Manual of Small Generator Interconnection Requirements for Direct Interconnection with EKPC Member Cooperative Distribution Systems

(For Generating Facilities of 10 MW or Less)

Fleming-Mason Energy Cooperative

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PREAMBLE

The Manual of Small Generator Interconnection Requirements for Direct Interconnection with Member Distribution Systems (For Generating Facilities of 10 MW or Less) (the "Manual") is a compendium of the technical, legal and financial requirements which must be satisfied in order for an electric generation facility with a rated capacity of 10 MW or less to directly interconnect and operate in parallel with the electric distribution system of a distribution cooperative within the East Kentucky Power Cooperative, Inc. ("EKPC") system. The purpose of these requirements is to provide reasonable protection and minimize the risks to the personnel and property of the Member Distribution System ("Member"), EKPC, and the Interconnection Customer arising from the construction and operations of unaffiliated generation sources that will potentially impact the value, safety and reliability of the Member's Distribution System, as required by the Member's co-generation tariff on file with the Kentucky Public Service Commission.

ARTICLE I - DEFINITIONS

1.01 "Affected System" shall mean an electric transmission or distribution system other than the Member's Distribution System that may be affected by the proposed interconnection, including, but not limited to the EKPC Transmission System.

1.02 "Applicable Laws and Regulations" shall mean all duly enacted applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

1.03 "Business Day" shall mean each day of the week, Monday through Friday inclusive, but shall not include Federal Reserve bank holidays.

1.04 "Confidential Information" shall mean all information, written or oral, which has been or is disclosed by the Member, EKPC, or the Interconnection Customer, or by any Person on behalf of the Member, EKPC, or the Interconnection Customer, or which otherwise becomes known to the Member, EKPC, or the Interconnection Customer, or to any Person associated with the Member, EKPC, or the Interconnection Customer, or any other Person in a confidential relationship with the Member, EKPC, or the Interconnection Customer, and which: a) relates to matters such as patents, trade secrets, research and development activities, draft or final contracts or other business arrangements, books and records, solar data and analysis, generation data and analysis, budgets, cost estimates, pro forma calculations, engineering work product, environmental compliance, vendor lists, suppliers, manufacturing processes, energy consumption, pricing information, private processes, and other similar information, as they may exist from time to time; b) relates to the existence or the terms of this Manual; or c) the Member, EKPC, or the Interconnection Customer expressly designates in writing to be confidential. Confidential Information shall exclude information falling into any of the following categories: a) information that, at the time of disclosure hereunder or thereafter, is in the public domain, other than information that entered the public domain by breach of the duty of confidentiality by the Member, EKPC, or the Interconnection Customer; b) information, other than that obtained from third parties, that prior to disclosure hereunder, was already in the Member's, EKPC's, or the

Interconnection Customer's possession, either without limitation on disclosure to others or subsequently becoming free of such limitation; c) information obtained by the Member, EKPC, or the Interconnection Customer from a third party having an independent right to disclose the information; or d) information that is available through independent research without use of or access to the Confidential Information.

1.05 "Delivery Meter" shall have the meaning given in Section 5.01(a).

1.06 "Delivery Point" shall mean the Delivery Meter.

1.07 "Distribution System" shall mean the Member's facilities and equipment used to distribute electricity to end users directly from nearby generators or from interconnections with EKPC's Transmission System which transports bulk power.

1.08 "Distribution Upgrades" shall mean any and all additions, modifications or upgrades to the Member's Distribution System required at or beyond the Delivery Point at which the Small Generating Facility interconnects with the Member's Distribution System to accommodate the interconnection of the Small Generating Facility with the Member's Distribution System. "Distribution Upgrades" shall exclude Interconnection Facilities.

1.09 "Emergency Condition" shall mean a condition or situation: a) that in the judgment of the party making the claim is imminently likely to endanger life or property; or b) that, in the case of the Member, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Member's Distribution System, the Member's Interconnection Facilities or the EKPC Transmission System; or c) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities.

1.10 "Energy" shall mean three-phase, 60 hertz, alternating current energy generated at the Small Generating Facility.

1.11 "Force Majeure" shall mean an event or circumstance beyond the reasonable control of and without the fault or negligence of the party claiming Force Majeure, which, despite the exercise of reasonable diligence, cannot be or be caused to be prevented, avoided or removed by such party. Force Majeure shall include, to the extent consistent with the preceding sentence: an act of God; war (declared or undeclared); sabotage; riot; insurrection; civil unrest or disturbance; military or guerilla action; banditry; terrorist activity or a threat of terrorist activity which, under the circumstances, would be considered a precursor to actual terrorist activity; economic sanction or embargo; civil strike, work stoppage, slow-down, or lock-out that are of an industry or sector-wide nature and that are not directed solely or specifically at the affected party; explosion; fire; earthquake or seaquake; abnormal weather condition; hurricane; flood; lightning; high winds; drought; peril of the sea; the binding order of any Governmental Authority (provided that the affected party has in good faith considered reasonably contesting such order); the failure to act on the part of any Governmental Authority (provided that such action has been timely requested and diligently pursued); unavailability of equipment, supplies or products, but only to

the extent caused by an event of circumstance of Force Majeure; and failure of equipment. With respect to the Interconnection Customer, Force Majeure shall also include (to the extent beyond the reasonable control of and without the fault or negligence of the Interconnection Customer) any interruption in distribution service on Member's side of the Delivery Point. No party shall be deemed to have suffered an event of Force Majeure due to the failure of equipment which that party is responsible for operating or maintaining unless the equipment has been operated and maintained in accordance with Good Utility Practice. Neither the lack of money nor changes in market conditions shall constitute an event of Force Majeure.

1.12 "Good Utility Practice" shall mean any of the practices, methods and acts employed by owners and/or lessors, operators or maintainers of electric generation, transmission or distribution facilities similar in size and operational characteristics to the Small Generating Facility, Interconnection Facilities, Distribution System and Transmission System which, in the exercise of reasonable judgment in the light of the facts known or that reasonably should have been known at the time that a decision was made, could reasonably have been expected to accomplish the desired result at the lowest reasonable cost, consistent with licensing and regulatory considerations, environmental considerations, reliability, safety, protection of lives and property, expedition, the technical specifications and manufacturer's maintenance requirements, and the applicable requirements of any Governmental Authority. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.13 "Governmental Authority" shall mean the federal government of the United States, and any state, county or local government, and any regulatory department, body, political subdivision, commission (including the Kentucky Public Service Commission and FERC), agency, instrumentality, ministry, court, judicial or administrative body, taxing authority, or other authority of any of the foregoing (including any corporation or other entity owned or controlled by any of the foregoing), any regional transmission organization or independent system operator, any national or regional reliability organization or council (including NERC) or any reliability coordinator, in each case, having jurisdiction or authority over the Manual (or any portion thereof), the Member, the Interconnection Customer, the Facility or the Buyer's Distribution System, whether acting under actual or assumed authority.

1.14 "Independent Party" shall mean a party not affiliated with the Member, EKPC, or the Interconnection Customer.

1.15 "Interconnection Customer" shall mean any Person that proposes to interconnect its Small Generating Facility with the Member's Distribution System.

1.16 "Interconnection Facilities" shall mean all facilities, lines, equipment and appurtenances between the Small Generating Facility and the Member's Distribution System, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Member's Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Transmission Upgrades.

1.17 "Letter of Credit" shall mean an irrevocable, transferable, standby letter of credit, issued by a major U.S. commercial bank or a financial institution with a Credit Rating of at least: a) "A-" by Standard and Poor's or "A3" by Moody's Investment Services; and b) assets of at least $1,000,000,000.

1.18 "Member" shall mean a Kentucky cooperative corporation: a) formed under Chapter 279 of the Kentucky Revised Statutes for the primary purpose of distributing electricity to end users; b) that has been granted a certified service territory by the Kentucky Public Service Commission; and c) has entered into a membership agreement with EKPC.

1.19 "Operating Requirements" shall mean any operating and technical requirements that may be imposed by a regional transmission organization, independent system operator, control area coordinator, balancing authority, Member or EKPC.

1.20 "Person" shall mean any legal or natural person, including any individual, corporation, partnership, limited liability company, joint stock company, association, joint venture, trust, governmental or international body or agency, or other entity.

1.21 "Reasonable Efforts" shall mean efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Person would use to protect its own interests.

1.22 "Small Generating Facility" shall mean the Interconnection Customer's device for the production of electricity, but shall not include the Interconnection Customer's Interconnection Facilities.

1.23 "Tariff" shall mean the Member's or Affected System's Tariff through which transmission service or interconnection service are offered, as filed with the Kentucky Public Service Commission or FERC, and as amended or supplemented from time to time, or any successor tariff.

1.24 "Transmission System" shall mean the facilities owned, controlled or operated by EKPC that are used to transmit electric power to the Member and to or from Affected Systems.

1.25 "Transmission Upgrades" shall mean any and all additions, modifications or upgrades to EKPC's Transmission System to accommodate the interconnection of the Small Generating Facility with the Member's Distribution System or to allow wheeling of power across EKPC's transmission system.

ARTICLE 2 – SCOPE

2.01 Scope. The Manual and all attachments hereto, shall govern the terms and conditions under which the Interconnection Customer's Small Generating Facility may directly interconnect with, and operate in parallel with, the Member's Distribution System. The Manual shall remain in full force and effect throughout the term of any power purchase agreement entered

into between the Member and the Interconnection Customer or the period of actual interconnection, whichever is longer.

2.02 Power Purchases. The Manual does not constitute an agreement to purchase or deliver the Interconnection Customer's power by either the Member or EKPC. The purchase or delivery of power and other services that the Interconnection Customer may require must be set forth in a separate power purchase agreement(s) between the Member and the Interconnection Customer.

ARTICLE 3 – INTERCONNECTION OBLIGATIONS

3.01 Obligations of the Member, the Interconnection Customer, and EKPC. The Member, the Interconnection Customer, and EKPC shall perform all obligations set forth herein in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice. The Member, the Interconnection Customer, and EKPC shall respectively, construct, operate, maintain, repair, inspect, and be fully responsible for the Interconnection Facilities that each currently or subsequently may own unless otherwise specified in the Attachments incorporated herein. The Interconnection Facilities shall adequately protect the personnel and property of the Member, The Interconnection Customer, and EKPC and other Persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Manual.

3.02 Obligations of the Interconnection Customer.

a. General. The Interconnection Customer shall design, construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities as set forth herein and in accordance with all Applicable Laws and Regulations, Operating Requirements, Good Utility Practice and shall reasonably minimize the likelihood of a disturbance adversely affecting or impairing the Member’s Distribution System, EKPC’s Transmission System, or any other Affected Systems.

b. Standards. Without limiting the obligations owed by the Interconnection Customer, the Small Generating Facility and Interconnection Customer’s Interconnection Facilities shall meet or exceed: 1) specifications provided by the National Electrical Safety Code, the American National Standards Institute, IEEE and Underwriter's Laboratory that are in effect at the time of construction; 2) the technical and functional interconnection requirements set forth in Attachment 4; and 3) any other applicable federal, state or local codes or standards.

c. Manufacturer’s Maintenance Schedules. The Interconnection Customer shall adhere to the recommended maintenance schedule of the applicable manufacturer of each component of the Small Generating Facility and Interconnection Facilities.

3.03 Obligations of the Member and EKPC.

a. General. The Member shall design, construct, operate, and maintain its Distribution System and Interconnection Facilities as set forth herein and in accordance with all Applicable Laws and Regulations, Operating Requirements and Good Utility Practice. EKPC shall design, construct, operate, and maintain its Transmission System and Interconnection Facilities as set forth herein and in accordance with all Applicable Laws and Regulations, Operating Requirements and Good Utility Practice.

b. Coordination. EKPC shall coordinate with the Member to support the interconnection of the Small Generating Facility into the Member's Distribution System. When applicable, the Member shall inform EKPC of activities relating to the engineering studies and commissioning tests set forth in Attachment 4.

3.04 Milestones. The Member and Interconnection Customer shall agree on milestones for which each is responsible and list them in Attachment 3 of this Manual. A deadline for performance of the obligations under this provision may be extended by agreement. If the Member or Interconnection Customer anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall: a) immediately notify the other party of the reason(s) for not meeting the milestone; b) propose the earliest reasonable alternate date by which it can attain this and future milestones, and c) request appropriate amendments to Attachment 3. The party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless: a) it will suffer significant uncompensated economic or operational harm from the delay; b) attainment of the same milestone has previously been delayed; or c) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted. EKPC shall be provided with a copy of Attachment 3 and all amendments thereto.

3.05 Infrastructure Protection. Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Member and Interconnection Customer shall, to the greatest extent possible, comply with Good Utility Practice regarding infrastructure protection, including satisfaction of basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

ARTICLE 4 – AUTHORIZATION, TESTING AND RIGHT OF ACCESS

4.01 Authorization Required Prior to Parallel Operation. The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Member's Distribution System without prior written authorization of the Member. The Member will provide such authorization once the Member receives notification that the Interconnection Customer has complied with all applicable parallel operation and testing requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed. The Member shall use Reasonable Efforts to list any applicable parallel operation requirements other than those set forth in the Attachments hereto. Additionally, the Member shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Member shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

4.02 Initial Testing and Inspection. The Interconnection Customer shall test and inspect its Small Generating Facility prior to interconnection. Such testing shall, at a minimum, comply with the requirements of Attachment 4. The Interconnection Customer shall notify the Member of such activities no fewer than five (5) Business Days (or as may otherwise be mutually agreed) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Member and EKPC may, at its own expense, send properly accredited representatives to the Small Generating Facility site to inspect the Small Generating Facility and observe the testing. If requested at the time of testing, the Interconnection Customer shall provide the Member with a written test report within five (5) business days when such testing and inspection is completed. The Member shall acknowledge that it has received the Interconnection Customer's written test report, however, such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Member as to the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

4.03 Right of Access. Following the initial inspection process described above, the Interconnection Customer shall allow properly accredited representatives of the Member to have access to the Facility, upon advance notice and during any Business Day, to observe the operation and maintenance of the Small Generating Facility or Interconnection Customer's Interconnection Facilities. Such representatives shall observe such safety precautions as may be required by the Interconnection Customer and communicated to the Member in writing and shall conduct themselves in a manner that will not interfere with the operation or maintenance of the Small Generating Facility or Interconnection Customer's Interconnection Facilities.

ARTICLE 5 – METERING

5.01 Installation.

a. Location. Energy delivered by the Interconnection Customer to the Member pursuant to a power purchase agreement shall be measured by a meter ("Delivery Meter") located at the Delivery Point, and shall have the metering instrument transformers, which measure the output of the Small Generating Facility, located on the Member's side of any transformer of the Interconnection Facilities. Should the Interconnection Customer require an express feeder to deliver energy directly to a Member substation, the Delivery Meter shall be located within the Member substation.

b. Cost and Installation. The Member shall specify, install, own, operate, and maintain the Delivery Meter. All Delivery Metering equipment, installation, maintenance, and operating costs will be borne by the Interconnection Customer. The Delivery Meter used to determine the billing hereunder shall be sealed, and such seals shall be broken only when tested by the Member, and only when the Delivery Meter is to be inspected, tested, adjusted, or replaced as described in Section 5.02 and Section 5.03. If applicable, the Interconnection Customer shall provide access, per 807 KRS 5:006 Section 19, for the Member to the Delivery Meter at all reasonable times for the purposes of inspecting, testing, adjusting and calibrating the same, provided that such access shall not unreasonably interfere with Interconnection Customer's normal business operations. In the event that the Delivery Meter fails to register during any period of time,

the Member shall estimate the amount of Energy delivered during such period using an appropriate methodology.

5.02 Meter Testing. The accuracy of the Delivery Meter shall be tested and verified by the Member, at the Interconnection Customer's expense, prior to commercial operation of the facility. The Delivery Meter shall be tested by the Member, at the Interconnection Customer's expense, per 807 KRS 5:006 General Rules Sections 16 and 17, and 807 KAR 5:041 Electric. The Interconnection Customer may, at its own expense, at any time, per 807 KAR 5:006 Section 18, request the Member to test the Delivery Meter. Upon receiving written notice, the Member shall have forty-five (45) days to perform such test. All tests shall be coordinated to minimize the impact on Small Generating Facility operations.

5.03 Corrections and Maintenance. If, upon testing, the Delivery Meter is found to be inaccurate, the Delivery Meter shall be promptly adjusted or replaced by the Member to record correctly. The Interconnection Customer shall have the right to have a representative present whenever the Delivery Meter is, replaced, repaired, tested, calibrated, or adjusted.

ARTICLE 6 – SMALL GENERATING FACILITY OPERATIONS

6.01 Reactive Power. The Interconnection Customer shall design the Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Delivery at a power factor within the range specified in Attachment 4 of this document unless the Member has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

6.02 Disconnection.

a. Expiration/Termination of a Power Purchase Agreement. The Small Generating Facility shall be disconnected from the Member's Distribution System upon the expiration or termination of any purchase power agreement in effect between the Interconnection Customer and the Member. All costs required to effectuate such disconnection shall be borne by the Interconnection Customer unless the disconnection is the result of a default under an applicable power purchase agreement or a violation of any term of this Manual by the Member.

b. Temporary Disconnections. Temporary disconnections shall continue only for so long as reasonably necessary under Good Utility Practice. Permissible temporary disconnections shall include:

(i) Emergency Conditions. Under Emergency Conditions, the Member may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Member shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the Member promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Member's Distribution System or any Affected Systems, including EKPC’s Transmission System. To the extent information is known, the

notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the facilities and operations of both the Member and Interconnection Customer, its anticipated duration, and the necessary corrective action.

