FARMERS RURAL ELECTRIC COOPERATIVE

P.O. Box 1298 • 504 South Broadway • Glasgow, KY 42142-1298
Tel. (270) 651-2191 • (800) 253-2191 • Fax: (270) 651-7332

February 22, 2007

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

RE: Administrative Case No. 2006-00494

Dear Ms. O'Donnell:

Please find enclosed an original and six copies of the response of Farmers Rural Electric Cooperative Corporation to the data request of the Commission dated February 9, 2007 in the above-styled matter. I certify that a copy of this filing has been served on the persons shown on the service list attached.

Thank you for cooperation in this matter. Please contact me at (270) 651-2191 if you have any questions.

Sincerely,

Jackie B. Browning
President & CEO

Enclosures

Service List for Case No. 2006-00494

Allen Anderson
South Kentucky R.E.C.C.
P.O. Box 910
Somerset, KY 42502-0910

Mark A. Bailey
Kenergy Corporation
P.O. Box 1389
Owensboro, KY 42302-1389

Rick Lovekamp
Louisville Gas & Electric
P.O. Box 32010
Louisville, KY 40232-2010

Debbie Martin
Shelby Energy Cooperative
620 Old Finchville Road
Shelbyville, KY 40065

Michael Williams
Blue Grass Energy Cooperative
P.O. Box 990
Nicholasville, KY 40340-0990

Jackie B. Browning
Farmers R.E.C.C.
P.O. Box 1298
Glasgow, KY 42142-1298

Sharon K. Carson
Jackson Energy Cooperative
115 Jackson Energy Lane
McKee, KY 40447

Lawrence W. Cook
Office of Attorney General
Utility & Rate Intervention
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

Service List for Case No. 2006-00494

Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45202

Paul G. Embs
Clark Energy Cooperative
P.O. Box 748
Winchester, KY 40392-0748

Carol H. Fraley
Grayson R.E.C.C.
109 Bagby Park
Grayson, KY 41143

Ted Hampton
Cumberland Valley Electric
Highway 25E
Gray, KY 40734

Larry Hicks
Salt River Electric Cooperative
P.O. Box 609
Bardstown, KY 40004-0609

Kerry K. Howard
Licking Valley R.E.C.C.
P.O. Box 605
West Liberty, KY 41472

James L. Jacobus
Inter-County Energy Cooperative
P.O. Box 87
Danville, KY 40423-0087

Robert Hood
Owen Electric Cooperative
P.O. Box 400
Owenton, KY 40359-0400

Service List for Case No. 2006-00494

Burns E. Mercer
Meade County R.E.C.C.
P.O. Box 489
Brandenburg, KY 40108-0489

Vince Heuser
Nolin R.E.C.C.
411 Ring Road
Elizabethtown, KY 42701-8701

Timothy C. Mosher
American Electric Power
P.O. Box 5190
Frankfort, KY 40602

Barry L. Myers
Taylor County R.E.C.C.
P.O. Box 100
Campbellsville, KY 42719-0100

G. Kelly Nuckols
Jackson Purchase Energy Corporation
P.O. Box 4030
Paducah, KY 42002-4030

Anthony P. Overbey
Fleming-Mason Energy Cooperative
P.O. Box 328
Flemingsburg, KY 41041

Bobby D. Sexton
Big Sandy R.E.C.C.
504 11th Street
Paintsville, KY 41240-1422

Honorable Frank N. King, Jr.
318 Second Street
Henderson, KY 42420

Service List for Case No. 2006-00494

Honorable Mark R. Overstreet
P.O. Box 634
Frankfort, KY 40602-0634

Mellisa D Yates
P.O. Box 929
Paducah, KY 42002-0929

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION
OF KENTUCKY

In the Matter of:

AN INVESTIGATION OF THE RELIABILITY	)	
MEASURES OF KENTUCKY'S	)	ADMINISTRATIVE
JURISDICTIONAL ELECTRIC	)	CASE NO. 2006-00494
DISTRIBUTION UTILITIES AND CERTAIN	)	
RELIABILITY MAINTENANCE PRACTICES	)	

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION RESPONSE TO THE INFORMATION REQUESTS CONTAINED IN COMMISSION'S ORDER OF FEBRUARY 9, 2007

February 22, 2007

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 1

RESPONSIBLE PARTY: Tony Wells

REQUEST 1. Describe in detail how the company utilizes all of the reliability measures it monitors.

RESPONSE 1. Farmers periodically reviews its reliability measurements to determine system and feeder performance. System and feeder performance trends and problem areas are identified and evaluated. Farmers uses this information in the development of its annual maintenance programs and construction work plans.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 2

RESPONSIBLE PARTY: Tony Wells

REQUEST 2. Has the company determined an appropriate operating range or performance threshold based on these measures? If yes, identify.

RESPONSE 2. Yes. Farmers uses the guidelines established in RUS Bulletin 1730-1 "Electric System Operation and Maintenance" and RUS Bulletin 161-1 "Interruption Reporting and Service Continuity Standards for Electric Distribution Systems."

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 3

RESPONSIBLE PARTY: Tony Wells

REQUEST 3. Describe in detail how the company develops formal plans to address its worst performing circuits. If the company does not develop such plans, indicate so in the response.

RESPONSE 3. Farmers periodically reviews its reliability measurements to identify poor performing circuits. Performance trends and problem areas are identified and evaluated. Farmers uses this information in the development of its annual maintenance programs and construction work plans.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 4

RESPONSIBLE PARTY: Tony Wells

REQUEST 4. Why are momentary outages excluded?

RESPONSE 4. Farmers does not have the equipment installed necessary to monitor and record momentary outages.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 5

RESPONSIBLE PARTY: Tony Wells

REQUEST 5. Why are major event days or major storms excluded?

RESPONSE 5. Farmers does not exclude major event days or major storms from its reliability measurement.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 6

RESPONSIBLE PARTY: Tony Wells

REQUEST 6. Provide a hard copy citing of the Rural Utilities Service ("RUS") reliability monitoring or reporting requirements or, in the alternative, provide an accessible Internet site.

RESPONSE 6. Please find attached RUS Bulletin 1730-1 "Electric System Operation and Maintenance" and RUS Bulletin 161-1 "Interruption Reporting and Service Continuity Standards for Electric Distribution Systems."

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

Bulletin 1730-1

SUBJECT: **Electric System Operation and Maintenance (O&M)**

To: RUS Electric Borrowers and RUS Electric Staff

Effective Date: Date of Approval

Expiration Date: Seven Years from Effective Date

Office of Primary Interest: Electric Staff Division

Filing Instructions: This Bulletin supersedes REA Bulletin 161-5, Electric System Review and Evaluation, dated October, 1978. File this bulletin with 7 CFR 1730.

Purpose: This bulletin contains guidelines related to electric borrowers' operation and maintenance (O&M) and outlines the Rural Utilities Service's (RUS) standard practices with respect to review and evaluation of O&M practices.

Assistant Administrator - Electric Program

1/24/98

Date

TABLE OF CONTENTS

INDEX: Inspection
Maintenance
Operations and Maintenance
Records

ABBREVIATIONS

ANSI	American National Standards Institute
CAP	Corrective Action Plan
CFR	Code of Federal Regulations
CT	Current Transformer
EMF	Electric and Magnetic Fields
EPA	Environmental Protection Agency
GFR	General Field Representative
IFT	Interfacial Tension
kVA	Kilovolt-Ampere
kW	Kilowatt
kWh	kilowatt-hour
NESC	National Electrical Safety Code
O&M	Operations and Maintenance
OCR	Oil Circuit Recloser
PCB	Polychlorinated Biphenyl
PSD	Power Supply Division
PT	Potential Transformer
REA	Rural Electrification Administration
RUS	Rural Utilities Service

1. Purpose: This bulletin contains guidelines related to electric borrowers' operation and maintenance (O&M) and outlines the Rural Utilities Service's (RUS) standard practices with respect to review and evaluation of O&M practices. 7 CFR 1730 contains the policies and procedures of RUS related to electric borrowers' O&M practices and RUS' review and evaluation thereof.

