Request for Comments & Comment Summary

Straw Proposals for SREC-only Pilot Cap and Additional CORE Budget Market Segment Allocation

May 18, 2007

At the direction of the New Jersey BPU Commissioners we are seeking input on two items as listed below: 1. Straw Proposal for SREC-only Pilot Caps and;
2. CORE Budget Market Segment Allocation for additional funds as discussed at the CEC meeting on April 19, 2007 in Trenton. **It is anticipated that these issue will be addressed by the Board at their June 14, 2007 agenda meeting.**

1. Since the Board's Order establishing the SREC only phase one pilot and the registration form refer to the CORE Policies, as adopted by the Board, as rules for the SREC-only phase one pilot, do the CORE rebate limits on the system size caps and entity caps apply? Specifically, should there be a cap on the size of the system in the SREC phase one pilot for each project and for an entity in total?

   Based on OCE's analysis there may be a need to generate 8 MW of solar installed through the SREC only phase one pilot in order to meet the Solar RPS requirements for Energy Year 08. There is currently no cap on the overall size of the SREC-only phase one pilot. The input being sort is in regard to the project cap and entity cap and not a cap on the overall size of the phase one pilot which has a time limitation and not a size limitation.

   This straw proposal does not address the OCE projected 34 MW potential solar shortfall for EY 09 nor does it address the procedures for any future revisions to the SREC-only phase one pilot which will be discussed, reviewed analyzed and decided by the Board as part of the ACP/SACP proceeding. Several proposals on the caps were discussed at the RE Committee meeting and the April 19, 2007 CEC meeting but there was no consensus position and therefore OCE is presenting the following staff straw related to the following: The SREC pilot is based on "no CORE rebates" however the SREC is still an incentive funded through the ratepayers and there is an overriding policy to apply ratepayer funding equitability across all customer classes and in a manner that minimizes the ratepayer's impacts - considering overall costs and benefits.

Therefore, the OCE is proposing the following straw for the phase one pilot which would have to be approved by the Board as set forth in current OCE Policies and Procedures:

a. Residential systems in the pilot would be maintained the 10 kW AC cap or the net metering limits whichever is less;
b. Commercial and Industrial customers cap would be increase to 2MW AC or the net metering limits whichever is less at one site and per entity. The entity cap would be in place until July 1, 2007 and if the shortfall for EY 08 were not filled, the entity cap would be increased to 4 MW. The per site cap would be maintained at the 2MW AC cap or the net metering limit whichever is less.

2. Additional 2006 RE carryover not required for other RE Commitment - CORE market segment allocation as follows:

Please refer to the Honeywell budget report and the OCE 4th quarter summary that were distributed to the RE work group and the CEC for the April 19, 2007 meeting.

As discussed at the CEC meeting, based on the actual 2006 expenditures of the RE program and the OCE Administrative budget versus the 2006 approved budget and the estimated carryover for the 2007 budget, there are now additional funds that can be reallocated to the various CORE market segments in addition to the Board approved 2007 approved budget CORE budget market allocation as a potential line item transfer. The estimated carryover for the 2007 budget is based on actual expenditures through September 2006 and estimated expenditures through the end of the year. The actual 2006 expenditures were less than the estimated amounts which provides for an opportunity to reallocate funds as a line item transfer. This line item transfer would have to be approved by the Board as set forth in current OCE Policies and Procedures. Currently these additional funds are approximately $18.7 million and may be less depending on the need to cover RE Power Plant projects. This total is made up of the following

a. $6.5 million in CORE and Clean Power Choice
b. $5.2 million in other RE program – REW Power plants, RE business venture and RE Manufacturing Incentive
c. $3 million in OCE oversight – Administration
d. $4 million in estimated potential interest on the FY 07 Clean Energy program funds to be calculated and disbursed by Treasury after July 1 , 2007.

There were four proposals discussed for the allocation to the CORE market segments at the CEC meeting as follows:

a. 50 % to the LTE 10 kW and 50% the GT 10 kW;
b. 40% to the LTE 10kW; 30% to the GT 10 kW and 30% to publics;
c. 70% to the LTE 10 kW and 30% to the GT 10kW; and
d. Based on the 2007 market segment allocation.

Given the above policy on the SREC pilot, the beginning of a queue for public facilities the OCE staff proposes the following:

a. 50 % for LTE 10 kW;
b. 25 % to GT 10 kW; and
c. 25 % for publics

Please submit comments by Friday May 11, 2007. Comments can be submitted to the OCE at OCE@bpu.state.n.us with the subject highlighting the following caption: Straw Proposal for SREC cap and Additional CORE budget –market segment allocation. Comments may be submitted in writing to the following address:

NJBPU – Office of Clean Energy
POB 414
Trenton, NJ 08625-0414
Attn: Michael Winka – Director
Straw Proposal for SREC cap and Additional CORE budget – market segment allocation

Comments may be submitted at the Special Meeting on the Draft Summit Blue Report to be presented on May 9, 2007 in Newark in the Board Hearing room from 1pm to 4pm.

Jon S. Corzine
Governor

Kristi Izzo
Board Secretary

NOTICE[1]

Pursuant to the Open Public Meetings Act, N.J.S.A. 10:4-6 et seq., the New Jersey Board of Public Utilities is giving notice of a Public Hearing.

Hearings will be held:

June 6th 2007
NJ Board of Public Utilities
2 Gateway Center
Newark, NJ 07102

June 7th 2007
NJ Department of Environmental Protection
401 E. State
Trenton, NJ 08625

These hearings are pursuant to the Board Order "In the Matter of the Renewable Portfolio Standard: Recommendations for Alternative Compliance Payments and Solar Alternative Compliance Payments for Energy Year 2008, A Stakeholder Process Regarding Alternative Compliance Payment and Solar Alternative Compliance Payment Levels for Energy Years 2009 and 2010 or Longer, and a Solar REC-only Pilot" issued on January 19, 2007. The hearings are intended to solicit public comment on the questions raised by the Board in the agenda meeting held on December 21, 2006 and memorialized in the above mentioned Order. The Board seeks comments on these issues in the context of the various models proposed to transition the solar market from reliance on subsidies delivered through rebate to a more market based approach. Evaluations of these models and associated background materials are available at www.njcleanenergy.com.

All comments should be submitted in pdf format to OCE@bpu.state.nj.us

Kristi Izzo
Secretary of the Board

Dated: May 1, 2007

Persons interested in attending the above Meeting who require special accommodations because of disability should contact the Office of the Secretary of the Board at (973) 648-3426 at least three (3) days prior to the Meeting date so that appropriate arrangements can be made.

[1] Not a Paid Legal Advertisement

349 Rt-31 Building A, Suite 301
Flemington, NJ 08822

908-782-4172 (V)
908-782-3054 (F)
www.sunfarmnetwork.com

New Jersey's Solar Power Company℠

May 08, 2007

To: Mike Winka
Scott Hunter

From: Mark Warner
Re: Comments on "Straw Proposal for SREC cap and additional CORE budget – market segment allocation"

We have reviewed the straw proposal issued by OCE staff on May 4, 2007, regarding "… SREC cap and additional CORE budget – market segment allocation", and are pleased to provide the following input. We welcome the opportunity to help make these ongoing program changes successful, and applaud the OCE's efforts to solicit input for finalizing program change details.

First, a general comment. There appears to be a philosophical intent behind these changes that we believe is counter to sound market development principles. By design, the RPS transition is intended to move away from budgeted rebate funds to more market based mechanisms funded through SREC revenues. SREC revenues are very different from the "free money" associated with rebates, and should not be managed on a similar basis. There is no need to ensure SREC revenues are "spread fairly" across the ratepayer base, since SREC revenues are by definition payments made for value delivered – not a handout that needs to be equitably distributed (like rebates). The market needs to be allowed to find its own efficiencies, and investors should be allowed to realize revenue in proportion to the investment they are willing to make. Its true that larger systems receive greater SREC revenue, *but they also made larger investments!*

The proposed changes reflect an intention to continue "shaping the market" through program rules and constraints that inhibit investment, discourage innovation, and retard the creation of a strong competitive environment. We believe that approach sets a very bad precedent for the overall RPS migration being planned, and we urge the board to consider more open market based principles when evaluating overall program design moving forward.

As to the specific changes being considered for the Pilot, we offer the following input:

1. Our independent analysis of SREC market balance over the next two years indicates a shortfall of 8.1MW in 07/08 and 34MW in 08/09 – approximately in line with OCE projections contained in this straw proposal. It should be noted, however, that SREC-only Pilot projects will have a modest impact on the 07/08 shortfall, due to commissioning relatively late in that production year. The primary impact of Pilot projects will be on 08/09 moving forward.

2. The 10KW residential limit is onerous, and prohibits some of the most economically attractive projects in the market. It also isn't a natural extension from the CORE program guidelines, since those guidelines restrict the amount of rebate, not the system size. In fact, both the program eligibility guidelines and the >10KW-resdiential cap letter emphasized that project size is not limited by the program. Introducing new project size limits now are a new constraint and not beneficial to creating market efficiencies.

3. The 2MW limit for larger projects is not unreasonable, although it is redundant with the existing 2MW net metering cap.

4. The 2MW entity cap probably won't have a significant impact on the current pilot, and therefore is not objectionable. But moving forward, it sets bad precedent for the broader RPS migration being considered. Some of the most cost effective projects are those large corporate customers that make significant private investment commitments to solar, and it doesn't further market development goals to restrict participation by those customers. Why does it make sense to tell a customer that wants to invest $50M in solar in NJ that they can't do so? The proposal to remove the cap by July 1 is not really practical since the current registration window ends at the end of July. We encourage removal of the entity caps from the Pilot changes proposed in the straw.

Please don't hesitate to contact me directly if I can be of further assistance.

Thanks,

Mark

Mark Warner
CEO, Sun Farm Network

Copy To:
Noreen Giblin
Lance Miller
Janeen Lawlor
Susan LeGros

Comments On The Summit Blue Final Report And Input To The SACP Proceeding As Requested In The Board Order "In The Matter Of The Renewable Energy Portfolio Standard" (Docket EO06100744)

Originally Published: May 14, 2007
This Revision: May 16, 2007

Mark Warner
President & CEO
(908) 782-4172
mark@sunfarmnetwork.com

Sun Farm NETWORK™

New Jersey's Solar Power Company^{sm}

Executive Summary

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. As part of this transition, the NJ Board Of Public Utilities is considering a variety of long term market models, evaluating how to accomplish the needed market transition, and considering what changes are needed to the Solar Alternative Compliance Payment (SACP) in the short term. Specifically, the board ordered a proceeding to set the SACP and address related questions that are material to that decision (Docket EO06100744). This document provides input to that proceeding as requested by the Board. The board identified eight specific questions, and a summary of our position on each is as follows:

SREC Shortfall: Our analysis projects a shortfall of approximately 16,000 SRECs in EY2008, increasing to 39,000 SRECs in EY2009, assuming only rebated projects are installed (i.e., if no SREC-only projects are enabled). This shortfall reduces to about 6,000 SRECs and 15,000 SRECs assuming significant and immediate uptake of non-rebated projects (such as the Phase One SREC-Only Pilot, and/or the PSE&G SREC investment initiative (not yet approved)). In either scenario, an immediate increase in the SACP is needed to enable projects beyond the limits of the current CORE program rebate budgets.

SACP Level: Based on project economics required to deliver investment-worthy IRRs, we recommend an SACP of $750/MWHR, assuming some level of securitization (a 10-year SACP schedule at least), an ability to sell SRECs for at least 15 years, and a 5% decline in SREC value annually. This is equivalent to $580/MWHR flat for 15 years, and is sufficient to support the required IRRs for tax advantaged commercial projects. A rebate (in addition to higher SREC value) will be needed to ensure adoption in the small project segments due to their higher costs. We recommend a strategy that combines SREC revenues (based on a higher SACP) for all projects as the primary incentive, and the selective use of rebates (funded from an extended SBC) to account for economic differences across segments. The recommended SACP of $750/SREC assumes this structure, and avoids the need for a much higher SACP to ensure small-project economics through SREC-only revenues. This approach also gives the Board the ability to "tune" program performance across multiple segments.

Multi-Year Schedule (and related implications): We strongly recommend that the board establish a 10-year (at least) SACP schedule, which is a relatively easy and inexpensive way to introduce some long term confidence in SREC value. We also recommend that the board introduce, coincident with establishing the 10-yr schedule, a new management mechanism for accelerating or decelerating the RPS requirements as dictated by market balance considerations. Provisions are proposed which create this flexibility while bounding the rate payer impacts to be NPV neutral with an originally established baseline.

SACP Changes Over Time: To reflect expected reductions in system pricing over time, we recommend that the SCP start at a given level, then decline by 5% annually.

Rebates Vs Non-Rebated SRECs: We believe that a single SREC class structure is critical to market simplicity, but we also recognize that the planned transition may motivate the need for a two-class structure (old $300-SRECs, new higher SRECs). In that case, the board will need to establish both SACP and allocation percentages for each SREC class annually.

SREC Term Issues: The question of Generation Term is closely tied to the SACP level analysis, and we recommend that <u>if</u> any limits are imposed they must be 15 years at the absolute minimum (consistent with existing and widespread industry practice), preferably 20 years or more. We also recommend extension of SREC life to 2 years. Note that the current RPS rules impose no generation term limits, and a SREC life of 1 year.

