2016

Missouri Microgrid Interconnection Requirements

PREPARED FOR THE MISSOURI DEPARTMENT OF ECONOMIC DEVELOPMENT, DIVISION OF ENERGY

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I. Introduction

Missouri 's Comprehensive State Energy Plan promotes microgrids as a technology that can play an important role in transforming Missouri's electric grid by strengthening grid resilience and reducing impacts of emergency events.[1]

While there is no universally accepted definition for microgrids, the definition that is most commonly cited comes from the U.S. Department of Energy's (DOE's) Microgrid Exchange Group[2]:

A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and islanded mode.

Microgrids are no longer a niche technology, but are poised to become an integral part of North America's energy transformation, according to a recent white paper from the International District Energy Association, Schneider Electric, and Microgrid Knowledge.[3] The paper identifies four reasons for this technology transformation:

1. Microgrids can spur economic growth by attracting high tech businesses, data centers, research centers, and similar industries that create sought-after jobs — and for whom energy security and business continuity are critical success factors.
2. Natural gas and solar prices, two common fuels for microgrids, have fallen dramatically in recent years. Lower fuel prices make microgrids increasingly cost-effective to operate. Prices also are declining for electric energy storage, allowing for more effective use of solar energy in microgrids.
3. New smart grid technology allows microgrids to perform in an increasingly sophisticated manner. Real time data displays, grid interfaces, and various software advances allow microgrids to maximize their use and timing of resources for greatest economy.
4. Industry and government officials are very concerned with ensuring grid reliability and security. Microgrids can keep the power flowing when the central grid faces threats from severe weather events or physical or cyber terrorism.

Distributed energy resources are essential to microgrids. As a result, the regulatory issues that affect these resources in general, also affect microgrids. These issues include interconnection processes and requirements, as well as tariff's applied to distributed energy resources. The resolution of these issues will have a direct impact on the viability of microgrids in the United

[1] Missouri Comprehensive State Energy Plan; Missouri Department of Economic Development, Division of Energy; October 2015
[2] "Microgrid Definitions," Microgrids at Berkeley Lab, 2015, https://building-microgrid.lbl.gov/microgrid-definitions
[3] Think Microgrid: A Discussion Guide for Policymakers, Regulators and End Users; Energy Efficiency Markets, LLC; 2014

States. If the interconnection process is too slow, cumbersome, and expensive; or if utility rates discourage distributed energy resource development, microgrids will not progress.

The Missouri Comprehensive State Energy Plan recommends actions that can be taken to encourage the development of microgrids in order to achieve significant improvements to Missouri's energy system. Recommendation 3.7: *Guiding the Development of Microgrids*, proposes the development of state policies for the development and deployment of microgrids.[4] The plan specifically makes the following recommendations:

1. Adopt standardized microgrid interconnection requirements and develop clear rules for how microgrid owners interact with utilities.
2. Develop tariff structures applicable to microgrids for Missouri utilities for review and approval by the PSC that would:
   a. Not be punitive or discriminating and appropriately price various types of standby power.
   b. Encourage microgrid development with an initial focus on areas of the grid that are congested or experiencing rapid demand growth.
3. Require that microgrid owners and operators provide utilities with information that could affect planning including information about capacity, system design, and location.

Missouri S&T recently formed a Microgrid Industrial Consortium for the purpose of advancing microgrid knowledge and opportunities for its members. Those members include investor-owned utilities, municipal utilities, high-energy-use industry members, microgrid equipment manufacturers, renewable energy consultants, the Missouri Department of Economic Development Division of Energy, and the U.S. Army. This report leverages the combined knowledge of the Microgrid Industrial Consortium members to respond to the above recommendations.

II. Benefits of Microgrids

A. Customer/Operator Benefits

Microgrids rely on integrated control systems to coordinate distributed generation with energy storage and demand response operations. Management of distributed energy resources as a microgrid allows for a single connection point with the distribution system. When a customer or microgrid operator acts as an aggregated single entity to the distribution system operator, this allows for innovations, efficiencies and custom operations.

One of the primary characteristics of a microgrid is the ability to island or disconnect from the area electric power system, and continue to provide power to its customers during events when the electric power system is down, or there is a fault condition on the local distribution feeder.

[4] Missouri Comprehensive State Energy Plan; Missouri Department of Economic Development, Division of Energy; October 2015

The microgrid control system coordinates energy storage and demand with generator output. This allows microgrids to provide reliable, lower cost electricity by decreasing the required peak and base-load capacity through effective utilization of intermittent renewable generation balanced with storage and demand modulation.

B. Utility Benefits

Microgrids can serve as a multi-function resource to the macro-grid, providing:

- A reliable, dispatchable energy resource;
- An ancillary service resource;
- A load shed resource; and/or,
- A consumption resource (to handle over generation)

To the extent that a microgrid, or the business entity representing the microgrid, can participate in wholesale markets, revenue streams can be associated with bulk electric system (BES) needs. A microgrid in a particular area can be designed and operated to address macro-grid conditions, at either the BES or local area power system, starting at low voltage levels in a particular area, while generating revenue streams that are associated with each of the services mentioned above.[5]

Per the whitepaper: *Think Microgrid - A Discussion Guide for Policymakers, Regulators and End Users*; Microgrid policies need to balance the market effectiveness of competition against the need to preserve utilities as a distribution backbone of the US electric system. The authors recommend an approach that marries the economic health of utilities and the deployment of microgrids with policies that allow the two industries to work jointly to strengthen the grid.[6]

III. States that are Developing Policies and Advancing the Use of Microgrids

Some states have begun to address the policy issues associated with microgrids, especially states in the northeastern part of the country, following the severe power outages associated with Superstorm Sandy in October of 2012.