2. Borrower Guidelines

2.1 Records: Each borrower is responsible for maintaining records of the physical and electrical condition of its electric system. Any or all of these records may be reviewed by RUS during its review and evaluation. Such records include, but are not limited to:

(a) Service interruption reports and summaries of experience (including power supply outages.)

(b) Overhead and underground line inspection and maintenance records, including pole inspection and line patrol records.

(c) Substation inspection and maintenance records.

(d) Recloser and sectionalizer records.

(e) Line Voltage regulator records.

(f) Distribution transformer records.

(g) Watt-hour and demand meter records.

(h) Right-of-way maintenance records.

(i) Line Voltage and current records.

(j) Up-to-date system maps.

(k) System losses.

(l) Idle services.

(m) External system impacts (including EMF questions, stray voltage, radio and television interference, etc.)--records of inquiries and resulting actions.

2.2 Emergency Restoration Plan: Each borrower should have a written plan detailing how to restore its system in the event of a system wide outage resulting from a major natural disaster or other causes. This plan should include how to contact emergency agencies, borrower management and other key personnel, contractors and equipment suppliers, other utilities, and any others that might need to be reached in an emergency. It should also include recovery from loss of power to the headquarters, key offices, and/or operation center facilities. It should be readily accessible at all times under any and all circumstances.

2.3 System Ratings: RUS Form 300, Review Rating Summary, includes a numerical rating system as follows:

0: Unsatisfactory - no records
1: Unsatisfactory - corrective action needed
2: Acceptable, but could be improved - see attached recommendations
3: Satisfactory - no additional action required at this time
N/A: Not applicable

Exhibit A provides a guide for the conditions normally needed to justify a rating of 3 for each of the items on RUS Form 300. The explanatory notes section of RUS Form 300 should include a list of all items rated as unsatisfactory (ratings 0 or 1) along with comments indicating the action or implementation that is proposed. This is in addition to the corrective action plan (CAP) required by 7 CFR 1730. Additional expenditures required for deferred maintenance should be

indicated in the O&M Budgets, Part IV of RUS Form 300. These may be distributed over a period of 2 or 3 years as indicated on the form.

3. Review and Evaluation of O&M Practices by RUS

3.1. RUS will conduct a periodic review and evaluation of each borrower's operation and maintenance programs and practices. The purpose of this review is to assess loan security and to determine borrower compliance with RUS policy as outlined in part 7 CFR 1730.

3.2. Distribution Borrowers: The General Field Representative (GFR) is responsible, within the GFR's assigned territory, for initiating and conducting a periodic review and evaluation of each distribution borrower's operation and maintenance programs, practices, and records. This review and evaluation is to be done at least once every 3 years.

3.2.1 The GFR may inspect facilities as well as records, and may also observe construction and maintenance work in the field. Key borrower personnel responsible for the facilities being inspected should accompany the GFR during such inspections.

3.2.2 If adequate information is available, the GFR will complete the review and evaluation and consult with the borrower regarding its programs and records for operation, maintenance, and system improvements. The GFR's signature on the Form 300 signifies concurrence with the borrower's analysis, ratings, and explanatory notes unless indicated otherwise.

3.2.3 If adequate information is not available, the GFR's review and evaluation will be deferred until the borrower has remedied the deficiencies identified by the GFR.

3.2.4 Upon completion of the O&M review and evaluation, the GFR will communicate his/her findings to the borrower.

3.3 Power Supply Borrowers: The Power Supply Division (PSD) is responsible for initiating and conducting a periodic review and evaluation of each power supply borrower's operation and maintenance programs, practices, and records . PSD will consult with the borrower and arrange a scheduled time for the review and evaluation. PSD will determine the frequency of this review and evaluation.

3.3.1 The GFR will, upon request by PSD, assist in the review and evaluation, particularly with respect to transmission, subtransmission, and substation facilities.

EXHIBIT A

RUS FORM 300 RATING GUIDE

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

PART I - TRANSMISSION and DISTRIBUTION FACILITIES

1. Substations (Transmission and Distribution)

a. Safety, Clearance, Code Compliance: No violations of RUS or NESC requirements including clearance or separations in any substation. All substations accessible by authorized personnel only. Operating manual available for each substation.

b. Physical Condition: Structure, Major Equipment, Appearance: Rare instances of rust, weeds, dangerous insects, and bird nesting. No leaks, no temporary bus being used on an ongoing basis, only minor material associated with maintenance of the substation equipment stored in yard. No debris, no openings under fence greater than 3 inches (76 mm), no broken insulators, parallel power transformers properly fault protected. Circuit, phases & airbreak switch handles are properly identified.

c. Inspection Records Each Substation: Written monthly inspection reports completed and reviewed by responsible personnel for all substations. Infrared inspection of all connectors at least every five years. Dielectric, dissolved gas, and interfacial tension (IFT) tests of oil filled equipment performed at least every five years or within one year of exposure to a through fault which causes the transformer protective devices to de-energize the transformer. Annual power factor test of all equipment rated 230 kV or above. Relays are functionally tested annually and cleaned, calibrated, and tested every three years.

d. Oil Spill Prevention: Oil spill prevention and mitigation plans prepared and available for all substations.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

2. Transmission Lines

a. Right-of-Way - Clearing, Erosion, Appearance, Intrusions: No uncontrolled erosion. Gates or gaps at all fence crossings. Structures and lines not impacted by untrimmed right of way. Structures generally accessible by service vehicles.

b. Physical Condition - Structure, Conductor, Guying: All structures vertical and guys taut. No broken insulators or crossarms, and no unauthorized attachments. Essentially all structures numbered. Structures and attachments conform to NESC requirements.

c. Inspection Program and Records: Walking, riding, or aerial line patrol of all lines (including those on private right-of-way) performed at least annually. Records maintained for pole inspection and line patrol and deficiencies corrected on a timely basis. Above and below ground pole inspection performed on cycle based upon decay zone using experienced inspectors.

3. Distribution Lines - Overhead

a. Inspection and Maintenance - Program and Records: Above and below ground pole inspection performed on cycle based upon decay zone using experienced inspectors. Records of all poles inspected, treated, rejected and changed out readily available in summary form. All overhead lines (including those on private right-of-way) patrolled annually (walking, riding, or aerial); more frequently if experience dictates. Records maintained for pole inspection and line patrol with deficiencies corrected in a timely manner. Pole and equipment changeout program in place to keep rejected poles and failed equipment to a minimum.

b. Compliance with Safety Codes - Clearances: All facilities staked prior to construction by personnel familiar with NESC requirements. Line patrols identify changed conditions requiring greater clearances.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

Compliance with Safety Codes - Foreign Structures: Utility has policy and practice of immediately remedying foreign structures which conflict with primary lines upon observation.

Compliance with Safety Codes - Attachments: All overhead attachments meet NESC separation and clearance requirements. Up-to-date joint-use and pole rental agreements are in effect. Unauthorized attachments and violations of the NESC promptly remedied.

c. Observed Physical Condition from Field Checking - Right-of-way: Structures and lines not impacted by untrimmed right-of-way. Right-of-way re-trimming cycles to be dictated by local conditions.

Observed Physical Condition from Field Checking - Other: Rare instances of leaning poles, slack guys, broken grounds, loose hardware and superfluous material on structures. No broken crossarms or insulators, and no pole steps on wood poles. Installation of miscellaneous distribution equipment meets NESC requirements. Neutral properly identified when located on crossarm.

