Please note: Ameren Illinois is providing this information as part of a Commission Staff-initiated workshop. Given that these discussions pertain to past litigation and may ultimately culminate in additional contested cases in the future, Ameren Illinois considers this information to be distributed in the context of a confidential settlement discussion, subject to Illinois Rule of Evidence 408.

Ameren Illinois appreciates this opportunity to provide comments related to the Illinois Commerce Commission’s June 28 Distributed Generation Valuation and Compensation workshop and the associated Distributed Generation Valuation and Compensation white paper, version 2. Developing an accurate, fair, and manageable distributed generation valuation methodology is important to ensure a) customers have appropriate information to base economic decisions, b) utilities can efficiently and effectively manage the distribution system, and c) the State can meet its energy goals.

As outlined in the initial comments provided on March 29, Ameren Illinois reiterates its belief that the determination of the value of distributed generation to the distribution system may be guided by a few key concepts.

1. While the term distributed generation will be used throughout these comments to be consistent with the Future Energy Jobs Act (FEJA), a more widely used term that may better encompass the full breadth of technologies and applications that may be connected to the distribution grid is distributed energy resource or DER. Ameren Illinois considers a broad definition of DER in which DER is defined to broadly encompass any generation, storage, or other load managing resource connected to the distribution grid.

2. Notwithstanding, FEJA calls for an assessment of the value of distributed generation or DG to the distribution system. While distributed generation may provide value in other channels (i.e., generation, transmission, ancillary services), and to various parties (i.e. customer, society), the focus contemplated by FEJA is its value to the distribution system.

3. When considering the value of distributed generation to the distribution system, the valuation should take into account:
   a. The specific location on the distribution system, possibly down to the distribution line transformer.
   b. The times of day, week, or year it is available, and during what types of weather.
   c. The capabilities the distributed generation can provide (real power, reactive power, or both).
   d. Other distributed generation operating characteristics (ramp rates, voltage support, dispatch ability, etc.)

Several questions have been posed to help further frame the Illinois context and advance the discussion on how to comply with distributed generation valuation contemplated by FEJA. Ameren Illinois’ responses to the specific questions are provided below.

1. Please provide any suggested revisions to the June White Paper.
Ameren Illinois has only one suggested revision to the June White Paper. Ameren Illinois does not agree that AIC's initial proposed distributed generation valuation approach is similar to Minnesota's. AIC's approach differs in many ways, including the following:

1. Minnesota’s approach addresses the value of solar (VOS) to the grid and does not address other DER types. AIC intends to build a framework that addresses different types of DER.
2. Minnesota’s approach is not location/geographic specific. Minnesota’s approach is a tariff structure that is evaluated at a system wide level applicable to every location on the electric distribution network. AIC believes the PUA (Section 16-107.6(e)) contemplates a framework that evaluates the value of DG to the distribution system at the smallest practical distribution system asset level.
3. Minnesota’s approach considered value blocks outside the distribution system, such as: Generation Capacity, Energy, Environmental and Distribution Capacity. The PUA properly appears to focus on the value of DG to the distribution system only.
4. Minnesota’s approach does not consider the value of Volt/Var support to the distribution system. AIC’s approach considers the value of DER in providing Volt/Var support to the distribution system.

2. What general approaches, whether they were included in the June White Paper or not, should be considered for use in Illinois?

In addition to the key concepts outlined above, Ameren Illinois offers the following framework which builds on the Company's previous comments:

The process should generally include:

1. System capacity studies starting at the smallest distribution system asset level (distribution line transformer) then aggregate results upstream towards the bulk supply sub-transmission power transformer. These studies could compare baseline system capacity (current state of the distribution system) against cases of distributed generation penetration at specific locations on the distribution system. These studies will use hourly historical load data, hourly load forecast data, DER generation profiles and current AIC planning and reliability criteria to assess system capacity needs at each distribution transformer node for a given distribution feeder. Costs of system upgrades for the current distribution system snap shot will be compared with costs of system upgrades with DER connected at a given location on the distribution system.

2. System line loss study comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system. System reliability studies including voltage, protection and phase balance comparing baseline (current state of the
distribution system) against cases with distributed generation penetration at specific locations of the distribution system. These studies will use hourly historical load data, hourly load forecast data, DER generation profiles and current AIC planning and reliability criteria to assess system capacity needs at each distribution transformer node for a given distribution feeder. Costs of system upgrades for the current distribution system snapshot will be compared with costs of system upgrades with DER connected at a given location on the distribution system.

3. Using the above results, an economic analysis could be used to determine the value of distributed generation at the specified location on the distribution system.

3. Regarding the different benefits of distributed energy resources, please provide input on the following:

   a. Which value streams should be included in the Section 16-107.6 DG rebate?

      See framework above. As outlined, there are only three types of value that should be considered:

      1. Avoided distribution capacity costs
      2. Reduction in distribution losses,
      3. Value of voltage support that may be realized from distributed generation.

   b. Which value streams should be separately compensated pursuant to Section 16-107.6?

      Other value streams that could be considered as additional services for separate compensation under Section 16-107.6 could include operating reserves, and frequency regulation. Compensation for operating reserves and frequency regulation would flow from the applicable regional transmission organization’s (RTO) available markets.

   c. Which value streams are outside the scope of Section 16-107.6?

      All non-grid related value streams such as, for example, societal value, carbon reduction value, etc.

   d. How do value streams differ by project? For example, how do they differ for projects with smart inverters and those without?
The applicable value streams would not change by project, but the value calculation would change by project, depending on the type and characteristics of the DER and the inverter being used.