(ii) Routine Maintenance, Construction, and Repair. Either the Member or the Interconnection Customer may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the Member's Distribution System when necessary for routine maintenance, construction, and repairs on the Member's Distribution System or the Small Generating Facility. Both the Member and the Interconnection Customer shall use Reasonable Efforts to provide the other with five (5) Business Days notice prior to any such interruption. The Member and Interconnection Customer shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with each other.

(iii) Forced Outages. During any forced outage affecting either the Small Generating Facility or the Member's Distribution System, the affected party may suspend interconnection service to effect immediate repairs. The affected party shall use Reasonable Efforts to provide the other party with prior notice. If prior notice is not given, written documentation explaining the circumstances of the disconnection shall be provided after the fact upon request.

c. Reconnection. The Interconnection Customer and Member shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the Member's Distribution System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

6.03 Adverse Operating Effects. The Member shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served by the Member, or if operating the Small Generating Facility could cause damage to the Member's Distribution System or Affected Systems, including EKPC's Transmission System. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Member may disconnect the Small Generating Facility. Except to the extent that an Emergency Condition exists, the Member shall provide the Interconnection Customer with five (5) Business Days notice of such disconnection.

6.04 Modification of the Small Generating Facility. The Interconnection Customer must receive written authorization from the Member before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the Member's Distribution System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Member's prior written authorization, the latter shall have the right to temporarily disconnect the Small Generating Facility. The Member shall notify EKPC prior to authorizing any such modification to the Small Generating Facility.

6.05 Environmental Releases. The Interconnection Customer-shall notify the Member, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the Member. The notifying party shall: a) provide the notice as soon as practicable, provided such party makes a good faith effort to provide the notice no later than twenty-four (24) hours after such party becomes aware of the occurrence; and b) promptly furnish the Member with copies of any publicly available reports filed with any Governmental Authorities addressing such events.

6.06 Wheeling. Unless otherwise required by law or tariff, the Distribution System may allow for any excess Energy produced by the Small Generating Facility to be wheeled across its distribution system for delivery to the EKPC Transmission System or other Affected Systems. Unless otherwise required by law or tariff, wheeling fees shall be calculated in accordance with Attachment 6. The Interconnection Customer may wheel power across EKPC's Transmission System in accordance with EKPC's Open Access Transmission Tariff.

ARTICLE 7 – COST ALLOCATION FOR INTERCONNECTION FACILITIES AND DISTRIBUTION UPGRADES

7.01 Interconnection Facilities. The Interconnection Customer shall pay for the capital, operations and maintenance costs of the Interconnection Facilities itemized in Attachment 1. The Member shall provide a best estimate cost for the purchase and construction of its Interconnection Facilities and shall provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Member. The Interconnection Customer shall pay all reasonable expenses associated with a) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities; and b) operating, maintaining, repairing, and replacing the Member's Interconnection Facilities.

7.02 Distribution Upgrades. The Member shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 5 of this Manual. If the Member and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The capital, operations and maintenance costs of the Distribution Upgrades shall be paid to the Member by the Interconnection Customer.

7.03 Billing and Payment Procedures; Audits.

a. Billing and Payment. The Member shall bill the Interconnection Customer for the costs of Member's Interconnection Facilities, Distribution Upgrades and Transmission Upgrades, described in Attachments 1 and 5, and actually incurred, on a monthly basis, or as otherwise agreed by them. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by Interconnection Customer and Member. Billings and payments shall be addressed as follows:

If to the Member:

Member: _____
Attention: _____
Address: _____
City: _____ State:_____ Zip:_____
Phone: _____ Fax: _____

If to the Interconnection Customer:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State:_____ Zip:_____
Phone: _____ Fax: _____

b. Final Accounting. Within three months of completing the construction and installation of the Member's Interconnection Facilities, Distribution Upgrades and Transmission Upgrades described in Attachments 1 and 5, the Member shall provide the Interconnection Customer with a final accounting report. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Member shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Member within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility, the Member shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

7.04 Interconnection Customer's Credit Support. Within five (5) Business Days of entering into any power purchase agreement to which this Manual shall apply, the Interconnection Customer shall deliver to the Member a Letter of Credit in the amount of $_____ to secure the Interconnection Customer's obligations as set forth in Article 7 and Article 8 herein. The Letter of Credit shall remain in place for at least six (6) months, and any outstanding Letter of Credit shall be renewed or replaced prior to its expiration by a replacement Letter of Credit in the same amount and for a term of at least six (6) months (provided, however, that the last such Letter of Credit shall have an expiration date that is no earlier than ninety (90) days following the date of the Member's issuance of the final accounting report required by Section 7.03(b)), which Letter of Credit shall be delivered to Buyer no later than twenty (20) days before the expiration of the replaced Letter of Credit, and which process shall be repeated as necessary until the Member has been paid for the costs of all Interconnection Facilities, Distribution System Upgrades and Transmission Upgrades. The Letter of Credit shall include a provision for at least thirty (30) days advance notice to Member of any expiration or early termination of the Letter of Credit so as to allow Member sufficient time to exercise its rights under the Letter of Credit if the Interconnection Customer fails to renew or replace the Letter of Credit prior to such expiration or early termination.

ARTICLE 8 – COST ALLOCATION FOR EKPC TRANSMISSION SYSTEM UPGRADES

8.01 Applicability. Article 8 shall apply in the event that: a) the Interconnection Customer anticipates using the EKPC Transmission System to wheel power to other Affected Systems; or b) the Interconnection Customer or the Member anticipates that, under normal

operating conditions, the Small Generating Facility may cause a backflow of power onto the EKPC Transmission System.

8.02 Consultations. Prior to the Member authorizing the Interconnection Customer to begin operation of the Small Generating Facility in parallel to the Member's Distribution System, the Member and EKPC shall consult regarding the anticipated and foreseeable affects of the Small Generating Facility on the EKPC Transmission System.

8.03 Transmission Upgrades. In the event that EKPC determines, in its sole discretion, that upgrades will be reasonably necessary to facilitate wheeling of power from the Small Generating Facility across the EKPC Transmission System or to protect the EKPC Transmission System from any backflow of power from the Small Generating Facility, EKPC shall provide a best estimate cost for the purchase and construction of the Network Upgrades and shall provide a detailed itemization of such costs in Attachment 5. Upon execution of any power purchase agreement between a Member and an Interconnection Customer and the posting of the Interconnection Customer's Credit Support set forth in Section 7.04, EKPC shall construct the Transmission Upgrades in accordance with Good Utility Practice.

8.04 Billing and Payment. The capital cost of the Transmission Upgrades shall be paid by the Member as a one-time payment due prior to the commencement of construction or installation of the Transmission Upgrades. The Member shall be reimbursed for the cost of the Transmission Upgrades by the Interconnection Customer in accordance with Section 7.03. Payments to EKPC shall be addressed as follows:

East Kentucky Power Cooperative, Inc.
Attention: CFO
P.O. Box 707
Winchester, KY 40392-0707
Tel. (859) 744-4812
Fax. (859) 744-6008

ARTICLE 9 - ASSIGNMENT, INDEMNITY, LIABILITY AND DAMAGES, FORCE MAJEURE, INSURANCE AND CONFIDENTIALITY

9.01 Assignment.

a. Assignment to Non-Affiliates. No rights, obligations or obligations arising from this Manual may be assigned, in whole or in part, by either the Member or Interconnection Customer without the prior written consent of the non-assigning party. Such consent may require that: i) the assignee agrees in writing, in form and substance satisfactory to the non-assigning party, to assume and to perform each and every obligation of the assignor under this Manual; ii) the assignment does not impair any security given by the assigning party hereunder unless the assignee posts replacement security which meets the requirements of Section 7.04; and iii) the assignee has obtained, prior to the assignment, such authorizations as may be required by applicable law. Any assignment in violation hereof shall be null and void and shall constitute a breach of this Manual by the assigning party.

b. Assignment to Affiliates. Notwithstanding Section 9.01(a), either the Interconnection Customer or Member may assign this Manual to an affiliate of such party without the consent of the non-assigning party, provided, however, that the assigning party shall remain liable for all of its obligations under this Manual unless and until the consent of the non-assigning party is secured in accordance with Section 9.01(a). The assigning party shall notify the other party of the occurrence of any event described in this paragraph.

9.02 Indemnity.

a. Duty to Indemnify. The Interconnection Customer shall indemnify, defend and hold the Member and EKPC and its employees, directors, officers, managers, members and agents, harmless from and against any and all third party claims, suits, damages, losses, liabilities, expenses and costs (including reasonable attorneys' fees) including, but not limited to, those arising out of property damage to the property of the Member and EKPC, environmental claims, and personal injury and bodily injury (including death, sickness and disease) to the extent caused by a material breach of any obligation contained in this Manual, negligence or willful misconduct of the Interconnection Customer. The duty to indemnify under this paragraph shall continue in full force and effect notwithstanding the expiration or termination of any power purchase agreement between the Interconnection Customer and the Member with respect to any cost or expense arising out of an event or condition which occurred or existed prior to such expiration or termination, or during the period of interconnection, whichever is longer.

b. Employees. The Interconnection Customer shall not be deemed an employee of the Member or EKPC nor shall it bring any claim against the Member or EKPC with respect to any liability for compensation under any applicable state or federal worker's compensation act, including worker's compensation and/or employer's liability claims of employees. The Interconnection Customer shall be liable for all claims of their employees arising out of any provision of any workers' compensation law.

9.03 Limitation of Liability and Damages. The Member or EKPC shall not be liable for consequential, incidental, punitive exemplary or indirect damages, lost profits or other business interruption damages, by statute (to the extent permitted by law), in tort or contract or otherwise (except to the extent that an Indemnifying Party is obligated under Section 9.02 to indemnify against third party claims for consequential, incidental, punitive, exemplary or indirect damages or lost profits or business interruption damages). The limitations herein imposed on remedies and the measure of damages is without regard to the cause or causes related thereto, including the negligence of the Member or EKPC, whether such negligence be sole, joint or concurrent, or active or passive. EXCEPT AS SET FORTH IN THIS MANUAL, THERE ARE NO REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, INCLUDING WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, WITH RESPECT TO THE SUBJECT MATTER OF THIS MANUAL.

9.04 Force Majeure. If a Force Majeure event prevents the Member, EKPC, or the Interconnection Customer from fulfilling any obligations under this Manual, the party affected by the Force Majeure event ("Affected Party") shall promptly notify the others, either in writing or

via the telephone, of the existence of the Force Majeure event. The notification must specify in reasonable detail the circumstances of the Force Majeure event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the others informed on a continuing basis of developments relating to the Force Majeure event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Manual (other than the obligation to make payments) only to the extent that the effect of the Force Majeure event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

9.05 Insurance. In addition to, or as a part of, any insurance required by a power purchase agreement, the Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection. The amount of such insurance shall be 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, but in no event shall be less than $_____. Such insurance shall be obtained from an insurance provider authorized to do business in Kentucky and certification that such insurance is in effect shall be provided upon request of the Member, except that the Interconnection Customer shall show proof of insurance to the Member no later than ten (10) Business Days prior to the anticipated commercial operation date.

9.06 Confidentiality.

a. Duty of Confidentiality. Any Confidential Information of the Member or EKPC which is disclosed to or otherwise received or obtained by the Interconnection Customer incident to an interconnection shall be held, in confidence, and the Interconnection Customer (subject to paragraphs (b) and (c) below) may not publish or otherwise disclose any Confidential Information of the Member or EKPC to any Person for any reason or purpose whatsoever, or use any Confidential Information for any purpose other than to effectuate the interconnection, without the prior written approval of the Member (or EKPC), which approval may be granted or withheld by the Member (or EKPC) in its sole discretion. Without limiting the generality of the foregoing, the Interconnection Customer shall observe at a minimum the same safeguards and precautions with regard to the Member's or EKPC's Confidential Information which such party observes with respect to its own information of the same or similar kind.

Any Confidential Information of the Interconnection Customer which is disclosed to or otherwise received or obtained by the Member or EKPC incident to an interconnection shall be held, in confidence, and the Member and EKPC (subject to paragraphs (b) and (c) below) may not publish or otherwise disclose any Confidential Information of the Interconnection Customer to any Person for any reason whatsoever, or use any Confidential Information for any purpose other than to effectuate the interconnection, without prior written approval of the Interconnection Customer, which approval may be granted or withheld by the Interconnection Customer in its sole discretion. Without limiting the generality of the foregoing, the Member and EKPC shall observe at a minimum the same safeguards and precautions with regard to the Interconnection Customer's

Confidential Information which such party observes with respect to its own information of the same or similar kind.

b. Disclosures to Employees, Contractors and Affiliates. The Interconnection Customer will make available Confidential Information received from the Member or EKPC to its employees, contractors and affiliates only on a need-to-know basis, and all Persons to whom such Confidential Information is made available will be made aware of the confidential nature of such Confidential Information, and will be required to agree to hold such Confidential Information in confidence under terms substantially identical to the terms hereof. The Member and EKPC shall observe the same conduct towards the Interconnection Customer's Confidential Information disclosures.

c. Disclosures to Governmental Authorities. Notwithstanding the foregoing, the Interconnection Customer may provide any Confidential Information to any Governmental Authority having jurisdiction over or asserting a right to obtain such information, provided that: i) such Governmental Authority: A) orders that such Confidential Information be provided; or B) such Governmental Authority requires disclosure of the Confidential Information in connection with the application for any required authorization; and ii) unless prohibited from so doing by applicable law, the Interconnection Customer promptly advises the Member (or EKPC) of any request for such information by such Governmental Authority and cooperates in giving the Member (or EKPC) an opportunity to present objections, requests for limitation, and/or requests for confidentiality or other restrictions on disclosure or access, to such Governmental Authority. The Member and EKPC shall observe the same conduct towards the Interconnection Customer's Confidential Information disclosures.

d. Injunctive Relief. In the event of a breach or threatened breach of the provisions of paragraph (a) above by the Interconnection Customer, the Member (or EKPC) shall be entitled, without limitation, to an injunction restraining such party from such breach, or likewise, in the event of a breach or threatened breach of the provisions of paragraph (a) above by the Member or EKPC, the Interconnection Customer shall be entitled, without limitation, to an injunction restraining such party(s) from such breach

e. Continuing Obligation. The obligation to retain the Member's, EKPC's, or the Interconnection Customer's Confidential Information in confidence shall continue in full force and effect throughout the period of interconnection and for a period of two (2) years thereafter, notwithstanding the expiration or termination of any power purchase agreement between the Member and the Interconnection Customer.

ARTICLE 10 – MISCELLANEOUS

10.01 Waiver. The failure of the Member or the Interconnection Customer to insist, on any occasion, upon strict performance of any provision of this Manual will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such party. Any waiver of this Manual shall, if requested, be provided in writing.

10.02 No Partnership. This Manual shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties with respect to the interconnection or to impose any partnership obligation or partnership liability upon the Member, EKPC, or the Interconnection Customer. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind any other Party.

10.03 Subcontractors. Any Party may utilize the services of any subcontractor(s) deemed appropriate to perform the obligations set forth herein; provided, however, that subcontractors comply with all applicable terms and conditions of this Manual in providing such services. The creation of any subcontract relationship shall not relieve any Party of any of its respective obligations hereunder. Each Party shall be fully responsible to any other Party for the acts or omissions of any subcontractor hired as if no subcontract had been made. Any applicable obligation imposed herein upon any Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such party. The obligations under this paragraph will not be limited in any way by any limitation of subcontractor's insurance.

10.04 Notices. Any written notice, demand, or request required or authorized herein shall be deemed properly given if delivered in person, via overnight U.S. mail or courier service or facsimile. Any notice or request required or permitted to be given and not required herein to be given in writing may be so given by telephone. All notices shall be delivered to the designated representative specified below:

If to the Interconnection Customer:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State:_____ Zip:_____
Phone: _____ Fax: _____

If to the Member:

Member: _____
Attention: _____
Address: _____
City: _____ State:_____ Zip:_____
Phone: _____ Fax: _____

If to East Kentucky Power Cooperative, Inc.

East Kentucky Power Cooperative, Inc.
Attention: CEO
Address: PO Box 707
City: Winchester State: KY Zip: 40392-0707
Phone: 859-744-4812 Fax: 859-744-6008

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Attachment 1

Description and Costs of the Interconnection Facilities and Metering Equipment

Equipment, including the Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, the Member, or EKPC. The Member will provide a best estimate itemized cost of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Attachment 2

One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Distribution Upgrades.
Operating Procedures

Attachment 3

Milestones

In-Service Date: _____

Critical milestones and responsibility as agreed to by the Parties:

Milestone/Date Responsible Party

(1) _____ _____
(2) _____ _____
(3) _____ _____
(4) _____ _____
(5) _____ _____
(6) _____ _____
(7) _____ _____
(8) _____ _____
(9) _____ _____
(10) _____ _____

Agreed to by:

For the Member_____ Date_____

For the Transmission Owner (If Applicable) _____Date_____

For the Interconnection Customer_____ Date_____

Attachment 4

Technical and Functional Requirements for Interconnecting the Interconnection Customer's Small Generating Facility with the Member's Distribution System

Attachment 5

Description of Distribution Upgrades and Transmission Upgrades and Best Estimate of Such Costs

The Member and EKPC shall describe Distribution Upgrades and Transmission Upgrades and provide an itemized best estimate of the cost of the Distribution Upgrades and Transmission Upgrades and annual operation and maintenance expenses associated with each. The costs and annual expenses shall be functionalized as either distribution or transmission related.

