BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Proposed Rulemaking	)	
Regarding Electric Utility Renewable	)	Case No. EX-2010-0169
Energy Standard Requirements	)	

COMMENTS OF THE UNION OF CONCERNED SCIENTISTS

The Union of Concerned Scientists (UCS) is an independent nonprofit alliance of more than 80,000 concerned citizens and scientists working for a healthy environment and a safer world. For more than three decades, UCS has combined rigorous analysis with committed advocacy to reduce the environmental impacts and risks of energy. UCS's Climate and Energy program focuses on encouraging the development of clean and renewable energy resources, such as solar, wind, geothermal and biomass energy, and on improving energy efficiency. Participating in the design and implementation of state renewable policies is one way UCS actively works toward these ends. UCS is interested in promoting the public interest, which is served by a reliable and efficient regional electricity market broadly defined.

UCS commends and supports the efforts of the Missouri Public Service Commission (Commission) in drafting regulatory language that will implement the state's renewable energy standard (RES). In particular, we would like to express our support for the required use of renewable energy certificates (RECs) and a REC tracking system as the only means to demonstrate and verify compliance, the prohibition of double counting of RECs used for the Missouri RES with other state RESs, and with the sale and purchase of RECs to meet voluntary green power and environmental goals. We also applaud the support provided to solar energy through the provision of a solar rebate and a payment for S-RECs.

There are, however, several areas where the proposed rules should be clarified and strengthened. Our specific comments below address these issues.

The definition of a REC should be expanded and clarified.
The proposed rule defines a REC as a tradable certificate that "represents that one (1) megawatt-hour of electricity has been generated from renewable energy resources." This definition is common to most other states in denominating RECs in megawatt-hours, but it speaks only minimally to the attributes of a REC: "Such attestation shall contain the name and address of the generator, the type of renewable energy resource technology, and the time and date of the generation." Because Missouri requires that eligible generators be located in-state, or their energy be delivered to Missouri consumers, we recommend that the Commission require the location of the generator as a necessary attribute or part of the REC. We also recommend that a generator vintage attribute be defined based on the date the generator first commenced operation. Although Missouri does not have such a requirement for resource eligibility (except for "other sources of energy…that become available after November 4, 2008, and are certified by rule by the department"), many other states do, and if a Missouri generator wished to sell its RECs out of state, this information should be a part of every REC.

Emissions from the eligible generator are also often attributes of interest. Renewable energy sources have either zero or much lower emissions than fossil fuels, and could be reported as such.

Many states simply define RECs as including "all renewable and environmental attributes," or "all generation attributes," but fail to spell out what this means. In addition, the REC definition does not specify whether avoided emissions or emission reduction benefits, credits or allowances (if available to the renewable generator), must be part of the REC for RES compliance. Clarity on this question is important because emission reductions will be in demand if a cap-and-trade program is adopted, and even in the absence of cap-and-trade, there is already a voluntary market for emission reductions that could result in double claims on the same environmental benefits if both the purchaser of the REC, and the fossil generator whose output was displaced, expect to claim emission reductions. Leaving RECs undefined as to their attributes may result in unnecessary confusion in the marketplace and the potential for double claims. Finally, the answer to the question of whether RECs include such indirect emission reductions will determine whether Missouri's RES reduces emissions, or whether the RES simply makes it easier and less expensive for capped generators to comply with any emissions regulations.

The REC tracking system should be specified and substitute for other REC requirements.

Section (3)(G) states, "All electric utilities shall use a commission designated common central third-party registry or other equivalent electronic tracking mechanism for REC accounting for RES requirements." It is our understanding that the Commission has designated the APX North American Renewable s Registry (NAR) for this purpose. If correct, then we suggest that the wording be changed to specify NAR and to eliminate the option for other equivalent mechanisms—unless you intend to accept RECs created and retired in MISO's Midwest Renewable Energy Tracking System (M-RETS). It would be simpler if all participants use the same tracking system. If some eligible energy originates in another tracking system, for example, the RECs created in those other regions could be exported to NAR and retired there.

Also on this subject, the definition of a REC in paragraph (1)(J) states that a REC must be "either certified by an entity approved as an acceptable authority by the commission or as validated through a generator's attestation. Regardless of whether RECs have been certified, RECs must be validated through an attestation signed by an authorized individual of the company owning the renewable energy resource." First, the "either…or" language of paragraph (1)(J) seems to undermine the requirement for the use of a common tracking system as required in paragraph (3)(G), because it allows for the alternative of a generator's attestation. Second, if NAR is operated anything like the other APX tracking systems with which we are more familiar, these requirements seem duplicative. The owner of a generating unit would have to register with the tracking system before it can be issued certificates, and that registration will entail the name and address of the generator and the type of renewable energy resource technology, at a minimum. The issuance of certificates by the tracking system is in effect a certification that the generation was measured and meets the verification standards of the tracking system. It appears that the requirements in paragraph (1)(J) are met

by use of the tracking system required in paragraph (3)(G), and that the requirement for generating company attestations for all RECs is an unnecessary and potentially burdensome administrative step.

