UNITED STATES

DEPARTMENT OF AGRICULTURE

RURAL UTILITIES SERVICE

SUMMARY OF

ITEMS OF ENGINEERING INTEREST

AUGUST 1998

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ABBREVIATIONS

AIM	Annual Isokeraunic Map
AEIC	Association of Electric Illuminating Companies
ANSI	American National Standards Institute
APLIC	Avian Power Line Interaction Committee
ASCE	American Society of Civil Engineers
BIL	Basic Impulse Level
CFR	Code of Federal Regulations
CITCEM	Commercial and Industrial Transformer Cost Evaluation Model
CRN	Cooperative Research Network
DTCEM	Distribution Transformer Cost Evaluation Model
EEI	Edison Electric Institute
EPA	Environmental Protection Agency
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ESD	Electric Staff Division
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilovolt
MVA	Megavolt-Ampere
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NRECA	National Rural Electric Cooperative Association
O&M	Operation and Maintenance
OSHA	Occupational Safety and Health Act
REA	Rural Electrification Administration
RER	Rural Electric Research
RSM	Rolling Sphere Method
RUS	Rural Utilities Service
RUS List of Materials	RUS Informational Publication 202-1, “List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers”
SCADA	System Control and Data Acquisition
T&D	Transmission & Distribution
TOC	Total Owning Cost
TR-XLPE	Tree-Retardant Cross-Linked Polyethylene
Western	Western Area Power Administration
XLP	Cross-Linked Polyethylene

ENGINEERING and DESIGN

7 CFR 1724 - Electric Engineering, Architectural Services and Design Policies and Procedures

The Rural Utilities Service (RUS) is pleased to announce the publication of its final rule on "Electric Engineering, Architectural Services and Design Policies and Procedures," 7 CFR 1724. This rule simplifies and codifies RUS policy and procedures to be followed by electric borrowers relating to architectural and engineering services. This rule also simplifies and codifies RUS requirements for the planning and design of electric distribution, transmission, and generation systems and facilities owned by RUS borrowers. This rule was published in the Federal Register on June 29, 1998. The effective date of this rule is July 29, 1998. These policies and procedures are presently contained in seven RUS bulletins, which will be rescinded after this regulation becomes effective. The bulletins replaced include:

- Bulletin 41-1, Engineering Services for Electric Borrowers
- Bulletin 42-1, Architectural Services for Electric Borrowers
- Five other bulletins (Bulletins 60-1, 60-2, 80-11, 81-9, and 86-2)

Some of the key provisions in this rule are:

Architectural Services

A. All borrower buildings must meet certain requirements regarding seismic safety and accessibility to persons with physical handicaps.

B. RUS Form 220, Architectural Services Contract, must be used for RUS financed projects. RUS approval of the contract is not required.

Engineering Services

A. RUS standard forms of engineering services contracts must be used for all RUS financed projects.

1. RUS Form 236, Engineering Service Contract - Electric System Design and Construction, must be used for all distribution, transmission, substation, and communications and control projects. RUS approval of the contract is not required.

2. RUS Form 211, Engineering Service Contract for the Design and Construction of a Generating Plant, must be used for all new generating units and repowering of existing units. These contracts require RUS approval.

B. All field inspection must be performed by a licensed engineer (or under the direct supervision of a licensed engineer) and performed within 6 months of the completion of construction. Each work order that was field inspected must be indicated on the inventory of work orders, which must be certified.

Electric System Design

A. Regardless of the source of funding, all borrowers must ensure that its electric system is designed, constructed, operated, and maintained in accordance with the NESC.

B. All distribution facilities must conform to the applicable RUS construction standards and utilize RUS accepted materials.

C. All transmission line and substation design data must be approved by RUS. A borrower may use previously approved design data for new projects without further RUS approval.

D. For all new generation units and for all repowering projects, the Design Manual, as described in RUS Form 211, must be approved by RUS.