Attachment 6

Calculation for Wheeling Energy Across a Member Distribution System to the EKPC Transmission System

Distribution Wheeling Rate

The Distribution Wheeling Rate shall be calculated by applying an Annual Fixed Charge Rate to the Net Distribution Line Investment. The result of this calculation will be divided by the 12-month sum of the monthly wholesale coincident peak demands for the EKPC Member Cooperative. The resulting Distribution Wheeling Rate per kW shall be multiplied by the capacity wheeled by the third party or EKPC. The Distribution Wheeling Rate shall be based on the financial information filed in the EKPC Member Cooperative's annual report to the Kentucky Public Service Commission (Commission). The Distribution Wheeling Rate shall be recalculated every June 1st to reflect the most current financial information.

Annual Fixed Charge Rate. The Annual Fixed Charge Rate shall allow for the recovery of depreciation expense, operation and maintenance (O&M) expense, and administrative and general (A&G) expenses associated with EKPC Member Cooperative's distribution system. The Annual Fixed Charge Rate shall also include a return on the investment in the distribution facilities of EKPC Member Cooperative. The components of the Annual Fixed Charge Rate shall be calculated in the following manner:

a. Depreciation Expense. The annual depreciation expense associated with the distribution plant shall be divided by the calendar year-end total distribution plant to calculate the depreciation portion of the Annual Fixed Charge Rate. The annual depreciation expense associated with the distribution plant shall be calculated by multiplying the total annual depreciation expense by the percentage of the calendar year-end total distribution plant to the calendar year-end total electric plant in service.

b. O&M Expense. The annual distribution O&M expense shall be divided by the calendar year-end total distribution plant to calculate the O&M portion of the Annual Fixed Charge Rate.

c. A&G Expense. The annual A&G expense associated with the distribution plant shall be divided by the calendar year-end total distribution plant to calculate the A&G portion of the Annual Fixed Charge Rate. The annual A&G expense associated with the distribution plant shall be calculated by multiplying the total annual A&G expense by the percentage of the calendar year-end total distribution plant to the calendar year-end total electric plant in service.

d. Return on Investment. The return on investment reflects a weighted cost of capital approach. The debt portion of capitalization is based on the calendar year-end balance of all long-term debt. The equity portion of capitalization is based on

the calendar year-end balance in the Patronage Capital account minus EKPC generation and transmission capital credits (G&TCCs). The cost of debt is calculated by dividing the calendar year-end balance for interest on long-term debt by the calendar year-end balance of all long-term debt. The cost of equity is based on the Times Interest Earned Ratio (TIER) authorized by the Commission in the EKPC Member Cooperative's last base rate case. The cost of equity is calculated by dividing the amount of margins required to achieve the authorized TIER by the calendar year-end balance in the Patronage Capital account minus EKPC G&TCCs.

Net Distribution Line Investment. The Net Distribution Line Investment is the net book value for two distribution plant accounts: Poles, Towers and Fixtures – Account 364, and Overhead Conductors and Devices – Account 365. The net book value for each account is determined by taking the calendar year-end balance for the account minus the corresponding accumulated depreciation at calendar year-end. The corresponding accumulated depreciation is calculated by multiplying the total accumulated depreciation balance for distribution plant at calendar year-end by a percentage of the calendar year-end balances for either Account 364 or 365 to the total calendar year-end total distribution plant.

Attachment 7

SMALL GENERATOR INTERCONNECTION REQUEST APPLICATION FORM

Member: _____

Designated Contact Person: _____

Address: _____

Telephone Number: _____

Fax: _____

E-Mail Address: _____

An Interconnection Request is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customer who requests an interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Member.

Processing Fee or Deposit:

The Interconnection Customer shall submit to the Member a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: _____

Contact Person: _____

Mailing Address: _____

City: State: Zip: _____

Facility Location (if different from above): _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address:_____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: _____

Title: _____

Address: _____

_____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Application is for: _____ New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe:

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ____ No ____
To Supply Power to the Interconnection Customer? Yes ____ No ____
To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

_____ _____
(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Member]

Contact Name: _____

Title: _____

Address: _____

_____

Telephone (Day): _____Telephone (Evening):_____
Fax: _____ E-Mail Address: _____

Requested Point of Interconnection: _____

Interconnection Customer's Requested In-Service Date: _____

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___
Hydro Type (e.g. Run-of-River):_____
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) _____

Prime Mover: _____ Fuel Cell _____ Recip Engine _____ Gas Turb
_____ Steam Turb _____ Microturbine _____ PV _____ Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: _____ kW

Generator Nameplate Rating: _____ kVAr

Interconnection Customer or Customer-Site Load: _____kW (if none, so state)

Typical Reactive Load (if known): _____

Maximum Physical Export Capability Requested: _____ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1._____	_____
2._____	_____
3._____	_____
4._____	_____
5._____	_____

Is the prime mover compatible with the certified protective relay package?____Yes ____No

Generator (or solar collector)

Manufacturer, Model Name & Number: _____

Version Number: _____

Nameplate Output Power Rating in kW: (Summer) _____ (Winter) _____

Nameplate Output Power Rating in kVA: (Summer) _____ (Winter) _____

Individual Generator Power Factor

Rated Power Factor: Leading: _____Lagging: _____

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: _____ Elevation: _____ Single phase ___ Three phase _____

Inverter Manufacturer, Model Name & Number (if used): _____

List of adjustable set points for the protective equipment or software: _____

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous or RMS? _____

Harmonics Characteristics: _____

Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

(*) Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _____ P.U.
Direct Axis Transient Reactance, X' d: _____ P.U.
Direct Axis Subtransient Reactance, X" d: _____ P.U.
Negative Sequence Reactance, X_2: _____ P.U.
Zero Sequence Reactance, X_0: _____ P.U.
KVA Base: _____
Field Volts: _____
Field Amperes: _____

Induction Generators:

Motoring Power (kW): _____
$I_2{}^2t$ or K (Heating Time Constant): _____
Rotor Resistance, Rr: _____

Stator Resistance, Rs: _____
Stator Reactance, Xs: _____
Rotor Reactance, Xr: _____
Magnetizing Reactance, Xm: _____
Short Circuit Reactance, Xd": _____
Exciting Current: _____
Temperature Rise: _____
Frame Size: _____
Design Letter: _____
Reactive Power Required In Vars (No Load): _____
Reactive Power Required In Vars (Full Load): _____
Total Rotating Inertia, H: _____ Per Unit on kVA Base

Note: Please contact the Member prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only:

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling?
__Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____ single phase _____ three phase? Size: _____ kVA
Transformer Impedance: _____ % on _____ kVA Base

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _____ Type: _____ Size: _____Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _____ Type: _____

Load Rating (Amps): _____ Interrupting Rating (Amps): _____ Trip Speed (Cycles): ____

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.			
2.			
3.			
4.			
5.			
6.			

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: Type: _____ Style/Catalog No.: _____Proposed Setting: _____
Manufacturer: Type: _____ Style/Catalog No.: _____Proposed Setting: _____
Manufacturer: Type: _____ Style/Catalog No.: _____Proposed Setting: _____
Manufacturer: Type: _____ Style/Catalog No.: _____Proposed Setting: _____
Manufacturer: Type: _____ Style/Catalog No.: _____Proposed Setting: _____

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: _____
Type: _____ Accuracy Class: _____Proposed Ratio Connection: _____

Manufacturer: _____
Type: _____ Accuracy Class: _____Proposed Ratio Connection: _____

Potential Transformer Data (If Applicable):

Manufacturer: _____
Type: _____ Accuracy Class: _____Proposed Ratio Connection: _____

Manufacturer: _____
Type: _____ Accuracy Class: _____Proposed Ratio Connection: _____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed?

_____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation). Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)

_____

_____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes.

Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are Schematic Drawings Enclosed? __Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____ Date: _____

Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, distribution circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Member station. Number of generation connections: _____

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes _____ No _____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes _____ No _____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

_____

_____

What protocol does the control system or PLC use?

_____

_____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, distribution line, and property lines.

Physical dimensions of the proposed interconnection station:

_____

Bus length from generation to interconnection station:

_____

Line length from interconnection station to Member's Distribution System.

_____

Tower number observed in the field. (Painted on tower leg)*:

_____

Number of third party easements required for distribution lines*:

_____

* To be completed in coordination with Member.

Is the Small Generating Facility located in Member's service area?

Yes _____ No _____

If No, please provide name of local provider:

_____

Please provide the following proposed schedule dates:

Begin Construction Date: _____

Generator step-up transformers receive back feed power Date: _____

Generation Testing Date: _____

Commercial Operation Date: _____

Cogeneration and Small Power Production Power Purchase Rate Schedule Over 100 kW from Dispatchable Generation Sources

Availability

Available only to qualified cogeneration or small power production facilities with a design capacity of over 100 kW which have executed a contract with EKPC and one of EKPC's member distribution systems for the purchase of electric power by EKPC. Qualified cogeneration or small power production facilities must be able to be dispatched by EKPC. Non-dispatchable qualified cogeneration or small power production facilities are covered under a separate tariff. Pursuant to Federal Energy Regulatory Commission ("FERC") regulations 18 C.F.R. §§ 292.303(a), 292.309, and 292.310, EKPC is no longer obligated to purchase electric energy and/or capacity from qualifying cogeneration or small power production facilities with a net capacity of over 5 MW. T

Rates

The rates set forth below shall be used as the basis for negotiating a final purchase rate with qualifying facilities pursuant to Section 7 of 807 KAR 5:054.

1. Capacity - $18.81 per kW per year is applicable if cogenerator or small power producer is dispatched by EKPC. R

2. Energy – A Qualifying Facility ("QF") will be credited monthly for the electric power produced by dispatchable generation facilities at the actual real-time locational marginal price for energy set by PJM at the EKPC zonal node during each hour of the day at the time of delivery. The payments will be offset by a market administration fee of $0.00012 per kWh to cover EKPC's market participation costs. R

Terms and Conditions

1. Pursuant to FERC regulations 18 C.F.R. §§ 292.303(a), 292.309, and 292.310, EKPC is no longer obligated to purchase electric energy and/or capacity from qualifying cogeneration or small power production facilities with a net capacity of over 5 MW. T

2. All power from a QF will be sold only to EKPC.

3. Seller must provide good quality electric power within a reasonable range of voltage, frequency, flicker, harmonic currents, and power factor.

4. QF shall provide reasonable protection for EKPC and the member cooperative's system.

5. QF shall design, construct, install, own, operate, and maintain the QF in accordance with all applicable codes, laws, regulations, and generally accepted utility practices.

DATE OF ISSUE: March 31, 2022

DATE EFFECTIVE: Service rendered on and after June 1, 2022

ISSUED BY: Anthony S. Campbell
Anthony S. Campbell,
President and Chief Executive Officer

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
6/1/2022
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Cogeneration and Small Power Production Power Purchase Rate Schedule Equal To or Less Than 100 kW from Dispatchable Generation Sources

Availability

Available only to qualified cogeneration or small power production facilities with a design capacity of 100 kW or less which have executed a contract with EKPC and one of EKPC's member distribution systems for the purchase of electric power by EKPC. Qualified cogeneration or small power production facilities must be able to be dispatched by EKPC. Non-dispatchable qualified cogeneration or small power production facilities are covered under a separate tariff.

Rates

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Terms and Conditions

1. All power from a QF will be sold only to EKPC.
2. Seller must provide good quality electric power within a reasonable range of voltage, frequency, flicker, harmonic currents, and power factor.
3. QF shall provide reasonable protection for EKPC and the member cooperative's system.
4. QF shall design, construct, install, own, operate, and maintain the QF in accordance with all applicable codes, laws, regulations, and generally accepted utility practices.
5. QF shall reimburse EKPC and its member cooperative for all costs incurred as a result of interconnecting with the QF, including operation, maintenance, administration, and billing.
6. QF shall obtain insurance in the following minimum amounts for each occurrence:
   a. Public Liability for Bodily Injury - $1,000,000.00
   b. Property Damage - $500,000.00
7. Initial contract term shall be for a minimum of five years.
8. QFs proposing to supply as available (non-firm) electric power shall not be entitled to a capacity payment.
9. Qualifying cogeneration and small power production facilities must meet the definition set forth in 807 KAR 5:054 to be eligible for this tariff.

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DATE EFFECTIVE: Service rendered on and after June 1, 2022

ISSUED BY: Anthony S. Campbell,
President and Chief Executive Officer

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
EFFECTIVE
6/1/2022
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Cogeneration and Small Power Production Power Purchase Rate Schedule Over 100 kW from Non-Dispatchable Generation Sources

Availability

Available only to qualified cogeneration or small power production facilities that are not able to be dispatched by ("EKPC") which have executed a contract with EKPC and one of EKPC's member distribution systems for the purchase of electric power by EKPC. Pursuant to FERC regulations 18 C.F.R. §§ 292.303(a), 292.309, and 292.310, EKPC is no longer obligated to purchase electric energy and/or capacity from qualifying cogeneration or small power production facilities with a net capacity of over 5 MW. T

Rates

1. Capacity - $0.00 per kW per year is applicable for the cogenerator or small power producer. N
2. Energy - QF will be credited monthly for the electric power produced by non-dispatchable generation facilities at the value of the real-time locational marginal price for energy set by PJM at the EKPC zonal node during each hour of the day at the time of delivery. The payments will be offset by a market administration fee of $0.00012 per kWh to cover EKPC's market participation costs. T R

Terms and Conditions

1. Pursuant to FERC regulations 18 C.F.R. §§ 292.303(a), 292.309, and 292.310, EKPC is no longer obligated to purchase electric energy and/or capacity from qualifying cogeneration or small power production facilities with a net capacity of over 5 MW. T
2. All power from a QF will be sold only to EKPC
3. Seller must provide good quality electric power within a reasonable range of voltage, frequency, flicker, harmonic currents, and power factor.
4. QF shall provide reasonable protection for EKPC and the member cooperative's system.
5. QF shall design, construct, install, own, operate, and maintain the QF in accordance with all applicable codes, laws, regulations, and general accepted utility practices.
6. QF shall reimburse EKPC and its member cooperative for all costs incurred as a result of interconnecting with the QF, including operation, maintenance, administration, and billing.
7. QF shall obtain insurance in the following minimum amounts for each occurrence:
   a. Public Liability for Bodily Injury - $1,000,000.00.
   b. Property Damage - $500,000.00

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PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Over 100 kW from Non-Dispatchable Generation Sources (continued)

8. Initial contract term shall be for a minimum of five years.

9. QFs proposing to supply as available (non-firm) electric power shall not be entitled to a capacity payment.

10. Qualifying cogeneration and small power production facilities must meet the definition set forth in 807 KAR 5:054 to be eligible for this tariff.

11. In negotiating a final purchase rate, consideration shall be given to the factors affecting purchase rates as set forth in 807 KAR 5:054, Section 7(5)(a).

12. Updated rates will be filed with the Public Service Commission of Kentucky by March 31 of each year. T

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Cogeneration and Small Power Production Power Purchase Rate Schedule 100 kW or Less from Non-Dispatchable Generation Sources

Availability

Available only to qualified cogeneration or small power production facilities that are not able to be dispatched by EKPC which have executed a contract with EKPC and one of EKPC's member distribution systems for the purchase of electric power by EKPC.

Rates

1. Capacity - $0.00 per kW per year is applicable for the cogenerator or small power producer. N
2. Energy - QF will be credited monthly for the electric power produced by non-dispatchable generation facilities at the value of the real-time locational marginal price for energy set by PJM at the EKPC zonal node during each hour of the day at the time of delivery. The payments will be offset by a market administration fee of $0.00012 per kWh to cover EKPC's market participation costs. T R

Terms and Conditions

1. All power from a QF will be sold only to EKPC.
2. Seller must provide good quality electric power within a reasonable range of voltage, frequency, flicker, harmonic currents, and power factor.
3. QF shall provide reasonable protection for EKPC and the member cooperative's system.
4. QF shall design, construct, install, own, operate, and maintain the QF in accordance with all applicable codes, laws, regulations, and general accepted utility practices.
5. QF shall reimburse EKPC and its member cooperative for all costs incurred as a result of interconnecting with the QF, including operation, maintenance, administration, and billing.
6. QF shall obtain insurance in the following minimum amounts for each occurrence:
   a. Public Liability for Bodily Injury - $1,000,000.00.
   b. Property Damage - $500,000.00
7. Initial contract term shall be for a minimum of five years.
8. QFs proposing to supply as available (non-firm) electric power shall not be entitled to a capacity payment.
9. Qualifying cogeneration and small power production facilities must meet the definition set forth in 807 KAR 5:054 to be eligible for this tariff.
10. Updated rates will be filed with the Public Service Commission of Kentucky by March 31 of each year. T

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Executive Director

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PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Technical and Functional Requirements for Interconnecting Distributed Generation with the EKPC Electrical Distribution System

East Kentucky Power Cooperative

Prepared by:

Paul A. Dolloff, Ph.D.
Senior Engineer, EKPC Research and Development

Technical and Functional Requirements for Interconnecting Distributed Generation with the EKPC Electrical Distribution System

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

Date	Rev #	Description
March 2011	0	Initial Document Release

Technical and Functional Requirements for Interconnecting Distributed Generation with the EKPC Electrical Distribution System

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

Senior Engineer	Date
Senior Vice President – Power Supply	Date

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COMPANY OVERVIEW

East Kentucky Power Cooperative (EKPC) is a not-for-profit, generation and transmission (G&T) electric utility cooperative that is owned by sixteen (16) distribution electric utility cooperatives, collectively known as the Member Systems. EKPC's purpose is to generate and deliver wholesale electricity to the Member Systems who distribute power to retail customers (members). The Member Systems own and maintain their own distribution and metering systems; EKPC owns and maintains all distribution substations.