Economic Analysis: The Summit Blue Final Report establishes a strong foundation for economic assessment of SREC-value requirements and the associated rate-payer impact. This analysis more than justifies the $750/SREC recommendation made above. We recommend that additional results from the report be published (especially annual cash flows per model and funding source), and that an amended analysis be conducted to estimate ratepayer cost for a hybrid program which provides enhanced SRECs for all projects and an incremental rebate for small projects. Lastly, we encourage the board to recognize that the economic analysis looks only at quantitative rate payer impacts, and decisions about long term market structure should also consider the extent to which different models create positive competition (among other assumptions that might vary across models), the appropriate risk allocation structure, and the need for long term program management flexibility.

In conclusion, the emerging SREC shortfall makes it clear that new solar projects must be enabled beyond the limits of the current CORE rebate program, and that an SACP change is needed immediately to allow new capacity deployments to begin immediately. Increasing the SACP to $750 and establishing a 10-yr schedule assuming a 5% annual decline provides the economics needed by commercial projects to gain investment support. Continuation of the rebate will be needed for smaller projects (past 2008) to level the economic playing field. Without these urgently needed changes in the NJ incentive environment, the current industry stall will continue and the shortfall in the SREC supply (relative to RPS goals) will grow to the point of putting the overall RPS commitment at significant risk. Once these changes are made, we recommend that the Board immediately launch a Phase Two Pilot (or open up the market entirely) so that these new market conditions can translate into new project commitments ASAP. These essential changes should be implemented immediately consistent with the scope of the current proceeding (Docket EO01100744). Additional enhancements, potentially including support for additional securitization, can be considered and added as part of the longer term market design proceedings.

Introduction

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. As part of this transition, the NJ Board Of Public Utilities is considering a variety of long term market models, evaluating how to accomplish the needed market transition, and considering what changes are needed to the Solar Alternative Compliance Payment (SACP) in the short term. Specifically, the board ordered a proceeding to set the SACP and address related questions that are material to that decision (Docket EO06100744). This document provides input to that proceeding as requested by the Board. Our comments are organized around the eight specific questions presented in the order, but focus exclusively on these questions as they relate to the solar industry (and the SACP and solar component of the RPS).

The following comments represent the views of Sun Farm Ventures, Inc, although they are based on the goals we share with the BPU and the Industry for overall market development. These comments are based on our experience over the last four years as an active participant in the NJ RPS market, and our familiarity with attracting investors into the NJ RPS market. In the spirit of full disclosure, it should be noted that Sun Farm Ventures, Inc. remains actively engaged in the NJ RPS market, and it has taken a long term position on SREC transactions associated with its customers' projects. We could be materially affected either positively or negatively by decisions currently being considered by the Board on this matter. That said, the following recommendations have been developed based on our active participation in the policy debate to date, and our strategic commitment to the long term growth of the solar industry in NJ.

SREC Shortfall

Question from the board order: "What is the expected shortfall in solar PV capacity required to meet the RPS if the SACP levels for 2009 and 2010 remain at their current level of $300 per MWHR?"

Summary Position: Our analysis supports OCE speculation that there will be a significant SREC shortfall emerging over the next two years. Based on current rebate budgets, and assuming only rebated-projects are built, we project a shortfall of about 16,000 SRECs in EY2008, and 39,000 SRECs in EY2009. These shortfalls could be decreased, potentially to about 6,000 SRECs in EY2008 and 15,000 SRECs in EY2009, if significant new non-rebated programs (such as the Phase One SREC-Only Pilot) succeed in getting new capacity on line quickly. SREC shortfall will increase in subsequent years unless significant capacity beyond the current CORE budget is enabled. Increasing the SACP, and enabling attractive economics for projects that minimize (and in some segments eliminate) dependence on rebates, is crucial to avoiding a significant shortfall in SREC supply over the next few years and beyond.

Detailed Discussion: If the SACP remains at $300, it is virtually certain that new project commitments will continue to depend heavily on rebates to be economical. The constraining factor in deployment rate is therefore the current rebate budgets. Assuming existing CORE budgets are fully allocated and projects are quickly built over the next two years, but no additional "non-rebated" capacity is installed, we project a shortfall of *at least* 16,000 SRECs in the 07/08 energy year, and about 45,000 SRECs in the 08/09 energy year.

The EY2008 analysis assumes approximately 35 MW of solar commissioned by 6/1/2007 (based on recent Market Manager reports), and that all 23MW of "currently committed" projects (letters in hand) are built, along with an additional 8MW of new commitments (based on the remaining 2007 budget), between June 2007 and the end of May 2008 (production of 1.0 annual kwhrs/W-DC). This capacity will generate approximately 45,000 SRECs[1], compared with the approximately 61,000 SRECs needed for EY2008. No "non-rebated" capacity (such as the current Phase One SREC-Only Pilot) is assumed. This 16,000 SREC shortfall for EY2008 translates to a capacity shortfall of about 16MW, assuming it was on-line June 2007. If the Phase-One SREC-Only Pilot can generate at create at least 15-20MW of new capacity over the 12-months ending June 1, 2008, this shortfall could potentially be reduced to about 6,000 SRECs – although this is highly optimistic given that much of this capacity will probably be later in the energy year.

Based on current capacity and commitment projections, the EY09 analysis assumes 65MW of PV on-line by June 1, 2008. There is currently projected to be approximately $73M of new budget for calendar year 2008, which at the current queue rebate levels, would translate to about 21MW of new capacity from that funding. Being extremely optimistic and assuming it is all installed during calendar year 2008 translates to a SREC projection for EY2009 of about 82,000 SRECs, which is 39,000 SRECs short of the 121,000 SRECs required by the EY2009 RPS. This shortfall could be reduced by a) capacity from the current Phase One SREC-only Pilot (assuming installed quickly), b) capacity from the PSE&G proposal, c) extensions of the 2008 rebate budget to support increased capacity due to potential Federal Tax Credit changes, and d) additions of new rebate funding past 2008 and "early release" of that funding. These changes are highly speculative at this time, especially with respect to timing, and were therefore not included in the capacity projections. Making optimistic assumptions about these programs, however, there is still likely to be at least a 15,000 SREC shortfall for 2009. This translates to approximately 15MW shortfall if it was all on-line by June 1, 2008.

Persistent SREC shortfall increases ratepayer cost of the RPS (through SACP payments), and puts continued support for state renewable energy programs at risk. Given current plans to reduce if not eliminate rebate support past 2008 (pending the outcome of the current CRA proceeding), it is clear that an increase in the SACP is needed to enable the

[1] This model accounts for a full-year of production for capacity on-line by the beginning of the year, and accounts for *partial year* production from capacity installed *during* the energy year. MW installed during the year do not generate as many SRECs as capacity on-line at the beginning of the year due to the partial year of generation.

deployment of capacity that reduces (and in some segments eliminates) use of rebate funds entirely. Without this change, SREC shortfall will emerge and grow after 2008.

SACP Level

Question from the board order: "What is the optimal SACP level required to ensure that sufficient solar PV capacity will be installed to meet the RPS goals at the least cost to the NJ ratepayer?"

Summary Position: The "correct" SACP level is the minimum amount needed to create the market adoption required to meet the RPS requirements in lockstep with the annually increasing schedule. The SACP needed depends heavily on other program design factors like facility generation term and whether the market is securitized or not. Shorter terms and less securitization require higher SACPs to generate the needed project volume. Longer terms and greater securitization lower the SACP required to accomplish the same goal. The SACP should be set in the context of those related decisions, as addressed in other comments below. Based on a review of multiple analyses, with a focus on project economics needed to create the needed adoption, **we recommend an SACP of $750/MWHR for a market with at least some security, and $850/MWHR for an unsecured market – in both cases assuming aggressive system pricing and that facilities can sell their SRECs for at least 15 years.** As noted in the comments on multi-year schedule below, this assumes a 5% decline in SACP annually moving forward, and is economically equivalent to $580 flat for 15 years. This is the SREC value needed to make project economics work for larger commercial systems (which are lower cost and benefit from additional tax incentives), and additional rebate incentive will be required for smaller projects to achieve similar economic performance. This two-part structure gives the Board great flexibility: providing a common incentive across all projects (through SRECs), then adding incremental support (through rebates) for projects that are a) desirable and consistent with strategic program goals, but b) need additional economic support to create adoption.

Detailed Discussion: A dominant driver in setting the SACP is determining what a project needs to recover from SREC value in order to achieve an Internal Rate of Return (IRR) that justifies investment by the customer. In this analysis, it should be noted that SREC revenues are usually taxable to the selling entity, and the value recognized by the project must reflect these after-tax discounts – typically, a SREC sold for $600 only translates to approximately $400 to support project payback. Here are several data points that bound the needed SREC value (actual revenue capture, not SACP) needed:

- *Rebate Equivalence*: One way to determine the needed SREC value is to look at what SREC stream, over 15 years, gives the same NPV as current rebates. That amount, plus current SREC value, provides a good snapshot of rebate-less SREC value needed to be "economically equivalent" with the current NJ incentive environment. Assuming SRECs that are flat over 15 years (highly securitized, no SREC decline over time), use of the IRRs noted in the Summit Blue Final Report as the discount factor, current SREC sales (for rebated projects) averaging

$220/SREC, and annual production of 1.0 kwhrs/watt-DC, the current rebate levels translate to:

- **$709/SREC for 10KW projects** (6%, 15 yrs, current rebate for 10KW project = $3.80/W, taxed at 20%),
- **$900/SREC for 40KW projects** (12%, 15 yrs, current rebate for 40KW project = $3.01/W, taxed at 35%),
- **$830/SREC for 100 KW projects** (12%, 15 years, current rebate for 100Kw project = $2.70, taxed at 35%), and
- **$749/SREC for 500KW projects** (12%, 15 years, current rebate for 500KW project = 2.34/W, taxed at 35%)

A SREC only market would therefore have to deliver SREC value between $709/SREC and $900/SREC constant over 15 years to be economically equivalent with the current rebate+$300-SACP incentive environment already in place. Note that this is actual SREC value captured, not SACP, and reflect tax impacts on the SREC revenue stream realized by the project.

- *Summit Blue Report*: The Summit Blue Final Report projected the need for SREC values of:

  - **$1,151/SREC for <10KW private projects** (6% IRR, securitized through an underwriter, no rebate),
  - **$705/SREC for >10KW private projects** (12% IRR, securitized through an underwriter, no rebate),
  - **$1,430/SREC for <10KW private projects** (6% IRR, 15 yrs, no securitization and significant discounting), and
  - **$849/SREC for >10KW private projects** (12% IRR, 15 yrs, no securitization and significant discounting).

  Note that this is actual SREC capture (not SACP), and varies by almost a factor of two between secured >10 KW and unsecured <10KW cases.

- *Project Pro-Formas*: We think the best way to assess SREC requirements is to establish a standard model and define a reference system with a specific IRR policy goal. This approach was used in the Summit Blue Final Report looking across multiple representative projects. We recommend using a 50KW commercial system as the reference design, with a targeted IRR of 12% (consistent with Summit Blue assumptions). As detailed in Appendix A, a non-rebated commercial project capturing SREC revenues for 15 years, and assuming aggressive pricing at $7.25/W and full capture of federal tax value, would need to see **SREC capture starting at $730 in the first year, assuming a securitized environment with only a 5% SACP decline annually thereafter**. The 5% decline assumption has a large impact on the economics, and this profile is equivalent to $575 flat for 15 years. For a less secure case, where discounting typical of the current market is applied, SRECs would have to start at $825 in the first year to achieve the same economic result.

- *The PSE&G Proposal*: The recent SREC-secured loan program proposed by PSE&G (not yet approved) assumed **SREC value of $475 flat for 15 years**, with recovery through a highly secure mechanism (such as the SBC, or other rate-based channel). The relatively low SREC value and its constant rate over the full term represent the highly secured case made possible by the BPU-protected recovery mechanisms assumed in this program. Note that this $475/SREC program was priced for aggressively priced commercial projects, and that availability of additional rebates were assumed for smaller projects. $475/SREC should therefore be considered the best possible case given a) 15 year term with no SACP decline (i.e., constant for 15 years), b) very low risk and assured recovery, especially compared with private capital markets, c) SREC revenue tax advantages that accrue when channeled through a regulated entity, and d) optimization for low cost commercial systems.

These multiple data points demonstrate the large impact that project size (market segment) and securitization factors have on the required SACP. It also demonstrates that comparing SREC values across different scenarios can be very misleading, especially since some first-year assumptions assume annual declines while others assume a constant value over the 15 year term. The RPS strategy is also structurally challenged by the fact that it sets a SINGLE SACP to cover all SRECs sold in the market, and that the current SACP is being set without securitization mechanisms being defined yet. In response to those challenges, we recommend the following methodology for setting the SACP:

- Assume modest “soft securitization” through the multi-year schedule approach defined below, and that the SACP declines by 5% per year after the first year.

- Set the SACP so that larger commercial projects achieve the needed adoption threshold, assuming it is able to sell SRECs for at least 15 years.

- Plan on an additional rebate being made available, past 2008, for smaller projects to level the economic playing field. This strategy implies “SRECs for all” as governed by a single market-wide SACP, with an additional rebate incentive for small projects to compensate for their higher costs.

