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BY ELECTRONIC DELIVERY
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Re: BPU Net Metering and Interconnection Rules Stakeholder Process
EDCs' Comments on Solar Alliance and IREC Submissions

Dear Mr. Teague:

This letter is submitted to the Board of Public Utilities ("Board") on behalf of Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G") and Rockland Electric Company ("RECO") (collectively, the "EDCs") in response to Board Staff's July 22, 2011 and August 5, 2011 informal request for comments concerning the positions expressed by the Solar Alliance and the Interstate Renewable Energy Council ("IREC") during ongoing stakeholder discussions regarding the future of the Board's net metering and interconnection rules, set forth at N.J.A.C. 14:8-4 and 8-5. It presents the high level views of the EDCs concerning the general topic of aggregated net metering, as discussed in the IREC comments circulated on August 5, 2011, as well as more specific comments concerning the Solar Alliance position paper circulated on July 22, 2011.[1] At this stage of the Board's consideration of these issues, the EDCs have determined that it would be most productive to address only general policy considerations, without delving into specific legal arguments. The EDCs, however, reserve their right to make legal arguments in the future if deemed necessary or appropriate.

By way of background, consistent with the stated goals of the draft New Jersey Energy Master Plan ("Draft EMP") and its focus on cost-effectiveness, the EDCs continue to support the development of solar and other renewable generating resources and the expansion of opportunities for smaller customers to invest in and benefit from solar and other renewable projects. The EDCs believe that a properly structured solar aggregation program may well advance the development of these resources in a manner that supports achievement of the Draft EMP goals; provided, however, that any such program does not violate fundamental principles of fairness and transparency.

As the Board has properly recognized in several different contexts, at present, net metering customers' bills include EDC transmission and distribution charges for every hour of the day, while the customer is permitted to offset those charges with renewable generation that is produced for only a portion of a given day. Specifically, for example, a solar installation produces electricity only during daytime hours. Yet, the Board's rules

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[1] IREC also addressed certain matters other than aggregated net metering, some of which overlap with aspects of the Solar Alliance position paper. Certain of those other IREC matters are addressed at the end of the "EDC Response to IREC Comments" section, with more detail on the overlapping issues contained under "EDC Comments on Solar Alliance Position Paper."

and EDC net metering tariffs in most instances do not differentiate between daytime and nighttime hours or provide any distinction between whether solar generation is provided during peak hours (i.e. for residential, nighttime) or off-peak hours. Thus, with respect to solar aggregation under the existing net metering paradigm "either [the EDC] or its non-net metering customers are in effect paying for the portion of the transmission and distribution charges incurred during the hours when no [solar] generation is occurring." See *I/M/O William C. Skye d/b/a Redskye Farms Net Metering Determination for Solar System by August 31, 2008*, BPU Docket No. EOO8060410 (Order dated February 3, 2009) at 4-5.

EDC Response to IREC Comments

1. **The EDCs believe that aspects of IREC's (and similar) aggregated net metering proposals violate fundamental principles of fairness and transparency.**

The community renewables proposals present yet another means of subsidizing customers who invest in solar or other renewable technology. Specifically, these proposals provide a subsidy in the form of an avoided or discounted charge for transmission, distribution and other services. It must be emphasized that the increase in renewable generation that can reasonably be expected in the foreseeable future due to this additional subsidy will not materially reduce EDC infrastructure costs and could actually increase costs due to a potential need for system enhancements and reinforcements.[2] In fact, increased renewables may not even serve to reduce system peak loads, which may occur, for example, on cold winter evenings, nor will maximum solar generation necessarily occur at times of system peak loads or PJM peak loads.

Aggregated net metering generally envisions a fictional arrangement under which the output of a single renewable generating facility would be shared by a virtual "community" of customers, all of whom would be entitled to receive the output of the facility as if some portion of the facility were behind each customer's meter, and all of whom would realize the benefit of aggregated net metering encompassing all of the individual customer accounts.[3] As a result, participating customers would not be required to pay the local EDC for the use of its infrastructure inherent in the delivery of the power from the facility to the participating customer, nor would the local EDC be compensated for the metering and other products and services it provides and which stand ready to serve this virtual community.

