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Executive Secretary
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IOWA UTILITIES BOARD

STATE OF IOWA
DEPARTMENT OF COMMERCE
BEFORE THE IOWA UTILITIES BOARD

IN RE:	:	
DISTRIBUTED GENERATION	:	**DOCKET NO. NOI-2014-0001**

ADDITIONAL COMMENTS OF MIDAMERICAN ENERGY COMPANY

COMES NOW, MidAmerican Energy Company (MidAmerican), and for its additional comments in response to the Iowa Utilities Board (Board) Order Soliciting Additional Comments on Distributed Generation, Net Metering, and Interconnection and Including Reports issued on May 12, 2014, submits as follows:

INTRODUCTION

MidAmerican appreciates the opportunity to provide additional comments in the Board notice of inquiry (NOI) proceeding on distributed generation (DG). These additional Board questions will continue to clarify the issues surrounding net metering and interconnection, and will assist in the development of sound policies that will position the state to move forward in a reasonable, fair manner with the expected growth of DG. As mentioned in MidAmerican's initial comments, the interconnection of DG to Iowa utility systems can play an important role in providing a balanced portfolio of energy resources in an economical manner for utility customers.

As an initial matter, MidAmerican would ask the Board to clarify the definition of DG in the May 12, 2014 Order. In that Order, the Board defined DG as 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. MidAmerican suggests that the

Board clarify the DG definition to exclude facilities whose primary purpose is for backup supply. We also suggest that the definition include the requirement that the DG facility's primary purpose is to operate in continuous parallel with the electric system. MidAmerican does not respond to all questions posed by the Board, as some were directed to specific interests, but does reserve the right to comment on these questions in the future.

MIDAMERICAN'S RESPONSE TO THE BOARD'S ADDITIONAL INQUIRY QUESTIONS

MidAmerican's comments are organized according to the Board's May 12, 2104 Order.

Questions for all utility participants:

1. **Various commenters recommended net metering policy changes which are listed below. Discuss the advantages, disadvantages, and the regulatory changes necessary to implement each suggested change.**

    a. **Increase the size cap from 500 kW to 2,500 kW or 5,000 kW.**
    b. **Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.**
    c. **Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.**
    d. **Allow an annual cashout of the net metering balance.**
    e. **Include aggregate metering for customers who may have more than one meter on their premises.**

Introduction and legal overview:

Before responding to the net metering policy changes addressed in this question, it is appropriate to first address the underlying legal issues surrounding net metering in Iowa. MidAmerican's Rate NM reflects the resolution of a settlement of litigation regarding the Board's ability to order rate-regulated utilities to net meter. Net metering involves purchases of capacity and energy from the net metering customer to the host utility, which in turn resells the DG and other resources at retail. Such sales for resale and wholesale sales of power and energy are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the

Federal Power Act. The authority to set rates, terms, and conditions of service for wholesale power sales is not delegated to the Board. When MidAmerican was ordered by the Board to implement net metering, MidAmerican appealed that decision. Ultimately, FERC resolved the issue in a decision involving MidAmerican.[1] FERC explained its jurisdiction over net metering in a more recent decision:

> The Commission has explained that net metering is a method of measuring sales of electric energy. Where there is no net sale over the billing period, the Commission has not viewed its jurisdiction as being implicated; that is, the Commission does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period, has the Commission asserted jurisdiction. *Sun Edison LLC*, 129 FERC ¶ 61,146 (2009) at ¶ 18.

FERC did not address the issue of whether a sale subject to its jurisdiction has occurred when there is a net sale to the host utility under a net metering arrangement. In *MidAmerican*, FERC simply held that it would not assert jurisdiction over netting occurring during the typical individual or farm monthly billing process.[2] But that does not mean that any net metering arrangement would be acceptable to FERC, particularly one that results in payments in excess of avoided cost. In *MidAmerican*, FERC clearly stated that net sales from a qualifying facility (QF) must be made at avoided cost rates:

> When there is a net sale to a utility, and the individual's generation is a QF, that net sale must be at an avoided cost rate consistent with PURPA and our regulations.

94 FERC ¶ 61,340 (2001) at ¶ 4.

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[1] *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001).

[2] FERC explained the parameters of the net metering over which it declined to assert jurisdiction in footnote 173 to Order No. 2003-A, *Standardization of Generator Interconnection Requests and Procedures*, 106 FERC ¶ 61,220 (2004) as follows: "[The] Commission [will] not assert jurisdiction when an individual home owner or farmer or similar entity installs generation and accounts for its dealings with the utility through netting."

Most of the policy options the Board wants commenters to address would extend net metering beyond Rate NM. Annual cashouts of the net metering balance, increasing the cap to encompass sizes beyond individual homeowners and farmers and similar entities, and adding types of generators beyond those that are clearly QFs are beyond the parameters of the current one customer/one site approach of Rate NM and may be subject to the jurisdiction of FERC over wholesale power before they can be implemented in Iowa.