- As of this proceeding, establish regulatory intent to create additional “strong securitization”, at which time SACP levels may be reduced if additional securitization can be realized.

- Assume relatively high market efficiency, and that SRECs trade for at least 95% of the SACP on average. Note that this is considerably higher than the current market, but we assume that transaction costs will decline as the SACP goes up (i.e, a flat $40/SREC, rather than a percentage). There is no market history on this transaction behavior so this critical assumption – which affects how to translate a needed project revenue requirement into required SACP – is highly speculative.

Based on this approach, **we recommend a SREC capture target of $730/SREC, and an SACP of $750/SREC to encourage that level of market realization**, both declining by 5% annually. This is equivalent to a FLAT SREC price of $580 constant for 15 years, and we believe this rationalizes well with the $475/SREC assumption in the proposed PSE&G program given its low risk profile and tax advantages. It is important to note that *actual* SREC prices will be set by the market, with the SACP being a cap (maximum). The numbers assume at least a 10 year SACP schedule (to provide soft securitization) and availability of rebates for smaller systems. If no securitization is provided (through a multi-year schedule), an SACP of at least $850/SREC would be required to deliver similar project economics given current discounting practices.

Regarding program management flexibility moving forward, it should be noted that recent experience has demonstrated that it is much easier to *start out* at a higher level and move the SACP downward. By contract, *increasing* the SACP from a lower initial starting point is much harder. We therefore believe that the program gains the most flexibility and efficiency in setting the SACP higher initially, then moving it downwards in the future as market conditions (or changes) dictate.

For an aggressively priced 50KW commercial project, with full capture of tax value (as per *current federal incentives*), with SREC revenues at $730 in the first year and declining by 5% annually thereafter, that translates to a 12% IRR – the minimum necessary to achieve adoption in most segments (consistent with Summit Blue assumptions). A modest additional rebate would be required in the small project segments to realize similar adoption levels given their higher cost.

As a final note, it is worth highlighting that the RPS framework, as driven by annual SACP decisions, is structurally challenged by the fact that SACP changes affect both installed projects and new projects being planned. The goal is to be able to reduce the SACP as system pricing declines in future years or if other market changes (like an increase in the federal tax credit) materialize. This creates the risk, however, of stranding previously installed projects whose cost structure is already fixed and which doesn't benefit from the future (relative to its installation) market change motivating the SACP decrease. A project in Year 1 makes SREC assumptions based on its cost structure *at that time*, and could potentially be stranded if the SACP is subsequently reduced significantly to reflect future market conditions. When considering future SACP changes, it is critical consider not only market conditions in a given year, but also the investment assumptions made by previous projects based on *expected* SREC value. Note that the MW of previously installed capacity will soon dominate over the capacity of new projects, and those "stranding risks" should therefore have a large impact on the SACP analysis. The multi-year SACP schedule being proposed below will help in managing this balance between previous installations and new projects, and how changing cost structure (or other market conditions) should affect SACP changes in the future.

Multi-Year Schedule, And Related Implications

Question from the board order: "For what number of years should the SACP be established? Should it be established only for the Reporting Years of the next BGS auction timeframe of RY 2008-2010, longer, or shorter? What timeframe is reasonable?" Separately, the order also asks the related question "What are the advantages and disadvantages to the Board's posting a multi-year schedule for SACP levels?" These two questions will be addressed together.

Summary Position: We strongly recommend that the **Board establish a long term SACP schedule, for 10 years at least**, preferably 15 years. This schedule would be absolute for the first year only, and establish *default* SACP levels for succeeding years unless specific board action is taken to change it. It is therefore not "cast in stone" or binding on a future board, but sends a very strong signal to the market of regulatory intent barring substantial changes in the market. We recommend this approach strongly since it is a relatively "no cost" way to create the needed market confidence in future SREC value. Creating this confidence, through a multi-year schedule or something similar, is almost as important to the success of the RPS framework as the actual SACP value itself[2]. Applying this schedule, combined with the SACP recommendations made above, would result in the following 10-yr schedule:

Energy Year	2009 (08/09)	2010 (09/10)	2011 (10/11)	2012 (11/12)	2013 (12/13)	2014 (13/14)	2015 (14/15)	2016 (15/16)	2017 (16/17)	2019 (17/18)
SACP	$750	$715	$680	$645	$615	$585	$555	$525	$500	$475

As with all SACP discussions, it is important to note that this does not set the actual price in the market, which will instead be determined by project pricing and market balance. The SACP sets only the SREC value cap, and actual pricing (and rate-payer impact) would likely be lower – especially in cases of reduced system pricing, SREC competition, and oversupply.

As part of establishing a long term multi-year schedule, **we strongly recommend that the board take this opportunity to establish a new and more flexible framework for managing the RPS demand and SACP**. This framework has been referred to as a "bi-directional circuit breaker" in that it allows the RPS demand curve to be accelerated or delayed, with associated changes in the SACP, to improve market balance. Under this proposal, the board would have the flexibility to advance or delay the RPS requirements,

[2] The German Feed-In Tariff structure is frequently cited as the strongest and most effective program in the world, as substantiated by the extraordinary deployment rates seen in that country. Although the feed-in tariff model can be very effective, it is not the tariff approach itself that makes it successful. Instead, we believe the German market has succeeded because a) they got the economic incentive levels right, b) they made a state-backed commitment to *long term* revenue assurance, and c) they made capital easily available for project investments. Any structure, including the NJ RPS approach, can be as effective as the German model if these three requirements are met simply and with strong confidence.

along with changes in the long term SACP schedule, so that the total NPV (and rate payer impact) of the program remains the same. We believe that introducing this flexibility is critical to creating the continuous long term growth needed to reduce costs, provide the flexibility needed to respond to changing market conditions, and ensure that rate payer impacts are contained.

Detailed Discussion: The dominant issue throughout the last 18 months of debate on this transition has been the need for securitization. There is widespread consensus – including substantiation in the recent Summit Blue Final Report – that without securitization SREC values will have to be much higher to achieve the desired adoption. There are varying degrees of securitization possible, each with relative costs and benefits. While we believe the board should continue to consider other "strong securitization" methods (like the PSE&G loan proposal, or an underwriter), establishing a longer term multi-year schedule now is a quick and virtually cost-free way to introduce confidence in long term regulatory intent. We believe this "soft approach" to securitization has the following benefits:

- *Confidence*: this is a "no cost" way to strongly signal long term regulatory intent and create the confidence needed in the market to encourage investment.

- *Avoids Abuse*: by establishing a clear public baseline, it reduces the potential for speculators or unscrupulous developers to misrepresent future SREC value to customers. The multi-year schedule represents a common and publicly transparent benchmark that all projects can use for project economic planning.

- *Helps Planning*: by setting a multi-year schedule, it is easier to establish a planning baseline that clearly set maximum possible rate payer impact, and to ensure that future decisions are made within that context.

- *Cheap and Easy*: compared with other proposed approaches to securitization, a multi-year schedule is easy to implement and virtually free. Precedent has been established for multi-year schedules with the most recent ACP order.

- *Appropriate Risk Allocation*: This approach takes the first step in properly spreading SREC-investment risk between the state, project developers, and project owners. Additional risk-taking is probably needed by the state (beyond this 10-year schedule), since it has the most direct control over future SREC value. But we believe this multi-year schedule approach is a good first step towards creating an appropriate risk allocation structure in the market, with the state taking responsibility for long term trust in SREC value while motivating system developers and owners to perform.

- *BGS Consistency*: Recent proposals have been made to create new long-term (10-yr) tranches within the BGS auction, and this proposal to provide a 10-yr SACP schedule would be supportive of those changes (if made).

There do not appear to be many disadvantages of establishing a multi-year schedule, other than the potential to retard system price reductions over time (i.e., the industry "prices to the incentive" rather than focusing on cost reductions). This risk is moderated by the fact that the market has become highly competitive in NJ and installers are therefore motivated to compete strongly on system price. These lower priced projects can therefore sell their SRECs at a lower price to recover the same IRR, and would be motivated to do so to ensure that their SRECs are sold. So regardless of the SACP schedule, reducing system prices should result in lower ACTUAL SREC prices over time. As noted above, actual SREC pricing is set by the market, not by the SACP (unless there is persistent undersupply, in which case higher SREC values are needed to encourage additional development anyway). There is also a potential "con" of this approach if the originally established multi-year schedule is too high given technology innovations or other dramatic market changes. As noted, we believe this risk is manageable since the board retains the freedom to change the multi-year SACP level if needed, but only after an appropriate proceeding to substantiate key market changes and the need for altered levels.

Establishing a multi-year schedule simplifies the ACP committee task: each year, the committee would meet to "add the next year" to the schedule and assess whether changes in the previously assumed levels are warranted. Under our proposal, absent committee recommendations and board action, the levels noted in the multi-year schedule become the SACP for the year by default. This approach also creates new flexibility in managing the timing of changes. For example if significant cost reductions are beginning to emerge the board could begin to reduce the SACP assumptions in the out-years of the schedule, thereby affecting new project commitments strongly but reducing the impact for projects already in the ground.

We strongly urge the board to consider a long term multi-year schedule as a relatively easy, low cost, low risk, highly flexible way to create the needed long term confidence in the market.

As part of establishing a long term multi-year schedule, we also strongly recommend that the board take this opportunity to establish a new and more flexible framework for managing the RPS demand and SACP. As seen with the failure of the ACP committee to adjust SACP levels in Fall 2006, the current structure does not provide the needed flexibility for responding to market changes. Of particular concern, it creates an environment where the industry could continue to hit market limits that result in recurring stalls – a stop-start environment that is very damaging to growth and cost improvement. We therefore recommend that that the board adopt a new framework for managing the combination of yearly RPS demand and SACP, so that it can flexibly respond to market imbalances without affecting cost to the ratepayer.

The proposed framework would work as follows: under conditions of either persistent undersupply or oversupply (of SRECs), the ACP board would recommend either an acceleration or a deceleration of the RPS demand curve, with associated changes in the SACP schedule so that NPV equality is maintained with the current program. For example, if the industry were able to reduce costs and was entering a period of overbuild, the board could move-up the RPS schedule to create market balance. The SACP in the long term schedule would be reduced proportionally so that the resulting NPV was equal to the NPV of the original baseline. Such reduction in the SACP would be appropriate given the overbuild conditions that were materializing. This approach allows more capacity to be built faster, but without increasing rate payer cost. The same scenario can work in reverse, under which increases in the RPS can be delayed (at a higher SACP) to bring better balance to persistence undersupply scenarios.

SACP Changes Over Time

Question from the board order: "Should the ACP and SACP in RY 2009 start at a higher level and decrease over subsequent Reporting Years, or should it start at a relatively low level, but higher than the RY 2008 level, and increase over multiple Reporting Years"?

Summary Position: We recommend that the SACP decline by 5% every year to reflect expected reductions in system pricing over time. 5% is an aggressive but appropriate number given recent experience with actual system price reductions. It should be noted that the Summit Blue Final Report quotes an EIA projection of a 2.2% decline in PV costs through 2030, and a average 4.3% reduction in the NJ market between 2003 and 2006. An annual SACP reduction of 5% per year is therefore aggressive, but probably not so steep as to create market stall short term.

Rebated Vs. Non-Rebated SRECs

Question from the board order: "Can the SACP be structured to enable different SREC prices for solar electricity delivered by rebated and non-rebated solar facilities?"

Summary Position: Moving forward, we believe the market (and the rate payer) would be best served by the efficiencies that result from SREC market simplicity and consistency. For that reason, we believe that the program should retain a single SREC class structure moving forward, and that all facilities and SRECs are subject to the same SACP and RPS requirements. We recognize, however, that this single class structure has policy complications, especially regarding projects funded early in the program that would benefit from both rebate and higher SREC value. This perceived "windfall", although of small amount in the program overall and supportive of the risk that early customers took in participating in the program, has significant policy implications. We therefore recognize that a response is needed, in which case creating a two-class structure is probably the simplest and most appropriate solution. In this scenario, projects initially funded from the rebate program (plus SRECs at the current $300 SACP) would generate one class of SRECs, while new projects (zero or reduced rebates, plus higher SACP) would generate a second class of SRECs. Should this two-class structure approach become necessary, the board would be required to issue both SACP and % allocations of the overall RPS demand to each SREC class.

SREC Term Issues

Question from the board order: "Should the SACP and the subsequent SREC have a life for payment to the renewable energy generator? Should the SREC continue only until the system is paid for? How long should that timeframe be?"

Summary Position: The length of time over which a project can sell its SRECs has a profound impact on the project economics. **We strongly recommend that a) the board consider generation term limits at the same time that SACP levels are being established, b) to avoid a significant material change in the current market, generation term limits (if any) be at least 20 years, 15 at the absolute minimum.** It should be noted that all the SACP recommendations made above assume 15 year SREC recovery, and that all the Summit Blue Final Report recommendations were based on computing IRRs over a 15 year period. **We also recommend that SREC life be extended to two years**, an increase from the current one year, to improve market balancing efficiency.

Detailed Discussion: The question in the board order, as written, appears to mix two different issues together. For clarity, we will use the following definition in these comments. "Generation Term" is the period of time for which a given facility can generate and sell its SRECs once commissioned. "SREC Life" is the period that a given SREC, once created, can be sold. Under these definitions, there is a profound difference between limits on *the facility* (generation term), and limits on *the SREC* (SREC life). CURRENTLY, there are no limits on Generation Term, and SRECs automatically expire at the end of the Energy Year in which they are created. In practice this leads to project economic assumptions of SREC capture for at least 20 years, and the need to sell a generated SREC by August 31 of the energy year within which it is created.