INTRODUCTION

This document specifies the minimum requirements for the safe and effective operation of Distributed Generation (DG) up to 10 MVA interconnecting with either an existing Member System's radially operated electrical distribution feeder (up to 25kV) or directly to an EKPC distribution substation via an express feeder. DG systems may not be interconnected to loop feed distribution systems, spot networks, or grid networks.

All DG interconnections that do NOT qualify for net metering in Kentucky must be approved by both EKPC and the Member System to which the DG will be interconnected.

For simplicity, this document will use the term "DG" to refer to any distributed generator, co-generator, or small power producer facility that does NOT qualify for net metering. The term "utility" will be used to refer to either EKPC or the Member System (as appropriate) to which interconnection is being sought.

DG owners/operators and utility personnel shall use this document when planning the installation of interconnected DG systems. Although this document establishes criteria and requirements for interconnection, this manual is not a design handbook.

This document provides the minimum functional technical requirements that are universally needed to help assure a safe and technically sound interconnection. As such, the requirements contained within this document may not cover all details for specific DG installations. Therefore, the DG is encouraged to discuss project plans with the Member System and EKPC before designing, constructing, and purchasing equipment for the DG facility.

The interconnection requirements set forth in this document for the parallel operation of DG with the utility's distribution system are provided for substation and distribution interconnections of synchronous generators, induction generators, D.C. generators with inverters, and other inverter based generating technologies.

At the utility's discretion, all requirements in this document may be superseded by requirements given in the following standards:

ANSI Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems;"

ANSI C84.1-1995, "Electric Power Systems and Equipment – Voltage Ratings (60Hz);"

IEEE Std 519-1992, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems;"

IEEE Std. 929-2000, "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems;"

IEEE Std. 485-1983, "Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations."

LIMITATIONS

As their wholesale and service provider, this interconnection document has been developed by EKPC on behalf of the Member Systems. All applicants must check with the Member System from which permission to interconnect is being sought to determine if additional requirements exist.

This document is not intended for net metering installations. Net metering rules and regulations are included in each Member System's net metering tariff.

DG installations with capacity greater than 10 MVA will need to contact EKPC for interconnection rules and regulations.

This document is not intended for DG installations seeking to interconnect with the EKPC transmission system at voltages 69 kV and above. For these installations, all applicants must contact EKPC for the appropriate documents.

The minimum required protective relaying and safety devices and requirements specified in this document are necessary to ensure the safety of utility workers and the public. In addition, these requirements are intended to protect utility facilities and other customer equipment from damage and disruptions caused by faults, malfunctions, and improper operation of the DG facility. The minimum protective relaying and interconnection requirements given in this document do not necessarily include additional protective and safety devices as may be required by industry and/or government codes and standards, equipment manufacturer requirements, and prudent engineering design and practice to fully protect the DG facility or facilities; compliance with these regulations are the sole responsibility of the DG.

The information in this document contains general information about the interconnection requirements for customer owned DG facilities. All applicable regulatory, technical, safety, and electrical requirements and codes are not contained in their entirety in this document. DG facilities are also subject to contractual and other legal requirements, which are only summarized in this document. Those regulations, requirements, contracts, and other materials contain complete information concerning DG interconnection and take precedence over the general provisions in this document.

This document, as well as the various other agreements and rate schedules, are subject to revision. Therefore, the DG is encouraged to check with the Member System and EKPC for the latest revision prior to commencing a DG project requiring interconnection and parallel operation with the utility distribution system.

DG GENERATING REQUIREMENTS

The utility will permit any applicant to operate DG in parallel with the utility's electrical distribution system whenever such operation can take place without adversely affecting other customers, the general public, utility equipment, and utility personnel. To minimize this interference caused by the interconnection of DG, the DG shall meet the criteria given in this attachment.

The DG operating requirements outlined in this attachment shall be met at the point of common coupling (PCC). The PCC is defined as that electrical point where the distribution system owned and operated by the utility interconnects to the DG facility's distribution system. Often, but not always, the PCC is the metering point. The PCC is not to be confused with the DG point of interconnection. The DG point of interconnection is that electrical point where the output terminals of a DG system interconnect to an electrical distribution system, which may or may not be the same point as the PCC.

The DG operating requirements outlined in this attachment apply to the interconnection of either a single DG unit or the aggregate of multiple DG units within a single DG facility.

The DG operating requirements outlined in this attachment are functional and apply to all generating technologies: Synchronous generators, induction generators, D.C. generators with inverters, and other inverter based generating technologies.

VOLTAGE[1]

The DG shall not actively regulate the voltage at the PCC.

In general, the Member System maintains a voltage schedule consistent with ANSI Std. C84.1-1995 Range A. With that, a DG shall produce voltages within 5% of the nominal voltage of the distribution system to which the DG is interconnected.

Under certain emergency situations, the Member System distribution system may operate within ± 10% of nominal voltage. The DG is required to provide voltage sensing equipment and an automatic means of disconnecting to protect their equipment during abnormal voltage operation.

The DG must disconnect its generating equipment if the DG cannot maintain a voltage within 10% of the nominal voltage of the Member System's distribution system.

FREQUENCY

The nominal operating frequency of the utility's distribution system is 60 Hz. The DG shall be designed for this frequency and will not contribute to any variation from the prevailing frequency when the DG is in operation.

[1] 807 KAR 5:041. Electric. Section 6. Voltage and Frequency.

POWER FACTOR

DG systems using synchronous generators shall absorb or produce reactive energy (VArs) such that the overall power factor is between 0.90 lagging and unity or between unity and 0.9 leading, respectively. The utility may request that the DG adjust the power factor within the above stated limits.

DG systems using induction generators with nameplate power factor below unity, shall install reactive energy capacity (capacitors) such that the DG will operate within 1% (leading or lagging) of unity power factor.

POWER QUALITY

The interconnection of DG to the utility distribution system shall not degrade the power quality for existing utility customers. The utility may install power quality monitoring equipment to verify compliance of the DG with the power quality requirements outlined in this document. Should the DG be found to be out of compliance, the DG will be responsible for reimbursing the utility for the cost of the power quality monitoring equipment, telecommunication equipment and services, and studies of the power quality data analysis.

FLICKER

Though defining the particular amount and frequency of voltage flicker that constitutes a problem is highly subjective, this requirement is necessary to minimize the adverse voltage effects to other customers on the utility system.

Any voltage flicker resulting from the interconnection of the DG to the utility distribution system shall not exceed the "Border Line of Irritation" curve given in Figure 10-3 – Maximum Permissible Voltage Fluctuations of IEEE Std 519-1992.

SYNCHRONIZATION

When energizing the DG in parallel with the utility's distribution system, the DG shall:

i. Not cause a voltage fluctuation greater than ±5% of the prevailing voltage on the utility's distribution system;

ii. Not cause a dip in voltage on the utility's distribution system due to inrush currents in excess of two volts on a 120 volt base;

iii. Meet the flicker requirements outlined in this document.

HARMONICS

In general, the utility restricts the injection of voltage and current harmonics to limits defined in the IEEE Std. 519-1992. With that, the total harmonic distortion (THD) of voltage or current created by a DG must not exceed 5% of the fundamental, 60 Hz voltage or current waveform.

$$\%\, THD = \frac{\sqrt{\sum_{i=2}^{\infty} h_i^2}}{h_1}\ x\ 100$$

Where:

h_i = the magnitude of the i^{th} harmonic of either voltage or current;

h_1 = the magnitude of the fundamental voltage or current.

Any single harmonic shall not exceed 3% of the fundamental frequency.

$$\%\ Single\ Harmonic\ Component\ Distortion = \frac{h_i}{h_1}\ x\ 100$$

Where:

h_i = the magnitude of the i^{th} harmonic of either voltage or current;
h_1 = the magnitude of the fundamental voltage or current.

SYSTEM PROTECTION

Abnormal conditions can arise on the utility's distribution system that require a response from interconnected DG to ensure safety of utility personnel and the general public. Additionally, the DG shall provide adequate protection to ensure safety to DG personnel and avoid damage to DG facilities.

The DG shall provide adequate protection to avoid damage to utility facilities and other utility customers' facilities during abnormal DG operation or DG fault conditions.

TRANSFER TRIP

If at any time it is determined that the DG cannot provide adequate protection to the utility distribution system for any abnormal condition discussed in this attachment, the DG shall furnish and install a transfer trip receiver(s) at its facility to receive a tripping signal(s) originating from a utility location(s). This additional protection would also necessitate the DG to reimburse the utility for the purchase and installation of transfer trip equipment at the utility location(s) and a communications channel and associated equipment between the utility location(s) and the DG facility.

Should the utility deem that a transfer trip system is required, the utility will specify all equipment and the choice of telecommunication including protocol necessary for the transfer trip scheme. The DG shall purchase and install a utility approved Remote Terminal Unit (RTU) and a utility grade relay with targets. This relay will be used to trip the DG interconnection breaker(s) and provide an alarm(s) to the RTU.

In some instances, it may be advantageous to simultaneously trip both the DG interconnection breaker(s) and the DG generator breaker(s). The DG is encouraged to discuss this additional functionality of the transfer trip scheme with the utility.

With utility approval, a generator breaker contact may be used to disable transfer trip of the interconnection breaker when the generator breaker is open.

The DG shall not be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for the transfer trip scheme is out of service or otherwise unavailable.

INADVERTENT ENERGIZATION

The DG shall not interconnect and operate in parallel with the utility distribution system when the utility distribution system is de-energized.

The DG interconnection breaker shall be automatically locked out and prevented from closing into a de-energized or partially de-energized (loss of any one phase) utility distribution system. The interconnection breaker close circuit shall include a synch check and an over/under voltage permissive contact to prevent closing the breaker when unfavorable voltage conditions exist.

FAULTS ON THE UTILITY

The DG shall detect and automatically disconnect from the utility distribution system for faults on the utility distribution system to which it is connected.

See the Reclosing Coordination and Reconnection requirements given in this attachment.

UNINTENTIONAL ISLANDING

An island is the condition in which a portion of the utility's distribution system is energized solely by the DG, while that portion of the distribution system is electrically separated from the rest of the utility's distribution system.

At no time shall the DG be allowed to form an island in which a portion of the utility's distribution system is energized solely by the DG. The DG shall detect and disconnect from the utility's distribution system within two seconds of the formation of an island.

RECLOSING COORDINATION

The EKPC transmission lines have automatic instantaneous and time delay reclosing. Likewise, the Member System distribution feeders have automatic instantaneous and time delay reclosing.

The DG is responsible for protecting its equipment and facility from being reconnected out-of-synchronism with the utility distribution system after automatic reclosing of a utility transmission line or distribution feeder breaker. The DG shall provide high speed protective relaying to remove its equipment from the utility's distribution system prior to automatic reclosures.

To avoid the DG from providing fault current, the DG shall disconnect from the utility distribution system to which it is connected prior to reclosure by utility breakers.

The DG will receive reclosing timing schemes for the distribution feeder and transmission line relays, as applicable, from the utility. As a general rule, those utility breakers set for instantaneous reclosing will have a re-strike time in the range of 6 to 8 cycles (0.1 to 0.133 seconds).

VOLTAGE

The DG shall disconnect from the utility distribution system when the prevailing voltage on utility distribution system is less than 88% or greater than 110% of the nominal voltage of the utility's distribution system.

FREQUENCY

The DG shall disconnect from the utility distribution system when the prevailing frequency on utility distribution system is less than 59.8 Hz or greater than 60.5 Hz.

RECONNECTION

Following an abnormal condition on the utility's distribution system, the DG shall contact the utility to ascertain if and/or when the utility distribution system has stabilized and if its

configuration can accommodate reconnection of the DG. The DG must obtain permission from the utility prior to reconnecting in parallel with the utility distribution system.[2]

DG INTERCONNECTION BREAKER RELAY

The following are the minimum relay requirements for the interconnection and generator (as appropriate) breakers:

A. All DG interconnection and generator (as appropriate) breaker relays shall be utility grade;

B. Phase over-current relays (one per phase) with instantaneous and voltage restraint time delay. One ground over-current relay with instantaneous and time delay elements. Each element of the phase and ground relays shall have its own target;

C. Over/under voltage relays, which monitors (is installed) on the utility side of the interconnection breaker;

D. Over/under frequency relays, which monitors (is installed) on the utility side of the interconnection breaker;

E. Directional power (reverse power flow) relays may be required to limit power flow to contractual agreements;

F. All solid state relays requiring an auxiliary power source shall be powered from a DG station battery; ac to DC converters are unacceptable. The station battery shall be sized for an eight hour duty cycle in accordance with IEEE Std. 485-1983. At the end of the duty cycle, the battery shall be capable of tripping and closing all DG interconnection and generator (as appropriate) breakers;

G. All DG interconnection relaying shall have dedicated current transformers (CTs). All relaying CTs shall have a minimum accuracy of C200. Saturation current shall not be more than 10% of the available fault current at the PCC.

ISOLATION DEVICE

The DG shall install and maintain a lockable, visible-break isolation device (disconnect switch) or motor-operated disconnecting device at the PCC (or at the generator terminals, as appropriate, for co-generation installations). The disconnecting device shall be appropriately labeled and accessible to utility personnel at all times.

[2] See agreed upon operating procedures.

MAINTENANCE AND OPERATING REQUIREMENTS

After the DG is in service, the utility reserves the right to test or review, on request, the calibration and operation of all protective equipment including relays, circuit breakers, batteries, etc. at the interconnection, as well as review DG maintenance records. A review of the calibration and operation of protective equipment may include utility-witnessed trip testing of the interconnection and generator (as appropriate) breakers by its associated protective relays.

The failure of the DG to maintain its interconnection equipment in a manner acceptable to the utility or to furnish maintenance records on demand may result in the DG being prevented from operating in parallel with the utility.

OWNERSHIP

The protective equipment (relays, breakers, etc.) located at the PCC required to disconnect the DG from the utility shall be owned, operated, and maintained by the DG.

INTERCONNECTION BREAKER RELAY SETTING CALCULATIONS

All calculations for the DG's interconnection breaker relay shall be submitted for review and acceptance by the utility to assure protection of utility equipment and reliability of service to the adjacent utility customers.

The DG shall be required to change relay settings, if necessary, to accommodate changes in the utility system.

CALIBRATION AND FUNCTIONAL TRIP TESTS

The DG shall be responsible to have calibration and functional trip tests performed on its fault and isolation protection equipment including the DG station batteries. These tests shall be performed prior to placing equipment in service. Thereafter, station batteries will be tested annually, while relays will be tested once every three years.

Copies of these test results shall be submitted to the utility no later than five working days after completion of the tests.

All testing and calibration shall be performed by a qualified, independent, testing organization acceptable to the utility in accordance with industry standards and shall be submitted to the utility for review and acceptance. Battery tests shall meet the requirements of IEEE Std. 450-1987. The utility reserves the right to witness and accept or reject the results of all tests. The utility shall be notified of testing five business days in advance.

POWER QUALITY

If harmonic distortion or flicker problems affecting other customers' equipment can be traced to the parallel operation of the DG with the utility, the DG shall not be allowed to operate in parallel with the utility until the problem is corrected.

DG SITE WORK

If the utility is requested to work at the DG site, the utility operating and maintenance personnel shall inspect the site to ensure that all utility safety requirements have been met. If not, commencement of the requested work shall be delayed until conditions are deemed safe by the utility.

REAL-TIME MONITORING

For those DG systems with rated (nameplate) capacity of 1 MW or greater (single unit or aggregate behind a single PCC), a Supervisory Control and Data Acquisition (SCADA) system is required. As part of the SCADA system, the DG shall purchase and install a utility approved Remote Terminal Unit (RTU) that shall provide key operating parameters of the DG to EKPC's Energy Management System (EMS) in real-time. The key DG operating parameters include but are not limited to:

A. Status
   i. Interconnection breaker and generator breakers;
   ii. Generator or inverter run and availability;

B. Alarms
   i. Loss of DC to interconnection and generator breakers;
   ii. Loss of DC to RTU and loss of ac to RTU battery charger;

C. Analog Telemetry
   i. Real time voltage, current, real power (watts), reactive power (VArs), and power factor at each breaker at the PCC;
   ii. Metering Data: Dual direction, pulse accumulation of MWHr and MVArHr;

D. Transfer Trip (if equipped)
   i. Output trip signal;
   ii. Input trip/alarm signal from interconnection breaker target relay;
   iii. Loss of transfer trip alarm.

When real-time monitoring of the DG is required, the utility will specify all equipment and the choice of telecommunication including protocol necessary for the scheme.

The DG shall not be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for the transfer trip scheme is out of service or otherwise unavailable.

With utility permission, the DG shall be allowed to operate in parallel with the utility if either the RTU or the associated telecommunication system necessary for providing all but the transfer trip scheme to the utility is out of service or otherwise unavailable.

All costs for additional hardware and software for integration on the utility's EMS necessary for the DG interconnection shall be the responsibility of the DG.

Should the Member System have a SCADA system in place and wish to receive any or all of these same DG operating parameters:

i. The Member System reserves the right to require DG operating parameters be made available for DG installations of less than 1 MW;

ii. The Member System will make every effort to reduce or eliminate redundant equipment and telecommunications burden of the DG by leveraging existing telecommunications in-place between EKPC and the Member System.

DIRECT SUBSTATION INTERCONNECTIONS

All costs associated with upgrading the utility's distribution substation to accommodate an interconnection of the DG by means of a dedicated (express) feeder are the responsibility of the DG. These costs include, but are not limited to:

A. Engineering design;

B. Labor for construction, inspection, and testing;

C. Equipment:
   i. Breaker and associated protection equipment;
   ii. Grade work;
   iii. Additional fencing;
   iv. Ground grid extension;
   v. Bus extension and associated support structures
   vi. Foundation work.

