LUTHER COLLEGE

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FILED WITH
Executive Secretary

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IOWA UTILITIES BOARD

Executive Secretary
Iowa Utilities Board
1375 E. Court Avenue, Room 69
Des Moines, IA 50319-0069

Re: Docket No. NOI-2014-0001

Dear Members of the Iowa Utilities Board,

Thank you for the opportunity to comment again on the topic of distributed generation. We offer below our responses to the questions you posed about net metering in your order dated April 30, 2015. We also appreciate your invitation to respond to the initial responses of other participants by July 15, 2015.

1. The Board has offered the following proposed policy goal for comment:

> **To provide a regulatory framework that allows distributed generation to grow in an equitable manner that balances the interests of regulated utilities and all utility customers.**

Comment on the advantages and disadvantages of the Board adopting such a policy goal.

We agree that the Board would be well served by an explicit policy goal regarding distributed generation. That said, we have some concerns about the draft policy goal and think it can be improved.

First, given that all of the questions in the Board's most recent order revolve around net metering, it appears the Board is most interested in providing a regulatory framework that allows certain forms of distributed generation (DG) to grow rather than others. Specifically, it appears the Board wants to grow the number of alternate energy production (AEP) systems rather than fossil fueled DG systems. In addition, since net metering in Iowa is limited to AEP systems "owned or operated" by utility customers,[1] it appears the Board prefers to grow the number of these systems rather than utility-owned DG. If these assumptions are correct, then this narrowed policy goal should be

[1] 199 IAC 15.11(1), https://www.legis.iowa.gov/docs/ACO/IAC/LINC/07-28-2010.Rule.199.15.11.pdf.

distinguished from the broader definition of DG the Board articulated in an earlier order in this docket:

> For purposes of this inquiry, DG is generation fueled by renewable or fossil-fuel sources that is built in order to serve load located at or near the generator and capable of delivering power to a utility's distribution system.[2]

Second, one way to read the draft policy goal is that the "interests of regulated utilities" are as important as the interests of all utility customers in Iowa. This would be unfortunate because the phrase "interests of regulated utilities" does not appear in the Iowa Code or the Iowa Administrative Code. The interests that are lifted up in Iowa law are the interests of utility ratepayers and, far more often, "the public interest." The Board's mission reflects this focus—"to ensure that reasonably priced, reliable, environmentally responsible, and safe utility services are available to all Iowans." The Board certainly does have an obligation to ensure public utilities have just and reasonable rates, as well as a consistent and fair return on common stock equity for shareholders of investor-owned utilities, but only when and because these utilities provide valuable services to Iowa utility customers.

Third, it could be clearer how the new regulatory framework will "enable distributed generation to grow in an *equitable* manner" while it "*balances* the interests of regulated utilities and all utility customers." (Emphasis added.) When two weights are placed on separate platforms of a scale they will only balance when they are of equal measure. Thus, one way to read the draft policy goal is that the interests of those that own DG systems, while not mentioned explicitly in the goal, are no more (or less) important than the interests of regulated utilities and all utility customers. In this case, the term "balances" implies that all interests are equal and that no single set of interests are weightier than the interests of others. In this case "an equitable manner" appears to mean an "equal manner." This phrasing is problematic because, as we point out above, Iowa Code does not place the interests of regulated utilities on par with those of Iowa utility customers or the public interest.

We assume that the issue of cross-subsidization has prompted these references to equity and the balancing of interests. In our view, justice does not always require equality. Sometimes departures from equal treatment are justified in order to achieve other public goods. As the IUB staff note in their memo accompanying the Board's order dated April 30, 2015, "some existing cross-subsidies are accepted because of the social, economic, or political benefit."[3]

This leads to our final concern. The draft policy goal is not framed in relation to existing state policy goals, legislative intensions, and legal requirements regarding renewable energy, energy efficiency, and local power production:

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[2] IUB Order, May 12, 2014, pp. 1-2.
[3] Gold Memo, April 8, 2015, pg. 4.

- It is the policy of this state to encourage the development of alternate energy production facilities and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient use. (Iowa Code §476.41)

- It is the intent of the general assembly to encourage the development of renewable electric power generation. It is also the intent of the general assembly to encourage the use of renewable power to meet local electric needs and the development of transmission capacity to export wind power generated in Iowa. (Iowa Code §476.53A)

- Every public utility is required to furnish reasonably adequate service and facilities. 'Reasonably adequate service and facilities' for public utilities furnishing gas or electricity includes programs for customers to encourage the use of energy efficiency and renewable energy sources. (Iowa Code §476.8)

Given these concerns, we respectfully propose the following alternative phrasing of a policy goal to guide the growth of AEP-DG in Iowa:

> **To provide a regulatory framework that allows customer-owned or operated alternate energy production systems to grow in a manner that achieves state policy goals regarding renewable energy, energy efficiency, and local power production while also being consistent with the mission of the Board "to ensure that reasonably priced, reliable, environmentally responsible, and safe utility services are available to all Iowans."[4]**

The narrowed focus of this revised DG policy goal is justified further given the various laws the Iowa Legislature has passed to encourage investments in renewable energy:

Iowa Code/IAC	State Laws Encouraging Development of Renewable Energy
§423.3(54), (90)	Sales Tax Exemption - Wind and Solar Energy Equipment
§427.1(29)	Property Tax Exemption – Methane Gas Conversion Property
§427B.26	Special Property Tax Valuation and Assessment - Wind Energy
§437A.6	Energy Replacement Generation Tax Exemption
§441.21(8)	Property Tax Exemption - Renewable Energy Systems
§476B	Wind Energy (Production) Tax Credit
§476C	Renewable Energy (Production) Tax Credit

[4] It might be wise to include in the revised policy goal parenthetical references to the sections of the Iowa Code noted above with regard to renewable energy, energy efficiency, and local power. We have omitted them here for the sake of brevity.

