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Comments on the Accelerated Development Renewable Energy Draft White Paper, 8-27-04 Workshop, Distributed PV.

Submitted by
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by

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Questions on Chapter 5: Key Policy Issues for Distributed Generation Photovoltaic Energy Systems

5. Performance-based Incentives
a. What are the advantages of a performance-based incentive relative to a capacity-based incentive? What are the disadvantages?

Several advantages for a PBI.

- Focus on kWh production vs. the rated size of the system. Only pay if the system performs, over time. The current capacity-based incentive pays the same to any system, regardless of performance. Does that seem right?
- Monitored performance will provide positive proof that PV does work, creating greater support in the public policy arena for expansion, if warranted.
- Potential simplification to the application process –eg. Customer contacts utility for an interconnection agreement, and at the same time signs up for the PBI tariff.
- Greater assurance that ratepayer investment is providing greatest collective good – ie. Pay only if the system continues to produce kWh.
- Eliminates concerns about retiring PV systems early and selling components elsewhere, thereby stripping ratepayers of the benefits. Once the system is dismantled and stops producing, it no longer receives a PBI payment.
- Potential to provide greater incentives to systems that provide greater utility peak value eg. West facing systems.
- Potential to provide greater incentives to systems in capacity constrained areas, which provide greater utility Transmission & Distribution (T&D) benefit eg. Dougherty Valley.
- Potential for aggregating the kWh produced for RPS compliance purposes. We strongly recommend that utilities provide some $/kWh compensation to the system owner for the Renewable Energy Credits. Currently, the City of Palo Alto Utilities pays up to 5 cents/kWh for solar RECS, as part of their green power program. The REC element would be bundled with the total $/kWh incentive. In this manner, the meter used for PBI can also be used for REC/RPS accounting, without additional meter reading cost.
- Potential for utilities to allocate more **non-Public Benefit Charge** funds toward PV systems that provide extra value to the grid and thus the whole ratepayer base.
- Greater potential for shaping installations that help reduce utility peak demand, thereby extracting greater value.

Disadvantages –

- Long term commitment by utility or CEC to administrate incentive program. This is not a real issue, as it seems logical that the utilities will continue to be there for many decades forward, and that this is merely an element in the evolving roll of Distributed Generation within the utility framework.
- Greater upfront payment by system owner. With over 75% of residential PV system owners paying CASH for their systems, at sums of $20,000 to $30,000, we suggest that it is not an issue for these buyers. Most commercial systems are

financed, thus not a real issue. One study by Tom Hoff of Clean Power Research, shows that commercial customers gain a greater tax benefit with PBI vs capacity-based incentive.[http://www.clean-power.com/research/customerPV/PBI_Economic_Benefits.pdf]. Greater financing options would actually create a more equitable market for PV, making it accessible to more of the population.

- Fear of change. There is fear of switching to an unfamiliar program. This should not be a deterrent. If the incentives are set right, then the market truly has the potential to greatly exceed current growth patterns.

b. How long should payments last and how much should be paid?

Payment timeline should be **10 years**. This timeframe also matches construction defect warranties for new home construction. The German model is 20 years, while some East Coast programs range from 1-3 years. The real questionable time is from year 5 to 10, when inverter life is unproven. The 10 year incentive time frame will provide motivation to inverter manufacturers to build inverters with longer lives, are easy to repair, or swap out, and be cheaper. The ten year payment period will result in companies providing 10 year service agreements, to insure maximum performance.

How much?
An amount of **$0.25/kWh** should be offered. The chart below shows the various options of payment. A 0.25$/kWh rate + $0.15/kWh (avg. net metering benefit) = total 0.40 $/kWh benefit, results in simple payback ~10 years. Some system owners will earn quicker returns, if they are consuming in the higher tiers (up to $0.26/kWh), or if Time-of-Use Rates work better for them. Net metering remains in place, in contrast to the Germany model which distributes the PV power directly into the grid.

This rate is meant to be the same for all systems. Some system economics will not be as good, while others will be better. It is up to the market to develop the best situations. Utilities will have the option of increasing the rate (using non-Public Benefit Funds) to reward systems that provide greater utility value (eg. West facing).