A. Connecticut

Connecticut launched a 3rd round of funding for local microgrid projects in November of 2015. The 3rd round of funding will bring the total amount invested by the state to $53M. Previously, $23M had been allocated for two solicitations for microgrids that will support critical facilities such as police stations, hospitals, cell towers, fire departments, shelters, as well as a naval

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[5] Microgrids: A Regulatory Perspective; California Public Utilities Commission, Policy and Planning Division; April 14, 2014

[6] Think Microgrid: A Discussion Guide for Policymakers, Regulators and End Users; Energy Efficiency Markets, LLC; 2014

submarine base, college campuses and schools. Bid winners for all three projects must support critical facilities when the utility grid fails. The state established the incentives as part of a storm emergency preparedness bill (Public Act 12-148) that became law in June 2012. In addition to offering financial incentives, Connecticut has fostered microgrid development through changes in utility franchise rules. Public Act No. 13-298, passed in July 2013, makes it possible to site microgrids that cross public streets without franchise infringement.

B. Maryland

Maryland's Governor Martin O'Malley directed the creation of a *Resiliency through Microgrids* Task Force to look at statutory, regulatory, financial, and technical barriers to microgrids. The Task Force published a final report in June of 2014 that included two major recommendations.[7]

The first recommendation was a short-term State focus on the deployment of utility-owned public purpose microgrids, those that serve critical community assets across multiple properties, through advocacy and incentives. Additionally, the Task Force recommended that the Maryland Energy Administration conduct a holistic analysis of tariffs that help define the value of distributed generation to the macrogrid as well as engage in a comprehensive review of siting, interconnection, and commissioning procedures.

For the longer term, the Task Force recommended that the State focus on reducing barriers to entry to third parties (non-utilities) wishing to offer public purpose microgrid services to multiple customers in Maryland, whether those services are offered in new developments or over existing electric distribution company assets. By authorizing competition for public purpose microgrid services, the Task Force believes the State can incent innovation, provide better reliability and resiliency to its citizens, and still allow traditional utilities to compete in this new business model.

C. Massachusetts

In June 2014, the Massachusetts Department of Public Utilities (DPU) issued an order requiring each Massachusetts utility to develop and implement a 10-year grid modernization plan. The Department determined grid modernization will provide several benefits including:

- Empowering customers to better manage and reduce electricity costs;
- Enhancing the reliability and resiliency of electricity service in the face of increasingly extreme weather;
- Encouraging innovation and investment in new technology and infrastructure, strengthening the competitive electricity market;
- Addressing climate change and meeting clean energy requirements by integrating more clean and renewable power, demand response, electricity storage, microgrids and electric vehicles, and providing for increased amounts of energy efficiency.

[7] Maryland *Resiliency through Microgrids* Task Force Report, June 23, 2014

Following the release of the Massachusetts' DPU Grid Modernization Proceedings, the Massachusetts Clean Energy Center sponsored a study entitled: "Microgrids – Benefits, Models, Barriers and suggested Policy Initiatives for the commonwealth of Massachusetts" to better understand the opportunities to promote and support the development of microgrids.[8]

One of the key recommendations from the study was to create a microgrid pilot project that could be used to test current processes and identify any exemptions from existing DPU regulations or special tariffs needed to implement the project. The study team recommend the pilot program approach because it was too early to anticipate all of the issues associated with microgrids and adopt a comprehensive framework at that time. By implementing a pilot program that identifies and resolves issues, Massachusetts would be able to advance the technology and processes more quickly than attempting to promulgate a comprehensive set of rules, which might end up being used by only a handful of projects.

D. New York

On March 16, 2016 the State of New York Public Service Commission issued regulations that will ease requirements for microgrids, and other distributed generation, to connect to the grid. The *order modifying standardized interconnection requirements*, which went into effect on March 18, 2016 changes regulations so that larger projects can undergo a standardized review that will speed-up the application process. The commission also lowered up-front application costs and streamlined steps. Other rule changes made by the commission include reducing upfront application costs to 25 percent. Previously, applicants had to pay 100 percent upfront. The commission also amended the rules so that utilities can more-easily process and analyze applications.

In addition, the state created ombudsman services to assist with the interconnection process and an Interconnect Working Group, made up of representatives from the Department of Public Services, New York State Energy and Research Development Authority, utilities, the New York Solar Energy Industry Association, and a few individual installers. The ombudsmen service will work on issues regarding individual installations, while the working group will work to solve technical interconnect problems that affect large numbers of projects.

IV. Interconnection Best Practices

When developing Interconnection policies, there are several "best practices" that the state can follow. Interconnection best practices vary, depending on the perspective of the agency that is

[8] Microgrids – Benefits, Models, Barriers and suggested Policy Initiatives for the commonwealth of Massachusetts; KEMA; Massachusetts Clean Energy Center; February 3, 2014

making the recommendations. The best practices provided below provide a framework for discussion on what practices should apply to the state of Missouri.

