of construction of solar power systems is lower than the RPS requirements, since there would not be ACP payments.

Analysis with regard to Evaluative Criteria

1. Achieve the RPS goals at the lowest possible price, and drive down the cost of PV

A. Achieve the goals of the RPS –

The Auction/Standard Contract model with 5-year SREC life gives the entire solar industry the tools it needs most to successfully market, sell, and construct PV capacity in the state, and thus meet the RPS goals. These tools include:

1. Price Transparency
The yearly auction will establish a market clearing price which will then apply to all projects for a year. Knowing this price will facilitate sales and marketing, allowing PV sellers to lay out the economic benefits of a project with confidence to customers.

2. Project Financing with 5-year SREC life
Receiving a large proportion of the present-value revenue for a project during the first five years of operation allows the use of an expanded array of project finance methods, including relatively short-term loan products, leases, etc. These methods are more simple, diverse, and familiar than the finance methods available for longer-term

B. Achieve the goals at the lowest possible price –

Project owners and financing entities (banks, underwriters, etc.) by their nature, and by necessity, assume worst-case conditions in analyzing a project and setting the minimum SREC prices that are necessary to support it. If actual conditions turn out to be better than those worst-case assumptions, then the actual revenues to the project are higher than expected, but correspondingly the costs to ratepayers are higher than required to support the real costs of production.

The useful life of a PV system is in excess of 30 years. If a long-term income stream from the electric power produced by the system could be assured, then the SREC price, and the cost over time, would reflect the true cost of production of the solar power (including a reasonable rate of return for project owners). Unfortunately, the EDECA legislation made New Jersey LSE's the parties responsible for achieving the RPS goals, and they are entities whose positions in the electric market generally are determined only 1 to 3 years ahead, based on the BGS auction process. They therefore tend to shun long-term contracts.

This creates a situation where long-term revenue is available over the expected operating life of the plant, but very short-term contracts prevail. The expected revenue post-contract tends to be discounted heavily, or entirely, by project financers, who must then set the target SREC price very high. Post-contract revenue then constitutes a windfall for the project owners, but an unnecessary burden on ratepayers.

The Auction/Standard Contract model with 5-year SREC life helps to short-circuit this problem, as well as lowering the total cost of the RPS in other ways:

1. 5-year SREC life
This feature compresses the SREC revenue for a project into a 5-year period. This solves several problems at once. The potential for windfall profits from unanticipated long-term revenue is eliminated. The perception of regulatory risk, market risk, and performance risk is greatly reduced, which should help lower SREC prices. The cost of capital is also reduced by allowing short-term financing. A greater variety of financing options also improves the chances of achieving lower rates, which will also translate into lower costs. While predicted SREC prices are higher because of this compression, the total payout over the life of the RPS is lowered substantially (see white paper Appendix B).

2. Elimination of ACP costs
The Auction/Standard Contract model inherently eliminates any significant role for the LSE's in creating the conditions for meeting the RPS goals, and therefore they cannot reasonably be held responsible for any shortfall, as long as they cooperate in the process. Therefore, the need for an ACP is virtually eliminated. The result is that ratepayers will only pay for the amount of PV that is actually produced. If that is less than the goal, then they pay less. Furthermore, with an ACP the difference between the actual production and the goal is paid at a higher rate, since the ACP price is set significantly higher than the actual price of SRECs. The cost savings due to the elimination of the ACP could be significant.

3. Reduction of transaction costs
Covered under Criterion #4

4. Elimination of some administrative tasks
Covered under Criterion #4

C. Drive down the cost of PV

New Jersey's SREC program can drive down the cost of PV (as distinct from the SREC cost delivered to ratepayers, covered above) in two ways. One is to ensure a highly competitive environment. The other is to create greater volume (over the long term higher volume drives down costs). The Auction/Standard Contract model creates a relatively stable and competitive environment through the auction process, which has been time-tested in New Jersey's BGS auction process. This model features the least amount of administrative interference in price-setting. It stands the best chance of creating greater volume of PV construction by giving the solar industry better tools for marketing PV projects successfully, as discussed above.

2. Allow all players to compete fairly.

The auction process and the availability of a standard contract will create a level playing field and facilitate participation by small businesses. All players will be working with the same SREC price – the market clearing price set in the auction. All players will be working the same contract terms. The simplicity and structured nature of the program helps small players participate.