In addition to potential federal issues involving jurisdiction over wholesale sales of power, the Board should consider the impact of assigned exclusive electric service territory on electric utility service in Iowa. The Board has described the assignment of service territory in the public interest as the fulcrum that balances the obligations of electric service providers and their rights to serve customers:

> MidAmerican has a statutory right, and an obligation, to provide electric service to retail customers located within its exclusive service territory. An example of the utility's obligations is found in IOWA CODE § 476.8, which requires every public utility to furnish "reasonably adequate service and facilities" at "reasonable and just rates." In addition, the public utility may not abandon, reduce, discontinue or impair service to any community, or portion thereof, without Board approval. IOWA CODE § 476.20. This obligation is not limited to providing transmission and distribution service but includes the provision of electricity itself.
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> MidAmerican's corresponding rights are largely contained in the service territory statutes. Like its obligations, there is no limiting of its exclusive service territory or rights to mere transmission and distribution. The Board believes the long-term, heavy capital investment traditionally associated with electric utility operations is the fulcrum on which the legislature balanced the rights and obligations expressed in Chapter 476.

In Re: MidAmerican Energy Company, Docket No. DRU-98-1, Declaratory Ruling, issued May 29, 1998 at 5.

Certain options addressed above could compromise this system. As noted above, the assignment of service territory applies to all elements of electric power and energy sold in Iowa – generation, transmission and distribution – so retail wheeling is not authorized in Iowa. To the

extent any extension of net metering would involve a utility distribution system, such as virtual net metering or aggregation of front-of-the-meter load, it may not be consistent with Iowa's system of coordinated, cost-effective electric service.

MidAmerican's comments on each of the options set forth in this question address the underlying policy implications and are not intended to suggest each option is legally permitted under state and federal regulatory frameworks.

Before making any changes to net metering, the Board should, as a matter of policy, determine that DG rates should not involve subsidization of DG customers by other customers or by the utility. Net metering makes the over-simplified assumption that the value of every kWh of net metered production delivered to the grid is always equal to the rate block that the net metered customer avoids paying for bundled electric service (e.g., customer services, distribution services, transmission services and generation services) provided by the utility. There is no nexus between the value to the grid (i.e., retail customers) of a kWh of unscheduled DG energy and the revenue requirement associated with the utility's depreciated embedded investments, costs of operation and maintenance, depreciation expenses, and costs of generation services dispatched by the Midcontinent Independent System Operator, Inc. (MISO).

When FERC indicated in *MidAmerican* that it would not exert jurisdiction over individual homeowners and farmers who net metered, the number of customers and amount of net metering resources were few and limited. This lack of nexus should not be ignored as the number of net metering customers increases and, particularly, should not be ignored while considering expanding the limit on net metering.

a. Increase the size cap from 500 MW to 2,500 MW or 5,000 MW

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. If the Board determines it is appropriate to continue net metering and to increase the size cap, it should not do so at the expense of customers who do not have DG facilities. Any subsidization is inappropriate because it would provide a competitive advantage to business or residential customers who are in a position to take advantage of net metering over those who are not. Prior to making any changes, the Board should restructure the net metering rate to eliminate all subsidies in the rate.

There is no statutory or Board rule requirements related to the size cap on net metering. Assuming that FERC does not take jurisdiction over such a net metering arrangement, the Board could increase the size cap through a Board order after consideration of evidence regarding the potential issues.

b. Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.

"Virtual net metering" assumes a delivery of retail energy across a utility's facilities, which is retail wheeling and prohibited by Iowa law. "Virtual net metering" by someone other than the utility creates a fundamental conflict with the Iowa service territory statutes. Those statutes reflect the state's policy that retail sales of electricity to Iowa consumers be regulated, either by the Board or municipal government or by cooperative consumers and their elected boards.[3] As a matter of policy, "virtual net metering" will increase the degree of cross-subsidization of customers that have invested in net-metered DG facilities by those who have

[3] There is one limited exception to this overall policy of coordinated electric retail sales in Iowa and that is the exemption in Iowa Code § 476.1 relating to sales to five or fewer customers from an alternate energy production facility off of a secondary line. This limited exception was created after the assignment of service territory by the Board and should not be interpreted to radically alter the Board's authority to regulate service to providers under the Assigned Area of Service division of Chapter 476.

not, perhaps significantly. If, as a matter of Iowa law, "virtual net metering" is permitted, the Board should first restructure the net metering rate to eliminate the subsidies inherent in the rate.

Allowing “virtual net metering” would potentially make DG investment by customers more economic and could eliminate some potential problem issues for customers related to DG ownership. Utility (and possibly third-party) ownership of the solar installation may allow for better utilization of tax credits, as individual customers may not be able to take full advantage of them. “Virtual net metering” might also allow for placement of DG facilities in places other than on a customer’s premises, where there may be local restrictions or where they may cause structural or other issues related to attachment to a customer’s home or business. It would also potentially allow for DG facilities to be placed in areas where changes in power flows caused by DG facilities would be less of a concern.

c. Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.

There are several legal concerns related to expanding net metering to add CHP and WHP facilities. First, it is not clear that CHP and WHP facilities are within FERC's expectation of permissible net metering facilities since they are not individual farms or homes. Second, they are not included in the statutory definition of alternate energy production facilities (AEP). The definition of AEPs, as included in Iowa Code § 476.42, is not parallel to the Public Utility Regulatory Policies Act (PURPA) definition of QFs. The AEP definition does not include certain types of renewable facilities and does not include cogeneration facilities.

In addition to legal issues with inclusion of CHP and WHP, there may be issues of cross-subsidization. If the Board determines that it is appropriate to continue net metering under the existing terms and to include CHP and WHP as net metering eligible facilities, it will increase the degree of cross-subsidization of customers who have invested in net-metered DG facilities by

those who have not. Prior to any changes or expansion, the Board should first restructure the net metering rate to eliminate the subsidies inherent in the rate.