As a result, the energy-only solar or other renewable generation product that is generated and exported by the renewable generation system -- either a system that is behind-the-meter of a particular customer but far in excess of the customer's on-site

2 Aggregated net metering, in particular, could add significant information technology and billing enhancement costs.

3 IREC's July 8 comments, in particular, apparently contemplate (at 9) an arrangement by which "excess customer-generator generation [would be credited] to multiple accounts or meters attributed to a single customer-generator," apparently without the customer-generator or the multiple accounts or meters compensating the EDCs for the use of their electric systems. It is not clear how widely-disbursed these participating accounts might be.

energy requirements or a "free standing" system -- would be wheeled, at no cost, over the EDC's delivery system, somehow be magically transformed into full-requirements electric service (i.e., including capacity, ancillary services, transmission, distribution, electric losses, the Societal Benefits Charge ("SBC") and other clauses and state taxes), and then exit as a tax-free product at the meters of the virtual community of dispersed customers.

However, the free wheeling and enhanced energy product would benefit only the renewable generator and the virtual "community" sharing its output. Stated another way, such an arrangement would constitute a veiled subsidy to the participants in the virtual community by all of the other non-participating customers of the EDC. More important, this arrangement quite possibly could result in unfair and artificially inflated rates for remaining customers. Allowing such customers to bypass the full delivery charges would, as noted, impact not only the EDC's rates, but the Societal Benefits Charge and other clauses, as well as state sales tax collections. This potential impact on clause collections (which fund the Board's own energy efficiency, renewable energy and Universal Service Fund programs, among others) could be significant, and would impose an inequitable burden on other non-participating customers (and/or an erosion of these programs), if large-scale virtual community systems develop. In addition, because these generation facilities will produce an energy-only product, all other customers will be responsible for providing the enhanced attributes discussed above that are required to transform the energy-only product into the full-service product supplied to all electric customers (both Basic Generation Service ("BGS") and Third Party Supplier ("TPS") service).

In considering the use of aggregated net metering as an additional subsidy -- indeed a particularly opaque form of subsidy that will not be generally understood and appreciated for what it is -- it is important to acknowledge that an array of relatively transparent sources of subsidization for solar (and, in some cases, other renewables) already exists or is in development. Among the other forms of subsidization currently in place are the reliance on a Solar Renewable Energy Certificate ("SREC") market and the published schedule of Solar Alternative Compliance Payments, the year-to-year increase in renewable portfolio standards requirements for solar and other class I renewables that will increase demand for them, the limited qualifying life of SRECs, the PSE&G solar loan program and the Solar 4 All Program, the SREC-based financing programs provided by JCP&L, ACE and RECO, the existing favorable net metering policies, federal investment tax credits and accelerated depreciation schedules.

Even if it is deemed an appropriate use of societal resources to further subsidize the development of solar and other renewables in the face of these existing subsidies, that subsidy should be transparent and easy for the public to quantify and understand and should not unfairly burden non-participating customers.[4]

Even if the virtual community were somewhat contained geographically, the concept would nonetheless entail the same subsidized use of the local EDC's delivery system that any other or more expansive form of aggregated net metering would entail. Indeed, it is important to recognize that aggregated net metering is not really "net metering" at all. Rather, it involves the free movement of electricity from one or more generation sources over regulated utility assets for consumption at other locations.

Moreover, such an arrangement would constitute a fundamental re-engineering of the existing net metering rules, rather than a modest expansion of those rules. Plainly, the existing net metering rules themselves entail a subsidization component, in that kWh delivered by the EDC to the net-metered customer are offset by solar generated kWh at the full retail price, including the delivery charges. These rules tightly circumscribe the scope of the subsidization imposed on the EDCs. Specifically, the existing rules also recognize that the annual true-up for solar net output should be made at the average wholesale *energy* price only, thus limiting the subsidy for renewable generation in excess of the customer's load (i.e., the subsidy does not include capacity, ancillary services, transmission, distribution, electric losses, the SBC and state taxes). The existing rules,

[4] The Draft EMP recognizes that "cost-effectiveness must be calculated from both the perspective of program participants and non-participants," noting that it is "not clear . . . if non-participants reap sufficient benefits [from renewable energy] to offset additional costs that then become enshrined in the retail electric bill." Draft EMP at 73.

consistent with statutory authorizations, also contain provisions designed to limit the financial impact on EDC revenues and therefore the level of the subsidy, including, for example, the requirement that the output of the renewable facility not exceed the customer's annual electricity usage. By contrast, the broader aggregated net metering models would expand materially the potential subsidy by allowing open-ended aggregated net metering and, as a consequence, open-ended subsidized use of the EDC delivery system.