3. Allow the development of tools for implementing related policy goals

There may be a need to implement several related policy goals through the solar RPS. These could include:

A. Reduce electric transmission in congested areas
B. Concentrate development and redevelopment in smart growth areas
C. Pair solar power with energy conservation
D. Foster Small business creation and job growth
E. Encourage public projects

All of the SREC models share one tool for implementing related policy goals. If rebates are reduced gradually, as suggested in the schedule presented in the Commodity Market white paper, then those rebates can be targeted as desired toward projects that foster policy goals.

The Auction/Standard Contract model provides a simple, additional tool for implementing related policy goals. As explained in the detailed description of the model, after the auction has been conducted the administrator sets a market clearing price based on the auction results. Incentives and disincentives can then be created by assigning a multiplier to the market clearing price – either greater than one for incentives or less than one for disincentives – to projects targeted for encouragement or discouragement.

4. Facilitate implementation through:

A. Low implementation costs

The use of a simple, standard contract and a simple, standard procedure will help to reduce LSE's internal transaction costs and administrative burden.

Other transaction costs resulting from the costs of middlemen will also be reduced.

Administrative costs: see B. below.

B. Ease of implementation

Several administrative tasks are rendered unnecessary in this model. These include:

Administratively setting a ceiling (ACP) price

Enforcement of the ACP, including calculating ACP's due and collecting ACP funds

Expending ACP funds

Administratively setting a floor price.

Setting up an underwriting entity to collect revenues, execute long-term "put" contracts with generators, pay out on those contracts, etc.

Creating and administering a "circuit breaker" mechanism.

On the other hand, some administrative tasks are added. These include:

Setting up a standard contract. This is a one-time process, although "tweaking" may be necessary on an ongoing basis. Contracts are assigned to LSE's by an administrator.

Conducting the auction once per year and setting the resulting market clearing price.

C. Short implementation period

The time to implement this model will be based on the following steps:

A new Board order would be issued to make the necessary changes to the RPS regulation. These include redefining the SREC for the 5-year life, adjusting the SREC reporting requirements accordingly, and setting up the structure of the auction process and the standard contract.

An administrator would be chosen to conduct the auction and conduct a stakeholder process to develop a standard contract. The first yearly audit and the initial contract development could be conducted by the BPU as soon as the new program begins, leaving additional time to select a contractor for the work on an ongoing basis.

The anticipated timeline to implement this process is presented below.

5. Carry low regulatory risk

The auction/standard contract model is specifically designed to minimize regulatory risk. Primarily this is done by compressing the SREC revenue into 5 years, and harmonizing the standard contract term with that period. The five year period also corresponds with the life of regulations in New Jersey. The relatively short period of SREC revenue generation and having it correspond with the contract and regulatory life should give prospective project owners and financers the confidence that regulatory risk is low, and therefore could result in low interest rates and risk premiums.

Regulatory risk is also minimized by keeping the program cost as low as possible, so that the perception of the program's worth and cost-effectiveness can remain high among New Jersey's citizens and governmental bodies.

6. Ensure compatibility with regional markets and ensure sources of supply

SREC's in this model could be traded freely. Imbalances between states are always possible. For the near future, the only nearby state to establish an SREC program is Pennsylvania. In Pennsylvania, the primary model that has been proposed and discussed to date has been the Auction/Standard Contract model. There is no assurance that this model will become the model of choice there, but if it does, compatibility between the New Jersey and Pennsylvania SREC markets may be facilitated.

Schedule

The following schedule assumes that a pilot program will be implemented in parallel with the rulemaking process, so that implementation of the rule is accelerated.

	Activity	Timeline
1	Develop concept positions with current stakeholder process	Sep 2006
2	SMALL work group develops draft straw	Oct 2006
3	Finalize draft straw with full stakeholder group and public process	Nov 2006
4	NJBPU develops, submits for Board approval, and publishes in the NJ	Jan 2007

	Register an SREC rule proposal	
5	REC rule proposal public hearing and public comment period	Mar 2007
6	REC rule comment/response document, submit for Board approval and publish adoption in NJ Register	Jul 2007
7	Start NJCEP rebate transition period	Aug 2007
8	Fully implement NJCEP SREC-based financing system	Sep 2007

Open Questions and Challenges

- Requires that LSE's accept standard contract terms.

- Reliance on BPU or Program Administrator – vulnerable to problems if BPU/PA is not effective and efficient in conducting auction, allocating SREC's, posting data, etc.

Advantages

- A relatively "pure" market model; little to no administrative influence or interference in the market's ability to set prices.

- No need to deal with the uncertainty of ACP prices and price setting. Administrative burden of ACP setting is eliminated.