§476.46	Alternate Energy Revolving Loan Program
§476.47	Alternate Energy Purchase Programs
§476.48	Small Wind Innovation Zones
199 IAC 15(5)	Net Metering
199 IAC 45	Electric Interconnection of Distributed Generation Facilities
701 IAC 42.47 (422)	Geothermal Heat Pump Tax Credit
701 IAC 42.48	Solar Energy Systems (Investment) Tax Credit (Corporate)
701 IAC 42.48	Solar Energy Systems (Investment) Tax Credit (Personal)

The vast majority of these incentives have been designed by the Legislature to encourage Iowans to invest in customer-owned or operated AEP systems. Iowans have embraced these incentives enthusiastically —so much so that repeated proposals to increase the capacity limits for relevant tax credits have been approved by the Legislature in recent years. In our view the Board's DG policy goal should be reframed to reflect these goals and to further increase these investments.

2. Would it constitute a "sale" if the Board were to determine that at the end of each year, unused kWh credits are to be diverted and used for a special cause?

The transfer of unused kWh credits for a special cause would not constitute a sale because no cash would change hands; only bill credits would be diverted electronically and used to offset charges to another ratepayer's account.

That said, just as the Board requires "each electric and gas public utility to establish a fund whose purposes shall include the receiving of contributions to assist the utility's low-income customers,"[5] the Board does not *require* utility customers donate to the fund. If the Board permits the transfer of kWh bill credits to a special cause, then such donations must be the *voluntary* choice of the utility customer. Ideally, the utility customer would be able to designate the special cause(s) to which kWh credits could be applied like charities or other non-taxable entities. If the customer does not exercise this option, then any annual kWh credits should carry over indefinitely as they do now.

Finally, we are not aware of any federal requirement limiting net metering to one year and requiring a zeroing out of any surplus on an annual or monthly basis.

3. Since the net-metering facility size cap and carry-over provisions were established through settlements between the investor-owned utilities and the Office of Consumer Advocate, a division of the Iowa Department of Justice, should any changes to those provisions be addressed via a rule-making docket, or through modification of the tariff provisions, or does the forum matter?

[5] Iowa Code §476.66 (1).

As the Board notes, the current 500 kW net metering capacity limit was set many years ago as part of a settlement agreement. MidAmerican has offered the following background to this decision in comments it filed in this docket on June 24, 2014:

> The Board should recognize that FERC stated in *MidAmerican* that it would not assert jurisdiction over individual farmers' and homeowners' installations. Based on that holding, MidAmerican used a 500 kW size cap in Rate NM.[6]

The Board's staff summarized and reiterated this background in the Gold Memo that accompanied the most recent order in this docket:

> The FERC stated it would not take jurisdiction over individual households and farmers so the 500 kW size cap seemed the appropriate size limit for those customers at that time. [7]

The implication in both sets of comments is that the Federal Energy Regulatory Commission (FERC) introduced a jurisdictional limit to net metering confining it to individual households and farmers. This is not the case. FERC referred to individual homeowners or farmers as *examples* of net metering:

> In essence, MidAmerican is asking this Commission to declare that when, *for example*, individual homeowners or farmers install small generation facilities to reduce purchases from a utility, a state is preempted from allowing the individual homeowner's or farmer's purchase or sale of power from being measured on a net basis, i.e., that PURPA and the FPA require that two meters be installed in these situations, one to measure the flow of power from the utility to the homeowner or farmer, and another to measure the flow of power from the homeowner or farmer to the utility. MidAmerican argues that every flow of power constitutes a sale, and, in particular, that every flow of power from a homeowner or farmer to MidAmerican must be priced consistent with the requirements of either PURPA or the FPA. We find no such requirement.[8] [Emphasis added.]

In addition, as MEC acknowledges, FERC's ruling in *MidAmerican* did not introduce or impose a 500 kW capacity limit on net metering. The only threshold of this size we are aware of pertains to utility obligations under PURPA regulations for small power producers and cogeneration facilities:

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[6] Additional Comments of MidAmerican Energy Company, NOI-2014-0001, pg. 6, https://efs.iowa.gov/cs/groups/external/documents/docket/mdaw/mjm2/~edisp/236048.pdf.
[7] Gold Memo, April 8, 2015, pg. 4.
[8] MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001), pg. 5, http://elibrary.ferc.gov/idmws/File_list.asp?document_id=3118258.

> (2) *Facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a net power production capacity of 500 kW or more until 90 days after the facility notifies the facility that it is a qualifying facility or 90 days after the utility meets the notice requirements in paragraph (c)(1) of this section.[9]

This 500 kW threshold pertains to utility obligations to purchase power from qualifying facilities; it does not pertain to net metering.