System Size [kW]	kWh/kW-yr*	kWh/yr	rate** $/kWh	Production revenue $/yr	System Cost [$/watt]	net system cost	Simple payback [yrs]
2	1900	3800	0.35	1330	10	20000	15.0
2	1900	3800	0.35	1330	9	18000	13.5
2	1900	3800	0.35	1330	8	16000	12.0
2	1900	3800	0.35	1330	7	14000	10.5
2	1900	3800	0.35	1330	6	12000	9.0
2	1900	3800	0.4	1520	10	20000	13.2
2	1900	3800	0.4	1520	9	18000	11.8
2	**1900**	**3800**	**0.4**	**1520**	**8**	**16000**	**10.5**
2	1900	3800	0.4	1520	7	14000	9.2
2	1900	3800	0.4	1520	6	12000	7.9
2	1900	3800	0.45	1710	10	20000	11.7
2	1900	3800	0.45	1710	9	18000	10.5
2	1900	3800	0.45	1710	8	16000	9.4
2	1900	3800	0.45	1710	7	14000	8.2
2	1900	3800	0.45	1710	6	12000	7.0
2	1900	3800	0.5	1900	10	20000	10.5
2	1900	3800	0.5	1900	9	18000	9.5
2	1900	3800	0.5	1900	8	16000	8.4
2	1900	3800	0.5	1900	7	14000	7.4
2	1900	3800	0.5	1900	6	12000	6.3
2	1900	3800	0.5	1900	5	10000	5.3
* estimated performance based on Clean Power Estimator. Southfacing, 30 degree tilt, san francisco weather file.							
Note: all kW and watt references are AC ptc with inverter included (ref. CEC definition)							
**kWh rate: assumes a combination of net metering and Production credit to receive current retail rate.							
0.40 $/kWh = $0.15/kWh (net metering average) + $0.25/kWh (PBI component).							

c. Who should be eligible for incentives: purchasers? Retailers?

The simplest is to have only system owners be eligible for the incentives. Credits, or payments, would most logically be integrated into the customer's utility bill. These payments would stay with the meter, such that if the home is sold, the PBI would be transferred to the new home (and system) owner.

While there are more systems being installed that are owned by a 3rd party, the net metering benefits still go directly to the system host, ie. The one paying the utility bill. Any payment arrangement between system installer(owner in this case) and system host, can be done outside of the PBI tariff agreement with the utility.

Thus, keep it simple, and only allow the system host, the one paying the utility bill, to be eligible for the PBI.

d. Should a competitive bidding process be used? How should it be structured?

It is not clear what benefit a competitive bid would bring. We cannot imagine all potential system owners bidding to receive a PBI. Instead, a thoughtful price ($/kWh) should be established that is available for all customer classes. The utilities will then have the option of **adding** price elements for: a. REC purchase; b. West facing systems; c. capacity constrained areas; d. other utility value addition.

A need for reservation, and thus qualification, for the tariff remains. The reservation is needed for customers to proceed with investment in the PV system, given assurance that the PBI will be available for their system.
A review of the current reservation process is necessary to determine what elements can be transferred to the PBI program, and what elements need improvement. It may be something as simple as having the customer fill a form with signature from certified installer. Interconnection application may also change to include proposed installation specs: size, orientation, tilt. And maybe even a sunpath diagram (as is required in Oregon). An adequate time should be allowed for customer to install the system, before losing the reservation.

e. What program design features should be in place to encourage a decrease in photovoltaic (PV) system costs over time?

A healthy stable performance based incentive will provide motivation to optimize systems, increase reliability, and long life. What is not captured in the current system cost analysis is the life cycle cost. The cost of replacing an inverter is not generally included in the $/watt installed cost analysis. Replacing a $3000 inverter (for a home system) can dramatically change the economics of the system owner. The incentive to reduce installed cost is greater with PBI, since there is no upfront rebate. Manufacturers will need to balance this desire to reduce installed costs with a focus on reliability, durability and high performance.
Note also that the installed costs achieved in Japan and Germany are closer to California costs today, given the differences in watt definition (see last page for details).

Inherent in the PBI design is a motivator for reducing system costs. System buyers will seek out the best price coupled with quality assurances.

We suggest establishing a fixed rate [$/kWh] that would be applicable for the first 3 years, then consider reducing or increasing the amount for new customers.

f. Should the current PV incentives be changed to a performance based incentive program? If so, when should the transition occur?

Yes. Ideally, this would start as soon as possible. January 1, 2005 is a good target date. Resist the temptation of piloting a PBI at the same time as a capacity-based incentive. This will distort the results and stretch limited administrative resources.

Responding to question h. (who should administer the pbi programs), the most logical is the utilities. The utility reads meters now, and administers the self-generation programs now. A PBI program would be simpler than the existing SGIP. PG&E representative at the 8-27-04 workshop in Sacramento was reluctant to take this on, thinking that they would be responsible for warranties etc. Managing warranties is not necessary for the administrator of PBI program. The administrator simply reads the additional meter and provide feedback on the customer's bill regarding the performance of their system and how much they have earned.

System warranties would still be the responsibility of the installer or perhaps via a service agreement with another party. The PBI program could require that only licensed contractors with an additional performance bond can participate. The bond requirement would be documented by the California State Licensing Board. This is not a dramatic additional cost for the contractor, yet would provide protection for customers with future disputes regarding warranty issues and system performance. Should a contractor business cease to exist, the insurance bond would remain to cover any warranty issues.

How to transfer administrative duties to the utilities is not clear. Perhaps a legislative directive is needed?
We would prefer that the CEC retain some program design role, or that a representative working group (similar to the SGIP working group) be formed to oversee the program(s).