E. The performance considerations for a new or replacement SCADA master system must be approved by RUS.

F. RUS approval of plans and specifications is required only for RUS financed projects.

1. Plans and specifications for any contract requiring RUS approval (in accordance with 7 CFR 1726) must be approved by RUS.
2. Drawings, plans, and specifications for standard distribution construction do not need to be approved by RUS.
3. Plans and specifications for transmission and substation construction projects which are based on approved design data and use standard structures do not need to be approved by RUS.
4. Plans and specifications for buildings must be approved by RUS.
5. The terms and conditions for generating plant equipment or construction contracts costing $1,500,000 or more must be approved by RUS.
6. The terms and conditions for SCADA contracts costing $500,000 or more must be approved by RUS.

G. For high hazard dams, borrowers must have an independent review of critical design and construction features.

The major changes from the previous requirements include:

- Eliminates the requirement that RUS approve the borrower's selection of the architect and of the engineer.

- Eliminates the requirement that RUS approve architectural services contracts and distribution and transmission engineering services contracts for all facilities, and generation engineering services contracts if the facilities are not financed by RUS.

- Eliminates the requirement that RUS approve closeout of architectural or engineering services contracts.

- Eliminates the requirement for submittal of progress reports to RUS for facilities not financed by RUS.

- Eliminates the requirement that RUS approve many plans and specifications. However, many requirements, such the NESC, OSHA, building accessibility standards, RUS standards, specifications, and use of acceptable materials, etc., apply regardless of RUS involvement.

- Allows design data that have been approved by RUS for other projects to be used for new facilities without further approval.

- Simplifies and clarifies RUS requirements regarding system design.

- Consolidates 7 bulletins and 3 contracting forms into one document.

If you would like more information or have any questions, please call Fred Gatchell, Deputy Director, ESD, at (202) 720-1398.

High Resistance Ground Fault Impedance Levels

The National Rural Electric Cooperative Association (NRECA), through its Cooperative Research Network (CRN), formerly the Rural Electric Research (RER) program, recently commissioned a study on the use of 40-ohm ground-fault impedance in calculating the minimum phase-to-ground fault currents on distribution systems. The study was completed by Clapp Research Associates, P.C., in mid-1997.

The study documents that the use of 40 ohms in the calculation of minimum fault levels is widely used in the industry, however, this is mainly because of the conditions set forth in RUS Bulletin 61-2, "Guide for Making a Sectionalizing Study on Rural Electric Systems." The study documented very clearly that non-cooperative utilities typically utilize levels of impedance much less than 40 ohms.

Electric distribution cooperatives using the 12.47/7.2 kV grounded-wye distribution voltage level, often experience main feeder tap load currents greater than 70 amperes. Larger single-phase reclosers are then required resulting in pickup levels that exceed calculated minimums based on 40 ohms. With a phase-to-ground voltage of 7200 volts and 40 ohm high resistance fault, the minimum fault current is calculated to be 180 amperes (*i.e.*, 7200/40). One can see that a 100-ampere size recloser with a 200-ampere pickup level will not cover the calculated minimum. This is the dilemma that must be addressed.

Single-phase reclosers work very well on rural distribution systems. Rural cooperatives do not have three-phase loads in much of their service areas and the use of single phase protection devices allows cooperatives to maintain service to a majority of the consumers on a feeder for single phase-to-ground faulted conditions. If three-phase reclosers are utilized with separate ground fault detection capability, the entire three-phase line will experience an outage, the result of which is poorer system reliability, more inconvenience to consumers, etc.

The NRECA T&D System Protection Subcommittee, working with RUS, has reviewed the CRN study and feels a change may be warranted from the "40-ohm" method. The review team believes that a "30-ohm" level appears to be a reasonable and acceptable level for calculating the minimum ground fault levels on a system, and perhaps should be used. The 30 ohm level results in a close-in minimum fault of 240 amperes for a 12.47/7.2 kV system (*i.e.*, 7200/30). Such a change should eliminate most of the problems outlined above regarding tap loads exceeding 70 amperes on 12.47/7.2 kV systems.

It is further felt by the committee that this is not in contradiction with the recommendations in RUS Bulletin 61-2 since it allows for the use of 30-ohms for substations with banks greater than 5.0 MVA in size or with feeders that are serving urban type loads.