We share this information to contest MEC's claim that net metering should be limited to customers who are individual householders or farmers. There is no reason to limit net metering to these two ratepayer classes (and fortunately Iowa's net metering rule does not). In addition, since the original 500 kW cap was set because it was presumed the related generation represented the maximum an individual household or farm might consume, the rationale for this particular cap falls away if the needs and interests of other ratepayer classes are considered.

Turning now to address the Board's specific question, it is our understanding that the Board has the authority to revise Iowa's net metering rule. While the existing rule and related tariffs are the consequence of a prior settlement agreement many years ago, it does not seem that any changes to Iowa's net metering rule necessarily mean they have to be confined to modifications of the existing tariff provisions. It probably makes most sense for the Board to propose changes to the rule in the appropriate venue, and then to explore how any changes will impact existing tariff provisions.

That said, the Board's staff recommend the use of pilot projects to test the wisdom of any long-term changes to Iowa's net metering rule and related tariff provisions. If this route is taken, and we think it has much to commend it, then presumably certain aspects of the net metering rules and related tariff provisions would be suspended, supplemented, or replaced in the pilot projects. It might be best for the Board to invite public comments on any intended changes first in this docket before presenting them for approval in a rule-making docket.

4. **If the Board decides to change the cap for eligible net-metered facilities, one option would be to allow customers to net meter 110 percent of their average annual electricity consumption up to 1 MW or 2MW. Comment on the short-term and long-term financial impact such a change would have on non-DG customers and the utilities. Would this have an impact on grid reliability? Would it impact the way utilities do their resource and system planning? Identify any other concerns associated with this change.**

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[9] 18 C.F.R. Part 292, Subpart B, §292.207, "Procedures for obtaining qualifying status," http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=90be7b6c18212e07ec007fe48eb219d3&mc=true&n=pt18.1.292&r=PART&ty=HTML#sp18.1.292.b

We begin by identifying some concerns and by asking several questions of clarification:

- Average Annual Electricity Consumption. If net metering were limited to 110 percent of average annual electricity consumption, would this be based on the last twelve months of consumption, the previous calendar year, or the average of the previous three calendar years?

  Luther would prefer customers have the option to choose one of these three options since annual consumption can vary for many reasons including weather conditions, economic production, etc.

- Net Metering and Billing Components. What specific components of a customer's electricity bill are affected by net metering?

  199 IAC 15.11 requires "a single meter monitoring only the net amount of electricity sold or purchased." Does the net amount of electricity sold or purchased include demand charges, or does it only pertain to volumetric charges per kWh for power generation, fuel cost, distribution, transmission, and energy cost adjustments? If the latter, then net metering of AEP facilities with a 1 MW or 2 MW cap will not be attractive to large general service customers because demand charges typically represent 30-35 percent of their bill.

  Neither MEC nor IPL explicitly exclude demand charges in their net metering tariffs. MEC describes net metering in terms of netting "energy flows, on a kWh basis, from the Company to the Facility and from the Facility to the Company, with each direction energy flow recorded independently," or as "power flows in each direction on an hourly or other real-time basis."[10] IPL describes net metering as "[t]he energy KWH inflow (received by AEP facilities) and energy KWH outflow (received by Company) … measured by a single meter in which only the net amount of electricity is monitored on a monthly basis…. Metered energy billed shall be the total energy inflow less the total energy outflow for the same period and same location."[11]

  At a minimum, this matter regarding what specific bill components are affected by net metering (and what components are not) should be clarified by the Board in the existing net metering rule and related tariffs, and certainly in any proposed changes to them.

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[10] MidAmerican Energy, "Rate NB - Net Billing of Small Alternate Energy Systems and Small Hydro Producers," August 6, 2014, http://www.midamericanenergy.com/include/pdf/rates/elecrates/iaelectric/ia-elec.pdf#Page=161.

[11] Alliant Energy, "Rate Code AEP – Alternate Energy & Small Hydro Production," Issued October 4, 2010, https://www.alliantenergy.com/wcm/groups/wcm_internet/@int/@tariff/documents/document/mdaw/mde1/~edisp/015431.pdf.

If the Board's goal is to grow customer owned or operated AEP-DG by raising the capacity limit for net metering, then it would be ideal if *all* components of a customer's electricity bill were affected by net metering (including demand charges) except for the basic service fee and energy efficiency cost recovery charges. This would have the virtue of treating all ratepayer classes in a similar way (because demand is not disaggregated in bills for residential customers), and it would incentivize larger electricity users to make investments in AEP-DG systems.

We are not sure how this best could be accomplished but one approach might be to adopt net *billing* based on the net production of an eligible net-metered AEP system. That is, if a net-metered customer's average retail cost for power after deducting the monthly service charge and the energy efficiency cost recovery charge is $0.10/kWh, then the customer would receive this cash value for all surplus kWh production as a bill credit rather than a kWh credit. We don't think this would constitute a purchase or sale since it is a bill credit and Iowa's net metering rule does not include a cash-out provision.