A. DOE Interconnection Best Practices

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) and Office of Electricity Delivery and Energy Reliability (OE) jointly developed voluntary "best practices" for use by States in implementing interconnection requirements that allow for simple connection of distributed energy technologies to the electric grid.
Per these DOE Offices, State and non-State jurisdictional utilities should consider the following "best practices" in establishing interconnection procedures:

- The Energy Policy Act of 2005 (EPAct) requires that agreements and procedures for interconnection service "shall be just and reasonable, and not unduly discriminatory or preferential." As such, generators and utilities should be treated similarly in terms of State requirements.
- Create simple, transparent (1- or 2-page) interconnection applications for "small generators" (equal to or less than 2 MW), as noted in the FERC Order 2006.
- Standardize and simplify the interconnection agreement for "small generators" and, if possible, combine the agreement with the interconnection application.
- Set minimum response and review times for interconnection applications. Provide expedited procedures for certified interconnection systems that pass technical impact screens.
- Establish small processing fees for "small generators", otherwise the interconnection request must be accompanied by a deposit that goes toward the cost of the feasibility study, per FERC Order 2006.
- Set liability insurance requirements commensurate with levels typically carried by the respective customer class.
- Require compliance with IEEE 1547 and UL 1741 for safe interconnection.
- Avoid overly burdensome administrative requirements, such as obtaining signatures from local code officials, unless such requirements are standard practice in a jurisdiction for similar electrical work.
- Develop administrative procedures for implementing interconnection requirements on a statewide basis through a rulemaking or other appropriate regulatory mechanism for state-jurisdictional utilities to apply uniformly to all regulated electric distribution companies in the State. Where practical, State interconnection administrative procedures should reflect regional best practices and be comprehensive in scope. Administrative procedures should also be transparent to both small generators and electric distribution utilities.

B. Institute of Electrical and Electronics Engineers (IEEE) Interconnection Best Practices:

- Coverage of all distributed generation technologies (including CHP)
- Use of existing technical standards: IEEE 1547 and UL 1741
- System capacity limits for small systems up to at least 10 MW
- Screens for complexity and size, allowing fast-track processing for smaller, less expensive, less complex systems
- Standardized interconnection agreement forms
- Transparent, uniform and accessible application information and procedures
- Prohibition of unnecessary external disconnect switches
- Prohibition of requirements for additional insurance

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 has been a foundational document for the interconnection of distributed energy resources (DER) with the electric power system or the grid.

C. Interconnection Best Practices identified in *Freeing the Grid 2015*[9]:

- All utilities (including municipal utilities and electric cooperatives) should be subject to the state policy.
- All customer classes should be eligible.
- There should be three or four separate levels of review to accommodate systems based on system capacity, complexity and level of certification.
- There should be no individual system capacity limit. The state standard should apply to all state-jurisdictional interconnections.
- Application costs should be kept to a minimum, especially for smaller systems.
- Reasonable, punctual procedural timelines should be adopted and enforced.
- A standard form agreement that is easy to understand and free of burdensome terms should be used.
- Clear, transparent technical screens should be established.
- Utilities should not be permitted to require an external disconnect switch for smaller, inverter-based systems.
- Utilities should not be permitted to require customers to purchase liability insurance (in addition to the coverage provided by a typical insurance policy), and utilities should not be permitted to require customers to add the utility as an additional insured.
- Interconnection to area networks should generally be permitted, with reasonable limitations where appropriate.

[9] Freeing the Grid 2015: Best Practices in State Net Metering Policies and Interconnection Procedures; http://freeingthegrid.org/

- There should be a dispute resolution process.

V. Review of Applicable Federal and State Interconnection Standards

The Database of State Incentives for Renewables and Efficiency (DSIRE) is operated by the North Carolina Clean Energy Technology Center at N.C. State University and is funded by the U.S. Department of Energy. DSIRE provides comprehensive information on incentives and policies that support renewable energy and energy efficiency in the U.S. The following summaries of Federal and State Interconnection Standards was provided by the DSIRE site.

A. Federal Energy Regulatory Commission (FERC)

FERC standards generally apply to all transmission-level interconnection while state standards generally apply to distribution-level interconnection.

Through its Orders 792 and 792-A, the Federal Energy Regulatory Commission (FERC) adopted new small generator interconnection standards for distributed energy resources up to 20 megawatts (20 MW) in capacity in November 2013 and September 2014, respectively. These standards made revisions to those promulgated by FERC in May 2005 through its Order 2006. The FERC's standards apply only to facilities subject to the jurisdiction of the commission; these facilities mostly include those that interconnect at the transmission level. Given that purely intra-state distribution grids are generally considered to not be in "interstate commerce", the FERC's standards generally do not apply to distribution-level interconnection, which is regulated by state public utilities commissions. However, FERC's standards tend to serve as a guidepost for a number of state-level standards.

Size Criteria

The standards apply for distributed energy resources up to 20 megawatts (20 MW) in capacity. A Fast Track process is available depending upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. The chart below outlines the requirements for Fast Track Eligibility.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

An interconnection customer can determine information about its proposed interconnection location by requesting a pre-application report from the utility.

Timeline for review

The new rules include other additional provisions intended to promote the efficiency of small generator interconnection, including, but not limited to:

- Allowing developers/customers to request a pre-application report that would allow for identification of issues that may delay or halt the interconnection process that must be issued within 20 days
- Revising the Fast Track process to ensure that the developer/customer does not wait more than 5 days for an initial determination, more than 30 days for a "supplemental study" if the initial determination is negative, or more than 10 days after a post-"supplemental study" determination
- The creation of three new standard technical screens for the "supplemental study"

Fees

The pre-application report fee is $300.00. Other fees dependent upon complexity of system and additional studies required.

Design and Operating Requirements

The Interconnection Agreement requires that the customer "construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule and, in accordance with this Agreement, and with Good Utility Practice".

Notably, the FERC standards do not require systems to include an external disconnect switch. Energy storage systems qualify for interconnection under the new process.

Insurance

Customers must obtain liability insurance "sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made." Additional liability insurance must be obtained "only if necessary as a function of owning and operating a generating facility".