Term assumptions have a profound impact on actual project economics as well as the *perceived* cost of solar electricity. Forcing a project to recover its costs in 10 years will make its "booked cost of power" about twice as high as a project that is financing over a 20 year term. The value of the SREC therefore depends heavily on the term assumption, and SACP levels and generation term limits (if any) MUST be considered together. The current RPS rule is completely silent on generation term limits, and there is widely established industry practice that systems can sell their SRECs for at least 20 years[3]. This is appropriate, since the longer the term, the lower the perceived cost of electricity per kwhr. **For solar to compete economically with large power plants which amortize over decades, solar investments must also be able to recover over extended**

[3] The primary reason the limit is 20 years in most current project planning is that the NPV value of revenues past 20 years is minimal. That, combined with the inherent risk of projecting that far in the future, minimizes the sales value of making assumptions beyond 20 years.

terms. Forcing shorter payback intervals forces the perceived cost of solar electricity higher, with a resulting need for higher SACPs. Given the absence of generation term limits in the current rules, and the desire to allow extended financing terms and lower $/kwhr economics, we believe there should be no limits on how long a facility should sell its SRECs. If the board wants to make a change from current practice, the generation term should not be limited to less than 20 years, 15 at the absolute minimum. It should be noted that most economic analysis associated with required SACP levels assumes terms of 15 or 20 years.

Separately, we also recommend that the board extend SREC life to two years. This would allow a generator greater flexibility in selling SRECs, and significantly improve the ability for the market to achieve balance with the RPS demand. In years with oversupply, generators could hold their SRECs until the following year and help adjust for year-to-year imbalances naturally and without state intervention.

The current debate on Generation Term and SREC Life does not account for another aspect of program design that should be considered: the ability to sell into non-RPS markets. Under the current program, SRECs automatically expire at the end of their vintage life and are no longer tradable. Even after a SREC has lost the ability to be traded in the NJ-RPS compliance market, it should still exist as a commodity and be sellable into other markets – either voluntary markets, non RPS markets (such as emissions), or non-NJ compliance markets. In that case, the above definitions of Generation Term and SREC Life may need to be refined further, since the current definitions focus exclusively on the ability of SRECs to meet NJ-RPS compliance.

Economic Analysis

Question from the board order: "What are stakeholder's views regarding the Board's detailed economic analysis of the customer bill costs and the rate impacts of transitioning to a certificate-based financing system without rebates?"

Detailed Discussion: The proposed transition represents a fundamental restructuring of the market, including significant changes in the TIMING and the associated RISKS in multiple unbundled value streams. These differences must be accounted for rigorously, and we recommend the use of Net Present Value analysis (at a 10% discount) for comparing scenarios consistently. It is also critical that tax impacts be properly reflected, since SREC revenues are taxable and that has a very large impact on the economic analysis. Lastly, the analysis must account for the profitability needed to create the required customer adoption – including profit incentive for the investing customer AND full recovery of the cost of capital. Policy "Break Even" payback goals must be consistent with market reality.

The "preliminary" analysis offered by the OCE to demonstrate the transition[4] from a rebated incentive environment to one funded exclusively by SRECs was highly optimistic since it did not account for these critical elements of the analysis. It did not provide an NPV comparison of the cash flows, and incorrectly assumed that a dollar in year 10 was the same as a dollar in year 1. It also did not account for the fact that SREC revenues are taxable, and that only after tax value applies to the project payback. It also assumed that SREC revenue would be flat over the 10 year term of the analysis, which is highly hypothetical since expectations are that SACP would decline over time, and that discounting would be applied to out-year assumptions. The analysis also assumed that "break even in 10 years" would be sufficient to motivate project adoption, when in fact some economic incentive is required for the customer ON TOP OF the cost of capital. Finally, the analysis was also highly optimistic in that it assumed a production factor of 1.2 annual kwhrs-AC per Watt-DC, compared with the actual NJ field average of 1.0 kwhrs/Watt-DC.

Although positioned as a "high level example", these analytic problems result in an estimate of SREC value that optimistically low – in this case, $502/SREC flat for 10 years. If this analysis is corrected for just three factors (tax impacts on SRECs, using an appropriate NPV basis (at 10%), and production at 1.0 kwhrs/watt), the required SREC value for this example is $1,230/SREC flat for 10 years, not $502. As this example shows, high level "back of the envelope" analysis can be highly misleading.

Fortunately the recently published Summit Blue Final Report was more rigorous in all these dimensions. They made extensive use of NPV analysis, made appropriate assumptions about production and IRR across different segments, and appear to have accounted for tax implications properly. Overall, based on the high level summaries of model results, the SREC value assumptions are approximately correct. There was limited reporting of results, however, and the actual year-by-year cash flows for the various scenarios were not provided. Since this analysis is intended to formally baseline the overall ratepayer costs for the full program, we believe it is critical that these full details be published. We recommend that the report be republished with full annual cash flows for the overall program included. Note that we are NOT asking for additional analysis, but more complete publication of analysis already completed.

There are several underlying assumptions behind the models, however, that could have a profound impact. As a particularly important example, the report assumes that project costs remain the same under different market structure scenarios. In fact, some models are more conducive to creating competitive pressures that reduce costs than others. A primary benefit of the poorly-named commodity model is that it allows the market to set prices for SRECs and creates an incentive for lower priced projects. These competitive pressures may not emerge as easily under other market structure scenarios. The overall program costs may therefore be somewhat misleading since they do not account for how the different market models would affect system pricing over time.

[4] In charts presented as the introduction to the "RPS Transition Round Table Discussions"

The key assumptions behind the Summit Blue analysis are therefore somewhat hypothetical, since they assume certain aspects of market performance remain constant across the different models. This was an appropriate initial approach by Summit Blue, since it was the only way to create proper "apples to apples" comparisons. But this constraint implies that the reported results do not account for how the different models would shape the maturity and performance of the markets over time. Also, as highlighted by Summit Blue in the initial chapter, this analysis considers only the rate payer impact which is but one of several factors that affect the decision. We urge the board to consider the Summit Blue Final Report recommendations in the light that it looked ONLY at rate payer impacts, and that other strategic factors should also be considered as part of the evaluation. In particular, we provide the following additional input:

1. As noted above, the models assume that key assumptions (especially system pricing) are constant across models. In fact, different models would likely lead to different competitive environments which means those assumptions are NOT constant across models as assumed. The current rate payer impact estimates do not account for these differences.

2. The decision about SACP level (and associated market structure) should also specifically consider the *how risk should be allocated* across all players. In the current rebate program the state assumes almost all risk, since it pays for capacity not production. At the other extreme of a pure SREC commodity market without any form of securitization, the investor assumes a great deal of risk over which they have very little control. Current feedback from the capital markets is that this approach is simply too risky to support without exorbitant risk premiums which can only be realized with very high SREC prices. The right answer probably lies somewhere in between, with each party assuming some risk that is tied to the aspect of the investment over which they have some influence. It will be critical for the state to step up to creating well founded confidence in the long term SACP (since that is exclusively under state control), while retaining strong responsibility for investors and project owners about project design and production. The rate payer impacts described in the Summit Blue Final Report do not reflect these risk allocation distinctions, which we believe should be strongly considered in the overall market design decision.

3. Lastly, it is critical that the market mechanism chosen allow changes to be made in the program in as non-disruptive a form as possible. This need for flexibility is somewhat antagonistic with the need for risk-reduction and predictability required by investors, and is therefore an essential part of the strategy decision. This aspect is also not strongly reflected directly in the rate payer impacts.

The current Summit Blue Final Report looks at seven models and assumes that each model is used exclusively to support the full market moving forward. Our recommendation is a hybrid approach in which the SACP is increased to allow SREC-only incentivized projects to dominate in the commercial sector, with a rebate (after

2008) for smaller systems that have increased cost. Assuming policy goals mandate continued support for the small system market, supporting continued rebates for these smaller systems avoids the need to set the SACP very high for the overall market (with an inappropriately high IRR for tax-advantaged large projects). The full rate payer impact is therefore a combination of rebate budgets for small projects moving forward, plus the cost of the SRECs based on the higher SACP for all projects. We recommend that the Summit Blue analysis be amended to consider the costs of this combined approach. As noted previously, we also believe the more detailed annual cash flows associated with the current (and any amended) analysis be published. The current SACP proceeding should clearly set a projected cost for the entire program required to reach the solar RPS goals.

Recommendation Summary

As detailed above, there are MULTPLE issues that need to be considered together when considering the SACP levels and the expected market transition. We offer the following recommendations in response to the board's request for input:

- There will be a SREC shortfall, estimated to be about 16,000 SRECs in 08/09 and 39,000 SRECs in 09/10 if only rebated-capacity is deployed over the next 18 months. It is imperative that new projects be enabled beyond what is already budgeted through the CORE rebate program to meet RPS goals. Hence there is significant urgency in increasing the SACP and allowing SREC-funded projects to begin development ASAP.

- Assuming the board establishes soft securitization through a 10 yr (or more) schedule, we recommend an SACP of $750/SREC. Additional rebates will be needed for smaller projects to level the economic playing field. This level of SACP assumes projects can sell SRECs for at least 15 years, and that the SACP will decline by 5% every year thereafter.

- We recommend that the board address the high impact securitization issue by establishing a 10 yr (at least) long term SACP schedule. This schedule could be adjusted annually (after the first year), but absent specific board action the projected SACPs become the default level for the scheduled year. At the same time, we recommend creating a new framework for managing the RPS-demand and SACP levels, establishing a bi-directional circuit breaker that can accelerate or decelerate the RPS schedule without affecting rate payer cost (on an NPV basis).

- We recommend starting with an SACP at $750, then planning for a 5% decline annually. Facilities should be allowed to sell their SRECs for 20 years at least, 15 years at a minimum. SREC life should be extended to two years. We strongly encourage a single class structure, but given multiple complicating factors, we recognize that a two-class structure may be needed. Whatever the structure, market simplicity should be a strong factor in the final design.

- Initial economic analysis by the OCE was not representative, since it did not account for critical factors such as the time value of money and tax implications. The more recent Summit Blue Final Report does a much better job establishing a rigorous framework for analyzing the needed SACP values and estimating rate payer costs through various models. The results were somewhat incomplete, however, and we recommend that the report be republished with more complete documentation of the annual cash flows associated with all scenarios. Regardless, we believe it is important to emphasize that the Summit Blue report only considers a single but important dimension of the decision (rate payer cost), but does so under highly hypothetical conditions that do not reflect other aspects of the decision. In particular, the model assumptions do not account for the difference in competitive environment that would emerge under the different scenarios, and how that would affect system pricing (and hence rate payer cost) over time. These and other strategic factors, in addition to the quantitative information derived from the models, should be used in the overall evaluation.

In conclusion, the emerging SREC shortfall makes it clear that new solar projects must be enabled beyond the limits of the current CORE rebate program, and that an SACP change is needed immediately to allow new capacity deployments to begin immediately. Increasing the SACP to $750 and establishing a 10-yr schedule assuming a 5% annual decline provides the economics needed by commercial projects to gain investment support. Continuation of the rebate will be needed for smaller projects (past 2008) to level the economic playing field. Without these urgently needed changes in the NJ incentive environment, the current industry stall will continue and the shortfall in the SREC supply (relative to RPS goals) will grow to the point of putting the overall RPS commitment at significant risk. Once these changes are made, we recommend that the Board immediately launch a Phase Two Pilot (or open up the market entirely) so that these new market conditions can translate into new project commitments ASAP. These essential changes should be implemented immediately consistent with the scope of the current proceeding (Docket EO01100744). Additional enhancements, potentially including support for additional securitization, can be considered and added as part of the longer term market design proceedings.