We are aware that some utilities favor levying demand charges for all customer classes, including residential ratepayers, to address alleged cross subsidization issues.[12] Adding separate demand charges would reduce the incentive for all ratepayer classes to invest in net-metered DG systems since, like large general service customers today, a significant portion of their electricity bill would not be reduced by the net-metered system. As a result, such a move would likely reduce the number of new net-metered AEP systems in Iowa rather than increase them, which it appears the Board wants to do. Such a move might also lead customers to invest in energy storage to better control and meet demand. When energy storage costs get low enough, these demand charges might lead ratepayers to become self-sufficient via energy storage and disconnect from the grid. We don't think grid defection would be in the best interests of Iowa ratepayers.

- Qualifying Cogeneration Facilities. Are qualifying cogeneration facilities under 18 C.F.R. Part 292, Subpart B[13] that meet Iowa's AEP fuel use requirements eligible AEP facilities?

  Item 1(b) under Iowa Code 476.42 says "a qualifying facility under 18 C.F.R. pt. 292, subpt. B is not precluded from being an alternate energy production facility under this subchapter." This section of the Federal Code establishes criteria

[12] Statement of Jonathan M. Weisgall, Vice President, Legislative and Regulatory Affairs, Berkshire Hathaway Energy, before the House Energy and Commerce Subcommittee on Energy and Power, June 4, 2015, pg. 33. http://docs.house.gov/meetings/IF/IF03/20150603/103551/HHRG-114-IF03-Wstate-WeisgallJ-20150603.pdf.
[13] 18 C.F.R. Part 292, Subpart B, http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=90be7b6c18212e07ec007fe48eb219d3&mc=true&n=pt18.1.292&r=PART&ty=HTML#sp18.1.292.b.

for two types of qualifying facilities: 1) Small power production facilities, and 2) Cogeneration facilities. Iowa Code 476.42 does not prefer one of these types of qualifying facilities to the other. Section 199.15 of the Iowa Administrative Code, however, clearly excludes from the definition of AEP any reference to qualifying cogeneration facilities and revises the definition of AEP facilities so that it is more consistent with the definition for qualifying small power production facilities in 18 C.F.R. Part 292, Subpart B.

It is our understanding that the Iowa Code supersedes the Iowa Administrative Code since the latter is established to implement the former. Item 1(b) under Iowa Code 476.42 says "a qualifying facility under 18 C.F.R. pt. 292, subpt. B is not precluded from being an alternate energy production facility under this subchapter." This portion of the Iowa Code does not expressly focus on small power production facilities, nor does it expressly preclude cogeneration facilities. Thus, it appears to us that qualifying cogeneration facilities that meet the AEP fuel use requirements are not precluded from being alternate energy production facilities and thus are eligible for net metering. It is interesting that this appears to be MEC's understanding because their net metering tariff (Rate NB) offers net billing to a "[c]ogeneration facility or a small power production facility that has a design capacity of 100 kilowatts or less and which has obtained qualifying status under 18 CFR Part 292, Subpart B."[14]

The Iowa Economic Development Authority has recently issued grants to research the economic potential of pipeline quality biogas development in the state.[15] Parties in several Iowa counties are considering or engaging in feasibility studies. It is possible that pipeline quality biogas may soon grow in supply in the state. This is another reason why we think the Board should add the following language to Iowa's net metering rule: "Qualifying cogeneration facilities that meet the AEP fuel use requirements are eligible for net metering."

We agree with Board staff that "the current cap size of 500 kW is too small to encourage additional CHP or WHP projects."[16] We also urge the Board to expressly exempt all eligible net-metered AEP systems (including eligible cogeneration facilities) from standby charges. Finally, we reiterate our request that the Board address IPL's disproportionate and punitive standby charges for CHP systems that do not meet the AEP fuel use requirements.

- Aggregated Metering. Would this proposed change to raise the net metering capacity cap and impose a 110 percent consumption limit include the optional use of aggregated metering?

[14] See http://www.midamericanenergy.com/include/pdf/rates/elecrates/iaelectric/ia-elec.pdf#Page=161. This tariff provision needs to be revised to reflect Iowa's current 500 kW net metering cap.
[15] Iowa Biogas Assessment Model, http://www.ecoengineers.us/ibam/about.php.
[16] Gold Memo, April 8, 2015, pg. 16.

We agree with Board staff that aggregated net metering would be a good candidate for a pilot project either in relation to these particular proposed changes or to others. It might be financially more beneficial for certain utility customers to spread the increased production from a net-metered facility with a larger 1-2 MW capacity across several meters rather than only one.

We disagree with IPL and MEC that aggregated metering should be limited to meters on contiguous parcels of land. This would be unnecessarily restrictive. For example, it would prevent a school district from utilizing aggregated metering for more than one of their facilities if they are not located on contiguous parcels, which is seldom the case. Aggregated metering might better be limited to a customer's meters in a county or school district, but should be limited to the same utility provider.

MEC's recommendations regarding common ownership, rate schedules, and aggregated customer load are reasonable, but we don't agree that physical integration of the meters at the customer's expense is necessary. Any administrative fees associated with meter aggregation should be modest and not so high as to discourage the option.

MEC's recommendation that aggregated billing "[a]pplies only to charges using kWhs as billing determinants" highlights the ambiguity we address above regarding which billing components are affected by net metering.[17]

- Virtual Net Metering. Would this proposed change to raise the net metering capacity cap and impose a 110 percent consumption limit include the limited use of virtual net metering?