Details of the cost of construction, operation, long term maintenance, and ownership issues of the distribution feeder shall be negotiated between the DG and the utility.

METERING

Depending upon the contractual agreement between the DG and the utility, metering may be required by EKPC, the Member System, or both. The DG shall contact EKPC and/or the Member System, as appropriate to the installation, to obtain metering requirements.

ENGINEERING STUDIES

Final acceptance of the interconnection by the utility will be contingent upon the utility's acceptance of all of the DG systems interconnection equipment.

The utility will perform engineering studies to determine the exact electrical configuration of the interconnection and DG systems and to identify any required additions, modifications, upgrades, or changes to the utility system. Major equipment requirements such as circuit breakers and special protective relaying shall also be studied.

Items and issues requiring investigation include:

A. Equipment short circuit duty;

B. DG breaker relay protection coordination with:
   i. Transmission relay breakers;
   ii. Distribution substation relay breakers;
   iii. Distribution feeder breakers;
   iv. Down-line distribution feeder breakers;
   v. Distribution branch circuit fuses;

C. Breaker failure requirements;

D. Dead-line Operating Constraint mechanisms and schemes;

E. Voltage profile and reactive energy (VAr) requirements;

F. Evaluation of distribution system capacity constraints.

PRELIMINARY REVIEW

To help avoid unnecessary costs and delays, a substation one-line diagram should be submitted to the utility for acceptance prior to ordering equipment or commencing construction. Installing the DG without prior written acceptance of the equipment by the utility is done at the DG's own risk. The DG shall be solely responsible for all costs associated with the replacement of any equipment that has not been accepted by the utility.

If the DG makes changes in the design of the project, any previous information furnished by the utility shall be subject to review and possible changes.

The DG shall meet all applicable local, county, municipal, and state (electrical, zoning, building, etc.) codes.

IMPACT STUDY

The Impact Study requires the DG to complete Attachment 7: Small Generator Interconnection Request Application Form

In addition, the DG must submit two copies of the following to EKPC and two copies to the Member System:

A. Substation one-line diagram;

B. Relay functional diagram showing:
   i. Current transformer (CT) circuits and turns ratio;
   ii. Potential transformer (PT) circuits and turns ratio;
   iii. Relay connections;
   iv. Protective control circuits;

   Note: All interconnections with utility circuits should be clearly labeled.

C. Three-line:
   i. ac schematic diagrams of transformers;
   ii. ac schematic diagrams of the bus protection relay;
   iii. Transformer connections;
   iv. Grounding connections;

D. Interconnection breaker data:
   i. ac and DC schematic diagrams;
   ii. Speed curve;

E. Protective relay equipment list:
   i. Manufacturer make and model number;
   ii. Relay ranges;
   iii. Manufacturer bulletins;
   iv. Relay curves and proposed settings;

F. Generator nameplate data:
   i. Transient impedance;
   ii. Sub-transient impedance;
   iii. Synchronous impedance;

G. Transformer
   i. Nameplate data;
   ii. Positive sequence impedance;
   iii. Negative sequence impedance;

H. Generator protection scheme.

I. Equipment specifications

J. Telecommunication Protocol

COMMISSIONING TEST

The DG will not be allowed to interconnect and operate in parallel with the utility's distribution system until appropriate commission tests, specified in this document, have been performed.

After construction is complete, functional tests of all protective equipment shall be performed by a qualified testing company acceptable to the utility. The utility reserves the right to witness such tests. For these tests, the utility must be given at least five business days written notice (or as otherwise mutually agreed) of the test schedule.

If the protective relay settings have been correctly applied and the functional tests are successful, the utility will permit the DG to interconnected and operate in parallel with the utility distribution system.

EAST KENTUCKY POWER COOPERATIVE

Requirements for Facilities Connecting to the EKPC Transmission System

EAST KENTUCKY POWER COOPERATIVE

Approved:	Darrin Adams	Date:	3-19-2010

Rev. #	Reason for Revision	Date
1	Added document review and availability information - RLO	3/24/09
2	Added paragraph 2 in section 1, wording on VAR support in section 9, and edited line grounding detail attachements – RLO	3/18/10
3	Revised section 2.1 to include requirements to be consistent with NERC Reliability Standard FAC-002-0 involving coordination of plans for new facilities.	5/3/10

Review History	Date
RLO	3/18/10
DWA	5/3/10

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1.0 Introduction

East Kentucky Power Cooperative (EKPC) has prepared this document, which outlines the minimum requirements for all **Transmission Interconnection** or **End-User facilities** and **Generation facilities** (hereinafter referred to as **Requesters**) connecting to the EKPC Transmission System.

All new connections or modifications to existing connections to the EKPC transmission system, including EKPC self-built facilities, must be in compliance with all applicable EKPC connection requirements. Such connections must also comply with all applicable Planning, Operations, and Critical Infrastructure Protection Reliability Standards of the Federal Regulatory Energy Commission's (FERC) approved Electric Reliability Organization (ERO), which is currently the North American Electric Reliability Corporation (NERC), and with all SERC Reliability Corporation (SERC) Supplements to the NERC Reliability Standards.

This document will be reviewed every twelve months to ensure best practices. Upon request, the most recent document of EKPC's Facility Connection Requirements, will be made available within four business days.

1.1 Background

The present electric utility environment is characterized by deregulation, open access to the transmission network, wholesale and retail competition, etc., This present era of rapid change places additional challenges in the planning and operation of electric systems to maintain reliability, safety, and quality of service.

The purpose of this document is to facilitate meeting the demands of this competitive environment. Each request to connect to and use the EKPC Transmission System will be reviewed to identify the impacts and necessary system improvements on the EKPC system. These reviews ensure that comparable treatment is given to all users, and that reliability, safety, and quality of service are maintained.

1.2 Scope

This document informs entities seeking facility connections to the EKPC Transmission System of the connection requirements. These requirements are not a substitute for specific Interconnection Agreements between EKPC and entities connecting to the EKPC Transmission System.

The scope of this document satisfies the NERC Planning Standards by identifying requirements for connections to the bulk transmission system at voltages generally 100 kV and above. This document also applies to connections to those systems designated as transmission facilities that are rated at lower voltages, which include 69 kV. Requirements applicable for all types of

Interconnection, End-User, and **Generation** facilities are covered. These requirements will be applied in a consistent manner to both EKPC-owned facilities and non-EKPC facilities wishing to interconnect to the EKPC transmission system.

The minimum requirements pertaining to connected facilities are contained herein. Reliability concerns in particular are such that additional facility and operational requirements may need to be imposed on connecting facilities based on their location within the system, facility power level and the associated impacts on EKPC's system performance. The need for additional requirements can only be evaluated once certain details of a proposed facility are made known and system impact studies have been conducted. The requirements for initial facility connection apply equally to any upgrades, additions, enhancements, or changes of any kind to an existing connected facility.

The scope of this document is limited to the technical requirements for connected facility design and operation. **Requesters** requiring transmission service are also referred to the EKPC Open Access Transmission Tariff.

1.3 Objectives

EKPC has prepared this document based on the following objectives:

(a) Maintain system reliability, personnel and equipment safety, and quality of service as load, system modifications, and new facilities are added to the transmission network.
(b) Ensure comparability in the requirements imposed upon the various entities seeking to connect facilities to the transmission network.
(c) Satisfy compliance with NERC Planning Standard FAC-001 and corresponding SERC Supplement(s) pertaining to documentation of facility connection requirements by those entities responsible for system reliability.
(d) Inform those entities that seek facility connections to the EKPC Transmission System of the various requirements for system reliability, reporting requirements, (as specified by the NERC Reliability Standards and SERC supplements), and other applicable standards and documents.
(e) Facilitate uniform and compatible equipment specification, design, engineering, and installation practices to promote safety and quality of service.

2.0 Procedures for Coordinated Studies and Notification of new or modified Facilities to Others (R2.1.1 & R2.1.2)

Contact one of the following EKPC personnel to request a new facility connection or significant change to an existing connected facility. This type of request will require a joint study to determine the implications on surrounding system facilities.

Type of Customer to Be Connected	Type of Service or Activity Required from EKPC	EKPC Contact
Generation Interconnection	Initial Contact To Request a Connection or Study	Manager Transmission Planning
Transmission Interconnection	Joint Transmission Planning Studies	Manager Transmission Planning
Transmission End-User	Initial Contact To Request a Connection or Study	Manager Transmission Planning

Following the initial contact regarding a proposed **Generation**, **Interconnection**, or **End-User** facility connection, when the proposed location and power level are established, a plan of service is prepared and system impact studies are undertaken and coordinated by EKPC. The information needed to develop a plan of service and to conduct the system impact studies is identified in this document and should be provided to EKPC at this point. The system impact studies may, as noted above, identify additional requirements for reliability beyond the minimum requirements covered by this document.

EKPC approval of a proposed facility or facility change is contingent upon a design review of the proposed connected facility. Operation of a connected facility is also subject to continuing compliance with all applicable construction, maintenance, testing, protection, monitoring, and documentation requirements described herein, as well as the applicable NERC Reliability Standards and SERC Supplement(s).

2.1 System Impact Studies

The Generator Owner, Transmission Owner, Distribution Provider, and/or Load-Serving Entity seeking to integrate **Generation Facilities**, **Transmission Facilities**, and/or **End-User Facilities** into the EKPC transmission system shall each coordinate and cooperate on its assessments with the EKPC Transmission Planner/Planning Authority. The assessment shall include:

- Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

- Ensurance of compliance with NERC Reliability Standards and applicable SERC and EKPC planning criteria and facility connection requirements.
- Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of the new facilities on the interconnected transmission systems. The results of these studies shall be jointly evaluated and coordinated by all of the entities involved.
- Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with NERC Reliability Standards.
- Documentation of study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

In order to assess the impact of a proposed facility connection on system reliability, system impact studies need to be conducted. These system impact studies, as a minimum, examine the transmission line and transformer loading, voltage profiles and schedules, and power quality impacts of the proposed facility for a range of expected seasonal loading and power transfer conditions. The effect of the proposed facility on short circuit duties would be examined for all transmission connections. A multi-step approach to the proposed facility may be considered where the impact of each step is assessed separately.

The criteria EKPC used to determine what constitutes acceptable performance in the above system impact studies is readily available from EKPC's FERC Form 715 filing.

The system impact studies will be coordinated with neighboring transmission system owners/operators as appropriate. As a minimum, all interconnected neighbors and other impacted parties will be notified of significant transmission system additions or modifications as soon as practical. In addition, significant additions and modifications will be reflected in the power flow models as submitted by EKPC to SERC. These additions and modifications will also be identified in the regional transmission system assessments as appropriate.

EKPC shall retain its documentation of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems for three years and shall provide the documentation to SERC and NERC within 30 calendar days of a request.

2.1.1 Power Flow Analyses

Power flow analyses will be conducted to examine the impact of the proposed facility on flows through transmission lines and transformers, and voltage profiles. These analyses may typically determine the

maximum load demand in the case of **End-User** facilities or through flow in the case of an **Interconnection** that can be accommodated with minimal or no upgrades to the transmission system. Contingencies consisting of single or multiple outages of lines and/or transformers are considered in these analyses. Where the analyses indicate that transmission upgrades are necessary, alternative reinforcement plans may be devised and evaluated for their capability to accommodate the proposed facility.

2.1.2 Short Circuit Analyses

Short circuit analyses are conducted to examine the impact of the proposed facility on equipment duties. These analyses are primarily concerned with **Generation** and **Interconnection** facilities. Increased fault duties may require upgrading existing circuit breakers and other equipment.

2.1.3 Additional Analyses

Other analyses may be required as part of system impact studies based on power flow analysis and depending on the nature of the proposed connected facility and its location within the transmission network:

(a) Power quality analyses are undertaken for all **End-User** load that could potentially cause harmonic current or voltage, voltage flicker, and/or telephone interference.
(b) The possibility of adverse subsynchronous torsional interaction is investigated wherever the **End-User's** equipment such as arc-furnaces and/or cycloconverters is to be located in close electrical proximity to existing generation.
(c) Stability studies (transient, small-signal, voltage, etc.) will be performed for Generation, Transmission, and End-User Interconnections whenever deemed necessary by EKPC or a neighboring utility.
(d) Impacts on transfer capabilities for EKPC and neighboring utilities will be assessed for Generation, Transmission, and End-User Interconnections.

The scope of all the above system impact studies will be determined by EKPC based on the type, location, and power level of the proposed facility. Normally, EKPC will perform the system impact studies. The cost of these studies will be chargeable to the **Requester** in accordance with the EKPC Open Access Transmission Tariff. Reports documenting the assumptions, results, and conclusions of the system impact studies are made available to the **Requester**.

EKPC must be notified of new facilities, upgrades, or additions such as an increase in load or generating capability of existing facilities connected to the transmission system within the EKPC Control Area. System impact studies are to be conducted to determine the need for any upgrades of transmission equipment or transmission system additions to accommodate the changes in the connected facility. Notification must be provided to EKPC sufficiently in advance of the proposed new facility or the facility modification to allow adequate time for EKPC to assess impacts and perform any necessary transmission-system modifications that may be deemed necessary to accommodate the new facility/facility modification.

3.0 Voltage Level and MW and MVAR Demand (R2.1.3)

The **Requester** will specify the voltage level at which it intends to interconnect to the EKPC transmission system. Nominal transmission system voltages presently on the EKPC system are: 345kV, 161kV, 138kV, and 69kV. The **Requester** connecting to EKPC's Transmission System, should expect voltage levels which generally under system normal conditions and single transmission element outage conditions range between 92% and 105% of nominal. All Interconnected Facilities are expected to operate in this range at all times. If the **Requester's** supply voltage requirements are more restrictive than the 92% to 105% range, EKPC recommends that the **Requester** consider the addition of voltage regulation equipment in their facility.

Under certain emergency conditions, the EKPC Transmission System may operate for a period of time outside of the 92% to 105% range. The **Requester** is responsible for providing any voltage sensing equipment required to protect their equipment during abnormal voltage operation.

Electrical system design of the interconnected facility (e.g., transformers, tap settings, motors and other loads, generator/exciter, voltage regulator) should not restrict any mode of project operation within the EKPC transmission system's allowable voltage range and regulation.

Transmission interconnected equipment should have the tap ranges and self-regulation necessary to operate within EKPC's transmission system voltage range and regulation. All reactive compensation devices associated with an Interconnected Facility must be coordinated with EKPC during both the design phase and system operations.

The impacts of a new facility connection to the EKPC system with regard to neighboring utilities' voltage and/or reactive compensation devices will be assessed. The Requester will be responsible for the cost of mitigating any adverse impacts on the neighboring system.

For an End-Use Facility, the **Requester** will supply 10-year demand projections (both MW and MVARs). For a Transmission or Generation Interconnection, the **Requester** will provide all necessary information needed for EKPC to conduct a System Impact Study to adequately assess the voltage levels and MW/MVAR flows expected if the Transmission or Generation Interconnection is implemented. This information typically will involve detailed modeling data for the transmission network that will be connected to the EKPC system sufficient for power flow, short-circuit, and other engineering analyses.

The Owner of a generating facility connected to the EKPC transmission system will be required to provide the net demonstrated real and reactive power capability of each generating unit to EKPC as required by SERC. The NERC Reliability Standards MOD-024 and MOD-025 provide additional information regarding the requirements for Generator Owners to be in compliance. All data accumulated from testing in compliance with the NERC and SERC requirements should be provided to EKPC in a timely manner. Other generator parameters must also be provided as required by EKPC.

4.0 Breaker Duty and Surge Protection (R2.1.4)

4.1 Interrupting Device / Breaker Duty

The **Requester** shall provide three-phase circuit interrupting device(s) with appropriate protective relaying systems (as stated in Section 5). The device(s) shall isolate the Facility from the EKPC electrical system for all faults, loss of EKPC supply, or abnormal operating conditions regardless of whether or not the Facility is operating.

This device shall be capable of interrupting the greater of the maximum available fault current at that location available from the Transmission System or from the Facility. EKPC will provide, existing and estimated future, 3 phase fault and single line to ground fault amps short circuit data. Recommended change of an interrupting device due to overrating short circuit capabilities, will be the responsibility of the utility causing the increased fault currents.

The three-phase device shall interrupt all three phases simultaneously and shall have maximum operation time of 2 cycles or less from time of energization of the trip coils(s). EKPC may accept 3 cycle interrupting devices depending on their location within the EKPC system. The tripping control of the circuit-interrupting device shall be powered independently of the Transmission System or Facility AC sources in order to permit operation upon loss of the Transmission System connection or the Facility AC supply. The protective trips to the interrupting device should be arranged into two independent trip circuits including separate relay trips, separate DC control busses and two trip coils.

Generally, automatic reclosing of the Facility's interrupting device is not desired. If the Facility's configuration requires automatic reclosing, EKPC will provide the specific reclosing times for the Facility's interrupting devices.

4.2 Surge Protection (Lightning Arresters)

Lightning arrester allowable separation distance from the equipment being protected is based on Table 4 of IEEE Std. C62.22. Consult the manufacturer's catalog for details concerning arrester protective characteristics, ratings, and application. Location and ratings of lightning arresters will be addressed during the design phase of the project.

5.0 System Protection and Coordination (R2.1.5)

The **Requester** is responsible, under all system operating conditions, for providing adequate protection to their facilities as well as EKPC facilities and maintain the safety of the general public. The **Requester** is also responsible for providing adequate protection to their generating facility under any EKPC transmission system operating condition whether or not their generation is in operation.