The separation of the solar rebate from the S-REC payment should be emphasized.
It is not clear if the rebate payment entitles the utility to ownership of the S-RECs, or if the purchase of S-RECs is separate from the rebate. Paragraph (4)(H) states, "At the time of the rebate payment or anytime thereafter, the electric utility shall offer a one (1)-time lump-sum payment, called a Standard Offer Contract, for the current ten (10)-year fixed price for associated S-RECs. The sale of any S-RECs created by the installed solar electric system shall not be included as a requirement of the utility's interconnection agreement." The two payments seem to be separate, but it is not clear to someone who has not participated directly in these discussions, probably because both payments are paid in a lump-sum up front. Inserting the phrase, "but separate from the rebate payment," immediately after "At the time of the rebate payment or anytime thereafter," would clarify the distinction.

The S-REC benchmark price should be explained in more detail.
Paragraph (4)(H) also states, "the electric utility shall offer a one-(1)-time lump sum payment…for the current ten (10)-year fixed price for associated S-RECs." It is unclear how the ten-year fixed price for S-RECs will be determined, and how frequently it might change. Since this is the benchmark for the standard offer contract, it would seem to require a public process and price transparency. One way to do this would be for the utilities to solicit bids, at least once per year and maybe twice per year, as a way to establish the price.

An example is provided by several New Jersey utilities that are required as part of that state's RES to offer 10 to 15 year contracts for S-RECs. The energy from the projects is not covered by the contracts but must be net-metered. At least twice a year, Jersey Central Power & Light, Atlantic City Electric and Rockland Electric Company jointly solicit proposals for S-RECs based on price and contract duration. The solicitations are for an amount of capacity needed to satisfy the RES requirement. Bids may be made by customers or by developers/installers. In each solicitation, the most competitive proposals are selected, and the amounts are posted. The average price in early 2010 was about $405 per S-REC. For more information, see http://www.njedcsolar.com.

Continuing the New Jersey example, it might also make sense for Missouri utilities to issue joint solicitations for S-RECs. By doing the solicitation jointly, developers that work across the state would always be responding to a single set of requirements, which would reduce their cost burden. All they would have to do is note, for each project bid, in which utility service territory the project is located. Similarly, commission review of the process and submittals or recommended contracts would be limited to the administrative costs of one proceeding.

Another important factor to take into account is that smaller systems are typically more expensive that larger installations, so it might be desirable to differentiate between small and larger systems. For example, if solar systems up to 100 kW will be considered for the

standard offer contract, there might be one benchmark for installations of 0.5 kW to 10 kW, and a different one for installations of 10 kW to 100 kW. Without this differentiation, the larger systems would generally be cheaper and therefore more competitive than the small systems, with the result that smaller, residential systems might not be supported.

As an alternative to the competitive bid approach, the commission would provide significantly greater price certainty if it were to establish a fixed price for these standard offer contracts—a price that is known in advance and that declines, according to a predetermined schedule, when certain installation thresholds are met. Although it may be harder to set the payment levels in advance, this approach has the advantage of sending a clear price signal that developers and customers can count on in making investment decisions—something that the bid approach lacks—and it would remove the uncertainty about whether a particular project will be successful in winning a bid. This approach is self-limiting in that as the capacity thresholds are met, the standard offer price would be reduced. It could also take into account the different costs facing small projects versus larger projects, and would avoid the administrative process of soliciting, evaluating and awarding bids.

Finally, the wording in the first sentence of paragraph (4)(H) is a little awkward and would be clearer if it read, "the electric utility shall offer a one-(1)-time lump sum payment…for associated S-RECs at the current ten (10)-year fixed price."

With the exception of small systems, S-RECs should be issued only as metered. Paragraph (4)(H) states, "For purposes of this subsection, the energy that shall be generated by a solar photovoltaic system with a nameplate capacity of ten (10) kW or less shall be estimated using generally accepted analytical tools, unless such smaller systems are equipped with monitoring theology to track actual production." We recognize that for small systems, the cost of additional metering equipment may be impractical, and the quoted statement appears to provide an exception to a general rule, but we do not find such a general rule described. As written, all eligible systems, regardless of size, would be paid a one-time lump-sum regardless of metered output.