2. **The existing paradigm for generation supply can be leveraged in ways that will support the advancement of solar generation without inequitably burdening non-participants.**

Available models of community renewables exist that the EDCs believe would avoid imposing the burden of subsidization on non-participating customers. For example, the TPS model already exists and is functioning effectively. Under this model, the renewable generator would act as a TPS or "electric power supplier" providing retail electric service to the "community" members, with the EDC being fully and fairly compensated for the use of its delivery system. The Board's existing regulations governing the licensing of TPSs would continue to apply. Alternatively, the virtual community could act as a wholesale generator selling directly into PJM or to a TPS. In any alternative model, virtual community participants would benefit from sharing the SREC values and any savings on the generation/commodity cost, while at the same time fixing their cost for a significant portion of their energy bill and would have the satisfaction of contributing to an important civic good.

In sum, while the EDCs support the stated goals of the Draft EMP concerning the development of cost-effective renewable generation, they believe that if the societal judgment is that the development of renewables should be further subsidized, those subsidies should be transparent and easy to quantify and understand. It would be unjust, unreasonable and bad public policy to disguise additional subsidies as net metering in a manner that inequitably burdens non-participating customers who would be left to pay for the transmission and distribution infrastructure.

3. Certain of IREC's more technical comments also raise concerns.

The EDCs also wish to address two of IREC's other comments:[5]

For Levels 1 and 2, Require that the Aggregate Generation Capacity Connected to a Radial Line Section Not Exceed at Least 50 Percent of Minimum Load between 10 a.m. and 3 p.m. on Circuits Where Real-Time Data Is Available and Develop Additional Criteria for Other Times of Day, as Appropriate

The suggested revision to the screening criteria for solar projects on distribution circuits to allow solar generation up to "at least 50% of the minimum load between 10 am and 3 pm" does not consider the impacts of dynamic, bi-directional flow on circuit protection schemes. The fundamental design assumption for circuit protection schemes is that power-flow will be in one direction. Such rules-of-thumb as the above-noted criteria suggested by IREC address only one of many factors that must be analyzed in our efforts to provide safe and reliable operation of the distribution system. The proper design of a protection and sectionalizing scheme for a distribution circuit with multiple power sources requires an engineering study, which likely will require changes to relaying equipment and sectionalizing devices. Costs for any modifications or additions for circuit protection resulting from the need to accept power produced by a renewable generator should be borne by the renewable generator, not all other customers.

Require New Jersey Utilities to Begin Installing Real-Time Monitoring Equipment on All Circuits Where Aggregate Generation Plus Planned Additions Represent 10 Percent of the Peak Load

The installation of real-time metering or monitoring for distribution circuits would represent a significant investment and on-going maintenance cost for the EDCs and their customers. Therefore, should these measurements be required, the renewable generator should be responsible for all meter/circuit upgrade costs and on-going maintenance costs.

EDC Comments on Solar Alliance Position Paper

For ease of reference, the following are bulleted comments responding to the specific sections set forth in the Solar Alliance Position Paper:

[5] These issues overlap with some Solar Alliance recommendations which are addressed further under the next section.

A. The “15% Rule" is overly Restrictive for Peak-Oriented Resources Such as Solar

1.1. Increase the current 15% of peak load rule for Level 2 interconnection by clarifying and codifying the Additional Review process, specifically allowing for approval up to 23% (with the differential representing only solar facilities with no storage).

EDC Response:

- The 15% Rule is a guideline under which threshold the proposed DG system likely will not adversely affect reliability and power quality on the electrical distribution system and above which threshold further engineering analysis is necessary to determine if, and to what extent, the system or circuit is adversely affected. Minimum load measurement is not performed on most of the distribution circuits and minimum load does not always occur at night. To increase the limit from 15% to 23% without additional study risks increases in islanding and flickering, as well as a decline in circuit performance and power quality.

- Peak solar power production does not necessarily coincide with system peak load or circuit peak load. The worse case circuit design with respect to solar power generation is a day of high solar insolation and low load (i.e. sunny spring or fall days with a moderate ambient temperature, resulting in little to no air conditioning load). Total system load data indicates that the minimum load during the 10am-3pm timeframe, as a percentage of peak load, approximates 25%, not the 50% suggested. Variation at the circuit-level can be greater, especially under a scenario where there is a high penetration of solar generation, where multiple solar generators peak simultaneously, under a low-load condition, therefore, the EDCs maintain that 15% loading remains a valid threshold for the screen.