EKPC will perform relay coordination and short circuit analysis, along with other studies as related to the system, in the area of the new facility. EKPC will provide functional specifications and relay settings for all protective relays at the **Requester's** facility that have a potential impact on the reliability of the EKPC transmission system. The criteria for these functional specifications and settings will be based on existing EKPC protection practices. EKPC reserves the right to specify the type and manufacturer for these protective relays to ensure compatibility with existing relays. The specific recommendations and requirements for protection will be made by EKPC based on the individual substation location, voltage and configuration.

5.1 Requester Protection

It is the **Requester's** responsibility to assure protection, coordination and equipment adequacy within their facility for conditions including but not limited to:

(a) Single phasing of supply
(b) System faults
(c) Equipment failures
(d) Deviations from nominal voltage or frequency
(e) Lightning and switching surges
(f) Harmonic voltages
(g) Negative sequence voltages
(h) Separation from EKPC supply
(i) Synchronizing generation.

(j) Synchronism checking of manual and automatic reclosing of transmission interconnections.
(k) Islanding

The protection systems should minimize system disturbances, outage area, and equipment outage times.

If at any time it is determined that the use of the above relay systems cannot provide adequate protection to the EKPC system, the **Requester** shall furnish and install upon the request of EKPC, a transfer trip receiver(s) at its facility to receive tripping signals originating from an EKPC location(s). This additional protection would also necessitate the purchase and installation of transfer trip equipment at the EKPC location(s) and a communication channel between the EKPC location(s) and the **Requester's** facility. If these systems are required EKPC will coordinate the protection of these devices.

5.2 Automatic Underfrequency Load Shedding

EKPC may require automatic underfrequency load shedding relaying on connected loads to comply with NERC Reliability Standards PRC-006 through 009 and the applicable SERC Supplement. This document requires SERC control areas to shed at least 30% of their connected load in successive steps during system underfrequency emergencies.

EKPC, as a SERC member, is obligated to have an automatic underfrequency load shedding plan in effect, which meets the SERC Supplement. Connecting parties without an automatic underfrequency load shedding plan meeting SERC Supplement requirements may need to install underfrequency relaying at the request of EKPC. The amount of load to be shed and the frequency setpoints will be coordinated and specified by EKPC as required to meet SERC underfrequency load shedding compliance.

5.3 Parallel Generation Facility

The **Requester** shall provide the following utility-grade relays for protection of the EKPC system. All relays specified for the protection of the EKPC system, including time delay and auxiliary relays, shall be approved by EKPC. Relay operation for any of the listed functions shall initiate immediate separation of the **Requester's** generation from the EKPC Transmission System.

Relay	**Function**
Frequency	To detect under frequency and over frequency operation.
Overvoltage	To detect overvoltage operation.
Undervoltage	To detect undervoltage operation.

Ground Detector	To detect a circuit ground on the EKP system (appoicable to three-phase circuits only).
Directional Overcurrent	To detect the directional flow of current in excess of a desired limit
Transfer Trip Receiver	To provide tripping logic to the generation for isolation of the generation upon opening of the EKPC supply circuits.
Directional Power	To detect under all system conditions, a loss of EKPC primary source. The relay shall be sensitive enough to detect transformer magnetizing current suppled by the generation.

The purpose of these relays is to detect the **Requester's** energization of an EKPC circuit that has been disconnected from the EKPC system, to detect the generation operating at an abnormal voltage or frequency, or to detect a fault or abnormal condition on the EKPC system for which the **Requester** shall separate their generation.

Output contacts of these relays shall directly energize the trip coil(s) of the generator breaker or an intermediate auxiliary tripping relay, which directly energizes the breaker trip coil(s). The relaying system shall have a source of power independent from the AC system or immune to AC system loss or disturbances to assure proper operation of the protection scheme. Loss of this source shall cause removal of the generation from the EKPC system. The protective relays required by EKPC and any auxiliary tripping relay associated with those relays shall be utility-grade devices.

Utility grade relays are defined as follows:

(a) Meet ANSI/IEEE Standard C37.90, "Relays and Relay Systems Associated with Electric Power Apparatus."
(b) Have relay test facilities to allow testing without unwiring or disassembling the relay.
(c) Have appropriate test plugs/switches for testing the operation of the relay.
(d) Have targets to indicate relay operation.

It is the **Requester's** responsibility to determine that their internal protective equipment coordinates with the required EKPC protective equipment and is adequate to meet all applicable standards to which the generation is subject. EKPC further reserves the right to modify relay settings when deemed necessary to avoid safety hazards to utility personnel or the public and to prevent any disturbance, impairment, or interference with EKPC' ability to serve other customers.

The following items should be coordinated with each other.

- Volts/Hz and overexcitation protection/limiting.
- Loss-of-excitation and underexcitation limiting.

5.4 Power System Stabilizer

A Power System Stabilizer (PSS) is required to be installed, tuned, and activated with the excitation system for all new synchronous generators connected to the EKPC transmission system.

For generators already connected to the EKPC system that do not presently have a PSS, a PSS must be retrofitted when the excitation system or voltage regulator is replaced. These retrofitted stabilizers must be tuned and activated unless EKPC determines this is not necessary. If EKPC identifies a need for a PSS for an existing generating unit, the generator owner may be required to procure, install, tune, and activate a PSS.

The PSS is expected to be an accelerating power delta-P-omega type. Other types that are functionally equivalent may be accepted on a case-by-case basis.

The generation owner will be responsible for the analysis, procurement, installation, tuning, and testing of the exciter and stabilizer controls for optimum performance. The generator owner must ensure that all necessary studies and field tests are performed to determine the optimum PSS settings prior to commercial operation of the generating unit. EKPC shall perform (or contract to have performed on its behalf) other relevant studies, and shall coordinate with the generator owner and the equipment vendor to establish reliable settings for the PSS. The PSS tuning test documentation – including the PSS dynamic model and final settings – shall be provided to EKPC for its review prior to the commencement of commercial operations for new generating units. For existing generating units that are retrofitted with a PSS, the documentation shall be provided when the testing of the PSS is complete.

If future system conditions change significantly, EKPC may require the generator owner to reset the PSS parameters to more appropriate settings to preserve the overall reliability of the transmission system.

A PSS may be taken out of service for scheduled maintenance only with EKPC's prior approval. The generator owner will be required to take the PSS out of service if EKPC identifies transmission system operating conditions during which the operation of the PSS would adversely affect the stability of the transmission system or its connected generators. If a PSS is removed from service or is not capable of automatic operation, the generator owner shall immediately notify EKPC. Operating limits may be applied in such cases based on system limitations identified by EKPC.

If system studies or field experience do not show need for a PSS, EKPC may waive these requirements for generators rated at 50 MVA or less, or for generators connected at 69 kV or below. These requirements will not be waived for any generating units at a single generating station with total rated output greater than 300 MVA.

5.5 Remote Relay Access

All new facilities, or upgrades to existing facilities, should use digital relays with fault recording capabilities. All digital relays, used for protection of EKPC transmission facilities, shall have the capability of recording system disturbance information and EKPC shall be allowed access to all relay records.

5.6 Relay and Equipment Data

At least three (3) months prior to the in-service date, the following data shall be received by EKPC. If the data is not available three months prior to the in-service date, the **Requester** shall provide estimates based on their design information. Such data shall be identified as "estimated" and replaced with actual data by the **Requester** as it becomes available prior to installation.

The purpose of the data to be provided to EKPC by the **Requester** is to ensure proper coordination to protect against equipment or facility damage, to mitigate safety hazards to utility personnel and the public, and to minimize disturbances, impairment, or interference with EKPC's ability to serve other transmission system users.

5.6.1 Data on Equipment to be installed

(a) Interrupting Devices and Relays - Complete manufacturer's data for interrupting devices and relays or fuses used for the protection of the EKPC system and/or the generation.
(b) Power Transformers - Complete nameplate or test sheet data, including manufacturer, serial number, high- and low-side voltage taps, kVA ratings, impedance, load loss and no load loss watts, high- and low-side voltage winding connections, low-side voltage winding grounding (if used), and high voltage inrush current.
(c) Power Capacitors – Location, KV, and KVAR rating of capacitor banks, number of units, and bank configuration.

5.6.2 Additional Data on the Generation Protection Equipment

(a) Including make-before-break transfer switches, fuses, breakers, relays, relay settings associated with the proposed generation.

(b) Complete manufacturer's data and specifications for make-before-break transfer switches, including transfer times and conditions of transfer, testing procedures, equipment schematics, and backup protection.

5.6.3 Final Generator Data

(a) Type (synchronous, induction, DC with solid-state inverter, etc.)
(b) Nameplate data and ratings, including any rectifying, regulating, or inverting equipment.
(c) Harmonic content at full rated output
(d) Detailed Dynamic Performance Data in accordance with Appendix A.
(e) Real and Reactive capabilities at scheduled voltages.

6.0 Revenue Metering and Telemetry Requirements (R2.1.6)

6.1 Revenue Metering

EKPC approved revenue class metering equipment shall be installed at the delivery point to meter the aggregated load of the connected facility consisting of instantaneous bi-directional real and reactive power and integrated hourly real and reactive energy metering.

The metering equipment will include potential and current transformers, meters and test switches. The accuracy of the instrument transformers will be 0.3 percent or better. The secondary wiring and burdens of the instrument transformers will be configured so that they do not degrade the total accuracy by more than 0.3 percent. The metering equipment should meet or exceed accuracy class 0.2 and will be tested periodically as defined in the service agreement and the test results will be available to all involved parties. The meters, test switches and wiring termination equipment will be sealed and the seal may be broken only when the meters are to be tested, adjusted or repaired. Proper authorities from both parties will be notified when seals are broken.

Three metering elements will be used to measure all real and reactive power crossing the metering point. Bi-directional energy flows including watt-hour and var-hour will be separately measured on an hourly basis. Appropriate demand quantities will be metered in terms of kilowatts, kilovars or kilovolt-amperes. If required, voltage measurements will be provided.

The instrument transformers used for revenue metering shall be installed on the high voltage side of the **Requester's** step-down transformer. Under special circumstances but only with written approval granted by EKPC, revenue metering may be performed on the low voltage side of the step-down transformer. Written approval shall only be given if the **Requester** can demonstrate that accurate transformer loss compensation will be programmed into the revenue metering

when instrument transformers are installed on the low voltage side of the step-down transformer.

6.2 Telemetry

Suitable telemetry equipment will be installed at the metering point to provide real-time telemetry data to EKPC and to all other participating parties.

Telemetry equipment will include transducers, remote terminal units, modems, telecommunication lines, and any other equipment of the same or better function. The remote terminal unit, or equivalent device, must have multiple communication ports to allow simultaneous communications with all participating parties. That device will accommodate data communication requirements specified by each participating parties control center, including communication protocol, rate and mode (either synchronous or asynchronous). All metered values provided to the telemetry equipment will originate from common metering equipment. All transducers used for telemetry will have at least 0.2 percent accuracy. As part of real-time data to be provided, EKPC has the right to require the status and remote control of switching devices at the Receipt and/or Delivery Points.

A continuous, accumulating record of megawatt-hours and megavar-hours will be provided by means of the registers on the meter. Freezing accumulation data for transmission will be taken every clock hour. The freezing signals must be provided by only one agreed-upon party. If the freeze signal is not received within a predefined time window, the remote terminal unit, or equivalent device, will be capable of freezing data with its own internal clock.

The metering, if external power supply is required, and telemetry equipment will be powered from a reliable power source, such as a station control battery, in order to allow the equipment to be continuously operational under any abnormal power supply situations. Proper surge protection will be provided for each communication link to protect communication hardware from ground-potential-rise due to any fault conditions. A separate communication media shall be provided to allow EKPC to remotely retrieve billing quantities from the meters. When real-time telemetry is required, a back-up data link must be provided in case of the outage of the primary telemetry line. The back-up link can be a data communication link between involved control centers; the party requesting service is responsible for furnishing the back-up link.

At the discretion of EKPC, generation control facilities and supervisory control and data acquisition of specific electrical devices from the EKPC Control Center may be necessary to integrate the generation into EKPC's control area. Such additional facilities, including required communication channels, shall, if required, be furnished and installed by the **Requester**. The requirement for data

acquisition and control will depend on the generation capacity, system location and voltage, and the net generation input into EKPC System.

Data acquisition and control information will typically include, but not be limited to:

(a) desired generation MW set point
(b) automatic generation control status (on,off)
(c) generator availability
(d) generation MW, Mvar output
(e) generator minimum and base MW capability
(f) generator MW AGC high limit and low limit
(g) connection facilities' breaker status/control/alarms
(h) connection facilities' MW and Mvar line values and bus voltage
(i) generator and substation metering (MWh) data

7.0 Grounding and Safety (R2.1.7)

7.1 Ground System Resistance

The grounding system should be designed in accordance with IEEE Standard 80 - latest revision, "IEEE Guide for Safety in AC Substation Grounding." In evaluating the step and touch potential the target body weight value should be set to 50 kg. If a reasonable grounding design is unobtainable using the 50 kgs, then consider a body weight of 70 kg as the absolute minimum allowable.

Ground fault levels from EKPC sources will be provided as needed for **Requester's** ground grid analysis. **Requester** equipment ground sources can contribute significant fault current independent of the ground fault values on EKPC's System. These **Requester** ground sources should be considered in the design of the grounding system.

If the facility structure is to be wood-pole type construction, the transmission line overhead ground wire, all switch bases, fuse bases, and other noncurrent-carrying metal parts shall be grounded to the station grid. See Appendix C for grounding installations.

7.2 Electrical Safety Clearances (Outdoor)

Electric facility design clearances are listed in the table in Appendix B. These design clearances should be used for electrical facilities up to and including any interrupting device connected directly to an EKPC transmission line and for all facilities that are part of the EKPC transmission system.

The minimum vertical clearance of the conductors above ground and the vertical and horizontal clearance of conductors passing by but not attached to a building or wall shall be in accordance with the NESC or applicable state and local codes.

7.3 Facility Fence Safety Clearances

The fence safety clearances in the **Requester's** facility shall comply with Section 11 of ANSI C2-1997, "National Electrical Safety Code."

8.0 Insulation and Insulation Coordination (R2.1.8)

8.1 Insulators for Station

Required station post insulator types are listed in Appendix B. Facilities in areas with significant airborne pollution may require a higher insulation level. Higher strength insulators are available and should be used if needed to meet bus momentary short circuit withstand values. Other requirements may be necessary due to atmospheric, geological, seismic, or environmental conditions and will be discussed during the design phase of the project.

8.2 Equipment Basic Insulation Levels

The minimum Basic Insulation Levels (BIL) for Equipment are listed in Appendix B. Facilities in areas with significant airborne pollution may require a higher insulation level.

9.0 Voltage, Reactive Power, and Power Factor (R2.1.9)

The NERC Reliability Standards state that distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems. The EKPC interpretation of "close to unity power factor" is that the power factor of the connected load should be within the range of 0.95 lagging to 0.98 leading.

Unless otherwise restricted by Retail Tariffs, the maximum hourly reactive power (kVAr) demand, both leading and lagging, will be identified each month at the delivery point(s). An **End-User** will incur no charges for power factor if the maximum lagging kVAr demands do not exceed 33% of the real power (kW) demand or maximum leading kVAr demands do not exceed 20% of the real power (kW) demand in the same time interval. If the maximum hourly leading and/or lagging kVAr demands exceed these values, charges will be assessed. The charges will be based on the applicable state or FERC filed tariff.

Capacitors generally provide an effective means of controlling the power factor of a **Requester's** facility. However, there are several factors that should be

addressed in applying capacitors. These factors can include, but are not limited to, transient voltages due to capacitor switching and voltage amplification due to resonance conditions. The services of a qualified consultant should be obtained to review the specific application and provide recommendations in regard to control of these phenomena.

For **Transmission Interconnections**, EKPC will evaluate whether the connection to the EKPC system creates a significant reactive burden. Potential reactive flows across the new Transmission Interconnection will be assessed for a wide range of conditions. Voltages in the vicinity of the Transmission Interconnection will also be assessed to identify potential degradation on the EKPC system. The **Requester** will be responsible for addressing any voltage or reactive flow issues that are created as a result of a proposed **Transmission Interconnection**.

All facilities interconnected to the EKPC transmission system should have the tap ranges and self-regulation necessary to accommodate the transmission system's reactive power flow requirements.

9.1 Generation Power Factor Requirements

The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging.

If an engineering study demonstrates that the Generating Facility cannot meet the reactive supply requirements, the Generating Facility must install power factor correction devices to support the VAR requirements in the local area.

9.2 Generation Voltage Schedules

All generators must contribute reactive power to the transmission system in order to maintain the reliability of the transmission system. NERC Planning Standards require that Generator Owners and Transmission Providers work jointly to optimize the use of reactive power capability. Therefore, all generators interconnected with the EKPC transmission system are required to maintain a prescribed voltage schedule in order to support VAR requirements in the local area.

The generation facility must be capable of continuous non-interrupted operation at a specified voltage setpoint that is within a steady-state voltage range during both system normal and single-contingency conditions. This range is from 91.7% to 105.8%. During emergency and/or transient-system conditions, when voltage may temporarily be outside of this range, all reasonable measures should be taken to avoid tripping the generator due to high or low voltage. Internal plant

design (e.g., transformer ratings/taps/impedance, cooling systems, generator/exciter ratings) should not limit continuous reactive capability.

EKPC's transmission system is designed to operate between 90% and 105% of nominal voltage during normal and single-contingency conditions. If the requirements of the Facility Owner's equipment is more restrictive than these limits, the installation of voltage regulation devices by the Facility Owner should be considered.

Specification of the generator voltage schedule will be provided to the interconnected generating facility by EKPC's System Operator. EKPC will exercise reasonable efforts to provide the Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the transmission system. A steady-state deviation from this schedule between +2.5% and –2.5% of the voltage setpoint will be permissible.