In reviewing other state RES solar programs, the best practice is to pay for performance. Some states apply this principle to even the smallest systems, because of a belief that it is critical that all RECs be of the same reliability, based on accurate and verified output. The same cited paragraph requires that a customer with a solar generator certify to the utility between five and six years after installation that the generator is still operating, but this is a far cry from pay for performance, and should apply only to small systems exempted from the general requirement to meter output.

We recommend that the rule clearly state that solar installations of 10 kW or greater (whether for solar rebate purposes or for the creation and sale of S-RECs) must have revenue-quality meters that record gross output; that such installations must report their output at least quarterly to the tracking system; and that customer-owners of such installations be paid only after the S-RECs are issued and transferred to the utility. Otherwise there is no incentive for

the owner (or the utility for that matter) to ensure that the system continues optimal functionality.

Paragraphs (4)(I) and (4)(J), which speak to what happens if a solar installation ceases to operate, and how a utility should count S-RECs from systems that receive a lump-sum payments, should clearly apply only to the exceptional small systems, and not to the larger, fully metered systems. Only the small systems should be eligible for the one-time, lump-sum payment.

There is a reference in paragraph (4)(E) to the net metering requirements of 4 CSR 240-20.065, but this paragraph appears to apply to the solar rebate, not the Standard Offer Contract, and in any event, the referenced regulation only requires a single bi-directional meter that does not measure the full output of the solar installation, although "employing multiple meters that separately measure the customer-generator's consumption and production of electricity" is optional.

Without a clear requirement to meter the gross output of systems of 10 kW or above, there is the potential for under compliance of the solar requirement and for ratepayers to get less than what they paid for.

For the retail rate impact calculation, more guidance is needed on the valuation of greenhouse gas emission reductions.

In the calculation of the retail rate impact, we applaud the Commission for reducing the renewable energy cost by subtracting the avoided cost of fuel not purchased and the avoided cost of greenhouse gas emission reductions. It is appropriate to fully account for all costs and benefits, but more guidance is needed in determining the value of greenhouse gas emission reductions. It is widely expected that power sector carbon emissions will in the next few years be subject to a mandatory cap on carbon emissions that lets the market set a price of emission allowances. Many states have projected the likely future costs of carbon allowances under such a regulatory structure, including California, Minnesota, New Mexico, Oregon, and Washington. We recommend that the Commission do the same, and periodically update its projections to reflect emerging regulatory and market conditions.

The most thorough projection of future CO_2 allowances prices under different regulatory scenarios is a 2008 report by Synapse Energy Economics, Inc.[1] Synapse's analysis revealed a mid-case forecast that begins at $15.00/ton in 2013 and gradually increases to $53.40/ton by 2030, and also includes lower and higher cost trajectories to reflect the uncertainty around such a projection. Since 2008, additional analyses by the U.S. Energy Information Administration, Environmental Protection Agency, and Congressional Budget Office have been released evaluating more recent federal carbon emission reduction proposals.[2] Nearly all

[1] David Schlissel, D. et al. 2008. *Synapse 2008 CO2 Price Forecasts*. Camridge, MA: Synapse Energy Economics, Inc.

[2] See Energy Information Administration. 2009. *Energy market and economic impacts of H.R. 2454, the American Clean Energy and Security Act.* Washington, DC: U.S. Department of Energy. Online at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html. Also see: Environmental Protection Agency. 2009.

of the price projections in these studies fall within the range of costs Synapse projected in 2008. We recommend the Commission use the Synapse CO_2 allowance projections to determine the value of avoided greenhouse gas emissions. If the Commission selects a single value (increasing over time), it should use the Synapse mid-case forecast of $15/ton. However, looking at the range of costs reflected in the Synapse low- and high-case forecasts (which start in 2013 at $10/ton and $30/ton, respectively), would allow for a more comprehensive consideration of the future costs of CO_2 emissions, and thus the future value of avoiding them.

The retail rate impact should be based on averaging costs over a 20-year period.
The proposed rule calls for the cost of the RES-compliant portfolio to be averaged over a 10-year period. We recommend that the cost of this portfolio be averaged over a 20-year period for two reasons. First, renewable generating resources are more likely to have a commercial life of 20 years (or more) than 10 years, and it more appropriate to average costs of the life of the investment. Second, a longer averaging will provide greater smoothing of cost bumps, which are more likely to occur in early years as the costs are amortized.