  If so, this would enable siting of AEP facilities to capture and utilize renewable energy resources at a point that is more optimal for the utility's distribution system.

  In addition, larger AEP facilities with virtually net-metered production would enable utility customers who lack a good site for an AEP system to invest in one while reducing the administrative and utility costs associated with interconnecting multiple, smaller, independent net-metered systems. Larger systems like community solar gardens also have the advantage of economies of scale, which drive down expenses for all concerned including low-income persons who want to invest in an AEP system.

  While we note in prior comments that legislation might be required to adopt virtual net metering on a permanent basis, we assume the Board can experiment with virtual net metering without specific legislation via limited pilot projects that utilize virtual net metering.

[17] Gold Memo, April 8, 2015, pg. 4.

- <u>Third Party-Owned AEP Systems</u>. Would this proposed change to raise the net metering capacity cap and impose a 110 percent consumption limit allow utility customers to net meter power production generated by a system installed behind their meter, owned by a third party, and financed via a third party power purchase agreement?

  Luther College is currently *leasing* a 280 kW solar array from a third party and IPL is net metering the power production at a single meter at Luther's Baker Village facility. Luther will soon interconnect another 825 kW to *offset electricity purchases* on our main meter. Luther is financing this system via a third party power purchase agreement. It is our understanding, however, that some customers that have sought to *net meter* power generated by a system installed behind their meter, owned by a third party, and financed via a third party power purchase agreement have been denied net metering by MEC and IPL because the third party is the owner of the system and not the customer.[18]

  It seems odd that one form of a third party commercial relationship (leasing) would qualify for net metering but a second form (third party power purchase agreement) would not qualify. As we note at the outset of our comments, net metering in Iowa is limited to AEP systems "owned *or operated*" by customers.[19] (Emphasis added)

  We urge the Board to address this matter. Third-party power purchase agreements are particularly attractive to non-taxable entities that cannot access various state and federal incentives available to for-profit entities. One way to address this issue would be by adding the following language to Iowa's net metering rule: "Notwithstanding any general or specific law to the contrary, net metering is available to utility customers who own and operate, lease and operate, or host and operate an AEP facility owned by a third party and financed via a power purchase agreement."

We turn now to answer your specific questions regarding raising the net metering capacity cap to 1-2 MW and imposing a 110 percent consumption limit:

- <u>Financial Impacts</u>. In our view the short and long-term financial impact of these possible changes would be positive for non-DG customers and the utilities.

  First, due to the annual consumption cap, system sizes would be designed only to satisfy annual power consumption requirements and thus the power from such AEP facilities would primarily be consumed on site. This reduces the amount of power and capacity the utility has to provide the customer with an

[18] Rick Smith, "Iowa court ruling lets public sector tap into solar," *The Gazette,* March 8, 2015, http://thegazette.com/subject/news/iowa-court-ruling-lets-public-sector-tap-into-solar-20150308.
[19] 199 IAC 15.11(1), https://www.legis.iowa.gov/docs/ACO/IAC/LINC/07-28-2010.Rule.199.15.11.pdf.

AEP facility and thus frees up a greater amount of power and capacity for non-DG customers. This is important given the considerable costs associated with building new power generation and distribution capacity.

Second, large, utility-scale (1-2 MW), solar photovoltaic arrays will generate substantial power at peak times of the day when it is most expensive for utilities to purchase peak power, which will result in savings to non-DG customers.

If the Board is concerned that the economic costs might eventually outweigh the economic, social, and environmental benefits of net-metered AEP systems, then the Board might consider capping the obligation of utilities to interconnect net-metered systems to a certain percentage of each utility's peak demand for electricity in a baseline year. For example, New York recently doubled the net metering limit for investor-owned utilities from 3 percent to 6 percent of a utility's demand in 2005.[20] Iowa's existing goals noted above regarding renewable energy and local power production suggest a high percentage statewide penetration cap would be in order.

- Grid Reliability. In our view grid reliability is already addressed through the interconnection agreement process. Under existing Iowa law no systems will be interconnected that put grid reliability in jeopardy. When the required utility studies raise concerns about safety or reliable grid operation any costs to ensure both currently fall to the customer that wants to interconnect an AEP system. Luther has firsthand experience in this regard having paid for studies and safety measures required to interconnect a 1.6 MW wind generator and 1.1 MW in solar PV arrays.

- Utility Resource and System Planning. We don't know how such a change to Iowa's net metering policy would affect utility resource and system planning. Implementing such a proposed change through a relatively long-term pilot project would provide data that could be used in such planning efforts.

5. Propose options to address long-term net-metering options as discussed in Option 3 in the staff memorandum, such as exploring the issue in the context of a rate case. These options should identify the associated advantages and disadvantages and also allow for the growth of DG while balancing the interests of the regulated utilities and all utility customers.

First, we agree with the Board staff that there is no good reason currently to address the rate impacts of net metering:

[20] "New York: Net Metering," http://programs.dsireusa.org/system/program/detail/453. This limit applies only to customer-owned net-metered DG and not to utility-owned DG.

