Suggested changes to Rule 21 – Renewable Fuels and AB 1969 – Feed-In Tariff
Russ Lester January 23, 2009

DESIRED OUTCOMES

1 Stimulate short and long-term economy and job gains.
2 Move the USA and CA energy sector toward domestic self-sufficiency.
3 Expedite adoption of Renewable Power Generation (RPG).
4 Meet the goals of AB 32, Renewable Portfolio Standards (RPS) and AB 1969.
5 Embrace Distributed Generation (DG) as a highly desirable method of meeting local energy loads without incurring the high environmental and economic costs of high voltage grid transmission and centralized generation.
6 Overshooting the goals of RPS, AB 32 and AB 1969 is better than under achieving them.

SPECIFIC RECOMMENDATIONS

I have read the "California Feed-in Tariff and Policy Options" report prepared November, 2008 for the California Energy Commission by KEMA, Inc. I concur with most of the recommendations and conclusions. I have also reviewed the documents on the Interstate Renewable Energy Council (IREC) website, www.irecusa.org. Some points that I would emphasize, clarify or add to are as follows:

1. All changes should be enacted immediately. This would help meet all outcomes.
2. All renewable fuels should be included.
3. It may be desirable to meld Rule 21 and AB 1969 into one working document.
4. AB 1969 and Rule 21 provisions should have a moving window of application for at least five years. This would automatically extend the program annually, for the following five years, and allow seamless expansion of RPS development. This is necessary for businesses, government, IOU's (Investor Owned Utility) and POU's (Publically Owned Utilities) to do long term planning, expansions, improvements and R&D.
5. Make all target goals of AB 32, RPS and AB 1969 minimums. Consider penalties if they are not met by the IOU's and POU's.
6. Continue target goals of AB 32, RPS and AB 1969 beyond 2020. They need to be more aggressive and definitive, ie. 20% by 2010, 30% by 2015, 40% by 2020, 50% by 2025, 60% by 2030, 70 % by 2035 and 80% by 2040.
7. Move upper energy production limits covered by Rule 21 and AB 1969/Feed-In Tariff (FIT) to 20 MW.
8. Remove the RPS cap for the state, IOU's, POU's and others. If these entities want to or the economy warrants going beyond the cap, they should be able to. Renewable Energy Service Providers (RESP) need to know that they will not be cut-off from interconnection as we approach these caps.
9. Create a separate category for Renewable Energy Service Providers (RESP) as differentiated from other ESP's.
10. "Must Take" provisions should stay in place for RPS and should apply to all IOU's, POU's and others.
11. Provide a clear, simple up-front picture of costs and what needs to be done to complete the application and interconnection. Samples of these are shown on the IREC website. Few businesses, even IOU's, would go into any project without these being determined prior to commencement. Usually, estimates are prepared as part of business and are free. This is not the case in Rule 21 or AB 1969 as currently written.
12. There are no clear cut or consistent requirements of what is required to interconnect. These requirements can be specified by using generation output brackets. These requirements should be the same for all IOU's and POU's, so that RESP have consistent costs and requirements, no matter where they are. The standard could be the Institute of Electric and Electronics Engineers

(IEEE) Standard # 1547, UL 1741 or the IREC (2007) “Interconnection Standards for Distributed Generation Model”.