If the Board elects to include CHP and WHP facilities as net metering eligible facilities, MidAmerican recommends that the Board retain the 500 kW size cap for these facilities, as well as the requirements of Rate NM that they be at one site and used primarily to serve their owners. Otherwise, this subsidization could provide a significant competitive advantage to business customers who are in a position to take advantage of net metering for CHP or WHP over those who are not. Use of a partial requirements (standby) tariff is more appropriate, particularly for larger customers pursuing CHP and WHP. In Docket No. RPU-2013-0004, MidAmerican filed updated standby tariffs that were supported by parties interested in promoting CHP development, so the Board should have no qualms about applying those tariffs to CHP or WHP facilities.

d. Allow an annual cashout of the net metering balance.

As noted above, one problem with a cashout is that it may convert a net metering arrangement to a wholesale sale and require approval of the FERC.

Assuming a cashout can be authorized by the Board under Iowa law without running afoul of the Federal Power Act, this is a question where the Board needs to consider what its goals should be regarding implementation of DG facilities. An annual cashout of the net metering balance is not consistent with the goal of allowing net metered customers to largely self-supply their own electricity needs. Under Rate NM, with its focus on a resource sized to meet individual customer needs, there should not be an accumulation of a large balance to be cashed out. If the Board does not restructure net metering rates to eliminate subsidies, allowing an annual cashout of net metering balances at full retail rates would encourage customers to overbuild their DG systems in order to take advantage of the subsidies contained in net metering.

One way to ensure that overbuilding is not incented would be for the Board to limit the amount cashed out to no more than 5% or less of the customer's annual DG production.

There is no statutory or Board rule requirement related to the cashout of net metering balances. The Board could allow for annual cashout of net metering balances through a Board order after appropriate measures are in place to ensure no subsidization is involved in such payments. Ultimately, if a customer wants to use production to offset purchases of energy from the utility, the customer can use net metering with the unlimited rolling forward of excess credits. If a customer wants to get into the business of selling power to the utility, that is what the QF rate is for, and the customer should not be net metering at all.

e. Include aggregate metering for customers that may have more than one meter on their premises.

In answering this question, MidAmerican assumes that aggregation would be of "behind the meter" accounts of one customer with multiple meters and would not rely on the utility distribution system. Any other type of aggregation would be retail wheeling. Aggregation was not envisioned by FERC in *MidAmerican* with its illustration of single farms, homes or similar entities, so it may result in a wholesale sale of power subject to regulation of the FERC. If these obstacles do not stand in the way of meter aggregation, additional efforts should be made to make sure aggregation does not result in preferential treatment under standard filed rates. For example, combining usage on more than one netted meter should not let a customer move from a medium to a large volume rate. It would not be appropriate to aggregate metering for customers who have more than one meter on their premises for net metering purposes if that metering is not aggregated for billing purposes under standard retail rates. If the information from the separate meters is not aggregated for billing purposes, crediting the amounts produced from the DG facility against each meter separately would be somewhat problematic. If the DG customer is

allowed to combine the metering information for billing purposes, other customers with multiple meters on their premises may believe they are being subjected to discriminatory treatment. An appropriate solution would be for DG customers to install their own distribution facilities in order to combine the separate loads so that they flow through a single meter. DG customers should not be permitted to engage in unlawful retail wheeling using MidAmerican facilities simply by relabeling the service as aggregated DG.

2. How does the utility account for energy "purchased" through net metering when reporting fuel type information to the Board, the United States Energy Information Administration, the Federal Energy Regulatory Commission, and others?

MidAmerican does not "purchase" energy through net metering. Energy from DG reduces retail sales, as opposed to increasing purchases. Energy produced by the generation of net metered customers can only be used to offset a customer's requirement to pay the utility's bundled rate (or rate block) for electric service through the billing process. Under the current Iowa net metering rules, this offset need not occur contemporaneously with the net metered customer's DG production, but instead can occur any time within the billing period in which the DG production occurred (including before the production occurred) and thereafter.

<u>Questions 3 and 4 for the rural electric cooperatives (REC) and municipal utility associations</u>:

MidAmerican has no comments related to these questions.

<u>Questions for all participants</u>:

5. Currently Iowa does not offer feed-in tariffs. Explain why you think feed-in tariffs should or should not be implemented in Iowa. In your discussion, address the advantages and disadvantages of both net metering and feed-in tariffs.

Both feed-in tariffs and net metering hypothecate a value of DG deliveries to the grid. Net metering assumes the value is always equal to utility rate blocks for bundled service. Feed-

in tariffs are somewhat more transparent, but often are set based upon the price (not value) that DG proponents claim they need to make a profit on DG installations. Neither approach actually measures the value to customers of DG deliveries to the grid. It is critical to always keep in mind that the utility does not ultimately pay for net metering or for feed-in tariffs or even for whatever the Board ultimately determines to be the value of DG delivered to the grid – it is Iowa retail customers who pay.

Feed-in tariffs should not be implemented in Iowa for the reasons explained below. MidAmerican has commented on the disadvantages of net metering in previous comments and with additional comments elsewhere in this response.