4. Distribution - Underground Cable

a. Grounding and Corrosion Control: Ground rods located at each transformer plus at least four per mile (1.6 km), not including grounds at individual services, in accordance with the NESC. Record system kept of visible cable condition when excavated. Periodic testing at selected locations of underground cable and grounding points for evidence of corrosion. Appropriate and timely actions taken to correct any unsatisfactory conditions.

b. Surface Grading, Appearance: Rare instances of earth settling which could create hazards to the general public and timely action taken to correct any deficiency.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

c. Riser Poles: Hazards, Guying, Condition: Cut-outs mounted per RUS requirements. Riser cable covered with conduit to within 4 feet (1.2m) of the bottom of the potheads. Adequate surge protection installed.

5. Distribution Line Equipment: Conditions and Records

a. Voltage Regulators: Voltage regulators inspected and maintained in accordance with the manufacturer's recommended timetable. Regulators checked for proper operation at least semi-annually. Knowledge of and compliance with EPA requirements with respect to PCB contaminated oil and equipment. Dielectric, dissolved gas, and IFT tests of oil filled equipment performed every five years or within one year of exposure to a through fault which causes the protective devices to de-energize the regulator.

b. Sectionalizing Equipment: Oil circuit reclosers (OCR's) and breakers inspected and maintained in accordance with the manufacturer's recommended timetable. Records reflect inspection results, maintenance performed, and date.

c. Distribution Transformers: Complete records kept as to size, location, and date installed. Knowledge of and compliance with EPA requirements with respect to PCB contaminated oil and equipment. Transformer loading analysis performed periodically as needed.

d. Pad Mounted Equipment - Safety - Locking, Dead Front, Barriers: All padmount enclosures meet RUS dead-front requirements (secondary barriers, recessed penta-head nut, and separate pad-lock.) Grounding in accordance with RUS and NESC requirements. "Danger" signs inside all enclosures and "Warning" signs on the exterior in accordance with ANSI Z535.

Pad Mounted Equipment - Appearance - Settlement, Condition: Rare instances of leaning or undermined enclosures. Prompt action taken to correct deficiencies.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

e. Watt-hour and Demand Meter Reading and Testing: All meters tested in accordance with state regulations (where applicable) or ANSI C12.1. PT, CT and demand meters are generally tested on at least a 3 year cycle. Complete records kept as to size, location, and date installed.

PART II - OPERATION AND MAINTENANCE

6. Line Maintenance and Work Order Procedures

a. Work Planning and Scheduling: All lines staked prior to construction by personnel familiar with NESC requirements. Work order inspections performed in accordance with 7 CFR 1724, Electric Engineering, Architectural Services and Design Policies and Procedures (i.e., within 6 months of completion of construction.) Utility promptly provides inspector with written notice that clean-up work has been completed. Construction Work Plan projects completed in time to meet load level requirements. New service connections completed in reasonable time frames.

Work Backlogs - Right-of-way Maintenance: Adequate resources being provided to address re-clearing on timely basis. Right-of-way re-trimming cycles to be dictated by local conditions.

Work Backlogs - Poles: All reject poles replaced within 6 months of inspection. "Danger" and "Hazard" poles replaced as soon as possible.

Work Backlogs - Idle Services - Retirement of: Policy and procedures in place to address retirement of idle services so that ratio of idle services to total is less than 10% unless specific local conditions dictate otherwise.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

Work Backlogs - Other: Job orders from line inspection completed in reasonable time frames.

7. Service Interruptions

a. Average Annual Hours/Consumer by Cause: Rating to consider the effect of all types of outages, including planned. Evidence of concern would be when total outages exceed 5 hours or power supply outages exceed 1 hour per consumer per year. Outages accounted for in accordance with RUS Bulletin 161-1.

b. Emergency Restoration Plan: Emergency restoration plan readily available and covers multiple scenarios, including loss of power to the headquarters, key offices, and/or operations centers.

8. Power Quality

General Freedom from Complaints: Minimal complaints with respect to television and radio interference, voltage flicker, neutral-to-earth voltage, harmonics, and EMF. Complaints generally resolved quickly and effectively. Summary of complaints maintained and analyzed periodically.

9. Loading and Load Balance

a. Distribution Transformer Loading: Loading ratio (kVA to peak kW) may range from 2 to 4, depending upon levels of load management, seasonal customers, as well as other factors.

b. Load Control Apparatus: Have records of individual controllers showing location, type of load being controlled, and any maintenance. Load control results summarized.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

c. Substation and Feeder Loading: All feeders balanced at each substation to within 20% during peak loads.

10. Maps and Plant Records

a. Operating Maps - Accurate and Up-to-Date: Consumers can be identified by location with a set of maps carried by all service personnel. Maps depict roads, grid lines, waterways, railroads, and other landmarks necessary to locate consumers. Maps are of a functional size and permit location of consumers irrespective of date of service. Detail maps are current and up to date, generally 1 year old or less.

b. Circuit Diagrams: Current and up-to-date map (generally 2 years old or less) depicting a multiple line layout of distribution facilities of the utility. The location and sizes of substations, line regulators, reclosers, capacitors, and substation boundaries are clearly shown. Primary voltage drops are indicated at the ends of primary feeder lines. All transmission lines are located and identified as to voltage and ownership.

d. Staking Sheets: Staking sheets are prepared for projects prior to construction. The sketch and construction units are consistent. North arrow and grid reference are present. Spans lengths are correctly listed and all line angles and guy lead lengths are stated. Final staking sheets are consistent with the "as-built" conditions.

PART III - ENGINEERING

11. System Load Conditions and Losses

a. Annual System Losses: System losses are appropriate for the conditions encountered. Reasonable efforts made to reduce system losses.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

b. Annual Load Factor: Load factor is appropriate for the conditions encountered, generally at least 45%. Reasonable efforts made to improve load factor, where possible.

c. Power Factor at Monthly Peak: Each distribution substation maintains a power factor between 0.95 lagging and 0.95 leading at time of power supply coincident peak demand.

12. Voltage Conditions

a. Voltage Surveys: Sufficient number of recording and/or indicating voltmeters are available and utilized to monitor specific locations where voltage conditions warrant special attention. Annual graphs or statistical analyses are kept for each meter for the most recent 5 year period.

b. Substation Transformer Output Voltage Spread: All substations include automatic voltage regulators or voltage regulating transformers. Each substation has continuous voltage recording which is monitored monthly by computer analysis. Regulated substation output voltage and line regulators are maintained so that Range A service voltage per RUS Bulletin 169-4 is provided to all consumers.

13. Load Studies and Planning

a. Long Range Engineering Plan: System planning study is current, meets the requirements of 7 CFR 1710, can be used as a guide for preparing the next Construction Work Plan, and is prepared in accordance with RUS Bulletin 1724D-101A.

b. Construction Work Plan: Work Plan is up-to-date, meets the requirements of 7 CFR 1710, and is prepared in accordance with RUS Bulletin 1724D-101B.

c. Sectionalizing Study: System sectionalizing is reviewed and updated as needed concurrently with each Construction Work Plan and with significant change in fault current conditions.

CONDITIONS NORMALLY NEEDED TO JUSTIFY A RATING OF 3

d. Load Data for Engineering Studies: A completely integrated data base automatically assigns consumers, and their load (kWh or kW) to specific geographical locations that are associated with specific distribution line sections. Data is sufficiently accurate that the difference between the calculated and measured substation kW is less than 5%.

e. Power Requirements Data: Power requirements study is current and completed in compliance with the requirements stated in 7 CFR 1710.