Once the Interconnection Customer has synchronized the generating facility with the transmission system, EKPC will require the Interconnection Customer to operate the generating facility to produce or absorb reactive power within the design limitations set forth above. EKPC's voltage schedules will treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. The Interconnection Customer shall operate the generating facility to maintain the specified output voltage (or power factor,if appropriate) at the Point of Interconnection within the design limitations of the generating facility set forth above. This may require operation of the interconnected Generating Facility to its maximum reactive capability when necessary to maintain the specified voltage schedule. If the Interconnection Customer is unable to maintain the specified voltage (or power factor), it shall promptly notify EKPC's System Operators.

For generators with output at or above 20 MW, the generator must have an Automatic Voltage Regulator (AVR) capable of maintaining the generator output voltage within limits (generally +/- 5%) for generator loading from no-load up to rated output.

All synchronous generators connected to the EKPC transmission system shall be equipped with speed governing capability. This governing capability shall be unhindered in its operation.

Whenever the generating facility is operated in parallel with the transmission system, and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the generating facility with its speed governors and voltage regulators in automatic operation. If the generating facility's speed governors and voltage regulators are not capable of such

automatic operation, the Interconnection Customer shall immediately notify EKPC's System Operator, or its designated representative, and ensure that such generating facility's reactive power production or absorption (measured in MVARs) are within the design capability of the generating facility's generating unit(s) and steady state stability limits.

EKPC typically specifies voltage regulation at the terminals of an interconnected generator. However, voltage regulator load compensation may be required to control voltage at a point beyond the generator terminals for a new generator interconnected to the EKPC transmission system. All appropriate excitation system settings of an Interconnected Generator must be coordinated with EKPC.

The Interconnection Customer shall not cause its generating facility to disconnect automatically or instantaneously from the transmission system or trip any generating unit comprising the generating facility for an under-frequency or over-frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the EKPC Control Area on a comparable basis.

The Customer shall provide a current-limiting device for the generating unit's excitation system that will act in conjunction with, or supersede, the AVR to automatically reduce excitation so that generator field current is maintained at the allowable limit in the event of sustained undervoltages on the transmission system. This device must not prevent the exciter from going to and remaining at the positive ceiling following the inception of a fault on the power system. The amount of time that the exciter is allowed to remain at the positive ceiling shall be provided to EKPC upon request.

The Customer shall equip the generating unit with a limiter to prevent instability resulting from generator underexcitation.

EKPC studies may identify the need for the use of Power System Stabilizers (PSS) depending on the generating facility output capability, excitation system type and settings, facility location, area transmission configuration, or other factors. This will be determined on a case-by-case basis.

The Customer shall coordinate the Generator Step-Up (GSU) and auxiliary transformer impedances and tap specifications with EKPC. EKPC may require the Customer to change these values either prior to connection or after the generating facility has become operational to meet voltage schedule and/or reactive support requirements, as warranted by transmission system analyses.

The Customer shall ensure that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges.

The requirements for generators contained in this Section 9 applies to all generating facilities with a total gross rated output in excess of 20 MW. EKPC may require generating facilities below this threshold to provide reactive support capability on a case-by-case basis.

10.0 Power Quality Impacts (R2.1.10)

Power quality studies will be performed, as deemed necessary by EKPC, to define acceptable operating ranges and limits. Studies may include, but not be limited to the following design parameters:

- Harmonic Distortion
- Voltage Fluctuation
- Voltage Flicker
- Sensitive Electrical Equipment
- Transformer Protective Devices
- Unbalanced Electrical Conditions
- Subsynchronous Torsional Interaction
- Transient Overvoltage
- Temporary Overvoltage
- Temporary Undervoltage
- Operating Frequency
- Interruption/Outage Frequency

Studies may identify additional equipment necessary to meet power quality standards.

Connection of a generator, transmission facility, or end-user load to EKPC transmission system should not unacceptably compromise or degrade the power quality for existing EKPC customers.

Installation of power quality monitoring equipment by EKPC may be required to verify compliance with EKPC's power quality performance requirements.

10.1 Harmonic Distortion, Voltage Fluctuations and Voltage Flicker

Certain electrical equipment located at the **Requester's** facility (arc furnaces, cycloconverters, etc.) will generate voltage flicker and harmonic distortion, which can negatively impact the EKPC system. Should this be the case, the **Requester** shall take responsibility, initially or in the future, for limiting interfering levels of harmonic voltage, current distortion, and/or voltage flicker. Limits for harmonic distortion (including inductive telephone influence factors) are as published in the latest issues of ANSI/IEEE 519, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." EKPC may, initially or in the future, require the installation of a monitoring system to permit ongoing

assessment of compliance with these criteria. The monitoring system, if required, will be installed at the **Requester's** expense.

Situations where high harmonic voltages and/or currents originate from the transmission system are to be addressed in the Connection Agreement.

EKPC will evaluate requests for **Transmission Interconnection** to identify potential unacceptable voltage flicker and/or harmonic distortion that would be created by the **Transmission Interconnection**. The Requester will be responsible for any mitigation that is required.

Voltage flicker limits are as specified in IEEE Standard 141-1993. Voltage fluctuation limits are as specified in the applicable IEC-61000 set of standards. Steady-state voltages should remain within the voltage limits prescribed in Section 3.0.

10.2 Sensitive Electrical Equipment

Certain electrical equipment in the **Requester's** facility may be sensitive to normally occurring electric interference from nearby connected loads in the **Requester's** facility, from other **End-Users** connected to the power system, from natural causes, and system switching, etc. If sensitive electrical equipment is to be supplied directly from the electric power system, **Requester** or **Requester's** consultant should examine the equipment grounding requirements and power supply requirements prior to installation. Attention should be given to equipment tolerance to various forms of electric interference, including voltage sags and surges, momentary outages, transients, current and voltage harmonic distortion, or other electrical and electromechanical noise. When electrical disturbances to sensitive electrical equipment such as computers, electronics, controls, and communication equipment cannot be tolerated, the **End-User** shall install additional equipment as may be necessary to prevent equipment malfunctions and protect against equipment failure. The **End-User** should consult the supplier of such sensitive electrical equipment regarding the power supply requirements or the remedial measures to be taken to alleviate potential misoperation or failure of the equipment. The **End-User** may need to hire a power quality consultant to also perform a site survey of the electric power supply environment and furnish recommendations to provide the acceptable levels of reliability and quality of service.

10.3 Transformer Protective Devices

EKPC has typically installed circuit switchers or circuit breakers on the high side of transmission/step-down transformers.

The use of a remote tripping (transfer trip) system to initiate tripping of a remote breaker(s) to isolate an End-User's transformer will not be considered as the

primary protection scheme, but may be considered as a back up system to the circuit switcher or breaker. Transfer trip systems must include a local isolating motor operated air break switch to permit remote terminal circuit breakers to reclose and return the transmission line to service. Remote tripping systems will only be considered where continuity of service of the line is not critical.

A grounding switch installation designed to place faults on the system and isolate a fault in the transmission/step-down transformer is not to be applied to the EKPC system. Ground switches cause objectionable voltage sags and momentary interruptions to the other EKPC End-Users and unnecessary stresses to the power system.

10.4 Unbalanced Electrical Conditions

Situations where high unbalance, in voltage and/or current, originate from the transmission system are to be addressed in the Connection Agreement.

10.4.1 Voltage Balance

Voltage unbalance attributable to the **End-User** facilities shall not exceed 1.0% measured at the point-of-service. Voltage unbalance is defined as the maximum phase deviation from average as specified in ANSI C84.1, “American National Standard for Electric Power Systems and Equipment – Voltage Ratings, 60 Hertz.”

10.4.2 Current Balance

Phase current unbalance attributable to the **End-User** facility shall not exceed that which would exist with balanced equipment in service, measured at the point-of-common coupling. In no event should current unbalance exceed 5% measured at the point of delivery.

10.5 Subsynchronous Torsional Interaction

Certain **End-User** equipment, in particular electric arc furnaces and cycloconverters, may cause adverse interactions and possible damage to existing turbine-generators located in close electrical proximity. These situations will be analyzed by EKPC, or EKPC’s consultant, and appropriate corrective or preventive measures identified as needed. Corrective and preventive measures may consist of torsional current monitoring at a defined point of compliance, special protective relaying on the turbine-generator shaft(s), or constrained operation of the **End-User** equipment under certain system configurations. Costs of studies and the design and installation of protective and/or monitoring equipment shall be the responsibility of the **Requester**.

10.6 Transient and Temporary Overvoltages

The design of facilities connected to the EKPC transmission system must address the mitigation of transient and temporary overvoltages that may be caused by lightning strikes, faults, breaker switching, etc. A facility connected to the EKPC transmission system shall not cause a peak transient voltage at the Interconnection Point that is 140% or more of the nominal system voltage. Furthermore, a facility connected to the EKPC transmission system shall not cause a peak temporary (lasting greater than 20 milliseconds) voltage at the Interconnection Point that is 120% or more of the nominal system voltage.

10.7 Temporary Undervoltages

A facility connected to the EKPC transmission system should not result in more than two occurrences in a 12-month period of a voltage level at the Interconnection Point that remains at 85% or less of the nominal system voltage for more than 20 milliseconds. During non-fault conditions, the voltage at the Interconnection Point should be at least 92% at all times.

10.8 Operating Frequency

The nominal operating frequency of the EKPC transmission system is 60 Hz. Operation of any Facility connected to the EKPC system shall be designed for this frequency. The Facility should not contribute to any variation from this frequency. As discussed in section 5.2, an End-User Facility may be required to participate in EKPC's automatic load-shedding program. EKPC will also assess the impacts of Generation and Transmission facilities on system frequency to ensure that adequate protection exists to prevent significant frequency excursions from nominal system frequency.

10.9 Interruption/Outage Frequency

EKPC operates and maintains its system to provide reliable and safe service at all times. Connection of a Facility to the EKPC system requires that connected equipment not restrict timely outage coordination, automatic switching, or equipment maintenance scheduling. If a Facility is determined to present a potential risk to the reliability of the EKPC transmission system, additional switchgear, equipment redundancy, or bypass capabilities at the Interconnected Facility may be required.

The Interconnected Facility shall not cause an unplanned interruption/outage of another facility on the EKPC system more than once in any twelve-month period.

11.0 Equipment Ratings (R2.1.11)

For tap and looped connections, the **Requester's** high voltage bus and associated equipment, such as breakers, switches, connectors, and other

conductors shall have continuous, long-term emergency, short-term emergency, and momentary asymmetrical current ratings which: (1) do not limit the EKPC transmission system network capability and (2) have adequate capability for the initial and future system conditions identified by EKPC. All substations connected to the EKPC system shall meet the requirements of EKPC's substation design and construction standards, and must be designed to the applicable requirements of NESC, ANSI, and IEEE Standards. All interrupting devices, such as circuit breakers shall have interrupting capability sufficient to satisfactorily interrupt the maximum short-circuit currents that may occur at the location of the interconnection, including margin for circuit-breaker duty and DC offset. Where the substation becomes a facility within the intercepted path, EKPC shall design, construct, own, and maintain the facility at the Customer's expense.

For transmission lines interconnecting into EKPC's facilities, transmission line ratings shall meet the requirements of EKPC's transmission line design standards, including MVA, operating voltage, ampacity, insulation critical flashover, insulation clearances, shielding, tower grounding, and short circuit withstand requirements. In all cases the National Electric Safety Code (NESC) and OSHA requirements shall be satisfied. The Requester shall make available to EKPC all drawings and specifications, termination plans, and equipment ratings.

The effects resulting from wind storms, floods, lightning, altitude, temperature extremes, and/or earthquakes shall be considered in the design and operation of a facility connected to the EKPC system. Depending on the location, size, type, etc., of the facility, EKPC may impose additional requirements to be met by the owner/operator.

EKPC, as a borrower from the Rural Utilities Service (RUS), must comply with all RUS regulations, including following the NEPA environmental clearance processes. Any Project involving connection the the EKPC transmission system must follow these regulations.

Any equipment changes on the EKPC transmission system necessitated by connection of a new facility to the EKPC system will be performed by EKPC at the expense of the owner of the new facility requesting interconnection to the EKPC system. The proposed facility may not be allowed to connect to the EKPC system, or the facility's operations may be restricted, until any EKPC system limitations have been addressed.

12.0 Synchronizing Systems (R2.1.12)

All **Requester's** facilities, which include include transmission interconnections, End Users with backup generation and all Generation Owners, capable of independent voltage support or power supply, shall have equipment to measure

or check for synchronism of the facility with the EKPC system. Connection or reclosing of the facility shall not be allowed for out-of-sync conditions to protect the EKPC and **Requester's** systems from damage or loss of stability. Remote synchronizing to the EKPC system will be acceptable provided the Requester have adequate synch check equipment installed, and approved by EKPC, at their facility.

The **Requester** shall assume all responsibility for properly synchronizing their generation for operation with the EKPC Transmission System. Upon loss of the EKPC supply, the **Requester** shall immediately and positively cause the generation to be separated from the EKPC system. Synchronizing of generation to the EKPC Transmission System may be, at EKPC's discretion, performed under the direction of the EKPC Control Center.

13.0 Maintenance Coordination and Scheduled Outages (R2.1.13)

The Requester is to consult and coordinate with an EKPC Operations Engineer on all requests for outages to a Requester's facility that affects the EKPC Transmission System. Outage requests should be made according to the schedule outlined in EKPC's Outage Submission and Coordination document. After approval of the Requester's outage request by the Operations Engineer and, if applicable, the TVA Reliability Coordinator (RC), the Transmission Operator will follow EKPC's Lock Out and Tag Out Procedure to provide switching instructions to field personnel, issue Hold Cards and/or Caution Orders, and to issue safety working clearances to field personnel.

All **Requester** owned equipment up to and including the first protective fault interrupting device is to be maintained to EKPC standards. This may include substation equipment such as circuit breakers, circuit switchers, power fuses, instrument transformers, switches, surge arresters, bushings, relays, and associated equipment (including DC systems, grounding systems, etc.). Any **Requester** owned transmission line and its associated parts – up to the first fault interrupting device must also be maintained to EKPC standards. Detailed maintenance procedures shall be provided on request. EKPC is required to follow NERC Standard PRC-005 to maintain all equipment necessary to protect the system.

The **Requester** shall have an organization, approved by EKPC, test and maintain all devices and control schemes provided by the **Requester** for the protection of the EKPC system. Included in the testing and maintenance will be any initial set up, calibration, and check out of the required protective devices, periodic routine testing and maintenance, and any testing and maintenance necessary for an upgrade or changeout of the protective devices initiated by a **Requester** or EKPC.

If the **Requester's** testing and maintenance program is not performed in accordance with EKPC's maintenance requirements, EKPC reserves the rights to inspect, test, or maintain the protective devices required for the protection of the EKPC System.

All costs associated with the testing and maintenance of devices provided by the **Requester** for the protection of the EKPC system, including costs incurred by EKPC in performing any necessary tests or inspections, shall be the responsibility of the **Requester**.

EKPC reserves the right to approve the testing and maintenance practices of a **Requester** when the **End-User's** system is operated as a network with the EKPC transmission system.

The owner/operator of a facility connected to the EKPC transmission system is responsible for the regularly scheduled calibration and/or maintenance of its equipment, including, but not limited to generators, circuit breakers, power transformers, protective relays, revenue metering, communications devices, trip circuits, interrupters, DC power sources, grounding systems, and transmission facilities. Maintenance practices should be consistent with Good Utility Practice, and should be performed at a level that ensures the reliability and continuity of service of the interconnected transmission system. All relevant maintenance records should be maintained and provided to EKPC within 15 business days of a request.

14.0 Operational Issues (R2.1.14)

Operational issues on EKPC's system, either during normal or emergency conditions, may affect EKPC's control performance. Under certain conditions the **Requester** may have to install disturbance monitoring and/or control equipment as appropriate and detailed in section 5.

15.0 Inspection Requirements (R2.1.15)

The **Requester** is responsible for installing appropriate equipment and facilities to be compatible with the EKPC Transmission System. The **Requester** is also responsible for meeting any applicable federal, state, and local codes.

Before a **Requester** owned facility can be energized, it must pass a final inspection by EKPC personnel. EKPC will inspect all substation equipment from the point of interconnection to the first protective fault interrupting device and the ground system. This may include circuit breakers, circuit switchers, power fuses, instrument transformers, switches, surge arresters, bushings, and relays and associated equipment (including DC and grounding systems). The inspection will consist of a visual inspection of all major equipment as well as review of required

test results. Nameplate information on all equipment will need to be recorded and given to EKPC prior to final inspection.

The ground system must be checked before any overhead ground wires are attached from outside lines, by using the resistance measurement procedures in accordance with IEEE Standard 81 "Recommended Guide for Measuring Ground Resistance and Potential Gradients in the Earth." The EKPC inspection will be documented by completing a site-specific form supplied by EKPC. An example of the form, showing the types of information required is shown in Appendix D.

EKPC should be allowed access, upon notification, to **Requester's** facility for any requirement related to NERC standards, which may need to be reported. Details of access and notification can be determined when agreement is reached.

16.0 Communications (R2.1.16)

For any abnormal system operational issues, emergency telephone numbers agreed on by both parties will be available prior to the actual interconnection date. Under no circumstance shall a **Requester** energize EKPC transmission facilities that have been de-energized without the consent from EKPC Control Center. Circuits that are electrically disconnected from the EKPC transmission system and are energized by a **Requester** constitute a potential safety hazard for both EKPC transmission personnel and the general public. Also, the energizing of such circuits at abnormal voltage or frequency could cause damage to electrical equipment of both the EKPC Transmission System and the generation.