If you would like more information or have any questions, please call Harvey Bowles, Chief, Distribution Branch, at (202) 720-5082.

Steel Distribution Pole Design – Raptor Electrocution Prevention

Some borrowers are utilizing steel pole structures in the construction of new distribution lines. RUS is presently approving borrowers' requests to use steel distribution poles on a case-by-case basis. One of the guidelines RUS uses when considering a request concerns adequate raptor electrocution prevention mitigation. The borrower is asked to:

- Provide a statement regarding the anticipated impact that the pole-top assembly design may have on the possible electrocution of raptors, and

- State the mitigation measures that will be incorporated in the design to minimize such possibilities.

Distribution lines using steel pole construction with standard pole top configurations can reduce phase-to-ground clearances. These reduced clearances can pose as an electrocution hazard for perching raptors. Richard Harness, in a paper presented at the 1998 IEEE Conference in Dallas, Texas, suggested several solutions to mitigate this potential problem. One standard solution currently employed to increase phase-to-ground separation is to increase the center-phase separation from the top of the steel pole by using a pole top pin employing a pultruded solid fiberglass rod. However, this modification allows large raptors to perch on the pole top and bridge the gap between the pole top and the center phase wire. Modifying the structure by the addition of a plastic end cap may discourage birds from perching on the pole top and help alleviate possible hazards to the birds.

Harness suggested that reduced phase-to-ground separations and higher voltage gradient exposure can be mitigated by wrapping the pole with a band of thermoplastic wrap above the crossarm. Perch guards can be also be used on the crossarms to keep raptors away from the poles. In place of the thermoplastic wrap and perch guards, Caddis bird guards can be employed. Non-conducting wood or fiberglass crossarms should always be used.

Utilities should review design tolerances on all structures to ensure that there are adequate clearances for birds and animals that traditionally use utility structures. Incorporating new designs before construction is preferable to costly retrofits. Mr. Harness is continuing to work with pole manufactures to identify new mitigation that will minimize raptor electrocution.

If you would like more information or have any questions, please call Dennis Rankin, Environmental Protection Specialist, Engineering and Environmental Staff at (202) 720-1953, E-mail: drankin@rus.usda.gov, or Richard Harness of Electrical Systems Consultants at (970) 224-9100, E-mail: harness@electsys.com.

Update on EPA's DTCEM Program Development

The latest Distribution Transformer Cost Evaluation Model (DTCEM) Ver. 1.4, developed by the U.S. Environmental Protection Agency (EPA), is under revision. This revision came about as a result of the software evaluation effort of NRECA's T&D System Planning Subcommittee and RUS. Errors in the program have been identified, particularly in the coded formulas of the program. These errors are to be corrected as part of the revision.

The DTCEM computer program is intended to help electric utilities in the United States evaluate the cost-effectiveness and efficiency of distribution transformers to be purchased. EPA has recognized the importance and benefits of the use of efficient transformers by electric utilities to air emission control and environmental protection in general. Hence, EPA is focusing major efforts and resources in making the DTCEM program usable and more user friendly. For this effort, EPA has retained the services of GDS Associates, Inc. (Engineers and Consultants), The Cadmus Group, Inc., and ICF Kaiser Consulting Group.

The approach to engineering economic evaluation of distribution transformers used in the DTCEM is based on present-worth or equivalent first cost analysis. In this approach the Total Owning Cost (TOC) is calculated by adding the present transformer cost or bid price and the levelized annual costs of transformer losses (core and winding loses,) all converted to their present-worth values.