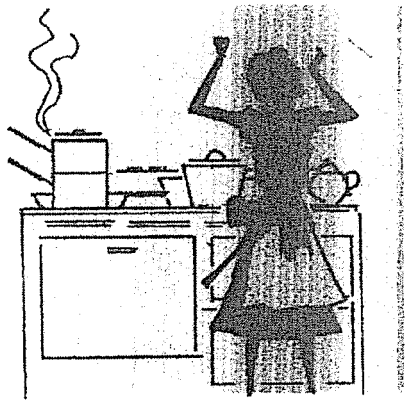
PART IV - OPERATION AND MAINTENANCE BUDGETS

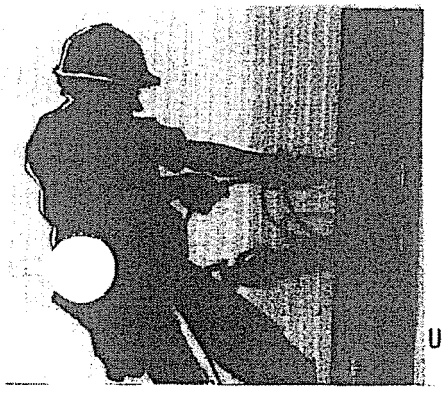
14. Budgeting

Adequacy of Budgets For Needed Work: Utility prepares an annual budget with specific item quantities and dollars prior to the beginning of each year for each department. The O&M budget is broken down to show each program, the quantities of work to be accomplished and the timing during the year when the proposed work is to be performed.

REA BULLETIN 161-1
MARCH 1972

INTERRUPTION REPORTING and SERVICE CONTINUITY STANDARDS for ELECTRIC DISTRIBUTION SYSTEMS





U.S. DEPARTMENT OF AGRICULTURE • RURAL ELECTRIFICATION ADMINISTRATION

FOREWORD

This revised bulletin contains a suggested form for reporting service interruptions, standard names and codes for the causes of interruptions, and standard formats for summarizing experience. These standards were developed from the experience of managers, engineers and operating people on rural electric systems. We urge you to take full advantage of this experience of others in the electric utility industry. Wherever data are collected, results are better and costs are less if people are willing to plan carefully and agree on the kind of information needed and the ways it will be used.

Your attention is invited particularly to the ways of using summaries and reports discussed in this bulletin, including monthly reports to your power supplier about supplier-caused interruptions to service.

We thank those who provided the ideas and comments that are included and hope this information will be helpful to others.

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

March 31, 1972
Supersedes 2/1/56

REA BULLETIN 161-1

SUBJECT: Interruption Reporting and Service Continuity Standards for Electric Distribution Systems

I. Purpose and Scope:

This bulletin provides suggestions on recording and reporting service interruptions (outages) and on the use of interruption records in the operation and maintenance of electric distribution systems. The bulletin does not include discussion of system engineering and design as related to service reliability. The influences of electric system planning, design and sectionalizing are discussed in REA Bulletin 60-7, Service Reliability.

II. General:

A. Purposes of Interruption (Outage) Records. The quality of electric service depends greatly on freedom from significant service interruptions; therefore, knowledge is required about the number and extent of interruptions, their causes, and the steps being taken to improve the continuity of service.

Well-planned procedures for interruption reporting and analysis will improve efficiency in handling trouble calls and responding to them so that the work can be done promptly and with a minimum of wasted motion.

The main purposes of interruption reporting and followup are:

1. To help make certain when a trouble call is received, that all of the information needed for responding to the trouble call will be available.

2. To identify multiple reports from the same line outage in order to expedite work and minimize confusion in storm and disaster situations.

3. To provide a record of causes and extent of interruptions, for determining adequacy of maintenance and for planning system improvements to increase service reliability.

4. To aid in informing consumers and in responding to consumer complaints.

5. To provide information required by power suppliers, public service commissions and REA.

B. Descriptions of Units and Terms:

1. The terms interruption and outage are interchangeable for much of this discussion. Present usage favors interruption when referring to loss of service to consumers, and outage when referring to components of a system. The following definitions are proposed by the IEEE Power System Engineering Committee:

> "Interruption. An interruption is a loss of service to one or more consumers or other facilities and is the result of one or more component outages."
>
> "Outage. An outage describes the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to consumers depending on system configuration."[1]

2. For discussing the quality of service, or service reliability, other terms are needed to define the extent of interruptions:

a. Annual service interruption hours per consumer is the interruption index specified by REA to indicate the average length of time each year that a consumer on the system is without service. The unit for measuring this interruption is the consumer-hour, i.e., the product of the number of affected consumers multiplied by duration of the interruption in hours. The annual service interruption hours per consumer is calculated by adding consumer-hours for all interruptions during the year and dividing the sum by the average number of consumers receiving service during that period. The index may be maintained separately for parts of the system such as substations or service districts, or by causes, but the index for the entire system should always be calculated.

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1. References are listed at the end of the bulletin.

b. Service interruption hours per consumer, "year-to-date" has been found to be helpful in compiling a monthly or quarterly report for comparing with like months of previous years.

c. The number of interruptions experienced during a month, quarter, or year helps to indicate the amount of crew time required for service or maintenance because of outages from particular causes. Some systems maintain records for the cost of restoring service.

III. Interruption Reporting:

A. Reporting Forms. A suggested interruption reporting form is provided in Figure 1. This form may be used as shown, printed on both sides of a card if desired, or adapted as necessary to fit local conditions or individual reporting procedures. The front side of the form may be printed on both sides of a narrow card rather than on the 5-inch by 8-inch card, if desired. The form is designed for entering information in a logical sequence as follows:

1. For the person receiving the call.

2. For the dispatcher or superintendent.

3. For completion, followup, evaluation and review.

Looking at the front of the suggested form, the person receiving the trouble call fills in the top portion but omits the report number. The information in and to the right of the box, through "Location of Cause, if Known," helps in making certain that all of the needed information is obtained at the time of the call. The time of the call is entered following the date, and the "Time Power Went Off," is also taken for use later in calculating duration of the interruption.

The superintendent, operations manager, or dispatcher may enter "Recloser or Tap Location" in the event of a feeder outage. This information will assist in determining number of consumers out of service. At the same time, if more reports are coming in, he can decide which of them are due to the same line outage. This is particularly important during storms when many reports are being received.

The action taken, the time (or times) of restoring service and the material or equipment responsible for the interruption are usually taken from work reports and/or voice reports to the dispatcher.

Figure 1. Interruption Report. This design is for a 5-inch by 8-inch card. It may be divided horizontally for printing on both sides of a narrower card if desired.

INTERRUPTION REPORT

REPORT NO.

DATE | TIME | RECEIVED BY

ACCOUNT NO. | REPORTED BY | PHONE NO. | TIME POWER WENT OFF

ADDRESS

- ☐ SERVICE OFF ENTIRELY
- ☐ NEIGHBORS ALSO OFF
- ☐ SERVICE DROP DOWN
- ☐ LIGHTS DIM
- ☐ CHECKED FUSES

CAUSE, IF KNOWN

LOCATION OF CAUSE, IF KNOWN

RECLOSER OR TAP LOCATION | ASSIGNED TO | TIME | TRUCK NO.

ACTION TAKEN

RESTORED SERVICE TO | TIME | REMARKS

RESTORED SERVICE TO | TIME

RESTORED SERVICE TO | TIME

MATERIAL OR EQUIPMENT; CAUSE OF INTERRUPTION | CODES

REVIEWED BY

Dispatcher | Superintendent | Engineer

Figure 1. (Continued) These checklists are for printing on back of 5-inch by 8-inch card if desired.