13. External disconnect switches shall not be required on systems less than 1.5MW.
14. Interconnection requirements should not be unreasonable, difficult or expensive. For example, RESP’s should not be required to feed all generated power back to the main, but should be able to use the same subpanels and wires used for the connected load. This would save rewiring costs, material costs and resources.
15. The rules should be available to all RESP’s so that they would not need to hire electrical engineers or consultants for each small project.
16. There needs to be means by which a RESP can object to excessive requirements. Excessive requirements will inhibit meeting the goals and RPG projects.
17. Establishment of an Information Clearinghouse, RESP Ombudsman and advocacy group is critical. This should cover all aspects of these projects and would include, but not be limited to; soil, water and air emission regulations, land-use regulations, fire and safety regulations, utility interconnections and available support funders.
18. All fees and interconnection costs should be revised. These are way out of line with the scope of small projects. They are truly game stoppers, as no business that is doing this is going to be able to recoup these costs, especially at the current Market Price Referent (MPR). Renewable Rule 21 installations are exempt from these costs on generation facilities up to 1.5 MW. The same should be true for AB 1969. Fees and costs shown in IREC documents seem reasonable.
19. Increasing generation capacities of existing RESP’s should be encouraged. Application and interconnection fees for these expansions should be ½ of the application fees for a new RESP.
20. If the proposed Renewable Distributed Generation (RDG) maximum output capacity from a RESP does not exceed the existing service capacity, then the fees, interconnection and meter costs should be minimal (less than $500) or none.
21. Remove the Federal Energy Regulatory Commission (FERC) fees on smaller DG’s. I understand that SCE does not have this requirement, but PGE does. Why?
22. No departed load or stand-by charges. These are currently not charged for solar. Since most other renewable generators are actually generating for a greater percentage of the time than solar, why should these charges be placed on them? Additionally, customers who use less electricity due to efficiency improvements, some of which are paid for by the IOU’s, do not pay these charges.
23. Establish a Renewable MPR (RMPR) schedule. RMPR rates should be at least TOU retail rates x 90%. RMPR should have different payments for different renewable technologies. Encouraging diverse sources of energy is good and necessary to meet the Renewable Portfolio Standard (RPS). However, some of these require higher levels of support. These RMPR’s can be adjusted, from time to time, to encourage development of emergent technologies. For example, if there is a major breakthrough in PV solar efficiencies, then continue with the current RMPR–PV solar for a while to encourage development, conversion and usage of the new panels. Then at some time, when the adoption is “mature”, this rate could be reduced without affecting other RMPR schedules.
24. Different RMPR’s should reflect environmental impacts such as Fuel Life Cycle, Green House Gas (GHG) reductions and Sustainable Fuels.
25. Create a Tier Schedule for RMPR. This would include the values above. The following is a possible format;
    1. Tier 1- composed of renewable generation fueled by renewable, sustainably produced by-products of existing industries and low GHG emissions, such as;
        1. Non-edible, food by-products such as shell, hulls, pits, chaff, plant & animal waste bio-gas, waste animal and vegetable by-products, fish by-products and waste, waste organic material, etc.
        2. Manufacturing by-products and waste such as heat, paper, wood chips, scraps and sawdust, fabric scraps, etc.
        3. Sewage and waste disposal site bio-gas
        4. Solar and wind produced by DG’s on roofs, parking covers, shade structures, walkways, etc. within load centers