The DTCEM general equation for calculating TOC is:

$$TOC = BP + CCL + CWL$$

where BP = Bid Price (present cost to acquire the transformer)
CCL = Cost of Core Losses (present worth of annual cost of core losses over a period)
CWL = Cost of Winding Losses (present worth of annual cost of winding losses over a period)

and CCL = (1 + LM) ∗ A∗ (CL)
CWL = (1 + LM) ∗ B ∗ (WL)

where LM = Loss Multiplier
A = “A” Factor (cost in $ per watt of annual core losses levelized to present worth)
B = “B” Factor (cost in $ per watt of annual winding losses levelized to present worth)
CL = Core losses in kW (provided by bidding manufacturer)
WL = Winding losses in kW (provided by bidding manufacturer)

The equations for A and B Factors are as follows:

$$A = \frac{SC + EC*HPY}{FCR*1000}$$

$$B = \frac{[SC*RF + EC*L_SF*HPY] * PL^2}{FCR*1000}$$

where SC = Annual avoided cost of system capacity ($/kW/yr)
EC = Demand charge per month ($/kW-hr)
LSF = Transformer Loss Factor
HPY = Number of hours per year (hrs/yr)
RF = Peak Responsibility Factor
PL = Levelized equivalent annual peak load
FCR = Annual fixed charge rate (%/yr)

RUS is considering the possibility of utilizing a validated and successfully beta-tested DTCEM program as a key reference in the soon-to-be-updated RUS Bulletin 61-16, “Guide for Economic Evaluation of Distribution Transformers.”

RUS welcomes comments and suggestions that may help improve the DTCEM program. If you have any information or questions, please call Jim Bohlk, Electrical Engineer, Distribution Branch, at (202) 720-1967 or Scott Thigpen, Director Energy Star Labeling Programs, EPA, at (202) 564-9002.

Revision of RUS Bulletin 61-2, "Guide for Making a Sectionalizing Study on Rural Electric Systems"

In conjunction with the Electric Staff Division, the NRECA T&D System Protection Subcommittee has been reviewing RUS Bulletin 61-2, "Guide for Making a Sectionalizing Study on Rural Electric Systems," for possible updating as well as evaluating the method used in calculating minimum ground fault levels. The following comments are offered with these efforts in mind.

RUS feels that revisions are needed to bring Bulletin 61-2 up to current technology standards. Working with the System Protection Subcommittee, RUS considered several alternatives. After much evaluation and comment, it is felt that the electric cooperatives would better be served by updating the bulletin as a guidance tool for coop technicians and engineers in the completion of a sectionalizing study and in the proper maintenance of a protection system and to address the special needs of cooperatives

Consistent with the change in focus, the name being considered for the revised bulletin is "Sectionalizing Guide for Rural Electric Systems."

If you would like more information or have any questions, please call Harvey Bowles, Chief, Distribution Branch, ESD, at (202) 720-5082.

Lightning Protection for Substations

The substation design engineer should be familiar with the weather conditions and lightning phenomena, especially the number of local thunderstorm days and ground stroke data. Since the effects of a direct lighting stroke to an unshielded substation can be devastating, the engineer should provide adequate lightning protection for substation equipment.

The most common method of shielding a substation includes the use of a lightning mast placed near the transformer and shield wire high enough to protect the substation equipment. This design was supported by use of the "Cone" method to calculate the zone of protection.

REA Bulletin 65-1, "Design Guide for Rural Substations," page IV-35, recommends the direct lightning protection method for substation equipment by using overhead shield wires and/or lightning masts in combination. The recommended method to calculate the zone of protection uses the Cone method, with an angle of 30 and 45 degree for single mast or shield wire and two masts or shield wires, respectively.

Recently, a more rigorous method has been developed for calculating the shielding system's zone of protection, called “The Rolling Sphere Method” (RSM). The reason behind using this new method of calculating the zone of protection is that the Cone method, even though economical, has proven to be somewhat inaccurate, especially when the ratios of the mast heights to the substation equipment heights become large. The Cone method also does not consider the Basic Impulse Level (BIL) of the substation equipment. The RSM method takes into account some of these Cone method shortcomings.

The RSM was first developed by Edison Electric Institute (EEI) and provides a means to design a more reliable shielding protection system. Using RSM, the engineer can select both a best-suited location and a shielding mast height based on the BIL.

For preparation, the engineer should have a copy of the “USA Annual Isokeraunic Map” (AIM) and also the latest copy of the “Transmission Line Reference Book.” Both can be obtain from the Electric Power Resource Institute (EPRI), in Palo Alto, California.