Attachment A: Example Project ProForma

Commercial Application: 50KW RPS Only
Assumes RPS Value declines 5% every year

Yellow = Input Parameter	
Orange = Computed Input	
Blue = Heading	
Green = Key Computed Result	

Constant Assumptions			
System Size (KW-DC)	50.000		
Construction Cost	$362,500	$7.25	$/watt
Capacity based incentive (NJ Rebate)	$0		
Production Factor (first year, kwhr/Wdc STC)	1.00	Note: degredation reflected in annual production estimates	
System Peformance Degredation (%/yr)	0.005		
Annual Power Cost Escalation	0.02		
Federal Tax Rate	0.35	Note: State tax implications not considered	
Federal Tax Credit Basis	$362,500	Assumes zero rebate received by customer and taxable, so basis is total construction costs	
Federal Tax Credit	$108,750	30% FTC, assuming service date by 12/31/07	
Federal Depreciation Basis	$308,125	Net cost (after rebate), minus half the FTC	

Annual Assumptions		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**
Retail Value Of Displaced Electricity ($/kwhr)		$0.1100	$0.1122	$0.1144	$0.1167	$0.1191	$0.1214	$0.1239	$0.1264	$0.1289	$0.1315	$0.1341	$0.1368	$0.1395	$0.1423	$0.1451
SREC Value ($/kwhr)		$0.730	$0.694	$0.659	$0.626	$0.595	$0.565	$0.537	$0.510	$0.484	$0.460	$0.437	$0.415	$0.394	$0.375	$0.356
Maintenance Costs (amortized $/kwhr)		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Annual Production (kwhr)		50,000	49,750	49,501	49,254	49,007	48,762	48,519	48,276	48,035	47,794	47,556	47,318	47,081	46,846	46,612
Project Economics (Customer Cashflow)		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Construction Investment		-$362,500														
Cashflows (pre-tax, + = income or savings)																
Rebate		$0														
SAVINGS From Displaced Power Purchase		$5,500	$5,582	$5,665	$5,750	$5,835	$5,922	$6,010	$6,100	$6,191	$6,283	$6,377	$6,472	$6,568	$6,666	$6,765
SREC Income		$36,500	$34,502	$32,613	$30,827	$29,139	$27,544	$26,036	$24,610	$23,263	$21,989	$20,785	$19,647	$18,572	$17,555	$16,594
Operating Expense (Maint. Sinking Fund)		-$1,000	-$995	-$990	-$985	-$980	-$975	-$970	-$966	-$961	-$956	-$951	-$946	-$942	-$937	-$932
Sub-Total Annual Cashflows (pre-tax)		$41,000	$39,089	$37,288	$35,592	$33,994	$32,491	$31,076	$29,745	$28,493	$27,317	$26,211	$25,173	$24,198	$23,284	$22,427
Federal Tax Calculation																
Taxable Income																
Net Annual Cashflows		$41,000	$39,089	$37,288	$35,592	$33,994	$32,491	$31,076	$29,745	$28,493	$27,317	$26,211	$25,173	$24,198	$23,284	$22,427
MACRS Deduction		-$61,625	-$98,600	-$59,160	-$35,434	-$35,434	-$17,871									
Sub-Total: Taxable Income (+=income)		-$20,625	-$59,511	-$21,872	$157	-$1,440	$14,620	$31,076	$29,745	$28,493	$27,317	$26,211	$25,173	$24,198	$23,284	$22,427
Federal Tax Obligation (+=refund)		$7,219	$20,829	$7,655	-$55	$504	-$5,117	-$10,877	-$10,411	-$9,973	-$9,561	-$9,174	-$8,810	-$8,469	-$8,149	-$7,849
Federal Investment Tax Credit		$108,750														
Net Federal Tax Benefit (+=refund)		$115,969	$20,829	$7,655	-$55	$504	-$5,117	-$10,877	-$10,411	-$9,973	-$9,561	-$9,174	-$8,810	-$8,469	-$8,149	-$7,849
Net Cashflow (after federal tax)	$151,389	-$205,531	$59,918	$44,943	$35,537	$34,498	$27,374	$20,199	$19,334	$18,521	$17,756	$17,037	$16,362	$15,729	$15,135	$14,577
Cummulative Cashflow		-$205,531	-$145,614	-$100,671	-$65,134	-$30,636	-$3,262	$16,938	$36,272	$54,792	$72,548	$89,585	$105,948	$121,677	$136,811	$151,389
Customer IRR	12.0%															

MSEIA
MID-ATLANTIC SOLAR ENERGY INDUSTRIES ASSOCIATION

600 College Road East, Suite 4400
Princeton, NJ 08540
T: 609.513.7295
F: 610.988.0862

May 11, 2007

VIA EMAIL
NJBPU
Office of Clean Energy
P.O. Box 414
Trenton, NJ 08625-0414

Attn: Michael Winka – Director

Re: Straw Proposal for SREC cap and Additional CORE budget – market segment allocation

Dear Mr. Winka:

We have reviewed the *"Straw Proposal for SREC cap and Additional CORE budget – market segment allocation"* issued by OCE staff on May 4, 2007 and are providing the following comments.

1. SREC CAP

The Straw Proposal for SREC cap and Additional CORE Budget ("Straw") proposes

a. *Residential systems in the pilot would be maintained the 10 kW AC cap or the net metering limits whichever is less;*

b. *Commercial and Industrial customers' cap would be increased to 2MW AC or the net metering limits, whichever is less at one site and per entity. The entity cap would be in place until July 1, 2007 and if the shortfall for EY 08 were not filled, the entity cap would be increased to 4 MW. The per site cap would be maintained at the 2MW AC cap or the net metering limit whichever is less.*

As a general matter, if the stated intention of the pilot is to test the ability of the market to develop solar projects based solely on energy savings and REC income, then the pilot should allow projects to be built at the level that will best accomplish that goal. If additional limitations are imposed on pilot projects simply because they are imposed on rebated projects for purposes of equity and conserving funds, then the pilot's ability to project levels of market demand would be skewed, its potential limited and its results undermined. From the perspective of the solar industry, another equally important intention of the pilot was to provide alternative project financing mechanisms for projects otherwise trapped in the queues. The pilot will not be able to

MSEIA
MID-ATLANTIC SOLAR ENERGY INDUSTRIES ASSOCIATION

600 College Road East, Suite 4400
Princeton, NJ 08540
T: 609.513.7295
F: 610.988.0862

help identify the elements necessary for non-rebated projects to proceed if the alternatives are so constrained.

We recognize, however, that considerations such as encouraging energy efficiency and ratepayer equity may support limiting residential systems at 10 kW or less. If the 10 kW residential cap is implemented as part of the pilot, it should be more specifically defined as was done in the CORE program. This constraint should be applied to sites that are single-family residences exclusively, and should specifically exclude farms, houses of worship, multi-family dwellings, or homes with on-site businesses.

The existing 2MW net metering cap is a regulatory requirement applicable to all projects. While we have no objection to a 4 MW cap, as a practical matter, increasing the scope of allowed projects after July 1, 2007 will not provide much information as to project financing options. The pilot was originally approved in January 2007 to help inform the ACP and REC transition processes. By July those proceedings will be far enough along that whatever input comes from the pilot will have been received. Unfortunately, the delays in establishing the pilot have made it possible that some pilot applicants may now be merely safeguarding their ability to construct if the ACP is increased. Therefore, it is possible that even now the pilot's purpose has been undermined by the delays in implementation.

2. Additional Core Budget

The Straw also proposes that additional funds from the 2006 budget and estimated carryover for the 2007 budget be allocated as follows:

a. 50% for Less Than 10 kW
b. 25% for Greater than 20 kW
c. 25% for publics

We note that $5.2M of the approximately $18.7 M identified in the Straw for reallocation would be diverted from Renewable Energy business venture and manufacturing Incentive programs. We object strenuously to this reallocation. Encouraging technology and new manufacturing is too important to curtail such programs.

With respect to the remainder of the monies (approximately $13.5 M), by letter dated April 19, 2007 to the Clean Energy Council, MSEIA recommended that the additional monies be allocated approximately 70% to the less than 10kW Private queue and approximately 30% to the greater than 10kW Private queue. This recommendation was based on the fact that these queues carry the greatest backlog and their applicants have been waiting the longest for movement. The OCE website's current posting of the queues, dated March 21, 2007, identify 1242 projects in the

MSEIA
MID-ATLANTIC SOLAR ENERGY INDUSTRIES ASSOCIATION

600 College Road East, Suite 4400
Princeton, NJ 08540
T: 609.513.7295
F: 610.988.0862

less than 10 kW queue and 193 in the greater than 10 kW queue. The Straw states that there is "the beginning of a queue for public facilities," although neither the Straw nor the website indicates how many projects are involved and of what size. If the OCE and the Board have information confirming that existing allocation to the public queue has been or will soon be committed, we favor an appropriate allocation of up to 25% of the monies with the understanding that they can be reallocated if no such queue develops in the public sector. The remainder of the monies should be allocated consistent with our prior recommendation.

It is also important to note that commitments against the 2007 budget have been significantly delayed due to the Program Management transition. By the end April only about 21% of the budget had been allocated. In order to fully spend the 2007 budget by the end of the year, project commitments should really be completed by the end of the first quarter. In order to ensure the timely use of these rate-payer funds, MSEIA strongly recommends that full allocation (i.e. new commitment letters) of the currently available funds be completed as soon as possible, by the end of June at the latest.

We appreciate the opportunity to submit these comments.

Very truly yours,

Susan P. LeGros

Steven A. Gabrielle
Business Development Manager
Tel. 610.774.7095 Fax 610.774.4198
E-mail: sagabrielle@pplweb.com

PPL Energy Services Group, LLC
Two North Ninth Street (GEN-PL8)
Allentown, PA 18101-1179
www.pplenergyservices.com

May 11, 2007

NJBPU - Office of Clean Energy
44 South Clinton Avenue
Trenton, NJ 08625-0350
Attn: Mike Winka, Director

RE: Straw Proposal for SREC Cap and Additional CORE Budget – Market Segment Allocation

Dear Mr. Winka:

On behalf of PPL and its many New Jersey customers who have received direct support from NJ Clean Energy Program, PPL appreciates the initiative and support of NJCEP in promoting the development of renewable energy technologies.

PPL would like to offer its comments on the following items:

<u>SREC-pilot Caps - COMMENTS</u>

For industrial and commercial customers, PPL supports the cap of 2MW AC or the net metering cap per site whichever is more and recommends there not be an entity cap of 4 MW AC per entity. PPL is of the opinion that for the State to meet its aggressive SREC goals that the State should encourage larger multi-megawatt projects. PPL's existing New Jersey customers should be viewed as the "early adopters" of solar and as such should be encouraged as an "entity" to install larger solar projects. PPL also supports applying any ACP changes to customers in the SREC-pilot.

<u>Additional CORE Budget - program Caps – REQUEST FOR RESPONSE</u>

PPL has successfully worked with the NJCEP and many New Jersey customers over the past several years to install fuel cells, solar projects and a landfill gas to energy project.

PPL installed two solar rooftop projects for Macy's in Jersey City and Mays Landing, NJ in November 2006 under the support of the CORE program. Commissioner Butler was gracious enough to provide a compelling presentation at a recently held ribbon cutting for these two projects. A third project for Macy's was installed in East Brunswick in 2007 by another provider.

PPL with Macy's and Bloomingdale's applied for seven additional CORE rebates in March 2006. All seven applications were found to be complete and placed over 13 months ago in the then new "queue" system established by NJCEP. (Macy's GT10PVT, queue numbers 291, 292, 293 and Bloomingdale's GT10PVT, queue numbers 267, 268, 269, 270).

In the last month it has come to our attention by OCE staff that these seven applications may be subject to the entity cap established in a July 7, 2005 Board Order – Docket EO04121550_20050707 and now may all be removed from the queue. Macy's and Bloomingdale's both exist under the parent company Federated Department Stores, Inc.

The language in the Board Order states "an entity other than a public school district or a public entity be defined as the corporate or public holding company" and the "the maximum annual funding level for these entities be set at $5 million per year".

Macy's first two projects, installed in 2006, received $2.5 million in rebates. The third project was installed in 2007 (being delayed due to the queue process) and received about a $1.85 million rebate.

Macy's and Bloomingdale's, after recently being made aware of this issue, have both submitted letters stating they are willing to work within NJCEP and Board guidelines of receiving no more than $5 million per year in funding. This can be achieved by staggering the installation of the projects between years 2007 and 2008, eliminating one project and reducing the size of several of the projects. The result of these efforts as defined in the attached letters clearly keeps these projects within the $5 million per year of funding and well below the $20 million total entity cap.

PPL has recently been become aware that there has been discussion that these projects may be eliminated from the queue for not complying with the entity cap. The solution offered above and in the attached letters clearly shows that the guidelines are followed. In support of the State's goals of promoting solar projects, PPL with the full support of Macy's and Bloomingdale's has spent nearly $200,000 in contract negotiations, roof reviews and engineering designs for all these projects to date. More importantly Macy's and Bloomingdale's have gone to their respective managements with these projects and had contracts signed with PPL in order to meet NJCEP guidelines. We would appreciate an answer to the question: How has this issue on the entity cap changed from the initial application in March 2006 through now, May 2007?

PPL, along with Macy's and Bloomingdale's, would recommend the Board allow these projects to stay in the queue by allowing the installation of two new projects in 2007 (upon funding approval) and four new projects in 2008 (upon funding approval). PPL will work with OCE staff to eliminate one project and reduce the sizes of the remaining projects such that the $5 million per year level would not be exceeded.

Thank you for your consideration.

Sincerely,

Steven A. Gabrielle

Bloomingdale's

April 16, 2007

New Jersey Board of Public Utilities
Office of Clean Energy
Attn: Scott Hunter, Renewable Energy Program Administrator
44 South Clinton Avenue
Trenton, NJ 08625-0350

RE: Bloomingdale's Solar Projects in Queue

Dear Mr. Hunter:

Bloomingdale's is excited about potentially working under the New Jersey Clean Energy Program to install solar projects at its New Jersey department stores.

I understand there has been some discussion in regarding Bloomingdale's four pending solar projects in the queue (GT10PVT, queue numbers 267, 268, 269, 270). There is discussion on whether Bloomingdale's under its parent Federated would be able to receive rebates along with Macy's which is also a Federated company. It should be noted that Bloomingdale's and Macy's are separate corporations with individual management teams.

Bloomingdale's intends to comply with the requirements of installing projects with rebates of less than $5 million per year of solar projects under the clean energy program and receiving less than $20 million in total rebates for all its solar projects.