- Costs to LSE's are relatively predictable and stable, aiding their bidding in the BGS auctions.

- LSE's are not subject to ACP costs under normal circumstances.

- Without ACP payments, ratepayers only pay for the amount of solar power that is actually built.

- Costs to ratepayers are reduced over the life of the program because long-term (> 5-year) regulatory and market risk is eliminated for SREC's, along with the premium costs associated with those risks.

- Costs to ratepayers may be further reduced if solar power construction falls short of RPS targets. Ratepayers pay only for what is actually built.

- 5-year SREC life and contract term means 5-year project financing. This makes possible the use of simple, familiar financing products (short-term loans, leases, etc.).

- SREC pricing is transparent and relatively stable. This facilitates marketing of projects. Small businesses participation and growth is enabled.

- Assures long term SREC contract availability to large and small customer classes.

- Standard contract minimizes transaction costs for SREC sellers. Administrative costs are minimized for LSE's

- Auction-set market clearing price maximizes value to SREC seller, compared to value that SREC seller would receive from an aggregator in a "commodity market" model.

APPENDIX A *[Excerpt from previous PV Now filing in PA]*

Importance of Standardized Long-Term Contracting

In order for solar to become a viable part of the New Jersey market, solar projects will need to have a combination of revenue streams from SRECs (solar renewable energy credits), electric bill reductions and net metering.

The RPS legislation and BPU rulemakings reflects the clear intent to bring about such a condition, and to effect a transition from rebate incentives to SREC incentives. Solar project developers and customers will rely increasingly heavily on their SRECs to provide an acceptable payback period.

Relying on SRECs to develop a financial pro forma that is acceptable to banks or other lenders that finance renewable projects can be challenging. SRECs created and traded on a year to year, spot market basis provide no assurance to lenders that the revenue from SRECs will exist in future years, creating a major regulatory risk. Furthermore, these lenders have no way to predict the value of future year SRECs.

As a result, lenders normally refuse to accept any projections of spot market SREC revenue in project pro formas; where the revenue is permitted, it is heavily discounted (by 70 -90%,) effectively making their projected revenue insignificant. This in turn raises the cost of implementing the solar requirements of the AEPS and is not in the ratepayers best interest.

The best mechanism to address this reality in New Jersey and provide more confidence to financial institutions concerning the viability and price of long term SRECs is to incorporate long term solar contracts into the solar portion of the RPS, with standardized terms used by all including the number of years over which the contract is effective.

We expect significant savings to consumers can be achieved when the terms and conditions of long term SREC contracts are standardized. These benefits accrue both to ratepayers and SREC owners. Ratepayers benefit from reducing the transaction costs associated with reviewing contracts, credit terms, technology decisions, and the like. SREC owners benefit because they are able to avoid the time and expense of hiring lawyers, consultants, etc. to interact with large companies. In the end, a standard contract will reduce transaction costs for all parties and lead to a more efficient, more timely, and less expensive program.

We recommend that within these standard contracts, the only terms and conditions determined by the parties would be the overall number of SRECs and the price per SREC, to be determined by the methods explained below.

The ultimate value of long term contracts for solar energy systems installed in New Jersey is the ability to deliver required SRECs for use in the RPS market at the lowest possible price. As mentioned above, in the absence of long term contracts there is only a spot market for SRECs, and financial institutions will require a very high risk premium for any money provided to finance solar energy systems. The only way to finance projects, then, will be to translate these risk premiums into higher SREC prices.

The table below shows the effects of this financial reality. The table shows the differences between likely SREC prices given a number of different contract lengths, and a likely risk premium that financial institutions will apply to projects without long term SREC contracts. When financing projects, banks will only consider SREC revenue if the revenue flow is certain. This certainty will only exist for those periods where SRECs are under contract. Banks will apply a substantial discount factor to any future non-contract SREC revenues as they determine how much debt a project can carry. Since there is not a substantial body of actual market history data from which to draw, the scenario below uses a 70% discount factor. Some solar project developers report that financial institutions discount non-contract SRECs by 100%- in other words they ignore those possible revenues. We have used a more conservative risk discount factor of 70% in the table. In other words, if an SREC owner signs a five year contract with a SREC buyer and goes to a bank to finance the project, the bank will reduce the imputed revenue from SREC sales in years 6-20 by 70%. The table demonstrates the sensitivity of the resulting SREC price to contract term. This analysis indicates that a market with long term contracting could result in SREC prices that are up to 50% less than those in a spot market.