We do recognize the slow reaction time by the CPUC may be a detractor to shifting regulatory oversight from CEC to CPUC, but perhaps a well designed program will alleviate this concern. In addition, the SGIP program could be switched to PBI for all the same reasons noted above. Adopting a more efficient, simpler PBI program for all system sizes, would make efficient use of existing administrative resources at the utilities.

g. Should the incentive structure vary by market segment? Some other factor?

NO. The incentive rate should be the same for all customer classes. The utility will direct additional (non-Public Benefit funds) where it will add value to the utility. Otherwise, there is no real good reason to select one market segment as more deserving over another in creating differential incentives.

h. Who should administer performance-based incentive programs?
As noted above, the utilities would be the most efficient and logical administrator of PBI programs, and with the potential to extract maximum value. Second choice is the CEC, though would seriously consider outsourcing this function and adopting a simpler approach that reading the meter in person, every month.

6. PV in new homes
a. Building on the success of existing PV incentive programs, what are the next steps needed to further encourage PV in new homes?

There are several simple steps to take in encouraging PV in new homes.

- Title-24 – in the near-term, allow for homebuilders to use PV system to meet T-24 requirements. With the new Time-dependent variable approach giving greater weight to peak reducing measures, PV can help certain homes with large windows in hot climates meet T-24 requirements.

- Title-24 – study other ways to incorporate PV into T-24 in a logical fashion for 2008. This energy code, and it's infrastructure, has greater potential for incorporating designs that truly can reduce demand and approach net zero energy.
- Work with CBIA to develop a buyers coop for their members. Help develop high quality standards for an RFP that they can solicit vendors for a 3-5 year delivery period.
- Most importantly, develop an incentive program that is stable over many years, such that building community can depend on it when structuring purchasing. OR it becomes a non-issue in the decision to incorporate PV and other low energy features.
- It is thought that the PBI program described above would be available to new home owners, and while this incentive would not go directly to the builders, it would provide a motivator for builders to include the PV feature.
- Consider a consumer marketing campaign. Showcase desirable solar homes. Highlight the features. Builders always say that homebuyers do not want the solar, so let's educate the buying public.
- Survey the 1000+ buyers of new homes with PV in California. Also interview the builders. This is a great pool of knowledge and perception that can be extracted from this base of people.

b. How can efforts to further encourage PV in new homes be better coordinated with developing rules for distributed generation in the RPS?

- The PBI program above will provide the mechanism for measuring kWh production that can potentially be counted, in aggregate, toward utility RPS goals. By allowing utilities to direct additional, non-public benefit funds, toward customer PV systems in return for RPS credits, there is potential for win-win here. This based on the assumption that the system owner retains some portion, if not all, of the Renewable Energy Credits and should be compensated for these. The best way would be to simply bundle the amount in with the PBI.

7. Net metering caps: The current cap of one-half of one percent could prevent achieving substantial penetration of PV in new homes. The cap may need to be increased to further the use of PV in new homes. What factors would encourage utilities to go beyond the current net metering cap?

- Utilities are awaiting the CPUC DG report on the costs/benefits of Solar Distributed Generation. It is not clear though who is drafting this report, and there is not agreement on generally benefit accounting practices with regard to Distributed Generation. Thus, the outcome could go either way.
- If the report shows utility value from Solar DG, then utilities will be the first to propose lifting the net metering caps.
- The other alternative is to raise the caps through legislation.

- One representative from SMUD (at the 8-27-04 workshop) suggested that the Net Metering law be potentially amended to be a % of any given local distribution network, basing the cap on physical restraints of the local wires. This seems logical, though it would need further research on how to document and administrate.

Other Considerations –

What watt? The use of different definitions of 'watts' to describe cost of systems, size of systems, rebate rates, tax credit rates, etc. – has created a mess. There is only one, standards-based, definition of what a 'watt' is, for photovoltaic systems, and that is the DC rated at STC conditions (IEC Standard 61724). This is the one standard that is used around the world, except for the US. All others (there are at least 6) are creations of incentive programs across the US, differing by as much as 25%! The data presented in the CEC Acclerated RE Development report (100-04-003D), that compares prices in Germany and Japan with California, are off by >$1/watt. The conversion between CEC watts and watts dc is : 1 watt ac-cec ~ 0.82 watt dc. So, for example, the Japanese price for a 3 kW system is reported as $5.60/watt (before rebates), it would be the equivalent of $6.83/watt (ac-cec). This difference in definition of watts also shows up in the aggregate totals reported installed per country [in MW]. In this respect, we (in California) are derating our total numbers compared to what is reported by other countries, due to the dc vs. ac-cec watt used.
Switching to a performance based incentive will alleviate some of this confusion. There is only one definition of kWh – that measured by the AC meter. The IEC may also consider defining AC watts, for reporting purposes, but it really isn't necessary. DC watts are fine. There is a standard that is established and by which all module manufacturers recognize and rate their panels.

Convert references to watts to DC stc watts throughout California & North America, so we're all speaking the same language.