**Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT**

Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning

**4 CSR 240-22.055 Distributed Energy Resource Analysis**

*PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for Distributed Energy Resource analysis and reporting. Planning for future Distributed Energy Resources are to be evaluated as part of the triennial resource planning process, but due to the rapidly evolving technology, relative speed of deployment, and site specific characteristics, this regulation requires some targeted analysis that is different from other rules in Chapter 22.*

1. Definitions. For purposes of this rule:
   1. Congestion means a situation where the desired amount of electricity is unable to flow due to physical limitations;
   2. Cost-effective means that a resource passes one of the cost-effectiveness tests defined by the commission’s Missouri Energy Efficiency Investment Act rules;
2. Distributed Energy Resource (DER) means a resource that can provide all or some of a customer’s immediate electric and power needs and can also be used by the system to either reduce demand, modify the net consumption of energy by customers or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are connected to the distribution system, and close to load. Examples of different types of DERs include distributed generation (DG), distributed energy storage, demand response (DR), electric vehicles (EVs), and energy efficiency (EE);and
3. Distributed Generation means generation of electricity from sources that are near the point of consumption. Examples of different types of DG include solar photovoltaic, wind, combined heat and power (CHP), and microgrids.

(E) Planning horizon means a future time period of at least twenty (20) years’ duration over which the costs and benefits of alternative resource plans are evaluated.

(2) Distributed Generator and Distributed Energy Storage Database. Electric utilities shall create, and update annually, a database of information on distributed generation and distributed energy storage for purposes of evaluating current penetration and planning for future increases in the levels of distributed generation and distributed energy storage as outlined in this subsection (2) below.

(A) Electric utilities will be responsible for maintaining the following information in the database:

1. Known distributed generation and distributed energy storage presently connected to the utility’s grid;

2. Information characterizing the location (according to Geographic Information System coordinates) on the distribution circuits where distributed generation and distributed energy storage are connected;

3. Aggregate capacity of distributed generation and distributed energy storage for each feeder or load; and

4. Relevant interconnection standard and standby service requirements, as applicable, that specify distributed generation and distributed energy storage performance.

(B) To the extent that the electric utility is not in possession of any of the information required herein, it shall state which information it does not possess, the reason the information is not possessed, and how the electric utility will obtain the information for future filings for planning purposes.

(C) The electric utility will file a report as part of its triennial Chapter 22 filing containing a list of feeder circuits displaying the aggregated capacity of the connected distributed generation and distributed energy storage for each feeder circuit, and the annual peak load of the feeder circuit. The electric utility shall also file an updated report annually on the on the anniversary of its triennial Chapter 22 filing between its triennial filings.

1. DER Adoption Potential. As part of each triennial compliance filing, the utility will consider, at a minimum, the potential for cost-effective DER within its service territory to help fulfill the fundamental planning objective set out in 4 CSR 240-22.010. This study must cover no less than a twenty (20) year planning horizon, and will consider both utility-owned DER and non-utility-owned DER. With respect to all DERs except utility- incentivized DG, utility-incentivized CHP, utility-owned or managed EVs, utility-owned or managed energy storage, and utility-incentivized energy storage, the study requirement can be satisfied by relying upon assessments of market potential developed as part of the utility’s load analysis and forecasting pursuant to 4 CSR 240-22.030, the utility’s supply side analysis pursuant to 4 CSR 240-22.040, and/or the utility’s demand side analysis pursuant to 4 CSR 240- 22.050. The assessment of potential shall consider options for utility management of existing DER not currently owned or managed by the utility.
2. Evaluating DERs as part of the Chapter 22 resource planning process. In accordance with the definition of “cost effective” prescribed above, as part of each triennial compliance filing, the utility will include planning for future levels of DERs, and how they will be integrated into the utility’s distribution system as follows:
   1. In order to facilitate DER, the evaluation will acknowledge and reference the obligation of utilities to provide cost-based interconnection and standby service to qualifying facilities, as defined in the Public Utility Regulatory Policy Act of 1978.
   2. DERs will be considered in the transmission and distribution (T&D) analysis required by 4 CSR 240-22.045. This analysis includes existing and potential utility-owned DERs and non-utility-owned DERs. The utility will describe and document:
      1. Reliability concerns which could include areas of congestion which could be improved by DERs;
      2. Avoided or deferred T&D costs as defined in 4 CSR 240-22.045(2) associated with, but not limited to decreased congestion, reduced transmission network losses, and the implementation of “non-wires alternatives; and

3. Acceleration or modification of planned T&D improvements and associated costs and benefits due to increased penetration of DERs.

(C) Evaluation of future deployment of cost-effective DER is to be based on utility- owned or managed DERs and customer-owned DERs.

1. The utility will evaluate the potential for integration of utility and customer-owned DERs to impact grid reliability, to beneficially modify customer energy consumption, and to delay or reduce the size of supply-side resources additions.

(E) The evaluation, including load forecasting, must cover no less than a twenty (20)-year planning horizon, on a year- by-year basis to assess annual and cumulative impacts of DER deployment.

(F) The evaluation must cover an estimate of the reduction in transmission and distribution line losses based upon existing and potential utility-owned DER, as well as existing non-utility-owned DER. The utility may focus its analysis on particular portions of its transmission and distribution systems based on factors including, but not limited to, the need for location-specific upgrades.

(5) The requirements of 4 CSR 240-22.055 shall apply to an electric utility effective with the due date of its first triennial Chapter 22 filing occurring at least one year after a final rule reflecting 4 CSR 240-22.055 is published in the Code of State Regulations