- The Solar Alliance comments indicate that it is very unlikely that all generators will be producing maximum power simultaneously with minimum load. However, data available from the ACE territory demonstrates the contrary, as ACE's historical data shows that solar power output can be at maximum (i.e., 10am-2pm) during minimum load periods – i.e. a period at 35% of peak. This situation has been seen to occur on a number of days in the year, more typically on a weekend day during spring or fall when many utilities experience minimum load periods.

- Changing the 15% peak load rule to another value ultimately does not change the amount of solar generation that may be accommodated on a circuit. The limit for the amount of solar generation on a circuit is strictly based on the impact that the single and aggregate systems have on the electrical grid. Voltage fluctuation, for which the EDCs' must operate within tariff limits, is a consideration when determining size limits for solar generation, as well to avoid premature failure of automatic line equipment due to excessive cycling.

- JCP&L operates distribution circuits where the minimum daytime load is equal to the minimum nighttime load- typically circuits that are largely commercial- where the larger PV net meter systems are targeted.

- Minimum daytime load on a JCP&L distribution circuit can be as low as 15% of the summer peak load.

- The 15% threshold is only a screen, not a hard limit, and it is the EDCs practice to perform additional engineering review to determine what would be required to connect a generator operating at a higher than 15% loading level, if possible.

1.2. Allow solar to meet up to 75% of minimum load during the hours of 10am to 3pm (daylight peak hours) on radial circuits where real time data is available via the Additional Review process described above.

EDC Response:

- Modifying the current threshold to allow PV to meet up to 75% of minimum load without additional engineering study is a concern for reliability and power quality.

- The issue is not that solar generation would be meeting 75% of the circuit's minimum load, but rather is the location of the solar generation on the circuit. The greater the distance between the source and sink, the greater the potential impact on circuit voltage.

- Reverse power flow is not the only design issue; voltage is also an issue. The EDCs must maintain voltage within tariff requirements. Accommodating the variability of solar output requires further engineering study to maintain circuit performance and service quality for all customers on the circuit.

- While there may be instances where PV can be operated up to 75% (or higher) of minimum load between 10 am and 3 pm, more rigorous analysis is necessary for satisfactory operation, including circuit modeling to predict voltage fluctuations, equipment operation frequencies, and fuse/conductor loading. Otherwise, the risk is degradation of service levels for existing customers, and possible premature failure of equipment.

1.3. Require utilities to add real time minimum load monitoring on radial circuits where proposed solar (or other distributed generation) installations would represent [15%] of the circuit peak load and real time monitoring does not currently exist. Utilities may impose a charge of $15,000 per MW on all applicants for interconnection on circuits where the aggregated capacity of installed solar and other distributed generation capacity has reached [15%] of peak load to offset the costs of adding real time monitoring to the circuit.

- The cost of installing real time monitoring is very expensive and the proposed $15,000 per MW to be paid by applicants only covers a small portion of the cost. The Solar Alliance provides no compelling justification why customers (as opposed to applicants) should be ultimately responsible for these costs.

- Although, as noted above, the EDCs would require solar generators to pay the full cost of installing real-time monitoring, the EDCs should be allowed to collect from solar generators the full cost of installing such real-time monitoring prior to installation. The costs of installing real-time monitoring can vary significantly, depending on the metering point and the design of the existing infrastructure. (e.g. $75,000-$200,000 per feeder).

- Real-time monitoring, when available, provides data that may be used to better model the impacts of solar generation on a specific circuit and system operations generally; however, real-time monitoring will not avert the possible negative effects of solar generation on the system.

B. Differential Treatment for Non-Exporting Generators

2.1. Allow penetration up to 50% of peak load for solar generators that do not export to the grid (all power used on-site).

- Solar generators that do not export to the grid can potentially cause voltage flicker and other operational issues. Reverse power-flow is not the only issue and, therefore, more detailed engineering analysis is required.

- The premise of this proposal incorrectly implies that solar generators that do not inject power into the circuit do not have the potential to adversely impact service levels. This is clearly not the case. For example, to the extent that the variability of the solar generation produces a highly variable load on a circuit, there may be adverse consequences to voltage and power quality. These consequences may be no less severe than if the solar generator exported power to the grid. Nonetheless, service requirements for non-exporting solar generators can require engineering analysis not unlike that which is required for exporting solar generators.