The formula used in the EPRI Reference Book assumes a relationship between T = average thunderstorm days per year (from AIM) and N = number of strokes to earth per square mile per year.

$$N = 0.31\ (T)$$

When lightning strikes equipment in a substation, a voltage wave is developed across connected conductors. The wave will then split in two and travel in opposite directions from each other along the conductors. The voltage of the wave will double when it reaches an open circuit. The relation between stroke current and voltage wave is as follow:

$$Es = 1/2\ (Is)\ (Zs)$$

where:

Es = voltage wave in volts,
Is = stroke current in amperes, and
Zs = line surge impedance in ohms

The BIL has a relationship with the stroke current (Is)

$$Is = \frac{2.0\ (BIL)(1.1)}{Zs}$$

The value of Zs can be determined as follows:

$$Zs = 60 \ln (2Hc/Rc)$$

where:

Hc = height of conductor,
Rc = outside radius of conductor, and
ln = natural log (a key stroke in any scientific calculator)

In a typical 115 kV and below substation, bus conductors will have a Zs value of approximately 300 ohms.

The strike distance (Sd) and the stroke current (Is) are related by the following equation,

$$Sd = 26.25 K(Is)^{0.65}$$

where:

Sd = strike distance (in feet),
K = 1.0 for strokes to shield wire,
K = 1.2 for strokes to shield mast, and
Is = stroke current in amperes

For any voltage level below 115 kV, the Sd value based on BIL may be so small that it may not be practical to use a large number of masts to shield the substation. At these lower voltage levels it is recommended that the engineer use a fixed value of 60 feet (18.3 meters) for Sd.

The following steps may be followed for a successful design analysis:

1. Obtain the value of stroke current (Is) based on equipment BIL.

2. Calculate strike distance (Sd) based on Is value in 1 above.

3. Draw the zone of protection from each mast on a scaled plan of the substation yard.

4. Determine the unprotected areas. Unused portions of the yard need not be protected. If the unprotected areas are large, the engineer may modify the design by adding more lightning masts or shield wires.

The above procedure involves only a brief description of a very wide range design requirement for an effective substation lightning protection system. The procedure described above should be in combination with other information and formulas gathered by the designer from the references listed below and thunderstorm data collected from local sources or AIM. A shielding system designed with this procedure which also incorporates use of surge arresters both of which are solidly bonded to the substation grounding system should lower the statistical probability of failure of substation equipment from lightning strokes.

The designer should refer to the following reference material:

> "Transmission Line Reference Book, 345 kV and Above," EPRI, 1981. This publication is available from EPRI at 3412 Hillview Avenue, Palo Alto, CA 94304-1395, telephone (650) 855-2000.
>
> "IEEE Guide for Direct Lightning Stroke Shielding of Substations," Publication 998, published in 1996. This publication is available from IEEE at 1 (800) 701-4333.
>
> "The Rolling Sphere Method of Lighting Protection," presentation by Jeff C. Camden, Black & Veatch to Missouri Valley Electric Association, Engineering Conference, April, 1990. This publication is available from Black & Veatch (Jeff Camden) at (913) 339-2000

If you would like more information or have any questions, please call Ted V. Pejman, Electrical Engineer, Transmission Branch, at (202) 720-0999.

Separation of Outdoor Oil-Insulated Transformers from Buildings and Other Equipment

Transformers in general contain the largest quantity of a combustible substance that is located in a substation. Therefore, special attention should be given to their location in relation to control buildings, other transformers, and other combustible substance filled equipment. Most fires related to oil-insulated transformers occur as a result of a breakdown of insulation caused by overloads, switching or lightning surges, low oil level, moisture in the oil, combustible gas accumulation within the transformer tank, or failure of the insulating bushing. Potentially such a fire could cause a considerable amount of burning oil to be expelled over a large area and an intense fire could follow. Therefore, the location of transformers in a substation should be of concern to the designer and engineer. Every possible attempt should be made to locate oil-filled equipment away from substation buildings, other equipment, possible fire hazards present in adjacent properties, etc.