If required under the clean energy program rules, Bloomingdale's is willing to coordinate its installation with Macy's so there are only a maximum of $5 million of rebated projects installed each year (Macy's had two projects installed in 2006 with $2.5 million in rebates). Bloomingdale's would be willing to decrease the size of one of its projects and eliminate one of its four proposed projects. The result would be the installation of one Bloomingdale's and one new Macy's project in 2007 (total of $4.4 million in rebates with the existing Macy's project already installed in 2007) and two Bloomingdale's (one at a reduced size) and two Macy's projects in 2008 (total of $5 million in rebates). All the new projects are at the $1.27 rebate level so the total 2007 and 2008 levels would be at less than $5 million in rebates. With these changes, the total Macy's and Bloomingdale's rebates would still be much less than $20 million.

I would appreciate an update if there is any intention to change Bloomingdale's status in the queue well ahead of this happening.

I again appreciate all your efforts in making these renewable energy projects a success.

Please call me at (212) 705-3604 if you have any questions.

Sincerely,

Brad Boyle
Operating Vice President, Risk and Energy Management

155 East 60th Street
New York, N.Y. 10022
Phone (212) 705-3604
Fax (212) 705-3519

macy's east

April 13, 2007

New Jersey Board of Public Utilities
Office of Clean Energy
Attn: Scott Hunter, Renewable Energy Program Administrator
44 South Clinton Avenue
Trenton, NJ 08625-0350

RE: Macy's Solar Projects in Queue

Dear Mr. Hunter:

Macy's appreciates the New Jersey Clean Energy Program and the New Jersey Board of Public Utilities support of its three rooftop solar projects at its stores in Jersey City, Mays Landing and East Brunswick. Macy's is excited about supporting the state's goals and taking the lead among its peers as one of the largest retailers to support implementing renewable energy projects.

I understand there has been some discussion in regards to Macy's three pending solar projects in the queue (GT10PVT, queue numbers 291, 292, 293). Macy's intends to comply with the requirements of installing projects with rebates of less than $5 million per year of solar projects under the clean energy program and receiving less than $20 million in total rebates for all its solar projects.

Macy's has installed two projects in 2006 (Jersey City and Mays Landing) that received about $2.5 million in rebates. One project was installed in 2007 (East Brunswick) that received a rebate of about $1.85 million (this project was delayed from 2006 installation due to being placed in the queue). Upon rebate approval, Macy's would install two new projects in 2007 at $1.27 in rebate each. The total 2007 installed would be $4.39 million in rebates. The third new project would be installed in 2008 with a rebate of $1.27 million.

I would appreciate an update if there is any intention to change Macy's status in the queue well ahead of this happening.

I again appreciate all your efforts in making these renewable energy projects a success.

Please call me at (212) 494-3024 if you have any questions.

Sincerely,

Robert Gisolfi
Energy Director

Macy's East, Inc. – 151 West 34th Street – New York – New York – 10001

Fat Spaniel TECHNOLOGIES

Visualize Renewable Energy[SM]

NJBPU – Office of Clean Energy
POB 414
Trenton, NJ 08625-0414
Attn: Michael Winka – Director

May 11, 2007

RE: Straw Proposal for SREC cap and Additional CORE budget – market segment allocation ("Straw Proposal")

Dear New Jersey Board of Public Utilities & Office of Clean Energy:

Thank you for the opportunity to provide comments on the *Straw Proposal for SREC cap and Additional CORE budget – market segment allocation* that was circulated for public comment via email on Friday, May 04, 2007 ("Straw Proposal").

While the Straw Proposal is directly seeking input on two items of note, per the recommendation and urging of Steve Wiese, Manager of the New Jersey REC Program, in this communication Fat Spaniel Technologies, Inc. ("Fat Spaniel") would like to offer comments and suggestions on other topics not specifically detailed in the Straw Proposal but which the New Jersey Board of Public Utilities ("NJBPU" or "Board") and the Office of Clean Energy ("OCE") have indicated in other public documents are inherently critical to the success of the SREC Pilot and the ultimate transitioning of the New Jersey solar market from rebates to market-based incentives.

Specifically, Fat Spaniel would like to take this opportunity to provide recommendations to the Board and OCE with respect to the underlying programmatic details of the metering and monitoring requirements for the SREC Pilot program and the SREC program in general.

In its Order dated January 19, 2007 the Board found that the SREC Pilot should:

> "…. be remotely monitored at all times, and the amount of energy generated shall be automatically and directly communicated to the Board designated REC tracking system at least monthly, or once per MWH generated, whichever is more often."[1]

Fat Spaniel commends the Board and the staff at OCE for the intent behind this component of the order. This order language clearly recognizes the importance of automatic and direct tracking of SRECs to enable the smoothest and lowest-cost operation of the SREC marketplace as well as the key role metering and monitoring holds in creating strong viable financial markets for SRECs.

---

[1] Page 13 of Board Order dated January 19, 2007 which memorialized action taken by the Board at its December 21,2006 agenda meeting in connection with the Board's Clean Energy Program (CEP) and the Renewable Portfolio Standard. BPU Docket No. EOO6100744.

Of course, since the Board's direction in the January 19th order represents generally high-level policy directives the actual specifics of the metering and monitoring requirements are spelled out elsewhere. At present it is Fat Spaniel's understanding that these metering and monitoring requirements for the SREC Pilot are embodied in a document entitled *"New Jersey Clean Energy Program Solar Renewable Energy Certificate (SREC) Pilot Program Requirements, Instructions, Terms and Conditions"* and are as follows:

> "…Registrant must also agree to meter and monitor energy production in accordance with Program procedures and guidelines. *Note: metering and monitoring requirements are being developed, and will be posted when they become available."*[2]

Accordingly, Fat Spaniel would like to herein provide its thoughts and comments on the specifics of these metering and monitoring requirements.

However, before doing so, it would perhaps be most appropriate to provide the Board and the staff at OCE with a quick background on Fat Spaniel. Specifically, Fat Spaniel provides independent metering and data monitoring solutions specifically designed for reporting, verifying, and auditing the performance of solar, wind, fuel cell, and other distributed generation installations. Fat Spaniel products and services are available worldwide and the company is currently monitoring systems throughout the United States and in nine other countries around the globe. Fat Spaniel has a number of clients in New Jersey and currently provides for the low-cost automatic uploading of SREC production data into the SREC trading system managed by Clean Power Markets. Additionally, as a recognized leader in this area, Fat Spaniel currently Co-Chairs the Metering Subcommittee of the California Solar Initiative and as such is actively engaged in facilitating the implementation and refinement of that program's metering requirements. Fat Spaniel's recommendation to the Board and OCE are thus based on its deep understanding of the metering and monitoring business, its experience in California, and its knowledge of other states with active or growing Renewable Energy Credit markets and policy initiatives such as in Massachusetts, Connecticut, and Rhode Island.

We sincerely hope that Fat Spaniel's comments attached in Exhibit A will prove useful to the Board and OCE as New Jersey moves forward in developing the metering and monitoring requirements of the SREC Pilot. Of course, should either the Board or OCE feel it would be appropriate, Fat Spaniel would be happy to help and participate in any activities or working groups that might provide further guidance on these issues.

Sincerely,

/s/ David Kopans

David Kopans
Director of Regulatory Affairs
(david.kopans@fatspaniel.com)

[2] Page 2 of document with file name "SREC Pilot Registration 070403" sent via email to the renewables@njcep.com listserv on 4/13/2007 and currently available on-line at http://www.njcep.com/media/SREC%20Pilot%20Registration%20070403.pdf

Sent Via email in PDF file format to OCE@bpu.state.nj.us

With Cc to:

BPU Commissioners:
Jeanne Fox, President
Joseph Fiordaliso
Frederick Butler
Connie Hughes
Christine Bator
Care of Noreen Giblin - BPU Chief of Staff - Noreen.Giblin@bpu.state.nj.us

Mike Winka - Michael.Winka@bpu.state.nj.us

Scott Hunter - Benjamin.Hunter@bpu.state.nj.us

Maureen Quaid - Renewable Energy Market Manager - maureen.quaid@csgrp.com

Steve Wiese - Manager, REC Programs - steve.wiese@csgrp.com

Exhibit A

Fat Spaniel proposes that relevant sections of the Requirements, Instructions, Terms and Conditions of the New Jersey Clean Energy Program Solar Renewable Energy Certificate (SREC) Pilot Program be modified to incorporate and clearly state the following metering and monitoring requirements:

1) Meter Accuracy

The electric meter used to record kWh information used to generate SRECs should meet the same standards for accuracy as revenue billing meters used in New Jersey to bill ratepayers for electricity use. Allowing any difference in the accuracy tolerance of an SREC meter in comparison to a revenue billing meter does not properly support the creation of a viable financial market.

Accordingly, whether internal to the PV system's inverter or as a stand-alone device, the kWh meter that records kWh information which is then used to generate SRECs should be required to meet the applicable standards for revenue billing accuracy.

In this regard there are two sets of internationally recognized standards that are used to certify a meter's revenue grade accuracy – those published by the American National Standards Institute (ANSI) and those published by the International Electrotechnical Commission (IEC). Only meters that meet the specific accuracy subsections of either set of standards should be allowed to be used in the SREC program.

More specifically, SREC meters should be required to meet or exceed either (a) the requirements of ANSI C12.20-2002, Sections 5.5.2.1 through 5.5.2.7 under the test conditions of Section 5.5.1, or (b) the requirements of IEC 62053-22 (2003-01) Sections 8.1, 8.2, 8.3.2 and 8.3.3 under the test conditions of Section 8.5.

Holding SREC meters to either of these testing standards will create financial trust in the SREC market and promote an SREC market where only accurately metered solar generation is rewarded for every dollar dedicated to RPS compliance.

2) Measurement

In addition to meeting an accuracy requirement the meter used to record kWh information used to generate SRECs should be bi-directional and report the system's net available / usable power (i.e. net of standby losses, transformer losses, and grid power utilized by the system for significant items such as tracking systems, pumps, etc.)

This bi-directional requirement is important as Fat Spaniel has seen significant standby and transformer losses on many PV systems. In some cases these losses have almost exceeded PV production. Without basing SRECs on a bi-directional kWh meter these losses are either (a) added to PV production thus overstating production or (b) not properly deducted from the PV production thus overstating the system benefit of the PV system.

Holding SREC meters to a bi-direction requirement promotes an SREC market where only truly useable solar generation is rewarded for every dollar dedicated to RPS compliance.

3) Frequency of Data Collection and Reporting

kWh meter data should be automatically transmitted to the SREC tracking system no less than once a month. Such regular reporting will give SREC administrators, OCE, the Board, and SREC market participants the appropriately timely information to SREC production data.

It is important to note that this recommendation is a departure from the Board's Order dated January 19, 2007 which promoted a reporting schedule that was the "more often" of (a) monthly or (b) each time a MWH of solar production was generated.

Fat Spaniel does not believe a production based reporting schedule (i.e. each time a MWH of solar production is generated) will provide a greater level of benefits to the SREC Pilot program to off-set the significantly higher costs associated with having to prepare for and possibly deliver and receive data under a production based reporting schedule.

At the present the SREC system is set up to receive data on a monthly calendar reporting basis and it can be assumed that any upfront changes to that system to handle a production based reporting schedule would be significant. Likewise, it should also be noted that there is a data handling and processing cost incurred by the sender and recipient of data each time data is sent and received. This is true even of automated systems and thus also raises costs.

Accordingly, Fat Spaniel strongly recommends that SREC reporting continue to occur only on a monthly basis to minimize costs to system owners and ratepayers while at the same time maximizing the benefits of automated data transmission.

4) Independence

The kWh meter data used to generate SRECs should always, and only, be handled by an independent third-party with no financial stake in the reported data. While this requirement is currently in place in NJ insofar as the SREC market itself is concerned it is now most appropriate to extend it down to the reporting of individual kWh meter data upon which the SREC market is supported.

It goes without saying that the generation of SRECs and the sale thereof create powerful financial incentives for generation owners to report inaccurate kWh production data -- even more so under a program in which rebate payments are entirely replaced with SREC sales. As such, all meter reading and reporting should be handled by an independent party with no financial stake in the reported data.

There is solid precedent for requiring independence in the handling of meter data in support of Renewable Energy Credit ("REC") markets such as the New Jersey SREC market. Indeed both compliance and voluntary REC markets across the country are increasingly requiring independent reporting and verification as a fundamental standard.

For example, the State of Rhode Island recently required independent monitoring to ensure data integrity for customer-sited and off-grid generation facilities. In its "Rules and Regulations Governing the Implementation of a Renewable Energy Standard" the Public Utilities Commission of Rhode Island stated the following:

> 6.8 (ii): NEPOOL GIS Certificates created by an aggregation shall be monitored and verified by a party ("Verifier") <u>independent</u> of the Generation Unit in the aggregation, the owner of the aggregation, the operator of the aggregation, and any other party that might create a conflict of interest in assuring accurate NEPOOL GIS Certificate creation…[3]

The importance of independence was clearly stated in the press announcement by APX, North America's leading infrastructure provider for environmental markets in renewable energy, including the WREGIS, PJM GATS, NEPOOL GIS, and ERCOT market systems:

> Noteworthy in Rhode Island's approach is the requirement that all behind-the-meter generation be recorded by an <u>independent third party</u> -- an important precedent <u>to help maintain the data integrity of the market system</u>.[4] (Emphasis added)

Rhode Island's perspective on independence is echoed in other REC markets as well as within the international carbon trading markets developed under the Kyoto Protocol.