B. Connecticut

In December 2007, the Connecticut Department of Public Utility Control (DPUC) approved new interconnection guidelines for distributed energy systems up to 20 megawatts (20 MW) in capacity. Connecticut's interconnection guidelines apply to the state's two investor-owned utilities: Connecticut Light and Power Company (CL&P) and United Illuminating Company (UI), and are modeled on the Federal Energy Regulatory Commission's (FERC) interconnection standards for small generators.

Size Criteria

Connecticut's interconnection guidelines, like FERC's standards, include provisions for three levels of systems:

- Certified, inverter-based systems no larger than 10 kilowatts (kW) in capacity (application fees: $100);
- Certified systems no larger than 2 megawatts (MW) in capacity (application fees: $500); and
- All other systems no larger than 20 MW in capacity. Note that the guidelines include "additional process steps" for generators greater than 5 MW (application fees: $1000, study fees will also apply).

Connecticut's guidelines include a standard interconnection agreement and application fees that vary by system type.

Design and Operating Requirements

Connecticut's guidelines are stricter than FERC's standards and customers are required to install an external disconnect switch and an interconnection transformer.

Fees and timelines

The guidelines address requirements for study fees and include technical screens for each level of interconnection. Utilities and customers must follow general procedural timelines.

> Systems 10 kW or less: Interconnections are provided in a first-come, first-serve basis in a non-discriminatory manner. The interconnection requires approval from the Municipal Electrical Inspector and a witness from the utility. After completion of the interconnection request, the utility has 10 business days to respond to the request, or the commissioning test is waived. The interconnection must be in compliance with local, state, federal and utility safety rules including the IEE 1547. The customers are required to maintain a liability insurance of $300,000 per interconnection. Total application fee of $100 is required for the process.
>
> Systems 10kW – 20MW: Interconnection process for systems greater than 10kW varies depending on the generation location, size, and customer requirements. Depending

where the customer wants to interconnect, the system could fall under either FERC jurisdiction or State jurisdiction.

Generators who want to interconnect to sell electricity the wholesale market fall under FERC jurisdiction and must submit an application to ISO NE, while customers under net-metering rules or under DUPC approved tariff are subject to State regulation and must submit application to their utilities. Systems smaller than 2MW that meet provided codes and standards have the option for fast track review process.

Insurance
Customers must indemnify their utility against "all causes of action," including personal injury or property damage to third parties and maintain liability insurance in specified amounts ranging from $300,000 to $5,000,000, based on the system's capacity.

C. Maryland

In April 2007, Maryland enacted legislation requiring the Maryland Public Service Commission (PSC) to form a small generator interconnection working group to develop interconnection standards and procedures that are "consistent with nationally adopted interconnection standards and procedures," and to revise the state's interconnection standards and procedures on or before November 1, 2007. Final rules were adopted in March 2008 and became effective June 9, 2008.

Size Criteria
The rules apply to interconnections of all types of distributed generation systems of less than 10 MW to the electric distribution system for all types of utilities: investor-owned utilities, rural cooperatives and municipal utilities.

The Maryland PSC Standard Interconnection Agreement employs a four-tiered approach to determine the level of review required before a system may be connected to the grid. Different levels of review are subject to specific technical screens, review procedures, and time lines. Generally speaking, the review process becomes more extensive and time consuming with increasing system size.

Basic criteria for determining the level of review required for a prospective project:

- Level 1: Lab certified, inverter-based systems of 10 kW or less.
- Level 2: Lab certified or field approved systems of 2 MW or less connected to a radial distribution circuit or to a spot network serving one customer.
- Level 3: Only applies to systems that will *not* export power to the grid and which do not require new facility construction by the utility. Systems being located on an area network must be inverter-based, use lab certified equipment, and have a capacity of 50 kW or less. Systems located on a radial network must have a capacity of 10 MW or less and not be served by a shared transformer. These systems are also subject to additional

criteria dealing with the aggregate capacity of interconnected systems on a given network.

- Level 4: Systems 10 MW or less that cannot be approved or do not meet the criteria for review under a lower tier.

Design & Operating Requirements

Lab certified equipment is defined to mean equipment tested and approved by a nationally recognized testing laboratory (NRTL) as being in accordance with IEEE 1547, UL 1741, and the National Electric Code (NEC). Field approved systems are generally non-certified systems that have been tested and approved under a prior review by a utility, subject to certain other restrictions. All interconnected systems must be equipped with a utility accessible "lockable isolation device" or alternately, a "draw-out type circuit breaker with a provision for padlocking at the draw-out position". This requirement is equivalent to "lockable external disconnect switch" frequently specified in other jurisdictions.

Fees

Utilities may not charge any processing fees to Level 1 applicants and processing fees are limited to $50 plus $1/kilowatt (kW) of capacity for Level 2 requests and $100 plus $2/kW of capacity for Level 3 and 4 requests. Utilities are also required to designate a contact person and provide assistance materials on their website for use by prospective applicants. Standardized interconnection agreements are available on the PSC renewable portfolio standard website for all levels of interconnection request. The regulations also contain provisions for dispute resolution and utility reporting requirements.

Insurance

The issue of insurance additional insurance requirements is not addressed by the regulations. However, the standard Level 1 interconnection agreement specifically states that applicants are not required to obtain general liability insurance as a condition of interconnection approval. For Levels 2, 3 and 4 the interconnection agreement requires liability insurance of at least $2 million per occurrence and $4 million in aggregate for systems of 1 MW or larger. It also specifies that the policy must name the utility as an additional insured party. A separate standard agreement exists for Maryland state and local government entities, which among other things contains modifications to liability insurance requirements that accommodate self-insured entities.