Determination of the physical separation design is based on type and quantity of oil in the transformer, size of a postulated oil spill (surface area and depth), type of construction of adjacent structures, power rating of the transformer, fire suppression systems provided, and type of electrical relaying protection provided.

Subclause 4.4.1 of IEEE Std 979, "IEEE Guide for Substation Fire Protection," states:

> "Transformers containing 2000 gal (7571 L) or more of insulating oil should be at least 20 ft (6.1 m) from any building. If these large oil-filled transformers are located between 20 and 50 ft (6.1-15.2 m) of a building, the exposed walls of the building should constitute, or be protected by, at least a 2-hour fire-rated barrier. The barrier should extend in the vertical and horizontal directions such that any point of the transformer is a minimum of

> 50-ft (15.2 m) from any point on the wall not protected by the barrier. Should it be necessary to encroach on the above minimums, the installation of a transformer fire protection system should be considered. Some jurisdictions require combination of barrier and fire protection systems."

Subclause 4.4.2 of IEEE Std 979, "IEEE Guide for Substation Fire Protection," states:

> "Transformers containing less than 2000 gal (7571 L) of insulating oil should be separated from buildings by the minimum distances shown in the following table:

Transformer Rating	Recommended Minimum Distance From Building
75 kVA or less	10 ft (3.0 m)
76-333 kVA	20 ft (6.1 m)
More than 333 kVA	30 ft (9.1 m)"

Where a transformer is installed next to a building with less than the minimum distance, the building should have fire-resistive wall construction. Guidance can be found in NFPA 255-1990, "Standard Method of Test of Surface Burning Characteristics of Building Materials."

Subclause 4.4.3 of IEEE Std 979, "IEEE Guide for Substation Fire Protection," states:

> "Large oil-filled transformers should be separated by at least 30 ft (9.1 m) of clear space and/or a minimum 1 hour fire-rated barrier."

For further recommendations regarding substation fire protection, including "Typical Oil Quantities in Equipment," refer to the IEEE Std 979, "IEEE Guide for Substation Fire Protection," and NFPA 850-1992, "Recommended Practice for Fire Protection for Electric Generating Plants," especially where this NFPA code has been adopted by authority having jurisdiction. If any local code or ordinance is more restrictive than a recommendation listed in IEEE Std 979, then the local code or ordinance should be followed.

If you like more information or have any question, please call Mike Eskandary, Electrical Engineer, Transmission Branch, at (202) 720-9098.

Revision of ASCE 7-95 Minimum Design Loads for Buildings and Other Structures.

Section 10 of the 1995 ASCE 7 standard, "Minimum Design Loads for Buildings and Other Structures," establishes minimum design ice loads. At the present time, the requirements portion of the standard does not include an ice map. However, in Fig. C-10-1, Glaze Ice Accretion Zones, an ice map is included in the commentary for guidance. Since this map is based on limited observational data on freezing rain ice thickness, Fig. C-10 should be used with caution. Much of the material in the commentary for Section 10 is based on the ASCE 74, "Guidelines for Electrical Transmission Line Structural Loading."

Revision of the commentary for Section 10 is now underway and it is expected to include a revised ice map. The revised map will show uniform thickness of ice due to freezing rain with concurrent 3-second gust wind speeds for a 50-year recurrence interval. The attached draft of this revised map (Figures C10-1, C10-2, and C10-3) is given for information purposes only. This map approximates ice loads for a single structure. Higher ice loads may be required to achieve the same reliability for a transmission line.

With experience and additional data collected throughout the years, this map will be revised and may eventually be moved from the commentary to the standard. However, as part of the commentary, these maps are suggested design criteria and are not minimum design requirements.

If you would like more information or have any questions, please call Don Heald, Structural Engineer, Transmission Branch, at (202) 720-9102.