- Whether or not power is exported, there will still be variability in power flow provided from the circuit. Such variability potentially results in flicker/voltage issues for existing customers.

C. Process Changes to Incorporate Minimum Load and Non-Export Standards within Level 2 Review

- Because the percentage of generation on a circuit in relation to the peak load of the circuit is only one component of the generation's impact on the circuit, it cannot serve as the sole criteria for determining when more detailed study is required. Since the size and location of the project also are major drivers, a rule-of-thumb percentage of peak is not a good threshold for further screening.

- The proposal to approve a solar project under level 2 when the aggregate generation connected to the circuit does not exceed 23% of the annual peak is not acceptable. For example, if one project that is 23% of the peak is to be connected near the end of a radial circuit, it could cause significant voltage fluctuation and steady state voltage rise. In contrast, if the same project were connected near the substation, it may have minimal impact on voltage.

- At the Net Meter level 2 and above, it is critical to perform a detailed engineering review of all applications to maintain service levels for existing customers.

D. Interconnection Levels and Timelines

3.1. Raise Level 1 limit to 25kW.

- Although 25kW is the typical size of distribution transformer for residential customers, there are a considerable number of 10 kW and 15kW distribution transformers on the system.

- Should the Level 1 limit be raised, other customers must absorb the application fees for 10-25kW systems.

- Based on the current distribution transformer deployment, 10kW is the most appropriate size for level 1.

- JCP&L does not support an increase to the level 1 threshold to 25 KW since it has many 10 and 15 KW transformers in service typically in rural areas, where solar generation is more prevalent. A more detailed engineering review is appropriate for any application over 10 kW.

3.2. Remove the 2 MW limit on level 2 and level 3 interconnections.

- Most of the RECO 13.2kV distribution lines are designed for 600A, and 2MW represents ~15% of the design limit. Any DG that is over 2MW should have a detailed review and study performed, in order to safely interconnect and avoid any adverse impacts on the system.

- Typical for JCP&L as well, which also has many 4.16 kV and 4.8 kV circuits where 2 MW represents 50% of the total capacity of the entire circuit. Need detailed study for these as well.

3.3. Update the area and spot network interconnection requirements to follow the proposed modifications being discussed in the IEEE 1547 working group.

- This can only be done only after the 1547 changes are made and each utility has determined that those standards will work for their unique conditions. ACE has one small secondary network.
- RECO has no networks.

- JCP&L has limited networks in the Morristown area.

- PSE&G has many networks in the large cities it serves.

3.4. Require utilities to confirm receipt of Interconnection Applications (indicating whether complete or not) within 5 business days.

- This is addressed in the proposed N.J.A.C. 14:8.

3.5. Require utilities to schedule and conduct a witness test for the final approval of a Level 2 generator within 10 days of the time a solar installer notifies the utility that it is ready to operate.

- RECO recommends to notify the applicant on scheduling the witness test within five business days and to schedule the test within ten business days. It will give more time to arrange resources for the inspection prior to informing the applicant on the available appointment timeframe.

- Depending on how a utility performs meter change out and inspection/testing, ten days is too short. This should remain 20 days, but utilities should work to make processes as streamlined as possible to allow the customer to turn on their system as soon as possible

- Scheduling a witness test usually is not an issue, but the EDCs try to be accommodating to the customer and the installer and work with their schedules- depending on when they are available, this may extend past ten days.

3.6. For projects where the witness test has been waived, utilities shall issue notice of permission to operate within 10 business days of customer notification that inspections are complete.

- This is addressed in the proposed N.J.A.C. 14:8.

3.7. Notifications generally required under the NJ IC rules should be encouraged to take place by email to reduce notification time. Solar installers should be copied on email notifications to customers.

- RECO sends most of the DG notifications through e-mail if it is available and the e-mail address is provided on the application.

- JCP&L prefers e-mail notification, and has not received any complaints in this regard. Requiring e-mail and regular mail notification will add nothing to streamline the process, and creates unnecessary work.
- JCP&L regularly only receives one e-mail address, which is usually for the installer. A designated contact e-mail address should be required, and that contact should be responsible for distributing notifications.
- ACE supports the use of e-mail but would like one official e-mail contact, not multiple. We have experienced problems with multiple parties calling for information, some of which do not have the authority to receive the information.

Thank you for this opportunity to comment on these important matters.

Respectfully submitted,

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