        5. Energy can be produced by anaerobic or aerobic digestion; pyrolysis, plasma, thermo combustion, bio-diesel, oil combustion, etc.
        6. Electricity can be produced by fuel cell, ICE, turbine, etc.
    2. Tier 2 - composed of renewable generation fueled by renewable, non-food products, such as;
        1. Using resources not suitable for food or fiber production such as toxic land mitigation, marginal land (ie. Westlands tree project), algae production tanks with recycled resources, etc.
        2. Fuel produced without the use of irrigation, fertilizers, etc.
        3. by-products of food production that need to be gathered from field to use, such as corn stover, straw, hay, pruning products, forestry slash, etc.
        4. Solar and wind produced on “farms” that are near load centers
    3. Tier 3 – fuel produced from resources that can be used for food, fiber, environment or building materials
        1. Grain ethanol, methanol
        2. Soy or palm oil based bio-diesel
        3. Solar and wind produced on “farms” that are far from load centers
        4. Algae farms that use resources without recycling
26. Tiered RMPR rates would be higher for those that provide the highest environmental and energy benefit.
27. The RMPR should be substantially increased if the IOU’s and POU’s do not meet RPS, AB 32 and AB 1969 goals.
28. RMPR for emergent technologies should be set and kept reasonably high to reward innovators, first and early adopters.
29. IOU’s can only count inter-connected and operating RESP’s toward meeting the goals of RPS, AB 32 and AB 1969. No credit should be given for those RESP’s that are not producing.
30. Remove the current restriction of Solar Initiative funded arrays and SGIF from participating in the FIT program.
31. Clarify that RESP’s that have received grants, funds or other incentives from various government and non-government programs are eligible to participate in the AB 1969/FIT program. The idea is that those programs would only incentivize emergent, speculative or R&D technologies or other needs such as GHG, energy and emissions reduction.
32. Accommodate the usage of different types of renewable generation on the same electrical service. Would possibly need to pro-rate RMPR based on the annual output of each type of renewable.
33. Federal tax credits (currently $.01/kWh Federal, only on power sold to a qualified IOU) (State too?) should be based on all renewable generation, even that which is not interconnected and/or used on site of RESP.
34. Additional credit should be given for on-site use at a greater level than RMPR as it lessens impacts and costs to the grid and other customers. It makes more electricity available without building more generators just as energy conservation does.
35. Tax credits for renewable energy generation should stay with the RESP.
36. Carbon and GHG credits or expenses should stay with the RESP.
37. Renewable Energy Credits (REC) belong to the RESP.
38. IOU’s can count energy produced by RESP’s, including electricity used on-site, towards meeting RPS, AB 32 and AB 1969 minimum goals.
39. All meters should be TOU. This would encourage generators to maximize production and minimize use during TOU Peak Rates (times when CA needs power). This would reduce the need for peaker-plants and the high costs and emissions associated with them. The ability of RESP’s to produce power during these times is a benefit to all rate payers. The IOU’s and POU’s charge more for electricity used during these periods. RESP’s should be rewarded for this.
40. TOU Net-Metering should be used on all renewable generation, at least up to 2MW systems. It is currently not clear as to how the metering and billing is handled under AB 1969 with bi-directional meters. Again, this is potentially a game stopper. If we are selling all the power generated at MPR, buying all the power used at retail, RESP’s would be losing lots of money. The best method

would be a net meter arrangement, paying retail for net purchases or getting paid RMPR for net exports. All non-electric costs should be paid only on the purchased power.