D. Massachusetts

In September 2012, the Massachusetts Distributed Generation Interconnection Working Group submitted its final report recommending changes to the state's interconnection standards. The Massachusetts Department of Public Utilities (DPU) incorporated changes from comments submitted in Docket 11-75, and adopted the report those changes in March 2013. Massachusetts' interconnection standards apply to all forms of distributed generation (DG), including renewables, and to all customers of the state's three investor-owned utilities (Unitil, Eversource, and National Grid).

Size Criteria

Massachusetts requires investor-owned utilities to have standard interconnection tariffs. There are three basic paths for interconnection in the state:

- The **Simplified** interconnection process applies to IEE 1547.1-certified, inverter-based facilities with:
    1. A power rating of 15 kW or less for single-phase systems located on a radial distribution circuit,
    2. A power rating of 25 kW or less for three-phase systems located on a radial distribution circuit (where the facility capacity is less than 15% of the feeder/circuit annual peak load, and if available, line segment),
    3. A power rating of less than 1/15 of the customer's minimum load and located on a spot network, or
    4. A power rating of less than 1/15 of the customer's minimum load and 15 kW or less and located on an area network.
- The **Expedited** interconnection process applies to:
    - 1) Inverter-based facilities 15 kW or greater for single-phase systems,
    - 2) Inverter-based facilities 25 kW or greater for 3-phase systems, and
    - 3) Other systems of all sizes that are served by radial systems and meet certain other requirements.
- The **Standard** process is for all other facilities that do not meet the specifications of the Simplified or Expedited process, including systems on all networks.

If a project fails the Simplified and Expedited screens, it must pass three supplemental review screens, otherwise it must go through the full standard review process. Massachusetts uses a 100% of minimum load penetration screen in the supplemental review process. If the generating capacity is less than 100% of minimum load, it may not require a detailed study. In addition to these different paths, for all systems 500 kW or greater, facility owners must request and receive a pre-application report from the utility. The pre-application report is optional for facilities less than 500 kW; no fee is charged for this report.

Design and Operating Requirements

For the simplified and expedited interconnection paths, technical requirements are based on the IEEE 1547 and UL 1741 standards. A manual external disconnect switch may be required at the discretion of the utility (project-specific, not required in the tariffs). Utilities must collect and track information on the interconnection process. This information will be used in revising and updating the standards.

Insurance

Five million dollars ($5,000,000) if over five (5) MW;

Two million dollars ($2,000,000) if greater than one (1) MW and less than or equal to five (5) MW;

One million dollars ($1,000,000) if greater than one hundred (100) kW and less than or equal to one (1) MW;

Five hundred thousand dollars ($500,000) if greater than ten (10) kW and less than or equal to one hundred (100) kW.

E. New York

On March 2016, the NY Public Service Commission (PSC) modified the Standard Interconnection Requirements (SIR) increasing the maximum threshold for interconnection capacity of distributed generation projects from previous 2 MW to 5 MW. New York first adopted uniform interconnection standards in 1999. Amendments were made to the SIR in March 2013 in order to simplify and expedite the interconnection application and review process, and to adopt changes made to net metering law in 2012.

The Standard Interconnection Requirements rules apply to systems up to five megawatts (5 MW) in capacity connected in parallel with the distribution system located in the service area of one of New York's six investor-owned local electric utilities: Central Hudson Gas and Electric, Consolidated Edison (Con Edison), New York State Electric & Gas, Niagara Mohawk (d/b/a National Grid), Orange and Rockland Utilities, and Rochester Gas and Electric.

Generation facilities that are not designed to operate in parallel with the utility's electrical systems are not subject to these requirements.

Size Criteria

Expedited Process: As amended in 2013, systems up to 50 kW are eligible for a simplified or expedited six-step process. Systems up to 300 kW may be eligible for this provided that the inverter based system is UL 1741 certified and tested. Systems proposed to be installed in underground network areas may be required to submit additional information and may be subject to a longer review process. Systems of 50 kW or less are not charged an application fee.

Basic Process: This process applies to all systems larger than 50 kW up to 5 MW, and systems between 50 kW and 300 kW that have not been certified and tested in accordance with UL 1741, applicants must use the basic 11-step process for interconnection as detailed in the SIR.

Both processes cover the initial inquiry to final utility acceptance for interconnection and include interconnection timelines, responsibility for interconnection costs, and procedures for dispute resolution. The appendices contain a standard contract and standard application forms. Utilities are also required to maintain a web-based system for providing information on the status of interconnection requests to customers and contractors. The SIR contain minimum content requirements for this information system, and also require that utilities offer a web-based application process for systems of 25 kW or less.

Design and Operating Requirements

A current list of type-tested equipment is available on the PSC's DG web site. Certified, inverter-based systems up to 25 kW are not required to have an external disconnect switch.

Insurance

The requirements specifically state that utilities are not permitted to require customers to purchase general liability insurance; however, the PSC does encourage distributed generation owners to purchase insurance for their own protection.

F. North Carolina

Legislation enacted by North Carolina in August 2007 (S.B. 3) required the North Carolina Utilities Commission (NCUC) to establish interconnection standards for distributed generation systems up to 10 MW in capacity. The law stated that the commission “shall adopt, if appropriate, federal interconnection standards.”

The NCUC approved revised interconnection standards in May 2015. The new standards used the FERC most recent Small Generator Interconnection Procedures as their basis, but with some modifications.