> Finding an immediate solution to the issue of potential rate impacts of net metering on other customers does not appear to be pressing. As mentioned earlier, ELPC et al. pointed out the customers from all classes that net meter account for 0.057 percent of total utility customers which equates to 0.11 percent of utility-owned generation.[12] Therefore, even if utilities are interested in proposing a rate design change that provides proper price signals, it may be several years before any further work is done--simply because of the low penetration rates and minimal amount of cross-subsidization that may exist.[21]

Second, we reiterate our concerns about placing the "interests of the regulated utilities" or "the financial health of the utilities"[22] on a par with the interests of those who own DG systems and the interests of all utility customers. Ultimate responsibility for the financial health of each utility rests with their corporate managers, not the Board. One key to financial health is the management efficiency of public utilities. The Iowa Code states: "It is the policy of this state that a public utility shall operate in an efficient manner."[23]

One of the concerns utilities have expressed in this docket revolves around the loss of sales revenue needed to defray fixed costs due to power production from AEP systems. It is worth noting that such revenue losses also occur when utility customers invest in energy efficiency measures that reduce electricity purchases both in delivered energy and demand. Iowa Code 476.6(15)(g) allows rate-regulated utilities to recover the cost of providing state-mandated energy efficiency programs to their customers through an automatic adjustment mechanism, but utilities are not allowed to recover the lost sales resulting from the energy efficiency measures adopted by their customers. The clear implication is that there are limits to the Board's responsibility for the financial health of the public utilities that have been granted exclusive service territories in order to serve Iowa customers. Utilities need to find ways to secure their own financial health while respecting and implementing state goals and laws regarding energy efficiency, renewable energy, and local power production.

With regard to specific suggestions about long-term solutions regarding net metering, we hope the Office of the Consumer Advocate (OCA) will explain in more detail how time-of-use rates could be a reasonable alternative. We also hope the Environmental Law and Policy Center (ELPC) will explain more fully how new, mutually-beneficial regulatory models and ratemaking principles can work better than the traditional cost-of-service paradigm to maximize clean DG and energy efficiency. While we certainly are not experts in these matters, we commend to the Board and its staff recent publications

[21] Gold Memo, April 8, 2015, pg. 17
[22] Ibid, pg. 6.
[23] Iowa Code §476.52.

by the Rocky Mountain Institute that explore rate design questions in the face of increasing investments in solar PV and energy storage.[24]

OCA also recommends the Board "evaluate the extent to which DG causes material cross-subsidization and the extent to which it then significantly interferes with utility recovery of fixed costs before instituting any major rate design change."[25] In response, we reiterate the Board staff's conclusion that the current market penetration of DG is too small to justify an extensive study of potential cross-subsidization. Furthermore, if and when such a study is undertaken, we reiterate that it needs to explore not only economic costs borne by non-DG customers but also economic, social, and environmental benefits provided by AEP-DG customers to non-DG customers. We have commended Minnesota's "Value of Solar" approach in previous comments in this docket as a comprehensive way to address this issue. If and when penetration levels get to the point where a study is justified, we now agree with ELPC that the investor-owned utilities should bear the cost since they are the ones asking for such a study.

6. **Propose options that could be implemented as net-metering pilot projects as discussed in Option 4 of the staff memorandum. Identify the advantages and disadvantages associated with each potential project. For each potential pilot project provide detailed elements including, but not limited to, the goal of the project, timelines, eligible participants, responsibilities of the utility and participants, potential impacts on non-DG customers, an explanation of how the proposal meets the specific needs of the utility, how each option would meet the objectives expressed in the draft policy goal, and possible results.**

We are not able to offer pilot project proposals developed to the level of detail you request. That said, we do encourage the Board to consider pilot projects that address the following opportunities.

- Community Solar Gardens. We have provided details in our comments submitted on October 24, 2014 regarding community solar garden (CSG) programs in Colorado and Minnesota. We encourage the Board and its staff to study these programs and to include some form of aggregated metering along with the necessary virtual net metering in any CSG pilot project. The Board should also approve the use of third-party ownership models (leasing or power purchase agreements) in these projects. We offer some detailed suggestions about all three of these features earlier in these comments as well as the likely positive impact on non-DG utility customers.

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[24] Rocky Mountain Institute, *Rate Design for the Distribution Edge,* August 26, 2014, http://blog.rmi.org/blog_2014_08_26_new_elab_report_rate_design_for_the_distribution_edge; *The Economics of Load Defection,* April 7, 2015, http://blog.rmi.org/blog_2015_04_07_report_release_the_economics_of_load_defection; and *Fixed Charges Don't "Fix" the Problem,* May 28, 2015, http://blog.rmi.org/blog_2015_05_28_fixed_charges_dont_fix_the_problem.

[25] Gold Memo, April 8, 2015, pg. 17.

We encourage the Board to raise the net-metering system capacity limit for these CSG projects to 2 MW, even though the Board may limit customers to invest in one or more CSG projects sufficient to generate only 110 percent of projected annual consumption. We encourage the Board to require rate-regulated utilities to interconnect at least five qualifying CSG projects per utility over the course of the next four years of this pilot project.