41. TOU Net-metering should be available to all classes of RESP.
42. If TOU bi-directional meters are required, then the RESP should only be billed or paid for the net power used or produced. It should not be “dual metering” or “net billing”. All non-electric costs should be paid only on the net purchased power.
43. All RESP meters should be able to be remotely monitored and read.
44. True-Up Periods need to be tailored to the type of renewable generation and service. I would suggest some sort of compromise “true-up period” if different renewable technologies are on the same meter. For example, we need an annual true-up. Our solar output varies over the course of the year. Our biomass gas is used to off-set propane use during harvest (October) and it is not available to produce electricity during this month. This is also our month of highest electrical usage. It would be best for us to be able to amass electrical credits to use during this time. Thus, we would be encouraged to produce excess electricity during the summer months when CA needs it the most and use it during harvest when we need it the most and CA does not. This would also simplify and reduce billing and payments for the IOU’s, POU’s and the RESP’s. There are annual pay-out programs that allow an RESP to use net-metering over the course of the year and then to be paid for the excess power produced.
45. RMPR TOU production rates should be higher than normal RMPR TOU purchase rates. This would be similar to Peaker Plant Rates and would encourage those RESP’s that can produce exportable power during these peak periods to do so.
46. “Wheeling” of excess electricity production between service accounts on a consolidated bill should be allowed. This allows RESP’s to efficiently produce power where the fuel is and use electricity where the load is, usually within a short distance. This is allowed with dairy bio-gas. Reasonable transmission costs, but not other non-electrical costs, could be paid by the RESP’s. These should be prorated depending on distance from the production service to the load service.
47. RMPR rates should not be based on natural gas MPR rates. Natural gas rates are subsidized and so therefore are artificially low. They are also unstable. The reason why RPS has not been met in the past is because natural gas prices fell, driving down the MPR rates. This made RPG uneconomical. Increasing RPS and the number and types of RESP’s will add stability to energy costs, actually benefitting rate-payers.
48. RMPR rates need to be set high at this point to encourage rapid RPG development in order to meet the AB 32 goals of 2010. This deadline is less than 2 years away.
49. IOU’s and POU’s must enter into Rule 21 or AB 1969 contracts with RESP within reasonable time. Timelines shown in IREC documents seem reasonable.
50. RESP’s must come on-line with-in 3 years of AB 1969 contract with an IOU or POU. If there is not a reasonable extension, then the RESP is responsible for all costs incurred and will forfeit their contract.
51. RESP needs to have fixed 7 year RMPR rates from time of Rule 21 or AB 1969 contract with IOU or POU to guarantee income to RESP’s. This is necessary to insure stable investment interest in RPG.
52. Term of Contract. Terms should allow changes to reflect the current requirements to meet AB 32. In other words, if 20% RPS is not meet by 2010, then RMPR and other incentives should be increased and all existing contracts changed to reflect these new RMPR’s and incentives.
53. IOU’s need to fully embrace the value of Distributed Generation (DG). For example, all rate payers are proposed to pay for the cost of the large, high voltage power lines required to transport the solar power from Imperial to San Diego. The large solar power projects would also get the benefits of all the solar programs. So therefore the true cost of the power is not being assessed to the solar power project. Yet DG is not given credit for using the existing local power grid. DG is actually helping mitigate the increase in local power use and demand. The IOU’s and POU’s are not incurring the costs to improve the local grid. This means that DG should be looked at like peaker power plant power, get paid higher amounts and receive expedited permitting and lower fees.
54. RESPs should locate as close to or within the areas of load. In 53 above, the solar can be located in San Diego (on roof tops, garages, parking lots, walkways, etc.). Only where the specific

renewable energy source is located a great distance from the load should transmission lines be built. The cost of this interconnection should be paid for by the RESP, not the rate-payers.

55. Customers who are increasing their service requirements, but are meeting or exceeding this increase by using on-site renewable energy (becoming or expanding a RESP) should not be charged for those service improvements. This would encourage existing customers to consider mitigating their new electrical load with renewable energy and becoming a RESP.
56. Competitive Renewable Energy Zones (CREZ) should be eliminated. Instead a policy whereby a balanced (equal) development of renewable energy with-in all load areas is superior. The generation needs to be close to the load, preferably on the same site. This reduces the need for added infrastructure and the costs, delay and impacts it causes.
57. Many of these suggestions have been practiced since 2004 in New Jersey's and Colorado's award winning statewide utility net-metering and RPS legislation. I would suggest that it might be simple to look at and adopt them as a unit; that we not reinvent the system.

Specific needs for Dixon Ridge Farms

1. We have had an 18kW solar array interconnected through a net-meter since Dec. 2004. We added a 50kW generator fueled by gasified walnut shells (a by-product of our walnut processing) in Nov. 2007. We assumed that since we were already a RSP and had interconnection, it would be very easy to add this. I couldn't have been further wrong.
2. We have been trying to get this done since Nov. 2007. We have tried to get straight answers from PGE and are still getting different ones with every meeting. With the help of Senator Wolk's staff, we have explained our problem to various well connected individuals, including Chairwoman Mary Nichols, Secretary AG Kawamura, Secretary Chrisman, various people in the CEC, CARB CDFA, CPUC, etc.
3. We have submitted a Rule 21 Multi-tariff application, due to the mix of solar and biomass. This was the suggested route by PGE in May. We have "played the game". We paid PGE for the analysis, hired an engineer and have had more and more requirements placed on this application. The most onerous of these requirements is to not export power and to pay for all the equipment that would need to be purchased and installed to meet this requirement. This equipment would cost at least $50,000. It would require the generator to throttle back, reducing power output and efficiency.