The current NCUC standards govern interconnection to the distribution systems of the state's three investor-owned utilities: Duke Energy Progress, Duke Energy Carolinas, and Dominion North Carolina Power. The standards apply to all state-jurisdictional interconnections (including interconnection of three-phase generators) regardless of the capacity of the generator, the voltage level of the interconnection, or whether the customer intends to offset electricity consumption or sell electricity.

Size Criteria
The NCUC standards, like the FERC standards, use a three-tiered approach to simplify the interconnection process:

- Inverter Process: Systems up to 20 kilowatts (kW)
- Fast Track Process: Systems larger than 20 kW that meet the eligibility criteria in the table below
- Study Process: Systems that fail to qualify for the Fast Track Process

Line Voltage	Fast Track Eligible Regardless of Location	Fast Track Eligibility on a Mainline and less than 2.5 Electrical Circuit Miles from Substation
Less than 5 kV	Less than or equal to 100 kW	Less than or equal to 500 kW
Between 5 kV and 15 kV	Less than or equal to 1 MW	Less than or equal to 2 MW

Between 15 kV and 35 kV	Less than or equal to 2 MW	Less than or equal to 2 MW
Greater than or equal to 35 kV	*Not eligible*	*Not eligible*

Design and Operating Requirements

Utilities are authorized to require an external disconnect switch, but must reimburse owners of systems smaller than 10kW for the cost of the switch. Interconnection agreements are not transferrable; new owners must secure an agreement by filing an interconnection request and submitting a fee of $50. (However, the interconnection will not need to be re-studied.) The standards include a provision for mutual indemnification and a weak process for dispute resolution.

Fees

The NCUC established a fee structure for interconnection applications: $100 for generators up to 20 kW; $250 for generators larger than 20 kW but not larger than 100 kW; and $500 for generators larger than 100 kW but not larger than to 2 MW. The FERC fee structure applies to the interconnection of systems over 2 MW. Additionally, systems in the Study Process must pay a deposit of $20,000, plus $1 per kW-AC, not to exceed $100,000.

Insurance

Utilities may not require residential customers to carry liability insurance beyond the amount required by a standard homeowner’s policy ($100,000 minimum). Non-residential generators proposing to interconnect a system no larger than 250 kW are required to carry comprehensive general liability insurance in the amount of at least $300,000. Non-residential generators proposing to interconnect a system that is larger than 250 kW are required to carry comprehensive general liability insurance in the amount of at least $1,000,000. Customers that meet certain eligibility requirements are allowed to self-insure.

G. Summary of State Policies

Federal and State Interconnection Standards	Size Limit for Standard Process	Size Limit for Expedited Process	Interconnection Application Processing Fees	Design and Operating Requirements	Insurance Requirement
FERC orders 792 and 792-A (standards apply only at transmission level, but provide a guide for distribution-level inteconnection standards)	20 MW	Up to 5 MW depending upon type and location	$300 for pre-application report; other costs vary depending upon requirements placed upon provider	No disconnect switch required.	"sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment"
Conneticut (2007)	20 MW	10kW	10 kW or less = $100; 2 MW or less = $500; 20 MW or less = $1,000 + study fees	Customers are required to install an external disconnect switch and an interconnection transformer.	$300 k - $5 million in liability insurance required, based on system size/capacity
Maryland (2008)	10 MW	10kW	Level 1 = $0; Level 2 = $50 + $1/kW; Levels 3 and 4 = $100 +$2/kW	Must meet IEEE 1547, UL 1741, and the National Electric Code (NEC). Lockable external disconnect switch required.	Levels 2, 3 and 4 = $2 million per occurance up to $4 million aggregate for systems greater than 1 MW
Massachusetts (2013)	no limit identified	15kW single phase 25kW 3 phase	$3/kW, with a $300 minimum and $2,500 maximum fee	Must meet IEEE 1547 and UL 1741 standards. A manual external disconnect switch may be required at the discretion of the utility (project-specific, not required in the tariffs).	General liability insurance required at amounts listed below 100kW = $500,000 1 MW = $1,000,000 5 MW = $2,000,000 Over 5 MW = $5,000,000
New York (2016, 2013)	5 MW	50kW	50 kW or less = $0 all other systems = $750	A current list of type-tested equipment is available on the PSC's DG web site. Certified, inverter-based systems up to 25 kW are not required to have an external disconnect switch.	Not required but is encouraged.
North Carolina (2015)	2 MW	20kW	20 kW or less = $100 100 kW or less = $250 2MW or less = $500 Study Process = $20,000 deposit plus $1/ kW not to exceed $100,000.	Utilities are authorized to require an external disconnect switch, but must reimburse owners of systems smaller than 10kW for the cost of the switch.	residential = $100,000 non residential and less than 250kW = $300,000 non residential and larger than 250kW = $1M minimum

VI. Missouri's Net Metering and Easy Connection Act

Missouri enacted legislation in June of 2007 requiring all electric utilities—investor-owned utilities, municipal utilities, and electric cooperatives—to offer net metering to customers that generate electricity using sources of energy certified as renewable by the Missouri Department of Natural Resources.