Feed-in tariffs typically involve long-term commitments at a fixed rate set above avoided cost. After that fixed price term is exceeded, a lower rate usually is negotiated with the supplier. This enables the facility owner to secure a loan based on the utility commitment to purchase at a defined rate for a specified period of time, usually equal to the term of the loan. This mechanism effectively shifts economic risk from the supplier to the purchasing utility and its customers. The tariff also results in higher costs for energy supply for customers since rates are above system avoided cost. The argument can be made that after the term of the commitment is exceeded to buy at higher than avoided costs, customers benefit from a lower rate. That argument suffers in two aspects. First, there is no guarantee that the supplier will still be producing at that point. Second, there is no guarantee that customers are held harmless over the full life of the purchase, even if the facility continues to operate. If the state decides to encourage these types of facilities, it would be better to be transparent through expanded use of tax credits or other mechanisms that provide direct, defined benefits to the facility owners.

There are also regulatory and legal aspects to feed-in tariffs that need to be considered. A series of orders[4] issued by the FERC have authorized feed-in tariffs in limited circumstances. Specifically, these orders clarified that there can be multi-tiered avoided cost rate structures, but they must be consistent with the PURPA requirements. FERC has reasoned that states have the prerogative to favor the development of particular types of generation resources, such as through renewable portfolio standards (RPS), and that these generation costs will be relevant to the determination of avoided cost for those procurement activities.[5] FERC also clarified that bonuses or adders that are not reflective of avoided costs, although outside the confines of PURPA, may be authorized by a state through the creation of renewable energy credits to recognize environmental attributes.[6]

The Legislature, in enacting Iowa Code § 476.41-44, established an RPS for Iowa and determined the avoided costs for the resources used to meet that obligation. By Order issued in Docket No. AEP-07-3, the Board found that obligation was satisfied for MidAmerican and, further, that any changes in resources used to meet these obligations would require Board approval. In order to have multi-tiered avoided costs, it would seem that the Board would need to create an additional RPS. It would be inconsistent with Iowa law for the Board on its own to take such action. While a feed-in tariff sounds like an innocuous regulatory action, the Board would exceed its statutory authority and violate PURPA if it were to adopt a feed-in tariff without a new RPS. MidAmerican adds that Iowa has demonstrated to the entire country that substantial renewable assets can be built without the mandate of a large RPS compelling such additions. In light of such success, a law providing for a feed-in tariff is unnecessary.

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[4] *Cal. Pub. Utils. Comm'n,* 132 FERC ¶ 61,047, *clarified*, 133 FERC ¶ 61,059 (2010) ["Clarifying Order"], *reh'g denied* 134 FERC ¶ 61,044 (2011).
[5] *Clarifying Order* at ¶¶ 26-27.
[6] *Id.* at ¶ 31.

6. Comment on whether you believe the Board has jurisdiction to extend the net metering requirement to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

MidAmerican has no comments related to this question.

7. If you believe that net metering results in cross subsidization of DG customers by non-DG customers, how should the net metering rule be revised to reduce or eliminate such cross-subsidization?

For residential and small commercial customer classes that take service under energy only rates (no demand charges), there is a significant level of subsidization of DG customers taking service under net metering by non-DG customers related to distribution service and, to a lesser extent, transmission service.

For example, if one assumes that the distribution component of the standard residential rate is $.025/kWh, for every kWh that is net metered by a DG customer, the utility effectively forgives that $.025/kWh for the use of the utility's distribution system by the DG customer, even though the DG customer has made no investment in facilities that allow the DG customer to deliver the excess energy produced by the DG facility to the utility. If a DG customer effectively nets its usage in a billing month to zero kWh, it owes the utility nothing for distribution, even if it drew power from the grid in significant amounts and, therefore, required utility-owned distribution facilities to be in place to provide that service. In this situation, it is left to other non-DG customers to pay for those distribution investments.

It is possible to eliminate most of the cross-subsidization problem by implementing demand rates with time-of-use (TOU) energy rates for residential and small commercial DG customers, where the allocated costs of providing distribution and transmission service are collected in the demand charge, as opposed to volumetric $/kWh charges. Demand/TOU rates can be developed for DG customers, based on the data already provided in MidAmerican's most

recent electric rate case Docket No. RPU-2013-0004, that is revenue-neutral to non-DG customers in the same rate class. Additionally, these demand rates would be consistent with cost of service principles used in Docket No. RPU-2013-0004, which allocate distribution and transmission costs to customer classes based on various measures of class peak demand. This approach reasonably ensures that all customers, both DG and non-DG, pay the costs that the utility incurs in providing service to both DG and non-DG customers. MidAmerican notes that there is nothing in the current net metering rules that dictates the specific rate design to be used to provide service to DG customers, so implementation of demand/TOU rates for DG customers likely does not require a change to the net metering rules.

8. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

Current net metering arrangements for residential and small commercial customer classes that take service under energy only rates (no demand charges) significantly over-compensate these customers for the limited benefits provided to non-DG customers. If this over-compensation is to be resolved, the rates that net metering customers pay the utility must be restructured. Implementation of the demand/TOU rates discussed in response to Question 7 above would alleviate this situation as it relates to distribution and transmission service. If DG customers can reduce their monthly peak demands via use of their DG facilities, they will be fairly benefitted through avoidance of demand charges. If DG customers cannot or do not reduce monthly peak demands even though they reduce or eliminate their overall kWh purchases from the grid, it is clear that they do not provide benefits to the distribution or transmission system and they should not see a reduction in cost for those services.