As to the specific issue of valuing and providing rebates to non-smart inverter installations, the application of any rebate should only apply to those non-smart inverter installations specifically referenced in the law, namely net metering customers who began taking service prior to June 1, 2017. It is in the best interest of all parties to limit the number of non-smart inverters on the grid. In fact, the Commission should consider requiring all new installations to use a smart inverter going forward, perhaps as an interconnection requirement.

e. How are any value streams reflected in current rate structures and how are they currently calculated?

As mentioned above, there are already rate structures in place or further proscribed by FEJA related to energy. Societal and carbon value of renewable generation is already captured in the Renewable Energy Credit framework already outlined in FEJA.

4. Regarding the calculations of the various value streams, if not included in your general response, please provide input on the following:

a. How should each value stream that is included in the Section 16-017.6 DG rebate be calculated?

See framework outlined in answer to #2 above.

b. What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the value of each value stream that should be included in the Section 16-107.6 DG rebate?

See framework outlined in answer to #2 above.

c. How should each value stream that is separately compensated pursuant to Section 16-107.6 be calculated?

As mentioned above, energy should be calculated in accordance with existing law or tariffs. Compensation for operating reserves and frequency regulation should be consistent with the rules and markets of the applicable RTO.

d. What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the
value of each value stream that should be separately compensated pursuant to Section 16-107.6?

Initially, no distribution system data is necessary for computing the value streams for separate compensation as outlined above. In the longer term, it may be appropriate to add a locational factor to the energy supply value based on the metered location on the distribution system. For this factor to be calculated, real time distribution system constraint / operating data would be needed.

e. Should utility service areas be divided into distribution areas for the characterization of locational value and, if so, how?

See framework outlined in answer to #2 above.

f. Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?

The framework outlines in #2 above if taken to the full extent would provide a unique value for every distribution transformer location on the system for each type of distributed generation type (solar, wind, etc.). With over 400,000 distribution transformers on the Ameren Illinois system, from a practical rebate communication and management standpoint, it may be beneficial to develop a more reasonable number of $ value categories (say 3-5 categories), that could be applied to each type of distributed generation for every distribution transformer location. The use of a circuit-level (or further upstream towards the bulk supply network) value may initially be practical and appropriate, although ultimately the benefits of geographic-, time- and performance-based value criteria will be better realized by the use of a distribution line transformer-level value.

g. Should calculations be standardized across utilities, areas, or other characteristics?

Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences in data type / availability, system configurations, operating parameters, etc.

5. For the distribution system data, pricing data, forecasts, analysis results, formulas, or other information that is necessary to compute the value of each value stream, please provide input on the following:

a. Should there be standardization with respect to information used to compute values?
Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences data type / availability, system configurations, operating parameters, etc.

b. **Should there be standardization with respect to formulas used to compute values?**

Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences data type / availability, system configurations, operating parameters, etc.

c. **Should there be transparency requirements with respect to information used to compute values?**

Ameren Illinois recognizes this process will incentivize customers to act as partners in the efficient development and utilization of the grid. Customers and DG developers will need sufficient price and location data to achieve the desired outcome. Ameren Illinois also recognizes the sensitivity of operating and customer data, and the proprietary nature of analysis systems that will be used. It is important to note that much of the data required for the calculation will be customer or operating sensitive and would not be prudent to release to the public. In addition, the software tools used to do the analysis are often specialized and proprietary. Considering these realities, a potential approach could be to make publically available only the methodology, the types of data that are inputs to the methodology, and the final locational computed values that are the outcome of the analysis.

d. **Should utilities be required to develop and share capital and investment plans and, if so, for what periods (for example, 5 year plans, 10 year plans, or some other period), and how often should such plans be updated?**

No more than is already required by existing regulation and practices.

e. **Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?**

See answer to 4f above.

f. **How often should compensation levels be calculated in order to ensure appropriate price signals are provided far enough in advance to meet anticipated need?**
As a starting point, rebate values could be calculated on a yearly basis. As the utilities are able to further refine and automate the calculation methodology, more frequent updates could be considered.

6. Apart from value formulas and/or specific rebate values, should candidate deferral projects, deferred distribution investment, marginal cost studies, or other information be made public?

No more than is already required by existing regulation and practices.

7. In terms of the next procedural steps prior to the initiation of the investigation pursuant to Section 16-107.6, we welcome your comments on the following:

   a. Should the Commission use a designated working group process? If so, how should the working groups be structured, governed, and otherwise implemented?

      Ameren Illinois favors a collaborative and structured process that promotes consensus to the extent possible. Ameren Illinois would be open to any approach proposed by the Commission Staff or the Commission.

      i. Are there areas or particular issues that more readily lend themselves to consensus resolution? If so, should these issues be separated from those issues where consensus may be more difficult to reach?

         At this point in the process it is difficult to determine what the full breadth of issues may be, much less which would more readily lend themselves to consensus resolution.

      ii. Are there any value streams that may take more time to develop that should be separated from value streams that may be more quickly developed?

         The process should first focus on the value streams directly related to the rebate – namely avoided distribution capacity costs, reduction in distribution losses, and value of voltage support that may be realized from distributed generation. The remaining value streams that may be applicable to the Section 16-107.6 process will take much longer to determine as their value will be dependent on the applicable RTO, and there is no existing mechanism in place to measure and manage at the distribution level.

   b. Should the Commission consider using a consultant to help with developing Section 16-107.6 compensation methodologies and values?
Using an experienced, unbiased, and objective third party consultant to help facilitate the discussion and reach as much consensus as possible would be beneficial.