It is our understanding that the Winneshiek Energy District will be proposing a pilot project that focuses on developing a CSG for non-taxable entities. Such entities are not able to take advantage of federal and state incentives available to for-profit entities. Luther College would welcome the opportunity to consider investing in one or more community solar gardens, including any limited to non-taxable entities. As we note on page 8 in these comments, it would be ideal if *all* components of a CSG customer's electricity bill were net billed (including demand charges) except for the basic service fee and energy efficiency cost recovery charges.

- Time-of-Use (TOU) Rates and Energy Storage. As we note above, we hope OCA will submit a fully-developed proposal for how time-of-use rates could increase the number of net-metered AEP systems. One key for customers considering this option will be gaining access to actual time-of-use consumption information from the utility. If the Board thinks this option has merit as a possible pilot project, then it should require rate-regulated utilities to furnish customers who request actual annual time-of-use consumption information at no cost within a reasonable period of time. In addition, OCA and the Board should consider how energy storage might impact utility customers contemplating a switch to TOU pricing.

- Smart Grids. The Board may wish to develop a pilot program that encourages large utility customers to invest in smart grids that are powered by various AEP systems (including cogeneration that meets AEP fuel requirements), utilize energy storage, deliver valuable grid services during regular operating conditions, and can function as emergency shelters for the public during unexpected grid outages. Public and private schools, colleges, universities, and hospitals might all be excellent sites for such smart grids. Luther College would be interested in exploring the feasibility of such a smart grid on our campus. It is likely, however, that even a 2 MW net metering cap would be too small for a smart grid on this scale. Pennsylvania has a separate 3-5 MW net metering cap for customers who build and operate smart grids that can offer emergency services.[26] Since such customers tend to be large power consumers, they typically pay much lower electricity costs per kilowatt-hour but higher demand charges. In order to incentivize investment in such smart grids it would be best if all components of a smart grid customer's electricity bill were net billed (including demand charges) except for the basic service fee and energy efficiency cost recovery charges.

[26] Pennsylvania: Net Metering, http://programs.dsireusa.org/system/program/detail/65.

- Technology-Specific Avoided Cost/Power Purchase Rates. If the Board wants to increase the number of AEP-DG systems in Iowa there is probably no better tool than technology-specific avoided cost/power purchase rates. The use of this policy tool in Germany has led to significant investments in renewably fueled DG that is normally owned by utility customers and often sited in strategic locations that benefit the grid. An important benefit of this approach is that it avoids the cross-subsidization debate because power sales and purchases between customers and the utilities are separate transactions.

  A Value-of-Solar (VoS) rate like the one developed recently by Minnesota offers an excellent way for investors to earn a reasonable and secure return on investment and simultaneously obviates the cross-subsidization issue because it quantifies costs and benefits in a comprehensive way. We have provided more information about this VoS rate in comments filed earlier in this docket. A VoS rate can function as an avoided cost/power purchase rate, or it can be considered as an alternative to net metering. While Minnesota allows *utilities* to decide whether they want to offer an approved VoS rate instead of net metering, we think utility *customers* should be able to choose which pricing option they prefer.

  Board consideration of technology-specific avoided cost/power purchase rates or simply a value of solar rate will likely raise the avoided cost issue.[27] In our experience the determination of avoided cost rates in Iowa is an opaque process that relies too heavily on input assumptions by the utilities and varies often with little explanation to AEP project developers and owner/operators.

  Recent decisions by the Federal Energy Regulatory Commission (FERC) empower state public utility commissions to establish technology-specific avoided cost/power purchase rates. In 2010, FERC allowed states to provide additional incentives for the development of qualifying facilities, including the use of environmental "adders" as compensation for avoiding environmental externalities.[28] Later that year FERC also ruled a state can set avoided cost rates specific to particular technologies so long as a state has a policy to encourage particular technologies.[29]

  We note at the outset in these comments that the State of Iowa does have several laws and policies that promote certain technologies, especially alternative energy production systems. In addition, the Iowa Administrative Code includes provisions for "rates for purchases from qualifying facilities" at avoided cost rates.[30] The

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[27] We note that there has been very little activity recently in the Board's avoided cost docket (INU-2014-0001).

[28] California Public Utilities Commission, 132 FERC ¶ 61,047 (2010) (July 15 Order), https://www.ferc.gov/whats-new/comm-meet/2010/071510/E-1.pdf.

[29] California Public Utilities Commission, 133 FERC ¶ 61,059 (2010) (October 21 Order), http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-2.pdf.

[30] 199 IAC 15.5(476). While FERC has relieved investor-owned utilities from their mandatory obligation to purchase power from qualifying facilities that are larger than 20 MW, this obligation remains in force for qualifying facilities that are 20 MW and smaller. If the Board does decide to develop technology-specific

Board, on the basis of FERC's rulings in 2010, could revise these existing provisions. Thus, in our view, the Board has the authority and the means to set technology-specific avoided cost/power purchase rates and could use these to grow the number of qualifying AEP-DG systems.

Demands for technology-specific avoided cost pricing could rise to the fore among owners of facilities eligible for Iowa's 476C tax credit.[31] Owners or operators of such facilities could petition the Board to approve a technology-specific avoided-cost PPA rate that accounts for the full value of the power from an eligible facility. Such a rate should account for several types of avoided costs including fuel, operations and maintenance, capacity, reserve, transmission, distribution, and environmental externalities.