It is more likely that the benefits provided by DG customers come in the form of generation benefits. Development of generation charges on a TOU basis, as discussed above in response to Question 7, would provide clear and appropriate price signals to DG customers regarding the value of the energy and capacity being provided by their DG facilities, and would help to ensure that DG customers are appropriately compensated for the generation benefits they provide to the system.

Questions for electric utility customers:

MidAmerican has no comments related to questions numbered 9 and 10.

With respect to interconnection, the Board has the following questions for all participants:

1. Do the current interconnection rules ensure that DG installations are safe for customers and utility employees? If not, what specific changes are needed to ensure safe installation and operation of DG equipment? Include specific examples of safety problems, if any, and customer or utility behaviors that may compromise safety.

Yes, for known DG installations that follow the current interconnection rules and the electrical inspection process, the DG installations are safe for customers and utility employees at the time of initial installation. These rules – all of which are necessary to provide protection – include the electrical inspection process by the appropriate local authority, the utility's review of the application and completed screens, the witness test by the utility, and the installed disconnect switch.

After the initial installation, there may not be the same level of oversight. If the DG installation is not adequately maintained or is altered without notifying the electrical inspector or utility, there is no required periodic inspection or testing of the DG installation that would reduce the potential for safety issues. If issues were discovered by the utility with such an installation, the existing rules would enable the utility to work with the DG customer to resolve the issues.

The installed disconnect switch provides added benefits to the utility worker for these non-maintained or altered installations that could cause safety issues.

2. Is there an issue with customer DG installations occurring without the knowledge of the utility? If so, what is the magnitude of this problem, and how should it be addressed?

Yes, there are instances where DG installations have occurred without the knowledge of the utility. These instances could result in safety, asset protection or reliability issues, depending on the nature of the DG installation. MidAmerican is aware of instances in its service territory where customers installed DG facilities without notification to the utility, but MidAmerican later found out and requested that the customer follow the interconnection process. The magnitude of those not following the interconnection rules on the MidAmerican system is likely small at this time, but the issue exists. MidAmerican may not be aware of all installations that may exist on its system.

Increased public awareness of the recent Iowa law requiring notification to the host utility of installation of renewable generation could be beneficial to all involved and the system. It should be noted that the interconnection rules process may exceed the 30-day advance notice in the law, such that a longer notice would be more beneficial to those involved in the interconnection.

3. Are rule changes necessary to ensure system reliability is not harmed due to the interconnection of DG resources? Provide specific examples of reliability effects from the interconnection of DG.

The interconnection rules provide reasonable methods to ensure system reliability in most DG installation scenarios. One particular scenario that is not explicitly covered in the interconnection rules is where an entire development is promoted as having renewable generation or even required to have such generation. This scenario is more likely to occur with

solar in a new residential development and exists in our service territory, but it also could occur in commercial or industrial areas. The existing rules do not enable a review of such a development and the planned DG as a whole. This review process would be beneficial to the customers and the utility in order to see if such a development may cause the need for system upgrades, rather than discovering the need for the system upgrades when the last of the customers in the development request interconnection and are assigned the upgrade costs.

While the existing rules allow for cost recovery of required interconnection facilities and upgrades because of a request, it should be recognized that there are generation thresholds that can result in required upgrades at the secondary, transformer, feeder tap, and further upstream system to accommodate the generation. This is especially true in a development where all or most customers have DG. There is a concern that with more and larger kW interconnection requests, the likelihood increases that the next interconnection request may trigger a required upgrade.

The following are potential reliability effects from the interconnection of DG:

- Reverse power flow from the distributed generator to the distribution system may damage equipment not designed for flow in this direction.
- Service restoration to customers during outages may take longer because electric crews may need to assure that all distributed generators on an affected circuit are visibly disconnected.
- High voltages during certain periods of light load may occur near each distributed generator and nearby customers.
- Voltage step changes may occur when the distributed generator is cycling output, such as cloud cover for solar generators.
- Circuit islanding may occur if the sum of the distributed generation exceeds the load on that circuit.
- During certain periods of under frequency, the strict settings on the distributed generators may exacerbate the under frequency problem.

4. Considering the benefits that accrue to the system from DG, what is the correct price to charge for interconnection of DG systems? Should this price be technology dependent?

Benefits accruing to the system from DG are very limited. Since MidAmerican is required to serve its customers, all DG customers benefit from the interconnected generation, transmission, and distribution system and should pay the full cost to interconnect and use the system, regardless of the DG technology.

5. How should distribution or transmission system upgrade costs associated with DG installations be properly allocated? Are there specific benefits that all customers (DG-owning and non-DG owning) receive from DG required transmission or distribution upgrades and, if so, what are the specific benefits?

Under traditional cost of service ratemaking, an allocation of system upgrade costs to DG customers requires that DG customers be set aside as a separate customer class within cost of service. It would also be required that these system upgrade costs be separately identifiable in a way that they can be separately allocated to DG customer classes.