LIKELY SREC PRICES (in bold)

Likely non-contract SREC risk premium		CONTRACT	TERM (yrs.)		
	1-3	5	10	15	20
70%	**$810**	**$665**	**$505**	**$440**	**$405**

While the benefits of long term contracting have been described above, it is unlikely that utilities (or other SREC buyers) will choose to initially enter into long term contracts without certain regulatory assurance and encouragement.

1. The SREC market in New Jersey is relatively new and unproven and thus will be seen as risky, particularly by traditionally risk adverse electric distribution companies.

2. Utilities may be concerned that their initial contracts may be later viewed as imprudent and subject to rate recovery disallowance (if RPS obligation were transferred to EDC's).

- Because of these factors, we recommend that minimum 15 year contracts be required for EDC's subjected to the solar portion of the RPS. We recommend that NJ designate a Program Administrator who would initiate a process of developing a standardized form of contract that all default providers and SREC owners would use. In order to provide assurance that the prudent costs of their contractual obligations will be recoverable as provided in RPS legislation, we recommend that the BPU review the initial long term contracts for SRECs and provide guidance and appropriate assurances to utilities regarding the cost recovery of those contract payments.

New Jersey Solar Market: Tarriff Model Outline

A White Paper

REVISION: September 19, 2006

Prepared By:

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Member Of The RPS Transition Working Group
A Sub-Committee Of The Renewable Energy Committee

Tariff Model Outline

Basic Concept:
In order to supplant the current CORE rebate program with an alternative performance based incentive program that would stimulate renewable energy project development, we need to find a mechanism that will provide renewable energy projects with a stable revenue source on a medium to long-term basis. The new incentive should be:

- Simple
- Transparent
- Predictable
- Dependable
- Usable

One mechanism for providing a reliable revenue stream for renewable energy projects would be to create a tariff-based program within the Electric Distribution Companies (EDCs) standard operating tariffs. This would create a stable environment for the development of renewable energy projects, would provide a medium to long term revenue stream that is both stable and financable. The tariff model as proposed here would be an energy only tariff and would be a companion to a market based trading program for SRECs

It would be possible to create a renewable energy rider to the tariff such as the Business Enhancement (BE) rider established to create the business enhancement incentive. (See attached JCP&L BE Rider from most current Tariff). This new Renewable Energy Rider could be implemented much like the BE Rider. There would be a list of criteria, an application process, required documentation, as well as clear implementation mechanisms. Also, like the BE Rider, incentives can be tailored to be more beneficial to preferred project types, e.g., 10% additional incentive for projects built in transmission/distribution constraint areas or 10% additional incentive for residential customers, etc. This mechanism could prove a simple and effective way to implement the best public policy strategies for New Jersey's future energy needs, as well as continue to provide a smooth transition to clean renewable electricity from other fossil fuel generation. The tariff could also accommodate varying rates depending on the renewable energy technology and its position in the marketplace. All of these factors make the tariff an attractive option over a purely market based commodity model. The market models do not accommodate for different types of customers like residential or public that can not take advantage of the tax benefits. Also, this tariff can be used with ALL of the renewable energy technologies, not just solar. This is an important fact as the rebate program is phased out.

This renewable energy tariff would be an applied rate for each unit of energy produced from renewable energy systems. This rate, unlike net metering, would be higher than the retail rate and would be over and above the energy savings value. In addition, the project would get the right to sell the SREC into the commodity market.

Example Financial Incentive per kWh:

Energy Offset Value:	10 cents/kWh
Renewable Energy Tariff Production Value:	15 cents/kWh
SREC Value:	25 cents/kWh
Total Revenues	50 cents/kWh

Benefits:

1) Provides a stable, long term revenue stream to replace the rebate portion of the incentives based on the performance.
2) BPU has the appropriate authority to enact through existing procedure. No rule change or legislation would be necessary. It would, however, involve a rate proceeding.
3) Cost of implementation would be extremely low. The tariff would be implemented through utility credits on electric bills. Only minimum implementation costs would be needed. Also, the tariff could be set with specific annual limits determined through calculation of the capacity shortfall for compliance with the RPS, a built in circuit breaker for both the cost of the tariff and to a large effect the commodity market as well.
    a. E.g., if the RPS required 15 MW of installed capacity 2007 and 7 MW is already installed, then the tariff would remain open until 8 MW of capacity had applied under the tariff. A waiting list would then be created to go against the next future tariff structure. This policy would allow for an orderly transition of the market and prevent overpaying for renewable energy capacity. Measures to protect against speculation would need to be applied, such as application fees and proof of project advancement.
4) Varying rates of incentives can be offered in order to appropriately fund all ratepayer classes and types. For example additional incentives for residential and nonprofit sectors could be offered.
5) Makes gaming the system very difficult because the systems would have to verify the production of power in order to receive the incentive.
6) Financial institutions would have confidence in the tariff revenue stream as it would be backed by contract with an Electric Distribution Company. Unlike RECs that have a regulatory and market risk, once a renewable energy facility is accepted under the tariff, there would be a contract to back up the revenues. In this way, the renewable energy tariff would better leverage private sector financing for the construction of projects.
7) Since the funding would be recoverable through rates by the EDCs, and the LSE's would not be impacted at all, there is no reason for the EDCs or the LSEs to oppose this policy.
8) A separate meter will track the actual production of the systems and the incentive will be paid out based on actual performance. This aspect will encourage the installation of the best performing and most cost-effective solar energy systems. There is a long-

term incentive to keep the systems performing at the highest level for both the tariff revenues and the SREC revenues.

9) Tariff for year new year could be established to be reduced automatically over a number of years or could be re-evaluated based on criteria established in the tariff to conform with changes in the renewable energy markets   Natural adjustments in the market would be handled from the SREC values, which would still be a free market commodity.
10) Allows the tariff to be applied only to new projects, thus renewable energy generators that received incentives under past programs would not be able to "double dip" and receive more than there fair share.
11) Creates a policy tool kit to enhance the development of projects in constraint areas, smart growth areas, combination with energy efficiency, manufacture of equipment in the state, etc.
12) The gross costs of incentives for ratepayers would be cut in half.

For example if you assume 8 MW of capacity installed, with an average rebate cost of $3.00 per watt the upfront cost would be $24,000,000. Whereas if you gave 15 cents per kWh over 10 years, than the cost would be $13,200,000, but would be paid out over 10 years instead of all in one year. This means that the incremental cost to the ratepayer for the same installed capacity would be dramatically less. (~1/20th of the annual cost for the same capacity)

13) Would work for all technologies, not just solar, whereas REC multipliers, long-term contracts for RECs etc. would not have the same potential impact.

Challenges:

- Creating the rate design, application criteria and ongoing implementation procedures for implementation.
- Making sure that the REC market is set to coordinate appropriately with the tariff.
- Justifying the cost of the new tariff, by monetizing the value provided by renewable energy systems and demonstrating long term ratepayer savings.
- Staffing the rate proceeding with BPU resources.
- Ensuring the EDCs have surety for recovering revenues over the long-term.
- Determining whether or not the EDCs can be obligated to sign long-term contracts to back the contract revenues of the tariff.

Ratepayer Impact:

The Ratepayer impact needs to be modeled based on the assumptions used for tariff rate, term and also SREC values. Using a common sense evaluation, the impacts to the Ratepayer would be less than the Rebate Model as shown above and should be lower than a purely commodity based model with a high ACP.

Conclusion:

Because the Tariff Model is a companion to the REC market, it solves many potential problems that might occur under a purely market based model. One significant benefit to the model is that it is a highly cost-effective mechanism for implementing a performance

based incentive in place of a rebate incentive. Like New Jersey's current system, it is a hybrid of several incentives which diversifies the risk of volatility of any one incentive. It allows for control of the amount of money that is paid out and to the growth of the market, so as to ensure the long-term sustainability of the growth. The Tariff Model is not in competition with the commodity market, but rather should be evaluated as a means to effectively guide the commodity market.
BPU Evaluative Criteria:

1. **Ability to achieve the RPS goals at the lowest possible price, and drive down the cost of PV: The Tariff Model offers an excellent mechanism to achieve the goals of the RPS at one of the lowest costs: The Tariff Model brings an assured minimum incentive level just like the underwriter model and creates a mechanism for adjust the incentive level both in response to market changes as well as to drive market prices. This hybrid approach of a combination of Tariff incentive and a continuance of the SREC commodity market allows for corrections in the incentive levels both through the market, as well as through BPU policy decisions. The ability to fine tune the incentive through both mechanisms is likely to result in the least incentive necessary to met the RPS goals. It is also the only model that proposes a system that could work for all renewables, above and beyond solar energy systems.**
2. **Allow all players to compete fairly. Because the Tariff can be adjusted to easily accommodate residential and Public projects by offering an adjusted rate to these entities, it is one of the best models for allowing all ratepayers to participate fully in the program.**
3. **Allow the development of tools for implementing related policy goals, including: Again, the Tariff Model can be adjusted to incentive the most desireable projects. For example a residential system in a smart growth area and congestion area could be offered a higher tariff than a commercial office in a non-smart growth non-congested area. None of the other models offer as simple a mechanism for layering policy objectives into the incentive program**
4. **Low implementation costs: The Tariff Model should have one of the lowest implementation costs of all the models. The administration of the program should be quite easy and should be able to be managed within the traditional EDC billing systems. The total incentive to the solar energy systems should be no more than and could be potentially substantially less than other mechanisms.**
5. **Ease of implementation: The Tariff Model will require a rate proceeding, but should have the same requirements for justification that any other performance based incentives would require.**
6. **Short implementation period: The Tariff would require a rate proceeding, which has a maximum time period of time, but could be truncated depending on the BPU's available staff to review and make recommendations.**
7. **Low regulatory risk: The Tariff Model as proposed involves a contract between the EDC and a solar facility owner. The solar owner then would have assurance that the Tariff would be in effective for the time of the contract. The Tariff going forward could be stopped at any time by decision of the BPU, however.**

ATTACHMENT

N.B. The following was copied from the current published JCP&L Tariff as published on their website; for example purposes only. As follows:

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 10 ELECTRIC - PART III ORIGINAL SHEET NO. 54

RESTRICTION: **RIDER BE IS NO LONGER OPEN FOR ENROLLMENT. EFFECTIVE AUGUST 1, 1999, A CUSTOMER MUST REMAIN A FULL SERVICE CUSTOMER TO CONTINUE TO RECEIVE BENEFITS UNDER RIDER BE. THIS RIDER WILL BE ELIMINATED WHEN THE EXISTING CONTRACTS EXPIRE.**

AVAILABILITY**: RIDER BE IS AVAILABLE TO CUSTOMER LOCATIONS RECEIVING SERVICE UNDER SERVICE CLASSIFICATIONS GST, GP OR GT, AND SERVICE CLASSIFICATION GS WITH MONTHLY BILLING DEMANDS THAT ARE PROJECTED TO EXCEED 100 KW, WHO MEET CERTAIN QUALIFICATIONS SPECIFIED BELOW.**

APPLICATIONS FOR SERVICE UNDER THIS RIDER MUST BE MADE NO LATER THAN JULY 31, 1998 AND BEFORE THE EXPANSION OF PHYSICAL FACILITIES OR HOURS OF OPERATION, OR THE EFFECTIVE DATE OF LEASE OR PURCHASE OF THE BUILDING SPACE REFERENCED BELOW, AND SUCH EFFECTIVE DATE MUST BE NO LATER THAN TWO YEARS AFTER THE APPLICATION DATE. ACCEPTED APPLICANTS MUST COMMENCE SERVICE UNDER THIS RIDER WITHIN TWO YEARS OF THE DATE OF APPLICATION.

ELIGIBILITY**: A CUSTOMER MUST LEASE FOR A MINIMUM OF FIVE YEARS OR PURCHASE, AND OCCUPY VACANT BUILDING SPACE, OR A CUSTOMER MUST EXPAND PHYSICAL FACILITIES OR HOURS OF OPERATION. A CUSTOMER MUST ALSO EMPLOY A MINIMUM OF TEN EMPLOYEES THROUGHOUT THE BASE YEAR AS DEFINED BELOW. *MANUFACTURING* CUSTOMERS WHO LEASE OR PURCHASE VACANT SPACE MUST OCCUPY A MINIMUM OF 15,000 SQUARE FEET, AND *NONMANUFACTURING* CUSTOMERS WHO LEASE OR PURCHASE VACANT SPACE MUST OCCUPY A MINIMUM OF 25,000 SQUARE FEET. A CUSTOMER MUST ADD AT LEAST TWO PERMANENT FULL-TIME EMPLOYEES TO THE PAYROLL AT THE SITE OF THE SERVICE ON OR AFTER SEPTEMBER 7, 1995. WHERE A SUITABLE VACANT BUILDING DOES NOT EXIST, A NEWLY CONSTRUCTED BUILDING MAY QUALIFY IF ALL OTHER CRITERIA ARE MET. AN ENERGY AUDIT OF THE CUSTOMER'S FACILITY MUST BE PERFORMED PRIOR TO RECEIVING DISCOUNT.**

THE BASE YEAR SHALL BE THE TWELVE MONTH PERIOD IMMEDIATELY PRIOR TO THE CUSTOMER'S COMMENCEMENT OF SERVICE UNDER THIS RIDER. IF THE DEMAND AND ENERGY BILLING DATA FOR SUCH PERIOD IS INCONSISTENT WITH THAT OF THE PRECEDING TWELVE MONTH PERIOD, AN ADJUSTMENT MAY BE MADE BY THE COMPANY TO ESTABLISH THE BASE YEAR.