Within Connecticut, the Connecticut Department of Public Utility Control (DPUC) certified a subsidiary of Fat Spaniel as the first independent verifier of generation data for the Connecticut Renewable Energy Credit market[5]. In its decision, the DPUC emphasized the fact that Fat Spaniel's subsidiary's independence from all market participants who may have an economic interest in the energy production of a distributed generation system such as a solar PV system was important to the DPUC's favorable ruling.

Likewise, independence plays a critical role within the framework of the Kyoto Protocol with an "Accredited Independent Entity" a required participant for the trusted monetization of any emission reductions.

---

[3] State of Rhode island and Providence Plantations, Public Utilities Commission, Rules and Regulations Governing the Implementation of a Renewable Energy Standard (emphasis added), http://www.ripuc.org/utilityinfo/RESRules(12-7-05).pdf.
[4] The email announcing the press release is attached as Exhibit B.
[5] DPUC Docket No. 04-05-13RE01

Finally, the Interim WREGIS[6] Operating Rules also recognize the importance of independent reporting. These rules state that, at a minimum, kWh data from distributed generation systems such as solar over 360 kW in capacity must be reported by a Qualified Independent Party and that self-reporting for units below that threshold and above 30kW will require annual verification. As is the case in Rhode Island, Connecticut, and the Kyoto Protocol it is expected that over time, as the value of REC markets grow, these kW thresholds will disappear and independent reporting will become the norm on all systems regardless of size.

Accordingly, the requiring of all SREC data to be handled at all times by an independent third-party with no financial stake in the reported data is in keeping with global trends in data handling practices for RECs and promotes an SREC market where only transparent, trusted, and verifiable SREC generation is rewarded.

[6] The Western Region Electricity Generation Information System (WREGIS) is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC). WREGIS tracks renewable energy generation from units that register in the system using verifiable data and creates renewable energy certificates (RECs) for this generation.

WREGIS was developed through a collaborative process between the Western Governors' Association, the Western Regional Air Partnership, and the California Energy Commission. The development was further guided by means of stakeholder input gathered over a period of more than 3 years from more than 400 participants from across the western region.

WREGIS is governed by a 7 member committee consisting of representatives from various stakeholder groups. Interested parties can participate going forward by joining the Stakeholders Advisory Committee (SAC). From: http://www.wregis.org

EXHIBIT B

APX EMAIL RELEASE:
(Emphasis Added)

-------- Original Message --------
Subject:REC Market News: State of Rhode Island's New Program, supported by APX Inc.
Date: Mon, 29 Jan 2007 12:38:00 -0800
From: Reiner Musier <RMusier@apx.com>
To:info@apx.com <'info@apx.com'>

The State of Rhode Island is applying a market based approach to manage its state renewable energy portfolio standard, using the market infrastructure supported by APX technology and services.

Noteworthy in Rhode Island's approach is the requirement that all behind-the-meter generation be recorded by an independent third party -- an important precedent to help maintain the data integrity of the market system.

To see the full press release, please use the following link:
http://www.apx.com/news/pr_APX_RI_RPS.asp

For an overview of solutions supporting the marketplace in environmental commodities for renewable energy certificates, energy efficiency, and carbon credits, visit:
http://www.apx.com/environmental/environmental-registries.asp

Please don't hesitate to call if you wish to chat about any of these exciting developments. Thank you.
Best Regards,
Reiner

Reiner Musier
Chief Marketing Officer

APX Inc.
5201 Great America Parkway, Suite 522
Santa Clara, CA 95054
Office (408) 517-2177
Cell (617) 699-0929
Fax (408) 517-2985

www.apx.com

APX PRESS RELEASE:

(On Following Page)

Rhode Island Public Utilities Commission selects APXInfrastructure to Manage its Renewable Energy Standard

State of Rhode Island manages Renewable Energy Certificates in the NEPOOL GIS, administered by APX

Santa Clara, CA - January 25, 2007 - APX, Inc., a leading provider of technology, operations, and professional services for the energy industry and environmental markets, is pleased to announce today that the State of Rhode Island has selected the APX environmental market infrastructure to manage Renewable Energy Certificates (RECs) and compliance with the state's Renewable Energy Standard (RES). As of January 1, Rhode Island commenced RES operations within the New England Power Pool Generation Information System (NEPOOL GIS).

Starting in Compliance Year 2007, Rhode Island load serving entities must obtain from Eligible Renewable Energy Resources, a target percentage of at least three percent (3%) of electricity sold by an Obligated Entity at retail to Rhode Island End-use Customers. In each subsequent Compliance Year through Compliance Year 2019, the target percentage increases to a maximum of 16% in 2019.

APX operates and administers the NEPOOL GIS. The GIS verifies and manages the Renewable Energy Certificates that are the basis for environmental trading and investment incentives in the New England states, and monitors emissions of all generators producing and/or selling power in the ISO-NE Control Area. Rhode Island Certificates adhere to the same principles as all other Certificates issued in the NEPOOL GIS, particularly that a single Certificate will be created for each 1 MWhr of generation.

"We were quite pleased with how easy it was for APX to integrate our new RES program into the GIS. Our State's requirements were met with a minimum of development, and in a remarkably short time," said Elia Germani, Chairman of the Rhode Island Public Utilities Commission. "Best of all, our requirements were met as a 'non-cardinal change,' meaning that APX implemented our additional requirements at no cost to the NEPOOL GIS participants."

A novel aspect of the Rhode Island RES relates to customer-sited and off-grid generation facilities (often called "behind-the-meter" generation) which may be certified as an eligible resource. This is generation that is not monitored by the ISO New England settlement system, displaces all or part of the metered consumption of the end use customer, and is not connected to a utility transmission or distribution system. The RES requires that such generation be monitored and verified by a party independent of the generation unit and any other party that might create a conflict of interest. This requirement sets an important precedent for third party verification to ensure data integrity in such circumstances. APX has implemented this capability in a way that can be used throughout the GIS program, if other states choose to adopt a similar approach.

"The NEPOOL GIS continues to be the platform of choice for compliance with the various RPS programs in New England," said Dennis Duffy, chairman of NEPOOL's Generation Information System Operating Rules Working Group. "We continue to be pleased with APX and the GIS's flexibility in integrating new state programs. Although the various state programs are similar, they are not identical. We appreciate APX's high level of service and their ability to handle each state's differences – in support of the region's REC markets."

Under the Rhode Island RES, eligible renewable energy resources include direct solar radiation, wind, movement of or the latent heat of the ocean, the heat of the earth, small hydro facilities, biomass facilities using eligible biomass fuels and maintaining compliance with current air permits (eligible biomass fuels may be co-fired with fossil fuels, provided that only the renewable energy fraction of production from multi-fuel facilities is considered eligible), or fuel cells using the renewable resources referenced in this section.

Developed, administered and hosted by APX, the NEPOOL GIS began operation July 1, 2002 to help verify retail electric supplier compliance with various green power and environmental regulations. A web-based system, the NEPOOL GIS records the fuel sources and other attributes associated with generation and creates a unique, traceable digital certificate for every MWh generated within or imported into the ISO New England Control Area. The system also tracks greenhouse gas (GHG) emissions for all generation, including CO, CO2, SO2, NOx, particulates, VOCs and mercury. Retail electric suppliers use the system's Certificates to report compliance with requirements set by New England states, including Renewable Portfolio Standards (RPS) and disclosure of fuel sources.

To date, the NEPOOL GIS has created and managed about 700 million Certificates. Over 290 market participants in Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont, Maine, and New York are currently using the GIS. Other implementations of the APX Environmental Market Solutions serve market participants in PJM (PJM GATS), ERCOT (Texas REC) and as of 2007, WECC (WREGIS).

About the Rhode Island Public Utilities Commission
The Public Utilities Commission serves as a quasi-judicial tribunal with jurisdiction, powers, and duties to implement and enforce the standards of conduct under §39-1 et seq. and to hold investigations and hearings involving the rates, tariffs, tolls, and charges, and the sufficiency and reasonableness of facilities and accommodations of railroad, ferry boats, gas, electric distribution, water, telephone, telegraph, and pipeline public utilities, the location of railroad depots and stations, and the control of grade crossings, the revocation, suspension or alteration of certificates issued pursuant to §39-19-4, appeals under §39-1-30, petitions under §39-1-31, and proceedings under §39-1-32. Through participation in the Energy Facility Siting Board, the Commission's Chairman also exercises jurisdiction over the siting of major energy facilities, pursuant to Chapter 42-98. More information is available at http://www.ripuc.state.ri.us/index.html.

About APX, Inc.
APX is North America's leading infrastructure provider for environmental markets in renewable energy and greenhouse gases, as well as corporate environmental management. APX technology is now the system of choice for every major renewable energy market in North America, including the PJM (GATS), ISO New England (NEPOOL GIS), WECC (WREGIS) and ERCOT (Texas REC) markets. Users of these systems include more than 400 of the nation's largest environmental commodity brokers, marketers, generators, and load serving entities. APX also provides technology, strategic consulting, and expert operational services to assist wholesale

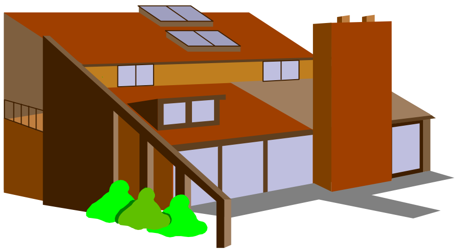
power market participants reduce costs and improve performance in power scheduling, settlement, market operations, and demand response programs. Clients include utilities, merchant companies, wind & renewable generators, financial institutions, retail service providers, ISOs/RTOs, and other electricity market participants. A privately held company, APX is headquartered in Santa Clara, CA.

About NEPOOL
NEPOOL is a voluntary association of more than 300 participants in the New England bulk power system. NEPOOL advises ISO New England Inc. on the operation and administration of the New England transmission system and wholesale power markets in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. More information is available at www.iso-ne.com.

Contact:
Reiner Musier
Chief Marketing Officer
617-699.0929
rmusier@apx.com

Jersey Solar, LLC.

408 Lambertville Hopewell Road
Lambertville, N. J. 08530
V: (609)466-8040, Fax: (609)466-8362
E mail: RickBrooke@JerseySolar.com
Website: JerseySolar.com



May 11, 2007

NJBPU-Office of Clean Energy
POB 414
Trenton, NJ 08625-0414
Attn: Michael Winka-Director

Re: Straw Proposal for SREC cap and additional CORE budget-market segment allocation

Jersey Solar, LLC makes the following comments on the Straw Proposal referenced above, and does so as a Vendor in the NJCEP, and not asa part of any other stakeholder organization:

(1) a   I support the OCE's proposed residential cap of 10 kW with the current CORE exemptions for bonafide farms, houses of workship, and multi-family buildings.
(1) b   I support the OCE's proposed cap of 2 MW per site pursuant to NJ net metering regulations, and the 4 MW cap per entity. I think 4 MW is enough capacity for any one entity to enjoy at the ratepayers' expense. I am certain this capacity will eventually be filled elsewhere with more equitable distribution.
(2)   Regarding carryover funds, I support the OCE's proposed segment allocation of 50%<10k, 25%>10k, and 25% for publics, but after the R&D/Manufacturing allocations are distributed through the planned RFP per same. R&D/Manufacturing is an important component of the CORE program. In addition, the publics are as well, because they contribute to the SBC, are highly visible, set good examples within local communities, and are facing a budget shortfall of their own shortly.

Thank you for giving Jersey Solar the opportunity to comment on this straw proposal.

Sincerely,
RB

Jersey Solar, LLC
Rick Brooke, Pres.

From: Steven Gabel [Steven.Gabel@gabelassociates.com]
Sent: Thursday, May 10, 2007 7:37 PM
To: OCE
Subject: Comments/questions on Summit Blue Report

Lance, Mike, Scott and the Summit Blue Team,

I'm sorry I was unable to attend the meeting on the Summit Blue report yesterday afternoon. I do have two comments/questions:

1) Can you provide the spreadsheets supporting the summary analysis presented in the report? It would be very helpful to be able to review the moving parts of the analysis, understand the relative impact of different variables, and review the assumptions. More detailed ratepayer impacts can also be assessed.

2) Early in the process I requested that the Summit Blue analysis consider the impact of transitioning the program to a "California style" performance based rebate program, whereby OCE would give performance based rather than up-front rebates.

Under the tariff model the payments would be from the utilities, thereby raising a host of regulatory/legal issues. Under a performance based rebate program the payments per mwh would be via contract over the course of years from the Office of Clean Energy. This would provide financial certainty, reduce upfront rate impacts and allow for cost control to the ratepayers' benefit.

Is it Summit Blue's view that the economic impact of a performance based rebate approach is embedded in the tariff model analysis? If not can you outline what the impact might be?

Thanks,
Steven Gabel

From: Potterrex@cs.com
Sent: Tuesday, May 08, 2007 12:53 PM
To: OCE
Cc: bhoey@njsolarpower.com
Subject: re: Straw proposal for $18.7 million reallocation
RE: Reallocation of $18.7 million in potential rebate funds:

To whom it may concern:

This law firm, Potter & Dickson, represents numerous solar installers and developers who filed an appeal in Superior Court (Appellate Division) last year to contest the retroactive application of newly imposed limitations on CORE rebates to the first 10 kW in the residential customer class. Please accept this initial and summary email memorandum on the above captioned topic, to be followed by a hard copy comment with greater detail in due course.