While there is every indication that the typical load shape for a DG customer is different than a non-DG customer, therefore justifying separate customer classes in cost of service, the exact nature of that load shape will be theoretical until there are enough DG customers on the system such that an accurate and stable DG load shape can be developed. This makes allocation of specific costs to DG customers problematic for the purposes of ratemaking in the short term. It is also likely that general distribution and transmission system upgrades will provide benefits to all customers, even though those upgrades may have been caused by DG customers. For these reasons, and because of the potential difficulty of maintaining separate cost categories for DG-related upgrade costs, DG-related distribution and transmission system upgrade costs should be treated in the same way that all other distribution and transmission costs are treated for the purposes of cost allocation and rate design.

6. Is there adequate protection for distribution assets from improperly installed DG equipment? If not, what additional protections are needed?

Yes, for known DG installations that follow the current interconnection rules, there is adequate protection for distribution assets at the time of initial installation. The electrical inspection process by the appropriate authority, the utility's review of the application and completed screens, the witness test by the utility, and the installed disconnect switch provide protection.

If the DG installation is not adequately maintained or is altered without notifying the electrical inspector or utility, there is no required periodic inspection or testing of the DG installation that would reduce the potential for adverse effects on the distribution assets. If there were customer complaints or issues discovered by the utility with such an installation, the existing rules would enable the utility to work with the DG customer to resolve the issues. The installed disconnect switch provides added benefits to the utility system and the non-DG customers for these non-maintained or altered installations that could cause damage or issues on the system.

7. Should the Board revise its interconnection rules in 199 IAC 45 to make them consistent with FERC's updated interconnection rules, which were adopted on November 11, 2013, in Docket No. RM13-2-0001 (Order No. 792) and can be found at 145 FERC Paragraph 61,159? In what specific ways should the Board's rules be revised?

There are no specific items from FERC's revised rules that require immediate changes to the Iowa interconnection rules.

8. Should the Board require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time. If so, why? If not, why not?

If such requirements were enacted by the Board, a large effort would be placed on the state or interconnected utility to periodically inspect and enforce such requirements. This would

be labor intensive, even for moderate DG penetration levels. Additionally, what criteria would be used to determine if a DG facility is properly maintained? If the DG facility is not properly maintained, what would be the remedy? How would disagreements with the DG owner be resolved? The requirements could also cause interference with a property owner wanting to sell property.

The DG owner is already obligated in the interconnection agreement to operate and maintain interconnection facilities in good working condition in order to protect the reliability of the electric system. As stated above, the electrical inspection process by the appropriate authority, the utility's review of the application and completed screens, the witness test by the utility, and the installed disconnect switch provide adequate protection to the utility's system.

9. For customers that have installed DG, what have been the positive and negative experiences when interconnecting with the utility and what specific changes would you suggest? (Identify whether the DG facility was renewable or nonrenewable and which utility you interconnected with.)

a. Does the interconnection process timeline take longer than necessary? If so, what are the problems and how can they be solved?

b. Has any DG owner-commenter experienced difficulty interconnecting a DG project with the system of any non-rate-regulated utility or utilities? If so, please describe the difficulty experienced and whether/how the difficulty was resolved.

MidAmerican has no comments related to this question.

10. Comment on whether you believe the Board has jurisdiction to extend its interconnection rules to coops and municipal utilities and if so, whether it should exercise such jurisdiction

MidAmerican has no comments related to this question.

<u>With respect to consumer protection and education, the Board has the following questions for all participants</u>:

1. Is there a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations? If so, whose role is it and what type of education should be provided?

Yes, there is a need to educate customers as there is a tremendous amount of scattered information available on these topics from a variety of sources, including utilities, government agencies, and the solar industry. There is a need to ensure Iowans have sources for objective and factual information available to make decisions about DG. Because DG is interconnected with the utility system, utilities and their regulators are logical points of contact for much of this information. MidAmerican has recently added information pertinent to its role in DG to its website. The information covers installation basics, safety, reliability, rate structure, and frequently asked questions.

Some of the topics referenced in the question are outside the scope of the utility's role in DG, such as tax incentives and reputable installers. It would be appropriate for a government agency such as the Board, working with other state agencies and organizations, to be the known and reliable source leading Iowa consumers to factual information on all aspects of DG. The agency could function more or less as a clearinghouse for factual information developed by other agencies, but it is also important that any information it provides constitutes verifiable facts, and not opinions.

2. Should the Board develop a checklist to assist customers in understanding the process and responsibilities associated with installing DG or does one already exist? What issues should consumers consider when installing DG (both renewable and nonrenewable)?

The Board should take reasonable steps to ensure customers are fully informed about responsibilities and processes surrounding DG facilities. Customers have a choice and they need to make informed choices regarding DG participation. Many times, the only source of DG information might come from a vendor and it is important for a customer to have access from various sources. With that in mind, MidAmerican took steps this year to provide education about

DG facilities to our customers by adding information on our website.[7] The following information is included:

- A description of DG;
- Material on how energy is delivered to a traditional customer and a DG customer;
- Responsibilities of a DG customer;
- Description of the interconnection process;
- Discussion of safety and reliability aspects; and
- The DG rate structure options.

MidAmerican also included on its website a decision-making checklist that DG customers can use to review whether important issues are clearly addressed in their DG contracts.

The Iowa Energy Center provides an additional source of information for DG installations and economics. The Iowa Energy Center is funded through contributions from all electric and natural gas customers in Iowa.

The Board could develop a similar site on its website or provide links to information on utility websites, such as MidAmerican's, and to the Iowa Energy Center's website.