   We asked PGE about AB 1969, but were told it was not applicable for our project. The stated reason was because the solar was installed with Solar Initiative tax credits and The BioMax was funded by a CEC grant. AB 1969/FIT states that we cannot benefit by "double dipping". We recently found out (from PGE) that it may now be OK to apply under AB 1969.

   Some aspects (such as allowing exportation of excess power and being paid for this power) are better under AB 1969. Some aspects, such as not being allowed to use a net-meter with an annual true-up are not. The biggest issues with AB 1969 are the various fees that PGE requires to be paid. They amount to about $50,000. They also will not reimburse or reapply the Rule 21 payments we have already paid.

   Speaking for myself (but I think CPC would echo this) I don't want to pay again. We were following their lead. We should get some sort of "credit" for what has already been done. Additionally, the AB 1969 fees are outrageous in light of the fact that we will only produce about $40,000 worth of electricity per year, none of which will be exported on an annual basis. There has been no real means for negotiation.

4. The term of contract is not clear. PGE stated that we could alter and/or terminate the contract in the future when changes and/or adjustments in the AB 1969, RPS and MPR happen. AB 1969 seems to state the opposite.

5. We have suggested making our interconnection a “pilot project”. This can happen by using some of the improvements to Rule 21 or AB 1969 listed above. One option would be to finish our application under Rule 21, use the existing annual true-up period, allow the possibility to export power for either a credit or payment and to wheel excess power to another account (as the dairy bio-gas customers do) on our consolidated bill. PGE has not responded to this suggestion.

6. We have a CEC grant requirement to be interconnected. We cannot be interconnected under the existing rules. We need to get this resolved so that we can move on.

7. It appears that AB 1969 prohibits us from participating in the AB1969/FIT because of the solar initiative credits and the CEC grant for the BioMax unit. This needs to be addressed.

8. We need to be able to maximize our BioMax electrical output so that our GHG emission per kW is the least possible. We cannot do so until we get interconnection.

9. We want to continue on our path towards greater renewable generation and for on-site improvements. We cannot do so until we get interconnection.

10. We want to reorganize our on-site power distribution, to better serve the renewable generation and increase our processing plant loads. We cannot do so until we get a better picture of what we need to do to interconnect and under what conditions.

11. We have been attempting to get interconnection with PGE since November 2007. We have all the safety protocols in place. We have a net-meter already in place. We can be safely interconnected with PGE with no additional cost to PGE or to us. We can be interconnected in a matter of hours. There is absolutely no (reasonable) reason why this should not happen.

PGE has a poor reputation in this area. The more we have worked in this field the greater number of horror stories we hear. Much time and many resources have been used to inhibit DG, RDG and small RESP’s. Much time and many resources have been used to promote PGE’s “green business practices”. There is a big disconnect between the two. This is why I have proposed this be termed a “pilot project” to allow a new model to be promoted. I think it would be much more productive to spend our time working on what can be, instead of the problems of what we have. There clearly are many problems with the rules as they now exist. We will be happy to work on these changes.

Secretary Kawamura, Secretary Chrisman, Senator Wolk, Susan Brown with CEC and others have asked how things are going. I have had to honestly say that they have not progressed. They have asked what they can do to help move it forward. If PGE cannot move beyond what we have due to their rules and regulations, then we have to move to the next step of involving them to change the rules and regulations. This kind of project is what the Governor, the Legislature, President Obama and the nation wants. It will happen. It merely is a question of how, when and at what cost.

I appreciate your help in trying to move this forward. We have been working with PGE on this issue for over a year. We need to get beyond understanding what we have that doesn’t work, to what we need to do to make it work. Hopefully this is what we can talk about and get implemented.