To recap briefly: The judicial appeal was transferred to Judge Landau, as a court appointed mediator, and resulted in a "Stipulation of Settlement," dismissing the litigation on condition that, among other requirements, <u>all</u> of the affected solar PV projects -- estimated to include 108 rebate-eligible projects -- would be returned to the appropriate queue in their "status quo ante" positions (i.e., where they would have been <u>but for</u> the retroactive rebate changes).

Since then, there have been continuing discussions regarding the implementation of that Stipulation. For example, it appears that the final number of affected projects is fewer than 108 since many project customers agreed to opt for the less than 10 kW queue in hopes of receiving rebates sooner. More importantly, for those that remained in the greater than 10 kW queue, it appears that they are <u>not</u> being treated as intended by the Stipulation in that they were placed in a separate greater than 10 kW queue <u>but without rebate funds allocated to that queue</u>.

Thus, in light of the OCE's recent "discovery" of an additional $18.7 million available for rebates, it is respectfully submitted that the Board should first dedicate the use of these funds -- or a substantial portion of them -- as rebates to these greater than 10 kW residential projects which were the subject of litigation and a settlement. They -- the project installers and their patient customers -- have been in a kind of "limbo" for far too many months. They deserve first priority on these newly discovered funds. The resolution we propose will finally serve to effectuate the terms and intentions of the Stipulation of Settlement, avoid further judicial proceedings, and generally produce an equitable result.

Thank you for your consideration of this important matter and for seeking public comment on the allocation of these funds. If you have any questions, please do not hesitate to contact this office at any time. As noted above, we will provide the OCE and the Board's secretary, Ms. Izzo, with "hard copy" versions of this memorandum in which we will provide additional detail in support of this proposed allocation.

Respectfully submitted,

R. William Potter
Potter & Dickson
194 Nassau Street
Princeton NJ 08542
609 921 9555
609 921 2181 (fax)

From: tleyden@powerlight.com
Sent: Thursday, May 10, 2007 6:30 PM
To: OCE
Subject: Straw Proposal for SREC Cap and Additional CORE Budget

Dear OCE,

CAPS

PowerLight supports the 10 kW residential cap and 2MWac per site and per entity cap as proposed by the OCE ONLY for this pilot since it is limited. In the future, restrictions should be lifted for larger projects and larger entity investments.

CARRYOVER ALLOCATION

PowerLight supports 70% to the <10kW queue and 30% to the >10 kW.

Respectfully submitted,

Thomas Leyden
Managing Director
PowerLight Corporation
A subsidiary of SunPower
700 South Clinton Avenue
Trenton, NJ 08611
tleyden@powerlight.com
www.powerlight.com

609-964-8900 off.
609-964-8924 fax.

State of New Jersey
DEPARTMENT OF THE PUBLIC ADVOCATE
DIVISION OF RATE COUNSEL
31 CLINTON STREET, 11TH FL
P. O. BOX 46005
NEWARK, NEW JERSEY 07101

JON S. CORZINE
Governor

RONALD K. CHEN
Public Advocate

May 11, 2007

VIA HAND DELIVERY
Honorable Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

RE: Straw Proposal for SREC Cap and Additional CORE Budget BPU Docket No.: EO06100744

Dear Secretary Izzo:

Please accept for filing an original and ten copies of the New Jersey Department of the Public Advocate, Division of Rate Counsel ("Rate Counsel") comments regarding the above referenced matter. Enclosed is one additional copy, please date stamp the copy as "filed" and return it to the courier. Thank you for your consideration and attention in this matter.

Introduction

Rate Counsel appreciates the opportunity to comments upon the Office of Clean Energy's ("OCE") SREC-Only Pilot and Additional CORE Budget Allocation Proposal as requested by public notice dated May 4, 2007.

Throughout the later part of 2007, the OCE held a number of discussions associated with establishing alternative compliance payments ("ACPs") and solar energy alternative compliance payments ("SACPs") for several of the upcoming energy years ("EYs"). The Board of Public Utilities ("BPU" or "the Board"), at its November 9, 2006 agenda meeting, directed the OCE to solicit comments on a proposed schedule and Strawman proposal for the ACP and SACP levels for EY 2008, 2009, and 2010.

The OCE-proposed ACP/SACP levels were submitted to the parties for comment on November 9, 2006. On December 6, 2006, the OCE submitted the SREC-Only Strawman proposal for comment. OCE solicited specific comments on a 14 point list of questions related to its SREC-Only Strawman. Rate Counsel submitted reply comments in response to both OCE requests.

At the December 21, 2006 agenda meeting, the Board considered two recommendations offered by the OCE. The first was to continue ACP and SACP levels at their current levels for EY 2008, which set the ACP at $50 per megawatt hour ("MWh") and the SACP at $300 per MWh. OCE also recommended that a stakeholder process be established to determine the appropriate ACP and SACP levels for EY 2009 and EY 2010. Both of the OCE's recommendations were consistent with the comments filed by Rate Counsel.

OCE also offered a second recommendation which defined an "SREC-Only Pilot Program." The goals of the program were twofold. The first goal was to develop and utilize a plan that would minimize the anticipated shortfalls for solar energy development in EY2008. The second goal was to develop a program that would provide the Board, OCE, and other stakeholders with more data about how a pure SREC-only market would work.

An important component of the SREC-Only Pilot was to establish an allocation of different types of solar energy applications during the pilot period. Allocations originally proposed by the OCE and approved by the Board include:

a. Private Less Than or Equal to 10 kW (residential) – 10%
b. Private Greater Than 10 kW (C&I) – 50 %
c. Public - 40%
    i. Local Governments - 40%
    ii. Public Schools – 40%
    iii. State Facilities – 20%

<u>OCE SREC Only Pilot Strawman Proposals</u>

The OCE is currently seeking comment on (1) its existing SREC-Only Pilot Program that was approved by the Board at its December 21, 2006 agenda meeting and (2) its proposals on how to allocate some $18.7 million in additional clean energy funds. OCE has offered two general proposals for comments which includes:

(1) Capping existing residential applications at 10 kW or the CORE-allowed net metering requirements whichever is less, and increasing the cap to larger commercial and industrial ("C&I") applications to 2 MW or the CORE-allowed net metering requirements, whichever is less. If the EY2008 shortfall is still apparent by July 2008, the OCE proposal would increase the C&I cap to 4 MW.

Tel: (973) 648-2690 • Fax: (973) 624-1047 • Fax: (973) 648-2193
http://www.rpa.state.nj.us E-Mail: njratepayer@rpa.state.nj.us

(2) Allocating an extra $18.7 million in unused clean energy funds to the following types of applications, in the following allocation:

a. Residential (less than or equal to 10 kW) – 50 percent;
b. C&I (greater than or equal to 10 kW) – 25 percent; and
c. Public entities – 25 percent.

It appears to Rate Counsel that the underlying rationale for the two proposals is based upon the desire by the OCE to continue a diversity in the types of programs supported in both the SREC-Only Pilot and the funding that has recently become available. Further, it appears that the OCE is attempting to maintain some type of consistency with prior CORE funding goals, particularly in the limitations that would restrict site-specific installations to levels which are equal to or less than on-site load requirements.

Proposed Application Caps and Limitations

Both of the proposals offered by the OCE are related since they attempt to define the composition of the SREC-Only Pilot program as well as how additional program dollars will be spent. While OCE's goals are laudable, they seem to be contrary to (1) what the developers are offering given the large scale projects that have currently applied for the program and (2) the Board-approved goals of the program which were to provide stakeholders with data regarding the potential for self-financing of solar generation projects.

It is Rate Counsel's understanding that currently, there are at least five different projects, proposing five MWs, which have applied under the SREC-Only Pilot. All of these proposals exceed the current CORE-equivalent limitations. The fact that the market is offering larger-scale projects that are not consistent with the current CORE program restriction is not entirely unexpected. In fact, in responding to OCE's original proposal to the original SREC-Only Pilot allocation, Rate Counsel noted:

> …that the BPU not define such a detailed market segmentation as offered in the [SREC-Only Pilot]. If the goal of the pilot is to see what the market will offer in terms of solar energy development on a stand alone basis (i.e., without a rebate program), then the market should be allowed to determine the appropriate configuration of the types of developments, particularly in this initial pilot process. [Comments of the Division of Rate Counsel, BPU Docket No. EO06100744, December 11, 2007.]

Tel: (973) 648-2690 • Fax: (973) 624-1047 • Fax: (973) 648-2193
http://www.rpa.state.nj.us E-Mail: njratepayer@rpa.state.nj.us

It would appear that the market values, and is offering, a different set of solar projects (to date), than those anticipated in the original goals of the SREC-Pilot. Rate Counsel does not object with the goals of seeking diversity from solar projects serving the SREC-only pilot, or ultimately, the final solar energy market model decided by the Board in future proceedings.

Rate Counsel is concerned, however, that insisting upon certain types of market configurations and net metering requirements at this stage of the process will result in larger and larger future solar energy shortfalls relative to the Board's RPS goals. Ultimately this will lead to greater levels of future solar energy implementation, which in turn could lead to an unnecessary rate shock if shortfalls are accelerated over an annual or otherwise short period of time.

For this reason, Rate Counsel would recommend that CORE limitations on all types of applications be relaxed for the SREC-Only Pilot. Goals associated with allocations of different types of solar installations should be further explored, and clarified, in the ongoing process examining a more permanent solar market model. The experiences from the SREC-Pilot Program, and reasons for non-CORE conforming offers, should be explored and condition these future market model recommendations.

Proposed Additional Core Budget Market Allocation

Further, as noted earlier, OCE is recommending that some $18.7 million in funding not spent from the 2006 renewable energy budget be used to fund new solar energy projects. OCE's May 2, 2007 analysis accompanying its Strawman Proposal noted that the Clean Energy Committee ("CEC") discussed four different funding options including:

(1) Residential = 50 percent, C&I = 50 percent;
(2) Residential = 40 percent, C&I = 30 percent, and Public = 30 percent;
(3) Residential = 70 percent, C&I = 30 percent.
(4) Existing 2007 Market Segmentation allocation.

OCE's Strawman proposal, however, recommends an allocation comprised of: residential = 50 percent; private = 20 percent; and public = 25 percent.

Rate Counsel would recommend that the Board consider Option "2" listed above that was discussed by the CEC. As seen from Table 1 below, Option 2 would be consistent with OCE's goals of providing diversity in the types of solar

Honorable Kristi Izzo, Secretary
May 11, 2007
Page 5

installations while at the same time resulting in a greater potential level of installed solar kWs for the same $18.7 million level of funding.[1]

Table 1: Proposed Budget Allocations and Estimated Solar Installation Potentials

Proposal	Residential ≤ 10 kW	Private > 10 kW	Public	Total
Percent of Budget (%)				
Allocation A	50%	50%	0%	100%
Allocation B	40%	30%	30%	100%
Allocation C	70%	30%	0%	100%
OCE Strawman	50%	25%	25%	100%
Allocation of Budget (million $)				
Allocation A	$ 9.38	$ 9.38	$ -	$ 18.75
Allocation B	$ 7.50	$ 5.63	$ 5.63	$ 18.75
Allocation C	$ 13.13	$ 5.63	$ -	$ 18.75
OCE Strawman	$ 9.38	$ 4.69	$ 4.69	$ 18.75
kW Installed				
Allocation A	1,157	1,227	-	2,385
Allocation B	926	736	761	2,423
Allocation C	1,620	736	-	2,357
OCE Strawman	1,157	614	634	2,405

Conclusions and Recommendations

To summarize, Rate Counsel makes the following recommendations relative to OCE's proposals:

(1) The Board should waive the maximum size limitations for all types of solar installations (residential, C&I and public) for SREC-Only Pilot purposes. Size waivers should be limited to the pilot only.

(2) The Board should allocate the additional $18.7 million funding amounts in the following fashion:

a. Residential applications (10 kW and less) = 40 percent;

[1] Potential solar installation estimates have been estimated using the most recent CORE installation costs and average project sizes.

Tel: (973) 648-2690 • Fax: (973) 624-1047 • Fax: (973) 648-2193
http://www.rpa.state.nj.us E-Mail: njratepayer@rpa.state.nj.us

Honorable Kristi Izzo, Secretary
May 11, 2007
Page 6

b. C&I applications (greater than or equal to 10 kW) = 30 percent; and
c. Public applications = 30 percent.

Respectfully Submitted,

RONALD K. CHEN, ESQ.
PUBLIC ADVOCATE OF NEW JERSEY

By: *Susan E. McClure, Esq.*
Susan E. McClure, Esq.
Asst. Deputy Public Advocate
Division of Rate Counsel

c: President Jeanne M. Fox (*via hand delivery*)
Commissioner Frederick F. Butler (*via hand delivery*)
Commissioner Connie O. Hughes (*via hand delivery*)
Commissioner Joseph L. Fiordaliso (*via hand delivery*)
Commissioner Christine V. Bator (*via hand delivery*)
Service List *(via list server)*

Tel: (973) 648-2690 • Fax: (973) 624-1047 • Fax: (973) 648-2193
http://www.rpa.state.nj.us E-Mail: njratepayer@rpa.state.nj.us