The Board also had the following general questions related to DG:

3. With respect to public safety, who is primarily responsible for the issue of firefighter safety and fire suppression activities, the customer or the local fire officials?

a. Should customers be required to provide local fire officials information regarding their solar installations?

b. Should fire officials be required or encouraged to maintain detailed logs regarding solar installations in their community or fire district?

There are two primary concerns with solar DG in firefighting activities. In the event of a fire, firefighters need to be able to disconnect power sources and access rooftops. Both of these aspects are addressed in the 2012 International Fire Code at section 605.11. The 2012 International Fire Code includes requirements for marking electrical equipment and its location.

[7] http://www.midamericanenergy.com/environment7.aspx

The Code also includes requirements for access, pathways, and smoke ventilation for rooftop solar collectors.

The Iowa Fire Marshal and most Iowa cities have adopted the 2009 International Fire Code, not the 2012 version. A 2015 version is under development and is expected to include these requirements and perhaps more, given the continued development of rooftop solar since 2012.

Because of the level of detail required for solar installations in the 2012 International Fire Code, it is clear that they are perceived as posing some level of safety risk. As a matter of public safety, customers should be required to provide information to local fire officials on their solar installations and, for that matter, on all DG installations. City fire departments typically maintain detailed records by address, and certain types of facilities, such as fuel storage tanks, are already required to be registered with the fire department. It is likely that solar installations could easily be "flagged" by address in the fire department system. This type of information would be an additional cross check in the event a solar facility is not compliant with the Fire Code or if protections such as required markings on conduit at the site are dim or non-existent.

4. Do current Iowa consumer protection laws adequately address the responsibilities of the DG suppliers/distributors? Who should be responsibility for resolving consumer complaints regarding DG suppliers/distributors (Iowa Utilities Board, the Attorney General's office, or some other agency)?

5. Should DG suppliers/distributors be required to be certified as qualified to supply/install the equipment/project in question? Who should perform the certification? Who, if anyone, should maintain a listing of certified DG contractors/installers?

MidAmerican's response for Questions 4 and 5 are combined below.

In its initial comments at pp. 18-19, MidAmerican addressed in detail its views on consumer protections. These views are founded in the role of DG as a substitute for utility

generation. Much of the regulation of utilities is intended to ensure the reliability of a level of supply to customers. Even though DG, as defined in MidAmerican's Rate NB, is primarily used to serve the owner of the DG facility, the net metering rate assumes that the value of every kWh of net metered production delivered to the grid is always equal to the rate block that the net metered customer avoids paying for bundled electric service (generation, transmission, and distribution services). If DG is to perform the key role of substituting for utility-generated electricity only, then it is appropriate for the Board to regulate this supply in all respects. In fact, much of the regulation surrounding utility generation is intended to ensure that it will be available whenever needed to serve load, which suggests that regulation of DG suppliers, installers, and distributors is the most appropriate role for the Board. If DG resources are not intended to be of the same caliber as utility generation resources, then the pricing of DG resources needs to change to reflect that reduced value and a different level of utility regulation of DG may be sufficient. A way to provide further assurance that DG is a substitute for utility generation is to regulate the resource to provide greater assurance of its availability to the utility.

Presently, beyond the interconnection process, there is limited regulation of DG suppliers, distributors or installations. As with other consumer products, consumers dissatisfied with their DG equipment are generally limited to seeking redress through the Attorney General's consumer fraud division, through private resources such as the Better Business Bureau, through the courts by civil litigation regarding breach of contract, fraud or other similar theories, or under the criminal laws applied to consumer frauds (Iowa Code § 714.16), should a vendor use deception or fraud in the sale of a DG unit. In addition, there is regulation of installers through electrician and HVAC installer regulation (unless the DG system is self-installed), but customers have no assurance that their installers received appropriate training in DG installations.

The Board has found within its plenary authority the ability to regulate DG interconnection. The purpose of regulation of interconnections was not only to ensure the reliability of the grid, but also to provide a standardized method of interconnection and standard contracts for all rate-regulated utilities to advance DG in Iowa. If the Board wants to continue to advance DG, it would be appropriate for the Board to regulate other parts of the DG process, such as DG device supply and installation. In its initial comments at pp. 18-19, MidAmerican outlined the simple certification process for DG installers that has been in place in Illinois since January 1, 2014. The act of certification of installers or suppliers will not involve the Board in professional regulation, but instead in the determination of the types of skills that must be maintained. Handling of complaints about DG installers, distributors, and suppliers would be a logical extension of the certification responsibility, as would maintenance of lists of certified DG contractors/installers. As an impartial and informed supplier of DG information, MidAmerican would also recommend the Board produce and publicize the availability of a checklist of considerations for DG customers.

The level of regulation that is appropriate for DG in all respects depends on the role DG is intended to play as an energy resource. If the Board compensates DG as it would any other power source that can be used by utility customers, the level of regulation should be comparable to utility supply regulation to make sure the resource is reliably available to utility customers.