Plant Codes *(Material or Equipment) (Check One)*

☐ 00 Power Supplier

Substation *(owned)*
- ☐ 10 Transformer
- ☐ 11 Regulatr. or brkr.
- ☐ 12 Sw. or lgtn. arr.
- ☐ 13 Source fuse
- ☐ 19 Other

Distribution
- ☐ 20 Pole
- ☐ 21 Crossarm or brace
- ☐ 22 Anchor or guy
- ☐ 29 Other fixture

Overhead Line *(Distn.)*
- ☐ 30 Conductor
- ☐ 31 Connector, clamp
- ☐ 32 Splice, deadend
- ☐ 33 Jumper
- ☐ 34 Insulator
- ☐ 35 Ligtng. arrestr.
- ☐ 36 Fuse or cutout
- ☐ 37 OCR or sectzr.
- ☐ 39 Other device

Underground
- ☐ 40 Primary cable
- ☐ 41 Splice, fitting
- ☐ 42 Switch
- ☐ 43 Lgt. arr. for URD
- ☐ 44 Sec. cable or fittings
- ☐ 49 Other

Line Transformer
- ☐ 50 Bad, replaced
- ☐ 51 Fuse or breaker
- ☐ 52 Lightng. arrester

Secondary, Service
- ☐ 60 Wire
- ☐ 61 Meter or loop
- ☐ 62 Security or street light
- ☐ 69 Other

☐ 99 Unknown

Generation or Transmission, if owned:
- ☐ 01 Generation
- ☐ 02 Towers, poles, fixtures
- ☐ 03 Conductors and devices
- ☐ 04 Transmission substation
- ☐ 09 Other

Cause *(Check One)*

☐ 00 Power Supplier

Scheduled
- ☐ 10 Construction
- ☐ 11 Maintenance
- ☐ 19 Other

☐ 20 Major Storm

Equipmt. or Inst.
- ☐ 30 Matl. or equip. fault
- ☐ 31 Install. fault
- ☐ 32 Sag, clearance
- ☐ 39 Other

Age or deterioration
- ☐ 40 Decay
- ☐ 41 Woodpeckers
- ☐ 42 Corrosion
- ☐ 43 Contamination *(leakage)*
- ☐ 44 Moisture
- ☐ 45 Elec. overload
- ☐ 49 Other

Weather
- ☐ 50 Lightning
- ☐ 51 Wind, not trees
- ☐ 52 Ice, not trees
- ☐ 53 Trees and ice
- ☐ 54 Trees, other
- ☐ 59 Other

Birds, Animals
- ☐ 60 Small, cause short circuit
- ☐ 61 Large, forced pole or anchor
- ☐ 69 Other, not woodpeckers

Public
- ☐ 70 Vehicles
- ☐ 71 Aircraft
- ☐ 72 Accidents, other
- ☐ 73 Vandalism
- ☐ 74 Fire
- ☐ 79 Other

☐ 99 Unknown

To calculate the interruption time in consumer-hours, the elapsed time in hours between "Time Power Went Off" and "Service Restored" is multiplied by the number of consumers affected. If service was restored in several steps, the calculations should be made separately and then added together. For example, if a recloser is tripped due to a broken (by gunfire) bushing on a distribution transformer (internally fused), we might have:

Restored service to main line at 3:42 P.M.

Restored service to Joe Black at 6:20 P.M.

If the "Time Power Went Off" was 3:00 P.M., and the line serves 31 consumers including Joe Black, the consumer-hour calculation is:

$$30 \text{ consumers} \times \frac{42}{60} \text{ hour} = 21.00 \text{ consumer-hours}$$

1 consumer x 3 hrs. 20 min. = 3.33 consumer-hours

Total for interruption = 24.33 consumer-hours

Codes shown may be printed on the reverse side of the form if desired. The report number is usually assigned after duplicate reports have been eliminated; it is used for locating, where the reports are filed chronologically, and for chronological listings of interruptions if desired.

Whenever an outage occurs on a feeder, it will be necessary to enter the number of affected consumers on the report form. This will require a record of the number of consumers beyond each sectionalizing point. Provision must be made to keep this information up to date.

B. Filing for Future Reference. The completed reports may be filed in simple chronological order, if the number is small. However, a file according to substation, feeder and sectionalizing point should be considered for systems of average or larger size. It may also be desirable to file individual consumer interruptions by account number, separately from line outages.

The filing arrangement should be carefully selected in light of detailed uses that may be made of the interruption information. Even though the number of reports per year or quarter may be large, many kinds of special evaluations can be made very effectively from the original reports. The burden of detail in summaries and in the data routinely processed may thus be reduced.

C. Interruption Log. A log such as shown in Figure 2 provides an orderly method of entering interruption information as calls are received, if a log is desired. However, some electric superintendents and managers have said they do not use an interruption (or outage) log because the reporting form is all that is needed. Others have radio logs which are adequate for this purpose.

Two cautions against use of the interruption log are:

1. It may represent unnecessary duplication of details that should be on the interruption report instead.

2. It may be taking the place of an interruption or outage summary, yet be poorly designed for that purpose, so that the interruption information is not being used to best advantage.

IV. Causes of the Interruptions: Categories and Codes -

A. Reports to REA. Borrowers are asked to report on REA Forms 7a[2] and 300[3] the average annual interruption hours per consumer due to causes in each of four major categories:

Power supplier

Major storm

Scheduled

All other

"Scheduled," for this purpose, refers to interruptions resulting when a distribution transformer, line or owned substation is deliberately taken out of service at a selected time for maintenance or other reasons. The interruptions resulting from either scheduled or unscheduled outages on lines or substations owned by the power supplier are charged to "power supplier."

"Major storm" represents service interruptions from conditions which cause many concurrent outages because of snow, ice or wind loads that exceed design assumptions for the lines.

Most service interruptions are for reasons in the category, "All other." These are the ones resulting from emergency conditions due to equipment breakdown, malfunction, or human error.

Figure 2. Interruption Log

_____ Month _____ Year

Report No.	Date	Time	Received By	Reported		Truck No.	Cause	Location Of Cause
				By	Phone No.			

B. Standard Codes for Interruption Analysis. The detailed categories for service interruptions, Tables 1 and 2 of this bulletin, have been carefully selected so that the important ones may be clearly seen when the interruption data are summarized. Numerical codes are assigned. These are recommended for use as standard codes for data processing.

To avoid excessive detail, the number of individual reasons (codes) has been kept to a minimum. In addition, they are arranged in groups -- nine for "Equipment or Material Responsible for Interruption" and nine for "Cause of Interruption." The two codes for equipment or material and cause are designed so that together they will provide the needed information about reasons for the interruption.

The importance of keeping detail to a minimum can hardly be overemphasized. When comparisons are to be made, such as between substation areas or feeders, sometimes on a quarterly or month-by-month basis, how much detail do you really want? When additional detail is needed for a special study, it is generally best to go back to the original reports for more information.

Additional detail codes or even group codes may be assigned to allow for circumstances that are particularly important in a geographic area or in a particular electric system. Users are urged to keep such codes to the absolute minimum.

C. Special Studies. Interruption reports may be a valuable source of information about performance of transformers or other equipment, or about soil or terrain conditions that have important effects on maintenance costs or quality of service. Such details may be summarized from the original reports as needed. However, it is generally a mistake to design any general plan of interruption analysis to encompass such detail. The resulting procedures and reports become cumbersome and costly and too often fail to accomplish the primary purposes of interruption analysis.

V. Interruption Experience: Summaries and Reports

A. For Operation and Maintenance. Tables 3, 4 and 5 show suggested ways to summarize interruption experience for purposes of electric system operation and maintenance.