The Missouri Public Service Commission (PSC) adopted administrative rules for investor-owned utilities that included simplified interconnection standards[10], and electric cooperatives and

[10] Missouri Revised Statutes: 386.890. 1. "Net Metering and Easy Connection Act"; August 28, 2015

municipal utilities adopted their own rules, including an all-in-one document that includes a simple interconnection request, simple procedures, and a brief set of terms and conditions.[11]

Interconnection Requirements under the Missouri Net Metering and Easy Connection Act:

1. Systems to be interconnected must be intended primarily to offset part or all of a customer's own electrical energy requirements, have a capacity up to 100 kilowatts (kW), and be located on a facility owned, operated, leased or otherwise controlled by the customer.
2. Applications for interconnection must be accompanied by a plan for the customer's system, including a wiring diagram and specifications for the generating unit. Utilities must review and respond to the customer within 30 days for systems up to 10 kW, and within 90 days for systems greater than 10 kW.
3. Systems to be interconnected must meet all applicable safety, performance, interconnection and reliability standards established by any local code authorities, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), the Institute of Electrical and Electronics Engineers (IEEE), and Underwriters Laboratories (UL) for distributed generation. Prior to interconnection, a customer must furnish the utility with certification from a qualified professional electrician or engineer that the installation complies with the established safety and operating requirements.
4. Utilities may require customers to provide a switch, circuit breaker, fuse or other easily accessible device or feature that allows the utility to manually disconnect the system.
5. Utilities must offer a net-metering tariff or contract that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator. Utilities may not charge the customer any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator.

Because the Net Metering and Easy Connection Act only applies to generating units with a capacity of 100kW or less, interconnection of generating units above 100kW must be negotiated on a case-by-case basis with the impacted utility.

VII. Recommendations for the State of Missouri

A. Missouri Standard Microgrid Interconnection Process (MSMIP)

The enclosed Missouri Standard Microgrid Interconnection Process (MSMIP) provides a recommended process for interconnecting microgrids in Missouri. A first draft of this document was prepared and delivered to members of the Missouri S&T Microgrid Industrial Consortium

[11] MPUA Sample Net Metering Policy http://www.mpua.org/_lib/files/MPUA_Sample_Net_Metering_Policy.pdf

on April 6, 2016. Comments were gathered and an on-campus review meeting was held on April 19, 2016. Attending that meeting were: Brent McKinney, City Utilities, Springfield; Rodney Bourne, Rolla Municipal Utilities; and Marc Lopata, President, Azimuth Energy. Additional comments and recommendations from the review meeting were gathered and incorporated into a 2nd draft document that was sent to consortium members on May 4th. Comments and recommendations were again gathered via email and a meeting with consortium members and representatives from the Missouri Division of Energy was held on the S&T campus on May 20, 2016. Attending that meeting were: Andy Popp and Barb Meisenheimer, Division of Energy; Chris Yates, Springfield City Utilities; Rodney Bourne, Rolla Municipal Utilities; George Mues, Ameren; and Chris Neaville, Doe Run. The document was updated to include comments and recommendations from that meeting and a 3rd draft was sent to consortium members on May 31, 2016.

Throughout the process, the consortium members shared the document within their organizations, which provided expertise at a very broad level. Ameren, as an Investor Owned Utility, was able to contribute a wide variety of knowledge toward the draft process, and the impacts that would apply to their operations. The participation of the municipal utilities through the Missouri Public Utility Alliance (MPUA) brought a very key perspective on the process requirements that could impact their operations, including the impacts to smaller utilities that are staffed at a minimal level. Doe Run, as a future microgrid owner, was able to bring the customer perspective; and Azimuth Energy was able to review the draft process with an eye to the constraints that the process might place on a microgrid consultant trying to grow their business in this market.
The below list identifies the contributors to the process:

Ameren:
Michael S. Abba, P.E., Director, Smart Grid Integration & System Improvement
Bill Davis, Economic Analysis and Pricing Manager
Kim Gardner, P.E.
Rodney B Hilburn, Manager, Technology Applications Center, Smart Grid Integration & System Improvement Department
Jeff Hynds, Interconnections Engineer, Transmission Connection Agreements
Wade Miller, Regulatory Consultant
George Mues, Principal Engineer
Joseph Wokurka, P.E., Supervising Engineer, System Protection
Arindam Maitra, Senior Project Manager, Electric Power Research Institute (EPRI)

Missouri Public Utility Alliance (MPUA):
Rodney Bourn, General Manager, Rolla Municipal Utilities
Floyd Gilzow, Chief Operating Officer and Director of Member Relations
& Public Affairs, MPUA

Brent McKinney, Manager, Electric Transmission, City Utilities, Springfield
Chris Yates, P.E., Manager, Electric T&D, Electric Substations, City Utilities, Springfield

The Doe Run Company: Chris Neaville, Asset Development Director

Azimuth Energy: Marc Lopata, President

Division of Energy, Missouri Department of Economic Development:
Andy Popp, Manager, Energy Efficiency
Barbara Meisenheimer, Manager, Energy Policy & Resources
Barbara J. Meyer, Energy Engineer

The final proposed Missouri Microgrid Standard Interconnection Process, included with this report, provides guidelines for the interconnection of microgrids that have a total combined generation capacity of no more than 5MW and that are operating in parallel with the utility.

Areas of concern to the reviewers included:

- The proposed size limitation of the microgrid for this process
- Clarifying that additional requirements may be required of a microgrid owner that is operating as an independent power producer and selling the energy from the microgrid to other customers
- Time required for the utility to process the interconnection application
- Design and Operational Requirements
- Appropriate application fees
- The interrelationship between the process and Missouri's current Net Metering laws

Each of these areas of concern is addressed below:

Size limitation:
The 5MW size limitation was proposed because this was the size identified in the most recently developed interconnection process for the state of New York. This was provided as a starting point for discussion, and final decision was to use 5MW with the understanding that it could be revisited after more microgrids had been installed in the state of Missouri. The comment was added to the paragraph that, while these guidelines could be used for larger microgrids, additional negotiations might be required with the utility.