The **Requester** is responsible for operating its generation with full regard for the safe practices of, and with full cooperation under the supervision of the EKPC Control Center.

16.1 Voice Communications

A. Normal – At EKPC's request, the **Requester** shall provide a dedicated voice communication circuit to the EKPC Control Center. Such a dedicated voice communication circuit would originate from the **Requester's** office staffed 24 hours a day and would be typically required for connected transmission facilities that significantly affect the EKPC transmission network capacity and operations.

All other normal voice communication concerning facility operations shall be conducted through the public telephone network to the Control Center phone number(s) issued by EKPC.

B. Emergency – Voice communications in the event of a transmission facility emergency shall use the dedicated voice circuits, if available, or public telephone network and phone number(s) designated for emergency use.

It is the **Requester's** responsibility to take prudent steps when an area or system wide capacity emergency is declared. Load reductions shall be implemented by reducing non-essential loads. This type of reduction is usually conveyed through the local media. If the **Requester** has generating units EKPC's Control Center may give specific instructions regarding the operation of the **Requester's** units, depending on the nature of the emergency.

The **End-User's** EKPC representative is responsible for providing the EKPC Control Center a "customer contact list." This listing contains the **End-User's** EKPC representative and backup person as well as their business, home and pager numbers.

These **End-Users** shall be provided an unlisted phone number to be used for emergency or routine operations. Operational emergencies (equipment) warrant a direct call either way.

16.2 Interruptible Contracts

Owners of transmission facilities that have an EKPC interruptible contract shall install communication facilities with the EKPC Control Center as specified in the contract.

16.3 Emergency Operating Conditions

End-User's facilities may be subject to EKPC's System Restoration Plan that can require interruption of load to deal with generation deficiencies and/or transmission system emergencies. It is noted that interrupting of load will only be done in extreme conditions that would result in a more serious degradation of system performance than if the load were not shed.

17.0 Coordination with Other Codes, Standards, and Agencies

The information contained in this document is supplementary to and does not intentionally conflict with or supersede the National Electric Code (NEC) as approved by the American National Standards Institute (ANSI) or such federal, state and municipal laws, ordinances, rules or regulations as may be in force within the cities, towns or communities in which EKPC furnishes electric service. It is the responsibility of the **Interconnection** or **End-User** to conform to all applicable national, state and local laws, ordinances, rules, regulations, codes, etc.

18.0 Indemnification

The use and reliance upon the information contained in this document shall in no way relieve the **Requester** or **Facility Owner** from the responsibility to meet NEC, NESC, ANSI, etc. requirements governing their design, construction, operation, and materials or from responsibility for the protection and safety of the general public.

The **Requester**, for itself, its successors, assigns and subcontractors agrees to pay, indemnify and save East Kentucky Power Cooperative, its successors and assigns, harmless from and against any and all court cost and litigation expenses, including legal fees, incurred or related to the defense of any action asserted by any person or persons for bodily injuries, death or property damage arising or in any manner growing out of the use and reliance upon the information provided by EKPC. Reliance upon this information shall not relieve the **Interconnection** or **End-User** from responsibility for the protection and safety of the general public.

Parties wishing to connect to the EKPC transmission system shall agree to the following terms to be included in any Interconnection Agreement:

Indemnity by (Entity)

(Entity) agrees to defend, indemnify and hold harmless EKPC, its directors, officers, employees and agents, from any and all damage, loss, claim, demand, suit, liability, penalty, or forfeiture of every kind and nature- including but not limited to attorney fees and other costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of a) injuries or deaths to persons, (b) damages to, destruction of or interference with the use of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations, or orders-whether suffered directly by EKPC itself or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from: acts or omissions of (Entity), its employees, agents, subcontractors or other representatives or from their presence on the premise of EKPC; from adverse impacts on EKPC's system, or other connected systems resulting from (Entity's) design, construction or operations of its facilities; or otherwise from performance of this Interconnection Agreement.

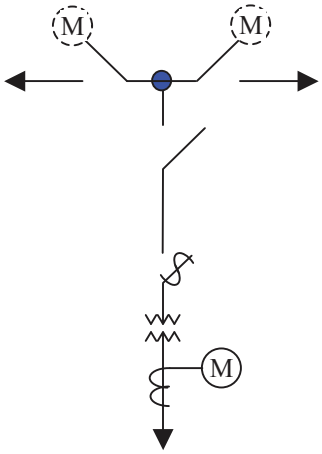
APPENDIX A

Figure 1 --Typical Transmission Tap Line Supply Configurations

Figure 2 – Typical Transmission Looped Supply Configurations (138 and 161 kV)

Figure 3 – Typical Transmission Looped Supply Configurations (345 kV)

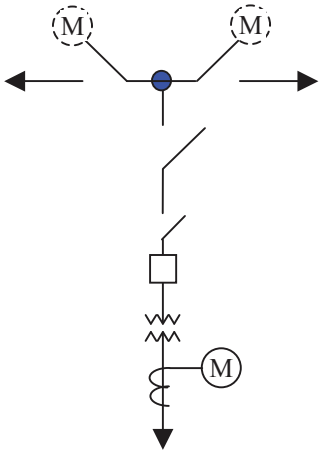
FIGURE 1 Typical Transmission Tap Line Supply Configurations



Transformers Under 10 MVA

Can Use Fuse Protection or Breaker Protection.

69 kV and below only.

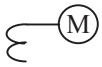


Transformers at 10 MVA or Larger And All Above 69 kV

Provide Circuit Breaker or Circuit Switcher Protection

(1) EHV End-User generally owns the step-down transformer
(2) EHV End-User Metering is typically installed on the low-side of the step-down transformer and compensated to the high-side to cover losses.
(3) All EHV and most >69 kV will have all facilities in a substation environment.
(4) Tap configurations without breaker(s) may not be suitable for some EKPC lines.

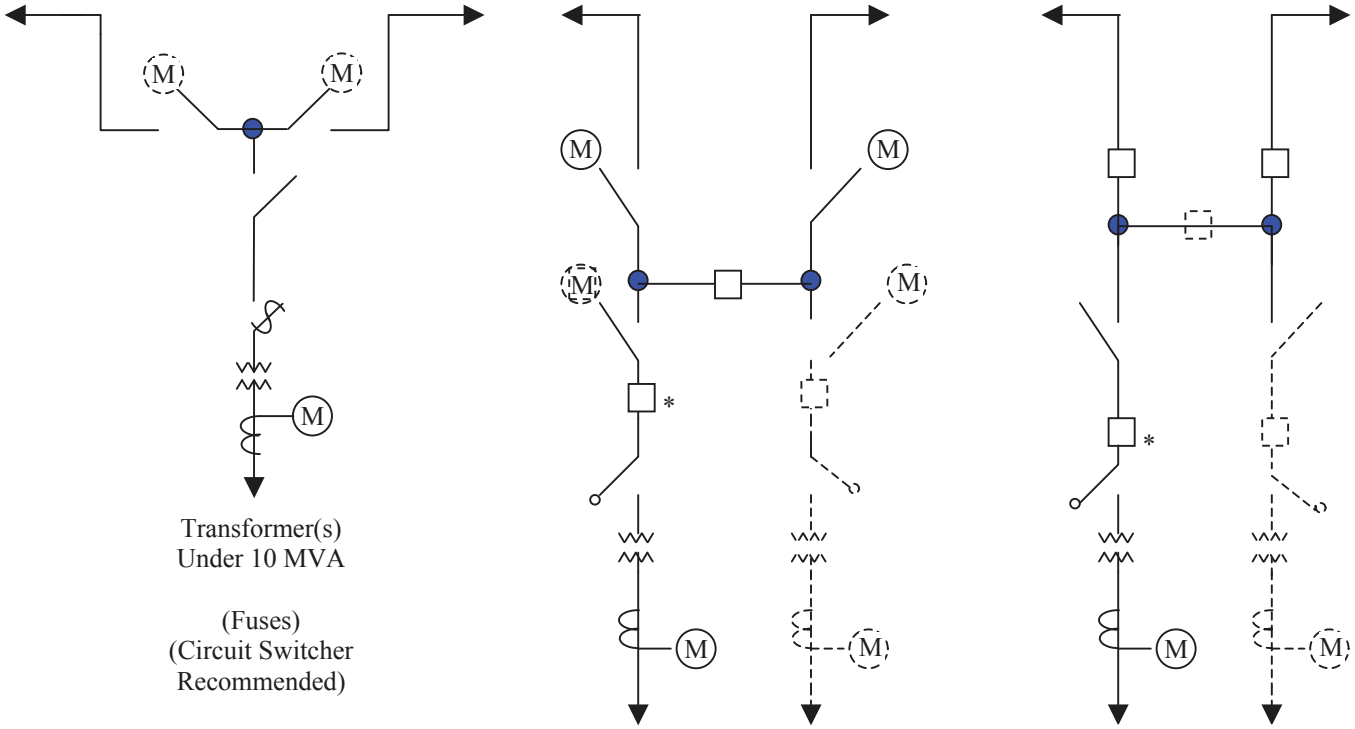
---------- Optional or Future



Metering

Motor Operated Air Break Switch

FIGURE 2 Typical Transmission Looped Supply Configurations (for 138 and 161 kV)

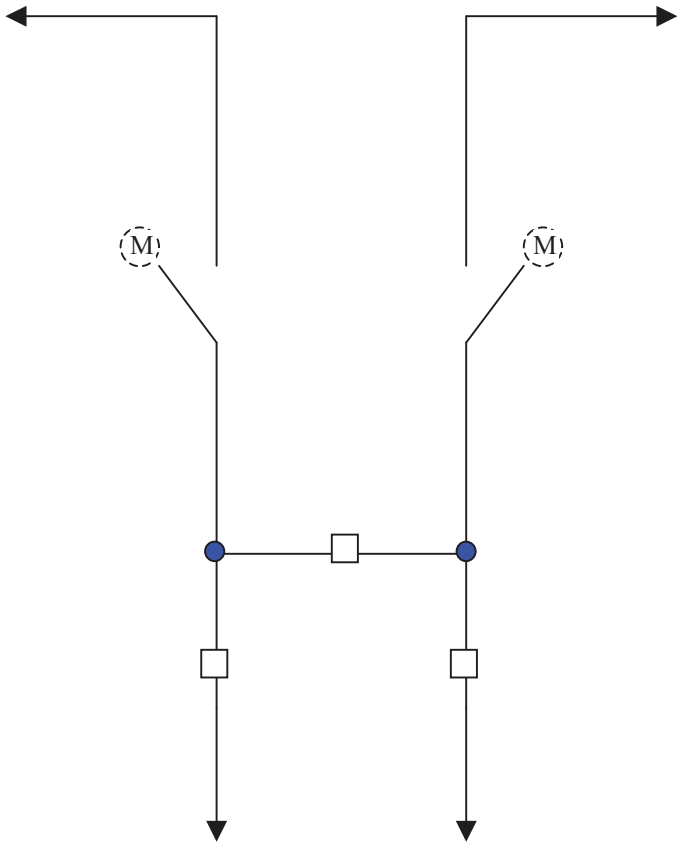


M Motor Operated Air Break Switch

---------- Optional or Future

M Metering

FIGURE 3 Typical Transmission Looped Supply Configurations (for 345 kV)



EHV End-User (1), (2)

---------- Optional or Future

Ⓜ Motor Operated Air Break Switch

(1) EHV End-User generally owns the step-down transformer.

(2) EHV End-User Metering is typically installed on the low-side of the Step-down transformer and compensated to the high-side to cover losses.

(3) All EHV switches and other equipment are to be in a substation.

APPENDIX B

Electrical Clearances and Equipment Ratings

NOTE:

INSERT APPENDIX B TABLE IN PLACE OF THIS PAGE

APPENDIX C

Switch Operator and Transmission Grounding Installations

APPENDIX C

Switch Operator and Transmission Grounding Installations

Reference to Drawings

All structures shall be grounded as shown on the TM-9SP or TM-9R and TM-9C drawings and subject to the following provisions.

Structure Grounding

1. East Kentucky Power (EKP) may require that ground resistance measurements be made for each structure and that additional grounding be added to that already provided by the basic structure grounding assembles.
2. Where structure grounding tests are required by EKP the Installer shall measure the ground resistance after the structure is erected, but before the overhead ground wire is installed. The method of measuring ground resistance shall be subject to the approval of EKP.
3. All labor and materials for ground resistance measurement and installation of additional grounding shall be provided by the Installer.
4. The Installer shall install counterpoise only after approval of EKP.

Bonding of Ground Wire

1. The pole wire shall be continuous and not spliced from top of pole to the pole butt grounding assembly. Should damage occur during erection of the structure, the pole ground wire may be spliced only with EKP approval.
2. Hardware shall be bonded to the pole ground wire as shown on the drawings. The ground wire shall clear any un-bonded hardware by at least 3 inches.

Special Requirements

1. Installer shall follow the EKP Single Pole or Two Pole Ground Configuration Procedures in order to achieve an acceptable grounding system.
2. Additional measures beyond the above procedures may be required in difficult locations. This may require special Engineering assessments.

NOTE:

INSERT THE FOLLOWING IN PLACE OF THIS SHEET:

Drawings: TM-9C, TM-9R, TM-9RH. TM-9HSP, TM-9R3P, TM-9SP, TM-9-3SP

Grounding instructions sheets Titled:

Single pole “X” Configuration
Two Pole Grounding Configuration

APPENDIX D

Inspection Requirements

Appendix D

CONNECTING FACILITY
Electrical Facility Checkout Guide

ITEM		ACTION/INFORMATION	BY	DATE
1. Facility Ground Resistance		Review Test Results	_____	_____
2. Air break and Disconnect Switch Alignment				
a. Switch Device Number	____	Visual Inspection	_____	_____
b. Switch Device Number	____	Visual Inspection	_____	_____
c. Switch Device Number	____	Visual Inspection	_____	_____
d. Switch Device Number	____	Visual Inspection	_____	_____
e. Switch Device Number	____	Visual Inspection	_____	_____
f. Switch Device Number	____	Visual Inspection	_____	_____
3. Circuit Breakers				
a. ___kV Circuit Breaker *Device Number* _____				
1. Gas Filled		Visual Inspection	_____	_____
2. Timing Test		Review Test Results	_____	_____
3. Digital Low R Ohmmeter		Review Test Results	_____	_____
4. Doble Test		Review Test Results	_____	_____
5. CT Ration & Polarity		Review Test Results	_____	_____
6. Breaker Alarms		Detailed Inspection	_____	_____
4. Circuit Switcher				
a. ___kV Circuit Switcher *Device Number* _____				
1. Hipot Test		Review Test Results	_____	_____
2. Timing Test		Review Test Results	_____	_____
3. Digital Low R Ohmmeter		Review Test Results	_____	_____
5. Fuses				
a. ___ kV Fuses *Device number* _____				
1. Rating/Type		Visual Inspection	_____	_____
2. Air Flow Test		Review Test Results	_____	_____
6. Power Transformer				
a. ___kV Transformer *Device Number* _____				
1. CT Ratio & Polarity		Review Test Results	_____	_____

2. Doble Tests	Review Test Results	_____	_____
3. TTR Tests (all Taps)	Review Test Results	_____	_____
4. Megger Tests	Review Test Results	_____	_____
5. Oil and DGA Tests	Review Test Results	_____	_____

7. CCVT/VT

a. ___kV *Circuit/Line Name* _____ *Device Number* _____

1. Doble Test	Review Test Results	_____	_____
2. Potential Polarizing Test	Review Test Results	_____	_____
3. Ration & Polarity Test	Review Test Results	_____	_____

b. ___kV CCVT/VT *Device Number* _____

1. Doble Test	Review Test Results	_____	_____
2. Potential Polarizing Test	Review Test Results	_____	_____
3. Ratio & Polarizing Test	Review Test Results	_____	_____

8. Phasing

a. _____ kV BUS *Number* _____

9. Batteries and Charger

a. _____V DC Battery and Charger

1. Battery Acceptable	Review Test Results	_____	_____
2. Intercall Resistance Test	Review Test Results	_____	_____
3. Charger Settings	Review Test Results	_____	_____
4. Ground Detector	Review Test Results	_____	_____

10. SCADA

a. Function Test with Dispatch/Control Center

1. Control	Detailed Inspection	_____	_____
2. Indication	Detailed Inspection	_____	_____
3. Alarms	Detailed Inspection	_____	_____

b. Metering	Detailed Inspection	_____	_____

c. Telemetering

1. Signal Levels	Review Test Results	_____	_____
2. Calibrations	Review Test Results	_____	_____

11. Relay and control Schematics

a. _____kV Circuit Breaker *Device Number* _____

1. Correct Settings Applied	Review Test Results	_____	_____
2. Calibration Test	Review Test Results	_____	_____
3. Trip Test	Detailed Inspection	_____	_____
4. In-Service Load Angles	Detailed Inspection	_____	_____
5. Remote Relay Communication	Detailed Inspection	_____	_____

b. Annunicators and Alarms

1. Set Undervoltage & Time Delay Relays	Review Test Results	_____	_____
2. Function Tested	Review Test Results	_____	_____

12. Miscellaneous

a. Arresters

1. Sized Correctly	Visual Inspection	_____	_____
2. Located Properly	Visual Inspection	_____	_____

b. Clearance

1. Bus to Ground	Visual Inspection	_____	_____
2. Bus to Bus	Visual Inspection	_____	_____
3. Bus to Steel	Visual Inspection	_____	_____

c. Conductors

1. Sized Adequately	Visual Inspection	_____	_____
2. Connected Properly	Visual Inspection	_____	_____