<u>Question for all utility participants</u>:

1. **For calendar year 2013, provide the following detailed information (in an Excel file) related to each DG facility connected to your utility system:**
    a. **Nameplate capacity;**
    b. **Date interconnected;**
    c. **Fuel type;**
    d. **Include all applicable classifications (i.e., qualified facility (QF), alternate energy production (AEP), net metering, and any others that may apply)**

e. For AEP interconnections, indicate whether this facility contributes to compliance with your AEP purchase obligation;
f. Indicate whether this facility is subject to a tariff or contracted rate;
g. The applicable retail tariff customer class; and
h. Indicate whether hourly load data are available for this facility.

See Attachment No. 1 for the information requested.

<u>Questions for all participants</u>:

2. Should Iowa have a policy goal to increase and diversify alternate energy production? If so, should that policy be achieved with utility-owned centralized generation, utility-owned distributed generation, customer-owned distributed generation or a mix of these alternatives? Discuss the advantages and disadvantages of these approaches.

Iowa should continue to have a broad approach to energy supply. All resources including, but not limited to, energy efficiency, natural gas, and utility and customer-owned wind, solar, and other renewables should be considered to help address future energy needs. Iowa's competitive low energy rates are a product of a diverse energy portfolio. Iowa's policies should continue to be focused on reasonable low cost resources, taking into account impacts on customer rates when achieving a proper balance of resources. As was discussed in MidAmerican's initial comments, that was the approach taken in the early 2000s when policies were constructed that led to significant generation being built in Iowa. These policies were not based on mandates. Rather, the policies were based on addressing barriers to encourage investment with emphasis on minimizing rate impacts on customers.

3. What are the current incentives, if any, for the utility to promote DG and for the customer to own DG? Should alignment of DG production with utility peak demand be the target of an incentive?

The current rate structure under which DG partial requirements customers receive full requirements service and current net metering policies create disincentives for MidAmerican to promote DG and barriers to integrating DG into the grid in an equitable manner that does not

benefit DG owners at the expense of all other customers. Getting the rates for sales to DG customers "right" and compensation to DG customers for deliveries to the grid "right" are the best incentives for DG. If Iowa can get those factors right, MidAmerican could potentially promote DG and offer its customers a DG option that would be regulated by the Board. Such participation could take the form of locally-sited solar installations owned, operated, and maintained by MidAmerican in which individual customers could choose to participate. This customer/utility collaboration also has added benefits of being located and, in the case of solar, oriented where it is determined by the utility to bring the most benefits to the resource mix and transmission and distribution system, and minimize any adverse reliability and safety impacts.

As to the question concerning whether alignment of DG production with utility peak demand should be the target of an incentive, with the proper rate structure, the DG customer will be incented to choose a type of DG facility that will maximize its economic benefits and bring appropriate value to the utility. For example, under current net metering rate design, the DG customer is incented to maximize energy production, not to assist the utility in minimizing and serving peak demand. In the proper rate structure, DG customers should consider energy production and reduced peak demand and, depending on the type of DG facility and its operating characteristics, customers may conclude that it is in their best economic interests to optimize peak demand and energy production in total rather than just maximizing energy production.

4. **Do utilities include distributed generation in their resource planning? If so, how is DG accounted for? If not, why and is this likely to change?**

MidAmerican includes DG in capacity credit planning to the extent such resources can be registered with the MISO. Load serving entities in MISO plan to meet the resource adequacy requirements defined in Module E of the Open Access Transmission, Energy and Operating Reserve Markets Tariff by registering capacity credits to meet forecasted peak demand

requirements. In order to be eligible for capacity credits, MidAmerican, as the market participant, must own or have contracts with the capacity resources and register these resources with MISO. DG assets registered with MISO for capacity credits as a Load Modifying Resource would need to have an obligation to be made available during emergencies. While MidAmerican has some behind the meter generation that meets these requirements, this would likely not be the case for small DG installations.

Peak demand and energy forecasts for load are net of DG not registered with MISO. Historical load data includes energy production from non-registered DG. Should significant increases in the amount of DG occur, new forecasting methods to include DG as a separate forecast may be required.

5. What is the rate of DG adoption currently experienced by each utility and what is the rate projected to be in the next five to ten years? Do these adoption rates cause problems with transmission and distribution planning? How do utilities cope with this challenge?

As provided in MidAmerican's original response, DG is not new to the MidAmerican electric system. There are 156 DG facilities on the system with 139 under the net meter tariff. Interest in solar rooftop facilities has increased over the last few years and we expect that to continue. We do not have projections nor have we determined a level where transmission and distribution planning issues may appear. Now is the time to address DG issues raised by this inquiry before penetration levels cause potential reliability and system planning issues, and before cross subsidization issues create significant rate increases for customers who do not have DG facilities.

The question asks how utilities cope with the DG challenge. DG is just one of the many issues we deal with on a day-to-day basis as we plan and operate the electric system and deliver energy supply to our customers. The plans developed to achieve our goal of being the best

energy company in serving our customers, while delivering sustainable energy solutions, typically include addressing possible impacts of many variables, such as environmental policy and regulations, load growth, wholesale electric prices, projected coal and natural gas prices, costs of materials and supplies, and many other factors. We deal with uncertainty in many aspects of our business, and the challenges of DG are just another factor to include in our analyses and planning.

WHEREFORE, MidAmerican Energy Company respectfully requests the Iowa Utilities Board to take these comments into consideration as it continues to develop policies regarding distributed generation.

DATED this 24th day of June, 2014.

Respectfully submitted,

MIDAMERICAN ENERGY COMPANY

/s/ Suzan M. Stewart

BY:_____

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