1. Table 3 shows comparisons of experience in individual substation areas, in terms of the number of interruptions (service calls) and summations of consumer-hours (the number of consumers multiplied by hours) representing the time that consumers were without electric

Table 1. Equipment or Material Responsible for Interruption

Code	Description	Items in Acct. No.
00	Power Supplier	
	Generation or Transmission (If Owned)	
01	Generation	
02	Towers, poles and fixtures	354, 355
03	Conductors and devices	356-358
04	Transmission substations	353
09	Generation or transmission, other	
	Distribution Substation (Owned)	362
10	Transformer	
11	Voltage regulator or breaker	
12	Lightning arrester or switch	
13	Source side fuse	
19	Other	
	Poles and Fixtures, Distribution	364
20	Pole	
21	Crossarm or crossarm brace	
22	Anchor or guy	
29	Other	
	Overhead Line Conductors and Devices, Distribution	365
30	Line conductor	
31	Connector or clamp	
32	Splice or deadend	
33	Jumper	
34	Insulator	
35	Lightning arrester, line	
36	Fuse cutout (damaged, malfunction or maintenance)	
37	OCR or sectionalizer (damage malfunction or maintenance)	
39	Overhead distribution line, other	
	Underground Conductor or Devices, Distribution	366, 367
40	Primary cable	
41	Splice or fitting	
42	Switch	
43	Lightning arrester for URD	
44	Secondary cable or fittings	
49	Underground, other	
	Line Transformer	368
50	Transformer bad, replaced	
51	Transformer fuse or breaker, refused or reset	
52	Transformer lightning arrester	
	Secondaries and Services	369, 370
60	Secondary or service conductor	
61	Meter or meter loop	
62	Security light or street light	
69	Other	
	Unknown	
99	Open OCR, sectionalizer or fuse, source of difficulty not known	

Table 2. Cause of Interruption

Code	Description
00	Power Supplier
	Scheduled
10	Construction
11	Maintenance
19	Other
20	Major Storm Disaster
	Equipment or Installation
30	Material or equipment fault
31	Installation fault
32	Conductor sag or clearance not adequate
39	Faulty material or installation, other
	Age or Deterioration
40	Decay
41	Woodpeckers
42	Corrosion or abrasion
43	Contamination (leakage)
44	Moisture
45	Electrical overload
49	Age or deterioration, other
	Weather
50	Lightning
51	Wind, not trees
52	Ice, sleet, frost, not trees
53	Trees and ice
54	Trees, other
59	Weather, other
	Birds or Animals
60	Small animal or birds (short circuit)
61	Large animals (affecting pole or guy)
69	Birds or animals, other (not woodpeckers)
	Member (or Public)
70	Vehicles or machinery
71	Aircraft
72	Public accidents, other
73	Vandalism
74	Fire
79	Activities of the public, other
	Unknown
99	Cause of interruption not known

Table 3. Interruptions Due to Each Cause -- November 1971

Substation and Cause	This Month Number	This Month Consumer-Hours	Year-to-Date Number	Year-to-Date Consumer-Hours
North Fork				
Power supplier	0	0	6	670.5
Scheduled	3	1.8	6	6.9
Major storm	0	0	35	1803.6
Unscheduled, other:				
Equipment or installation	0	0	15	63.1
Age	3	15.2	18	71.4
Weather	2	10.8	9	34.7
Birds or animals	1	6.2	6	62.1
Public	3	4.8	3	6.9
Unknown	3	3.5	33	22.8
Subtotal (Unscheduled)	12	40.5	84	261.0
Substation Total	15	42.3	131	2742.0
Wideawake				
Power supplier	1	556.2	4	1710.7
Scheduled	3	7.5	8	27.6
Major storm	1	401.8	2	842.3
Unscheduled, other:				
Equipment or installation	3	29.2	4	11.5
Age	0	0	12	142.6
Weather	0	0	15	73.2
Birds or animals	1	5.2	4	21.6
Public	2	20.4	2	8.1
Unknown	3	3.6	32	43.6
Subtotal (Unscheduled)	9	58.4	69	300.6
Substation Total	14	1023.9	83	2881.2
(Other substations follow)				
Total, entire system	104	1342.6	749	19681.2

Consumers served: 5,256 (average, 11 mo.)

Average hours interrupted: 3.74 (year-to-date)

service. This information is given separately for each major cause as shown in Table 2, for each substation service area. The example shows a monthly summary form. For small electric systems with relatively few interruptions, a quarterly summary may be preferable.

2. Table 4 gives details about the material or equipment items that were responsible for interruptions, using the same items that are shown on the code list, Table 1. For each item, the consumer-hour figures may be shown separately for each major cause of interruption as shown in columns across the page. For small systems, a quarterly summary may be preferable to the monthly one shown. Other variations of this summary may be desirable, depending on circumstances:

   a. A separate summary for a month or quarter, excluding previous experience in the same year, may be preferred.

   b. The number of interruptions (as well as consumer-hours) as shown in Table 3 may be desirable, in the first column (All Causes) or in all columns.

3. Table 5 gives additional details about causes of interruptions, using the same causes as are listed in the code list of Table 2. The information is further broken down according to major equipment or material items responsible, in a format like that of Table 4.

4. While not recommended for general use, other types of reports have been used to advantage and may be desirable in some situations:

   a. A report of the largest total hours on interruption for an individual consumer or line section. This might be a tabulation with one line per line section, distributed according to cause (group codes, only), including line sections with more than 10 hours (or some other specified number) of total interruption time during the year.

   b. A report of the elapsed time between the time of interruption and the time of the trouble report. This might be tabulated, one line per "Cause" category on nine lines distributed according to equipment or material category (nine columns).

Table 4. Interruptions Due to Material Items -- Year through December 1971

	Equipment or Material	All	Power Supplier 00	Scheduled 10-19	Major Storm 20	Equip. or Installation 30-39	Age 40-49	Weather 50-59	Birds & Animals 60-69	Member or Public 70-79	Unknown 99
						(Consumer Hours)					
00	Power Supplier	1580.0	1580.0								
	Generation & Transmission (Owned)										
01	Generation										
02	Tower or pole	780.9		66.1	294.3	92.4	58.0	108.6		133.7	27.8
03	Conductor	797.3		93.6	262.6	68.2	8.5	163.7	56.8	115.4	28.5
04	Substation	744.4		28.2	257.0	69.0	76.5	194.2	38.4	56.1	25.0
09	Other	479.0		8.4	280.1	51.5	16.3	78.3	3.4	23.9	17.1
	Subtotal	2801.6		196.3	1094.0	281.1	159.3	544.8	98.6	329.1	98.4
	Distribution Substation (Owned)										
10	Transformer	1147.1		328.0	184.2	181.6		163.5		171.3	118.5
11	Regulator or Breaker	503.9		211.8		58.4	18.9	91.1	48.9	22.6	52.2
12	Switch or Arrester	82.9		19.2	9.4	8.0	21.4	7.2		9.1	8.6
13	Source Fuse	132.7		67.6		37.1				14.2	13.8
19	Other	275.9		147.9		27.2	28.1			44.2	28.5
	Subtotal	2142.5		774.5	193.6	312.3	68.4	261.8	48.9	261.4	221.6
	Poles & Fixtures (Distribution)										
20	Pole	2969.8		374.2	1232.6	309.4	191.0	518.7	77.9	93.0	173.0
21	Crossarm or Brace	1086.7		196.8	513.3	77.9	63.3	172.1			63.3
22	Anchor or Guy	1016.9		109.4	222.5	189.0	56.1	228.2	77.5	75.0	59.2
29	Other	344.4		67.9	94.5	42.1	13.3	29.6	26.7	50.5	19.8
	Subtotal	5417.8		748.3	2062.9	618.4	323.7	948.6	182.1	218.5	315.3
	Overhead Conductor & Devices (Distribution)										
30	Line Conductor	2459.4		305.1	1048.7	122.2	13.8	421.3		437.6	110.7
31	Clasp, Conductor	455.4		124.0	173.6	28.7		97.5	11.0		20.6
32	Splice, Deadend	469.1		62.8	217.8	47.8	7.2	88.6		23.8	21.1
33	Jumper	290.7		54.7	83.5	22.5		63.3	16.2	37.4	13.1
34	Insulator	981.9		216.5	236.7	83.7	13.6	85.4	23.7	278.0	44.3
35	Lightning Arrester	633.8		68.9	257.1	42.1		102.6	27.2	107.4	28.5
36	Fuse Cutout	943.1		127.7	415.9	126.8		157.8	33.5	38.9	42.5
37	OCR, Sectionalizer	481.0		68.3				113.7	74.6	202.8	21.6
39	Other	726.9		67.6	229.1	10.0	16.9	59.8	1.5	307.7	32.3
	Subtotal	7441.3		1095.6	2662.4	483.8	51.5	1190.0	189.7	1433.6	334.7
	Underground, Conductor or Devices										
40	Primary Cable	402.8		39.7		72.8		38.1	26.6	116.8	108.8
41	Splice or Fitting	99.8		7.1		13.4		23.3			56.0
42	Switch	53.1		11.4		9.6					32.1
43	Lightning Arrester	175.9		13.2		20.8		80.5	9.3	32.3	19.8
44	Secondary Cable or Fittings	188.5		9.7		53.6		55.0	13.3	30.6	26.3
49	Other	129.7		7.1		21.4		14.4			86.8
	Subtotal	1049.8		88.2		191.6		211.3	49.2	179.7	329.8
	Line Transformer										
50	Transformer Bad	1169.4		73.8	15.9	136.2	210.6	139.8	133.3	84.5	375.3
51	Transformer Fuse or Breaker	251.6		12.9	27.8			116.5	28.2	9.3	60.9
52	Transformer Lightning Arrester	552.3		5.6	119.0	27.2	25.9	208.9	26.6	21.9	117.2
	Subtotal	1973.3		92.3	158.7	163.4	236.5	465.2	188.1	115.7	553.4
	Secondaries and Services										
60	Secondary or Service Conductor	806.9		41.9	109.8	53.2	34.4	206.1	19.8	77.2	264.5
61	Meter or Meter Loop	403.5		37.8	14.5	26.4	23.5	79.7	37.6	37.8	146.2
62	Security or Street Light	338.9		19.9	17.7	45.7	42.6	72.9	41.5	58.3	40.3
69	Other	154.3			19.2	13.4	11.8	41.7		15.6	52.6
	Subtotal	1703.6		99.6	161.2	138.7	112.3	400.4	98.9	188.9	503.6
	Total	24109.9	1580.0	3094.8	5332.8	2189.1	951.7	4022.1	855.2	2726.9	2356.8