CUSTOMERS STARTING A BUSINESS IN OR RELOCATING TO THE COMPANY'S SERVICE TERRITORY, OR EXPANDING AN EXISTING BUSINESS INTO AN ADDITIONAL SITE SHALL HAVE THE BASE YEAR DEMAND AND ENERGY LEVELS FOR THE ADDITIONAL SITE SET AT ZERO. CUSTOMERS RELOCATING FROM WITHIN THE COMPANY'S SERVICE TERRITORY SHALL HAVE THE BASE YEAR BE THE TWELVE MONTH PERIOD IMMEDIATELY PRIOR TO THE CUSTOMER'S COMMENCEMENT OF SERVICE UNDER THIS RIDER.

MANUFACTURING CUSTOMERS ARE DEFINED AS THOSE CUSTOMERS WITH A TWO-DIGIT STANDARD INDUSTRIAL CLASSIFICATION (SIC) CODES FROM 10 THROUGH 39. NONMANUFACTURING CUSTOMERS ARE THOSE CUSTOMERS WITH ALL OTHER SIC CODES.

INITIAL AND ONGOING ELIGIBILITY MAY BE VERIFIED BY THE COMPANY AT ITS DISCRETION. FORMS OF VERIFICATION MAY INCLUDE AFFIDAVITS FROM THE CUSTOMER, PHYSICAL INSPECTION BY THE COMPANY, OR OTHER INFORMATION AND DOCUMENTATION THAT MAY BE DEEMED NECESSARY AND APPROPRIATE BY THE COMPANY AND/OR THE BPU.

ISSUED: JULY 30, 2003 EFFECTIVE: AUGUST 1, 2003
FILED PURSUANT TO ORDER OF BOARD OF PUBLIC UTILITIES
DOCKET NOS. ER02080506, ER02080507, ER02030173 AND EO02070417
DATED AUGUST 1, 2003

RIDER BE
BUSINESS ENHANCEMENT INCENTIVE

ISSUED BY STEPHEN E. MORGAN, PRESIDENT
300 MADISON AVENUE, MORRISTOWN, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 10 ELECTRIC - PART III ORIGINAL SHEET NO. 55

INCENTIVE: **A CREDIT, IF APPLICABLE, SHALL BE APPLIED EACH MONTH TO THE CUSTOMER'S BILL FOR ELECTRIC SERVICE ON A ONE MONTH IN ARREARS BASIS. SUCH CREDIT SHALL BE AVAILABLE FOR A MAXIMUM OF 48 CONSECUTIVE BILLING MONTHS, ASSUMING ONGOING QUALIFICATION FOR THE RIDER, AND MAY SERVE TO REDUCE THE CUSTOMER'S BILL BELOW THE MINIMUM CHARGE OF THE APPLICABLE SERVICE CLASSIFICATION. THIS CREDIT WILL BE DETERMINED IN ACCORDANCE WITH THE FOLLOWING TABLE, COMPUTED UPON THE MONTHLY INCREASED KWH ENERGY USAGE OVER THE CORRESPONDING MONTH IN THE BASE YEAR.**

REDUCTION IN CHARGES FOR KWH ABOVE BASE YEAR LEVEL:

$/KWH REDUCTION $/KWH REDUCTION
IN APPLICABLE IN APPLICABLE
KWH ENERGY CHARGES KWH ENERGY CHARGES
FOR EXISTING FACILITIES FOR NEW FACILITIES

YEAR 1 $0.010755 $0.008067
YEAR 2 $0.008067 $0.005377
YEAR 3 $0.005377 $0.002689
YEAR 4 $0.002689 $0.002689

ADDITIONAL CREDIT, IF APPLICABLE, WILL BE APPLIED EACH MONTH TO THE CUSTOMER'S BILL FOR ELECTRIC SERVICE ON A ONE MONTH IN ARREARS BASIS IF ANY OR ALL OF THE FOLLOWING CRITERIA ARE MET: RELOCATION OR EXPANSION IN AN URBAN ENTERPRISE ZONE; RELOCATION OR EXPANSION OF A TARGET INDUSTRY, AND RELOCATION OR EXPANSION WHERE THE BUSINESS OPERATES FOR AT LEAST TWO SHIFTS DURING THE DAY AS DEFINED BELOW.