Microgrid Owner as Independent Power Producer:
This topic may become a key issue as opportunities arise for community microgrids in the state of Missouri. There is still much discussion at the national level about the requirements that should be placed on microgrid owners that desire to sell the power that is produced by their microgrid to other customers. Again, the statement was added that the proposed process

could be used in this case, but additional negotiations with the utility would be required. This issue will become clearer with the publication of the revised IEEE 1547 standard.

Time to Process Microgrid Application:
The originally recommended time was based on the New York Standard Microgrid Interconnection Process. A wide variety of times were proposed by reviewers, ranging from the originally recommended 20 business days up to 120 business days from several of the Ameren reviewers. The 40 business day review period in the final document was a compromise between processing within a reasonable time that would not dissuade future microgrid developers, and not placing a huge burden on the utilities. It was pointed out that, many of the smaller utilities would not have the expertise on staff to analyze and approve the application, and would be required to hire a consultant to do this – further increasing costs to the potential applicant.

Appropriate Application Fees:
Many of the current interconnection processes across the country provide various levels of review and associated fees. These interconnection processes, however, apply to all levels of distributed energy resources. They may range from an individual resident placing solar panels on their roof, up to a large combined heat and power project. Because this process applies specifically to microgrids, which are by their nature going to be more complex than a simple solar panel project, we recommend only two levels of review, based on the service voltage of the microgrid. Application fees for interconnection in other states range from no fee for projects less than 50kW up to $2,500 for larger systems. Many states utilize a “per kW” approach for interconnection application fees.

Collection of Utility’s Costs for Interconnection:
The first draft of the process document recommended that that applicant pay 50% of the utility’s estimated cost of the interconnection prior to start of modifications to the utility’s system. Some reviewers recommended that the full estimated cost be paid up-front by the applicant, and the utility reconcile estimated with actual cost at the end of the project. One reviewer commented that a lack of historical data on costs of interconnection will make estimating difficult, and for the first several projects, actual costs should be gathered to create a data base for future reference. The document is intentionally vague on what percentage of the utility’s costs should be paid up-front, but it was agreed that some amount must be provided before the utility invests their resources in modifying for the interconnection. The PSC will make the final decision on how Investor-Owned Utilities recover these costs.

Design and Operational Requirements:
Design and operational requirements addressed in interconnection processes developed by other states either reference or reiterate the requirements outlined in IEEE 1547 (2003 and

2014 Amendment 1): *Standard for Interconnecting Distributed Resources with Electric Power Systems*. We simplified the process document by referencing this standard throughout.

Microgrid Interconnection and Net Metering:
Reviewing representatives from the utilities felt strongly that the Missouri Standard Microgrid Interconnection Process should not include references to net metering, because of the complexities associated with combining a process with a rate making activity. However, the ability of a microgrid owner to partner with the utility to provide dispatchable energy, ancillary services, and load shed capability provides potential benefits to the utility. By creating a rate structure that encourages microgrid owners to partner with the utility to allow for load leveling and peak demand shaving, the utility may be able to delay or even avoid future capital investments. The full revision of IEEE Standard 1547 that is currently underway will address the integration of interoperability, communications, and information technology functions into interconnection systems that will drive new business models and value propositions for both utilities and customers.

B. Full Revision of IEEE Standard 1547

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 has been a foundational document for the interconnection of distributed energy resources (DER) with the utility grid. It was cited in the U.S. Federal Energy Policy Act of 2005, under Section 1254 *Interconnection Services*, stating "Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources With Electric Power Systems, as they may be amended from time to time".[12]

IEEE SCC21, the Standards Coordinating Committee on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage released the original IEEE 1547 *Standard for Interconnecting Distributed Resources with Electric Power Systems* in 2003 and issued Amendment 1 in 2014. A full revision of IEEE 1547 is currently underway that will address interconnection and interoperability, including associated interfaces. The title of the revised standard is: IEEE P1547 (full revision) Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Power Systems Interfaces. Per IEEE mandate, the revision must be completed by 2018. The full revision of the 1547 standard and the subsequent full revision of 1547.1 (conformance testing) will provide the widely accepted engineering consensus for ensuring that grid performance and reliability levels are maintained, or even increased, when interconnecting Distributed Energy Resources (DER) with the grid. The revised standards will:

[12] IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid, Thomas Basso, National Renewable Energy Laboratory (NREL) Technical Report, NREL/TP-5D00-63157, December 2014

- Enable high penetration of distributed energy resources, including clean solar technologies, at levels approaching, or exceeding, 100% peak load.
- Reduce interconnection approval time for advanced distributed energy projects.
- Reduce interconnection costs for projects.
- Accelerate conformance validation of state of the art interconnection systems for the future grid.

The integration of interoperability, communications, and information technology functionalities into interconnection systems will also:

- Enable the success of new business models and valuations for utilities and customers.
- Support transactive roles of customers.
- Help improve grid awareness of interconnected DER, including helping mitigate concerns about intermittency and dispatchability of renewable energy technologies.[13]

C. Conclusion

The draft Missouri Standard Microgrid Interconnection Process proposed with this report provides a first step toward advancing the use of microgrids in the state. As IEEE finalizes IEEE P1547 (full revision) Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Power Systems Interfaces, those guidelines should be incorporated into the standard process to further accelerate the use of microgrids. Given the complexity associated with the interconnection of microgrids, recommend the Missouri Department of Economic Development, Division of Energy, consider providing a data base of consultants who have been vetted to demonstrate their expertise in this area. The Missouri S&T Microgrid Industrial Consortium can also be a resource for information and expertise.

[13] IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid, Thomas Basso, National Renewable Energy Laboratory (NREL) Technical Report, NREL/TP-5D00-63157, December 2014