Table 5. Interruptions Due to Each Detailed Cause -- Year through December 1971

	Cause	All	Equipment or Material Responsible: Power Supplier 00	Gen. and Trahsm. 01-09	Substation 10-19	Pole, Fixture 20-29	Overhead Line 30-39	Underground 40-49	Line Transformer 50-52	Secondary, Service 60-69
		(Consumer Hours)								
00	Power Supplier	1580.0	1580.0							
	Scheduled									
10	Construction	1455.7		37.2	324.1	326.7	643.8	49.2	41.6	33.1
11	Maintenance	1258.6		98.4	394.0	298.4	341.5	32.3	35.6	58.4
19	Other	380.5		60.7	56.4	123.2	110.3	6.7	15.1	8.1
	Subtotal	3094.8		196.3	774.5	748.3	1095.6	88.2	92.3	99.6
20	Major Storm	6332.8		1094.0	193.6	2062.9	2662.4		158.7	161.2
	Equipment or Installation									
30	Material or Equipment Fault	956.9		86.7	165.7	328.0	166.1	96.4	57.2	56.8
31	Installation Fault	769.1		72.8	96.6	235.3	142.2	83.3	86.2	52.7
32	Conductor Sag or Clearance	214.2		42.1	21.9		113.9		11.4	24.9
39	Other	238.0		78.4	28.1	55.1	51.6	11.9	8.6	4.3
	Subtotal	2189.3		281.1	312.3	618.4	483.8	191.6	163.4	138.7
	Age or Deterioration									
40	Decay	138.9		40.4		98.5				
41	Woodpeckers	156.5		30.3		90.6			35.6	
42	Corrosion or Abrasion	167.0		20.7	12.3	35.6	20.1		41.6	36.7
43	Contamination	75.3		11.5	11.6		14.4		37.8	
44	Moisture	211.0		31.9	15.7	76.4	7.2		47.3	32.5
45	Electrical Overload	126.3		19.1	22.6		4.1		56.7	23.8
49	Other	76.7		5.4	6.2	22.6	5.7		17.5	19.3
	Subtotal	951.7		159.3	68.4	323.7	51.5		236.5	112.3
	Weather									
50	Lightning	1213.8		59.8	188.0	170.6	369.1	188.4	153.8	84.1
51	Wind, Not Trees	479.9		54.5	39.2	151.6	130.0		60.6	44.0
52	Ice, Sleet, Frost	1117.0		316.2	34.6	303.7	286.1		65.2	111.2
53	Trees and Ice	534.7		38.4		113.8	202.2		88.5	91.8
54	Trees, Other	424.2		43.5		116.7	129.7		74.4	59.9
59	Other	252.5		32.4		92.2	72.9	22.9	22.7	9.4
	Subtotal	4022.1		544.8	261.8	948.6	1190.0	211.3	465.2	400.4
	Birds or Animals									
60	Small Animals or Birds	497.0		46.5	43.3	52.7	96.8	38.6	143.7	75.4
61	Large Animals	173.9		20.6		90.8	62.5			
69	Other	184.6		31.5	5.6	38.6	30.4	10.6	44.4	23.5
	Subtotal	855.5		98.6	48.9	182.1	189.7	49.2	188.1	98.9
	Member (or Public)									
70	Vehicles or Machinery	612.9		82.1	66.3	61.3	272.6	81.7	17.4	11.5
71	Aircraft	237.4		59.2			178.2			
72	Public Accidents, Other	540.3		76.4	20.9	116.0	284.2		22.0	20.8
73	Vandalism	690.7		46.0	125.4	24.1	331.4	98.0	3.5	62.3
74	Fire	449.1		29.2	28.8	10.9	215.3		70.6	94.3
79	Other	196.5		36.2		6.2	151.9		2.2	
	Subtotal	2726.9		329.1	261.4	218.5	1433.6	179.7	115.7	188.9
99	Unknown	2356.8		98.4	221.6	315.3	334.7	329.8	553.4	503.6
	Total	24109.9	1580.0	2801.6	2142.5	5417.8	7441.3	1049.8	1973.3	1703.6

Table 6. Interruption Summary

For Month of _____
Year _____

	Power Supplier	Major Storm	Sched-uled	All Other	Total
Number of Interruptions:					
This month					
This month last year					
This year to date					
Last year to this date					
Consumer-hours Interruption:					
This month					
This month last year					
This year to date					
Last year to this date					
Average Hours per Consumer:					
This month					
This month last year					
This year to date					
Last year to this date					

Data for Computing Average Hours per Consumer:

Number of Consumers Served this Month: _____

Average Number of Consumers This Year to Date: _____

c. A report of the longest individual interruptions during the year. This could be a listing, one line per interruption distributed according to "Cause" category (nine columns), for interruptions of more than five hours or some other specified length of time.

B. For Directors and Members. Table 6, Interruption Summary, brings together the information most needed by the manager, the board of directors, and REA. This information can and should be prepared by hand from the other reports. This is easily done, and the use of data processing equipment for the report shown on Table 6 would be uneconomical. Newsletter reports to members also should not be forgotten. Emphasis might be upon interruptions influenced by activities of the public (see Table 2), on the results of delay in reporting that service is off, or on the progress being made in improving the quality of service. Newsletters or postcards may be used to notify consumers about scheduled interruptions.