AN URBAN ENTERPRISE ZONE IS A MUNICIPALITY PRE-DESIGNATED BY THE STATE OF NEW JERSEY. ZONES IN THE COMPANY'S SERVICE TERRITORY WHICH CURRENTLY QUALIFY INCLUDE PHILLIPSBURG, LAKEWOOD, PEMBERTON TOWNSHIP AND ASBURY PARK/LONG BRANCH (JOINT ZONE).

TARGET INDUSTRIES, WHICH WILL ENHANCE THE BUSINESS ENVIRONMENT IN THE STATE, ARE IDENTIFIED IN THE NEW JERSEY ECONOMIC MASTER PLAN AND INCLUDE PHARMACEUTICAL, BIO-TECHNOLOGICAL, ELECTRONICS, DATA PROCESSING AND TELECOMMUNICATION INDUSTRIES. THE COMPANY WILL ALSO QUALIFY ANY MANUFACTURING INDUSTRY AS A TARGET INDUSTRY.

THE CREDIT FOR RELOCATION OR EXPANSION IN AN URBAN ENTERPRISE ZONE, OR RELOCATION OR EXPANSION OF A TARGET INDUSTRY WILL BE DETERMINED IN ACCORDANCE WITH THE FOLLOWING TABLE, COMPUTED ON THE MONTHLY INCREASED KWH ENERGY USAGE OVER THE CORRESPONDING MONTH IN THE BASE YEAR.

ADDITIONAL REDUCTION IN CHARGES FOR KWH ABOVE BASE YEAR LEVEL:

$/KWH REDUCTION IN APPLICABLE KWH ENERGY CHARGES
URBAN ENTERPRISE TARGET INDUSTRY

YEAR 1 $0.005377 $0.005377
YEAR 2 $0.005377 $0.005377
YEAR 3 $0.002689 $0.002689
YEAR 4 $0.002689 $0.002689

ISSUED: JULY 30, 2003 EFFECTIVE: AUGUST 1, 2003
FILED PURSUANT TO ORDER OF BOARD OF PUBLIC UTILITIES
DOCKET NOS. ER02080506, ER02080507, ER02030173 AND EO02070417
DATED AUGUST 1, 2003

RIDER BE
BUSINESS ENHANCEMENT INCENTIVE

ISSUED BY STEPHEN E. MORGAN, PRESIDENT
300 MADISON AVENUE, MORRISTOWN, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 10 ELECTRIC - PART III ORIGINAL SHEET NO. 56

ANY FACILITY WHICH OPERATES ITS BUSINESS FOR AT LEAST TWO SHIFTS DURING THE DAY IS ELIGIBLE FOR CREDIT TO THE KW DEMAND CHARGES. THE REDUCTION IN KW DEMAND CHARGES WILL BE DETERMINED IN ACCORDANCE WITH THE FOLLOWING TABLE, COMPUTED ON THE MONTHLY INCREASED KW DEMAND OVER THE CORRESPONDING MONTH IN THE BASE YEAR. THE CUSTOMER'S MONTHLY LOAD FACTOR OF ABOUT 65 OR GREATER AT THE SITE WILL BE USED TO CONFIRM THAT THE CUSTOMER IS OPERATING FOR AT LEAST TWO SHIFTS DURING THE DAY. THE COMPANY HAS DEFINED A LOAD FACTOR AS THE RATIO OF THE TOTAL MONTHLY ENERGY USAGE TO THE HOURS IN THE MONTH MULTIPLIED BY THE MAXIMUM DEMAND IN THE MONTH.

ADDITIONAL REDUCTION IN CHARGES FOR KW ABOVE BASE YEAR LEVEL:

% REDUCTION IN APPLICABLE KW DEMAND CHARGES
FOR EXISTING BUILDINGS FOR NEW CONSTRUCTION

YEAR 1 100% 50%
YEAR 2 75% 50%
YEAR 3 50% 25%
YEAR 4 25% 25%

LIMITATIONS OF SERVICE**: THIS SERVICE IS NOT AVAILABLE TO FEDERAL, STATE, COUNTY, OR LOCAL GOVERNMENT ENTITIES, UTILITIES, AND TO RETAIL SERVICES.**

RIDER BE
BUSINESS ENHANCEMENT INCENTIVE