It is worth noting that IPL's biennial Report of Electric Utility System Cost Data includes avoided cost rates for wind projects that are 1 MW, 10 MW, and 20 MW in size. IPL also reports avoided cost rates for solar PV projects that are 1 MW in size.[32] It is not clear, however, which avoided costs are included in these rates. Undoubtedly environmental externalities are not included, but the same may also be true for avoided transmission and distribution costs. MEC does not currently include avoided cost rates for either wind or solar in their biennial utility system cost filings.[33]

Board development of technology-specific avoided cost rates would be a valuable pilot project to promote customer-owned or operated AEP-DG systems regardless whether the rate would be associated with facilities eligible for the 476C tax credit. It is worth noting that project developers could petition the Board at any time via a request for a declaratory order to exercise the options FERC has established regarding technology-specific avoided cost pricing.

Another issue related to this policy option has to do with the ownership of renewable energy certificates (RECs). The Board should clarify that utility

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avoided cost rates, we recommend the Board limit eligibility to Iowa utility customers who own or operate an AEP facility.

[31] Governor Branstad recently signed HF 645 into law. One provision of the bill limits 10 MW of capacity in the 476C "Other" category to "solar facilities with a generating capacity of one and one-half megawatts or less owned or contracted for by utilities described in section 476C.1, subsection 6, paragraph *"b"*, subparagraphs (4) and (5)." While 10 MW of capacity is now reserved for electric cooperatives, others eligible for the 476C tax credit could petition the board for a technology-specific avoided cost rate. For more information about HF 645 see, http://coolice.legis.iowa.gov/Cool-ICE/default.asp?Category=billinfo&Service=Billbook&menu=false&hbill=HF645.

[32] Interstate Power & Light, Updated Report of Electric Utility System Cost Data, Docket Nos. TF-2014-0294 and IAC-2014-1503, October 15, 2014, https://efs.iowa.gov/cs/groups/external/documents/docket/mdaw/mjyw/~edisp/260466.pdf.

[33] MidAmerican Energy Company, 199 I.A.C. § 15.3 – Avoided Cost Compliance Filing Supplemental Filing, December 17, 2014, https://efs.iowa.gov/cs/groups/external/documents/docket/mdaw/mjy4/~edisp/268557.pdf.

customers own any RECs generated via an AEP-DG system in Iowa that is net-metered or chooses to sell its power to the utility under a sale agreement. If the Board were to adopt technology-specific avoided cost PPA rates or a VoS rate, we encourage the Board to allow customers to decide whether they wish to retain or sell the RECs associated with the electricity generated under either pricing scheme. This is the status quo in Iowa. Owners of AEP systems who choose to sell their power under a PPA do not necessarily have to sell the RECs with the power. These RECs may increase in value if interstate trading is permitted if and when the EPA's Clean Power Plan is implemented.

7. **Participants should indicate their preferences for addressing net metering going forward based on each of the options presented in the staff memorandum. Participants should also explain the basis for their preferred options and address how their preferred approach achieves the draft policy goal.**

   We are in favor of making changes to Iowa's net metering rule per the terms of our comments in this filing and in previous filings. We have addressed at various points in these comments each of the possible select changes noted in Option Two, we have responded to possible long-term solutions in Option Three, and we have identified some pilot projects for the Board to consider in Option Four.

   We commend the Board for realizing that any changes to Iowa's net metering rule should be guided by a policy goal. As noted above, we respectfully offer the following alternative phrasing of the draft policy goal:

   > **To provide a regulatory framework that allows customer-owned or operated alternate energy production systems to grow in a manner that achieves state policy goals regarding renewable energy, energy efficiency, and local power production while also being consistent with the mission of the Board "to ensure that reasonably priced, reliable, environmentally responsible, and safe utility services are available to all Iowans."**[34]

In closing we would like to add one further comment about the larger policy context within which this discussion about net metering is taking place. In eighteen months, and absent congressional reauthorization, key federal investment tax credits for residential renewable energy systems will expire at the end of 2016. At the same time the federal investment tax credit for commercial renewable energy systems will drop from 30 percent to 10 percent of eligible expenses. Iowa's Solar Energy Tax Credit is tied to both of these federal tax credits, which means the state residential tax credit will drop to zero and the commercial tax credit will only be 60 percent of the substantially reduced federal credit.

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[34] As we note earlier, it might be wise to include in the revised policy goal parenthetical references to the sections of the Iowa Code that identify state goals regarding renewable energy, energy efficiency, and local power production.

If this transpires we assume there will be a marked drop in new investments in customer-owned or operated AEP systems in Iowa. In this likely scenario Iowa's existing net metering rule would be one of the few remaining significant incentives to invest in an AEP system. Given the state's policy "to encourage the development of alternate energy production facilities…" (§476.41), we urge the Board only to make changes to the state's net metering rule that will achieve this goal and not undermine it. The likely cessation of residential tax credits and the marked reduction of the commercial tax credits are good reasons for the Board also to consider adopting technology-specific avoided cost/power purchase rates to encourage the development of AEP-DG facilities.

Thank you for inviting further public input in this docket. Luther College looks forward to additional participation if requested.

Sincerely,

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