C. For Power Suppliers and Regulatory Bodies. A report giving the data specified in Table 7 should be sent each month to each power supplier (and regulatory bodies as required), including all delivery points, along with indications of no interruption when applicable. If the power is delivered through the facilities of a party other than the power supplier, reports to both may be desirable. The information in Table 7 is required by REA power-type borrowers for a monthly report (Form 12g4) to REA. For other power suppliers, the information outlined in Table 7 will serve as a regular reminder of the reliability of service being provided and the need for improvement when experience so indicates.

Table 7. Interruption Report to Power Supplier

For Month of _____
Year _____

Delivery Point	Interruption Time		Date	Time	
	Hours	No. of Consumers Affected		Off	Restored

VI. Service Continuity Objectives:

Every electric system should be providing the best service available. To do this, standards or goals are needed to establish the level of service reliability considered necessary to meet consumers' needs. This is true even though there may be wide variations in the levels that are feasible for particular systems.

Electric utilities in largely urban areas tend to aim at one hour or less service interruption per year for the average urban consumer and two hours or less for the average rural consumer. However, many rural electric systems would have difficulty meeting such goals because of longer lines, severe environmental conditions, and more frequent interruptions of power supply.

The present REA criteria for rural distribution systems are shown in Table 8.[3]

Systems that are well engineered and have experienced favorable weather during the year should expect considerably less than five consumer hours per consumer during the year. Conversely, in some situations it may not be possible to achieve the figure of five consumer hours per consumer per year.

Table 8. REA Service Reliability Criteria for Rural Electric Distribution Systems

Description	Average Service Interruption Consumer-Hours per Consumer per Year
Satisfactory	5 or less
Should be explained	More than 5

The significance of a high interruption hour figure will depend on circumstances. For example, long interruptions may result from severe ice or wind loads, or excessive interruptions may be due to trees, lightning or scheduled outages showing the need for corrective measures or different work procedures. When the satisfactory level is exceeded, management should examine the causes, consider the ways available to prevent the excessive interruptions and develop time, work, and cost schedules for future corrective action.

Assistant Administrator - Electric

REFERENCES

1. IEEE Power System Engineering Committee Report, "Definitions of Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service" May 1971

2. REA Bulletin 108-1, Electric Distribution Borrowers' Financial and Statistical Reports

3. REA Bulletin 161-5, System Operation and Maintenance Review and Evaluation

4. REA Bulletin 108-2, Operating Report -- Power Supply Borrowers and Distribution Borrowers with Generating Facilities

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 7

RESPONSIBLE PARTY: Tony Wells

REQUEST 7. Provide and describe in detail any service restoration or outage response procedure utilized.

RESPONSE 7. A copy of Farmers "Service Restoration Plan" is attached.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

ADMINISTRATIVE POLICIES AND PROCEDURES

"SERVICE RESTORATION PLAN" NO. A002

I. PURPOSE:

To insure the most orderly, efficient and safest continuity of electrical service to consumers and the safest environment to the public and workers in case of damage to electric facilities.

II. STATEMENT OF INTENT:

This document is meant to serve as a guide in restoration of electric service due to damage which might be incurred during severe weather, such as ice and wind storms or other acts of God and the unpredictable negative acts of men such as sabotage. However, it must be understood that the infinite number of variables involved in natural and manmade disasters can never be completely accounted for in any document of this nature; thus, flexibility in actual procedures must be afforded managers and supervisors as they go about the tasks outlined in this document.

III. DETERMINATION OF LEVEL OF INVOLVEMENT:

1. What is the number of consumers involved?

2. What is the number of circuits involved?

3. What is the level of priority for the affected circuits?

   A. Hospital and other emergency operations.
   B. Consumers with health priorities.
   C. Substation transmission lines and main feeder lines.
   D. All others.

IV. DETERMINATION OF WORK CREWS:

Determining the level of involvement will indicate the workforce needed to restore service.

Level 1 - Normal service restoration - regularly scheduled on-call crew.

Level 2 - Include level 1 plus additional off-duty or priorly assigned crews to be directed in the

assistance of service crew.

Level 3 - Request assistance of outside work crews through the activation of statewide emergency work plan.

V. SERVICE RESTORATION PROCEDURE:

Upon notification of service interruption or report of a hazardous condition to the on-duty dispatcher, a request will be made.

Upon arrival at the source of the service interruption, the service crew will determine whether restoration can be completed or a larger, better equipped workforce will be required, and a request will be made of the appropriate operations supervisor who will in turn determine the level of response to be initiated. In all cases, communication will take place before restoration begins.

VI. EXTRAORDINARY OUTAGE CONDITIONS:

Upon receiving indications of more service outages than available manpower will allow, a timely response to determine the degree of hazard or work required for repairs will be made by dispatching one or more operations supervisors to survey outage conditions.

Operations supervisors on survey duty:

1. Will establish level of priority.
2. Estimate manpower and equipment requirements.
3. Estimate time of repairs.
4. Determine safety requirements for area (will flagman or guard be needed until work crews arrive?)
5. Disconnect service, to ensure safety, as appropriate.

All survey duty personnel will report time, manpower and equipment estimates/request to one central operations manager.

All extraordinary outage conditions will be reported to:

Kentucky Public Service Commission
(502) 564-3940 FAX (502) 564-1582

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

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RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 8

RESPONSIBLE PARTY: Jerry Carter

REQUEST 8. Refer to RUS drawing M1.30G "RIGHT-OF-WAY CLEARING GUIDE" ("ROW Guide"), a copy has been provided in Appendix A.

REQUEST 8a. Is this type of clearance requirement appropriate for all areas of a distribution system? If not, what types of exclusions or exceptions should be made?

RESPONSE 8a. No. Drawing M1.30G reflects a clear-cut approach which is impractical and unachievable in most developed areas.

REQUEST 8b. If the distribution utility is not already following this guide, provide an estimate of the cost and time-line to implement?

RESPONSE 8b. Farmers believes that strict adherence to drawing M1.30G is impractical and unachievable in most developed areas. Regardless of the amount of money devoted to meeting this guide, Farmers does not believe it could be achieved.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

PSC ADMINISTRATIVE CASE NO. 2006-00494

AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 9

RESPONSIBLE PARTY: Jerry Carter & Tony Wells

REQUEST 9. Refer to North American Electric Reliability Corporation ("NERC") standard FAC-003-1 "Transmission Vegetation Management Program" ("NERC Standard"), a copy is attached in Appendix B.

REQUEST 9a. Does the company prefer the type of standard described in the NERC Standard over the type of standard described in the ROW Guide? Explain why you prefer one over the other.

RESPONSE 9a. Farmers believes that both standards fail to adequately take into account the varying conditions found on distribution systems. Therefore, Farmers does not prefer one standard over the other.

REQUEST 9b. Refer to section R3 of the NERC Standard and substitute "distribution" for "transmission." Is the distribution utility capable of meeting the reporting requirements described in the section? If not, why not?

RESPONSE 9b. Yes.

REQUEST 9c. Again referring to section R3 as applied to distribution, how many sustained outages would be reportable for the calendar year 2006?

RESPONSE 9c. This information is not attainable.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

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RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 10

RESPONSIBLE PARTY: Tony Wells

REQUEST 10. Provide and discuss any right-of-way maintenance standard which is preferable to those identified in questions 1 (sic) and 2 (sic) above.

RESPONSE 10. Farmers assumes that this request refers to questions 8 and 9. Farmers is unaware of any right-of-way maintenance standard that adequately addresses the conditions typically encountered in operating and maintaining a distribution system.

FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION

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RESPONSE TO COMMISSION'S SECOND DATA REQUEST DATED FEBRUARY 9, 2007

REQUEST 20

RESPONSIBLE PARTY: Tony Wells

REQUEST 20. Can Farmers monitor System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") in addition to Customer Average Interruption Duration Index ("CAIDI")?

RESPONSE 20. Yes.