Furthermore, we urge the Commission to address the need for long-term contracts. Requiring obligated utilities to offer long-term contracts for renewable electricity and/or RECs will help developers get financing, reduce project costs, and cut overall RES compliance costs, while helping to stabilize prices for basic service customers. Renewable energy facilities have several unique characteristics that make them especially well suited for long-term contracts of at least 15 years and preferably 20 years. These power plants do not rely on fossil fuels, so their forward pricing of energy is tied largely to the amortization of initial capital investment. In contrast, fossil fuel plants must price to account for future long-term fuel price risk in the form of a premium under a long-term arrangement. As a result, a renewable energy generator can offer a stable, lower price over the long term relative to a fossil fuel generator. Therefore, requiring electric utility distribution companies to enter into long-term contracts for RES compliance would be in the best interest of the customers.

The Commission should clarify the relationship between Missouri RES compliance and possible future federal RES compliance.
Paragraph (5)(E) states, "Costs or benefits attributed to compliance with a federal renewable energy standard or portfolio requirement shall be considered as part of compliance with the Missouri RES." To the extent that a federal RES has the same requirements as the Missouri RES, the costs of complying with the federal RES should be counted in calculating the retail rate impact. However, where federal RES requirements differ from the Missouri RES, we believe that those federal compliance costs should not be counted when calculating the Missouri RES. For example, if resources used for compliance with the federal RES are not eligible for complying with the Missouri RES, their costs should not be included in calculating the rate impact. Similarly, if the federal RES requires more renewable energy than

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EPA analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress. Washington, DC. June 23. Online at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf. Also see: Congressional Budget Office. 2009. *H.R. 2454 American Clean Energy and Security Act of 2008.* CBO Cost Estimate. Washington, DC. Online at http://www.cbo.gov/ftpdocs/102xx/doc10262/hr2454.pdf.

Missouri, or if a utility makes federal alternative compliance payments that are not eligible under the Missouri RES, or if a utility buys federal RECs from afar and the energy is not delivered to Missouri consumers as required by this rule, then these incremental costs should not be used in calculating the retail rate impact. That may in fact be the intent of the quoted sentence, but as it stands it would appear to allow any federal compliance costs to be counted towards the retail rate impact regardless of whether these costs help the utility achieve its Missouri obligations.

In general, we recommend the principle that federal compliance costs should not have the effect of reducing the amount of state-eligible generation that is required under Missouri statute and regulations. If the expenditure on federal compliance does not simultaneously help achieve compliance with the Missouri RES, it should not be included in the calculation of the retail rate impact.

Disclosure to consumers, if required, should emphasize RES benefits as well as costs.
The proposed rule includes several requirements to inform consumers about the RES. Paragraph (6)(A)(6) requires an initial notice explaining the authority under which the utility is undertaking the program; an annual notice explaining the RESRAM and the effect of RES compliance; and a line item on each customer's bill specifying the amount of the RESRAM. The effect of the last requirement will be to draw attention to the renewable energy cost, when no similar requirement exists to itemize the cost for other specific fuels, coal or nuclear energy, for example. We see no requirement for this level of disclosure in the law, and believe that renewable energy should be treated the same as other traditional resources, not singled out. In addition, a RESRAM line item on the bill would only focus on the costs without similarly reporting any benefits from the program.

For these reasons we recommend deleting the requirement for a line item on each customer's bill, and instead use the required annual notice to explain the purpose of the RES, its costs, and its benefits, such as jobs, economic investment, clean air, reduced greenhouse gas emissions, energy security, and resource diversity.

The Commission should establish clear, minimum penalties for non-compliance.
The draft rules call for the non-compliance penalty to be calculated on an annual basis by Commission staff, and that it shall be "twice the average market value during the calendar year for RECs or S-RECs…" We believe this approach does not give the obligated utilities enough information about the potential cost of non-compliance in advance or over the long-term, and therefore about how much they should be willing to pay compliance (either for RECs and S-RECs or in new renewable generation). This uncertainty may be a barrier to long-term investment.

The RES statute, however, states that non-compliance penalties shall be "at least twice the average market value of renewable energy credits for the compliance period" (emphasis added). The Commission therefore has the authority to establish a default minimum non-compliance penalty on a dollar per megawatt-hour (MWh) basis, with penalties being higher if the calculation for twice the average market value for RECs exceeds the minimum

threshold. This would provide a clear long-term signal to obligated utilities of what penalties would be for non-compliance. We recommend setting a minimum penalty of $50 per MWh, adjusting annually for inflation. This is consistent with a range of states that use a similar penalty mechanism, including California ($50/MWh), Connecticut ($55/MWh), Ohio ($45/MWh), Texas ($50/MWh), and Washington ($50/MWh).

Thank you for the opportunity to offer these comments on Case No. EX-2010-0169.

Respectfully submitted,

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Jeff Deyette
Assistant Director, Energy Research and Analysis
Union of Concerned Scientists
Two Brattle Square
Cambridge, MA 02238-9105
617.301.8012