An Update on New or Revised RUS Transmission Bulletins

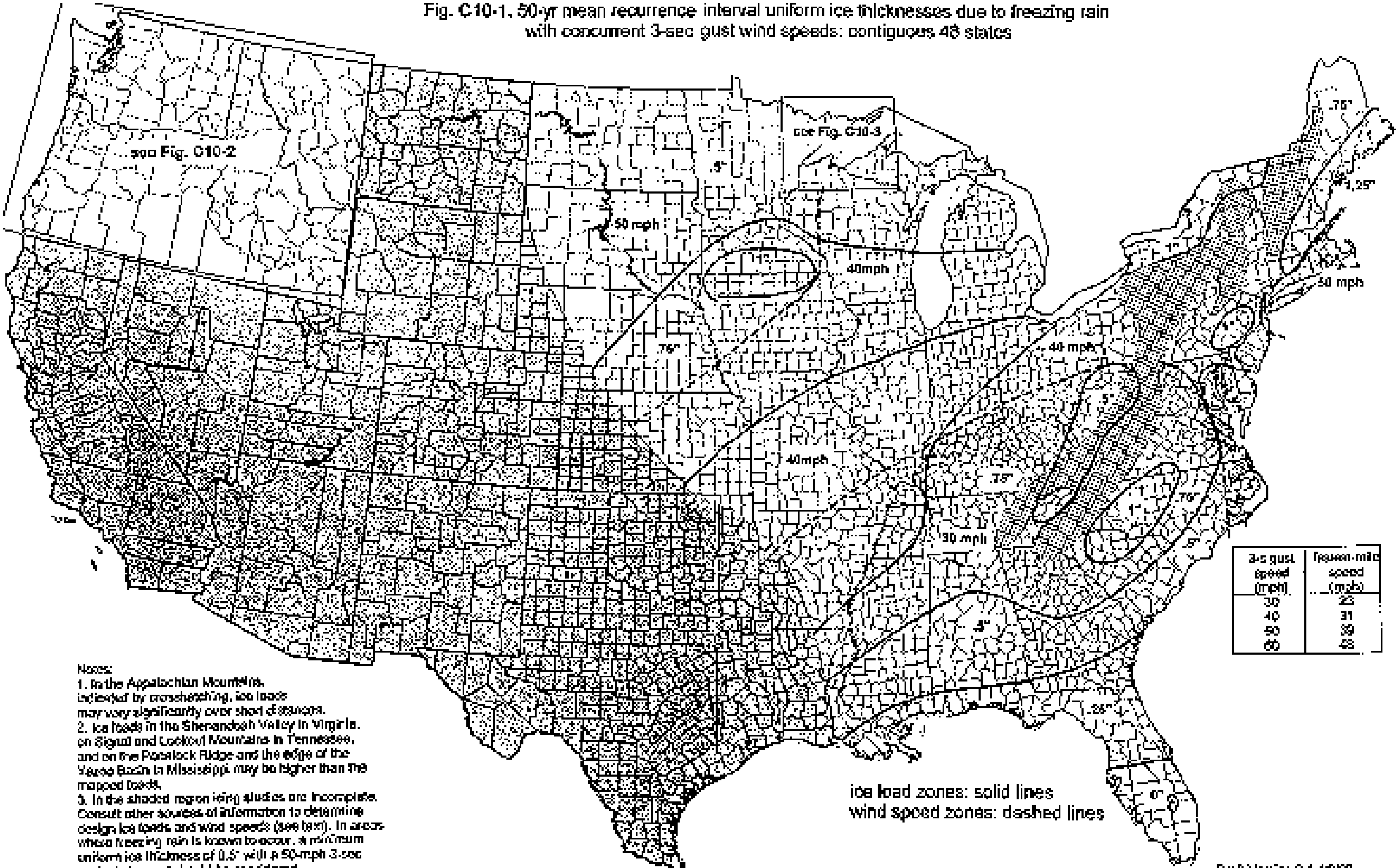
A. On December 22,1997, RUS published Bulletin 1724E-206, "Guide Specification for Spun, Prestressed Concrete Poles and Concrete Pole Structures." This guide publication is a new bulletin which provides the user a useful written format to procure spun, prestressed spun, prestressed concrete poles and concrete pole structures. This guide specification is similar to existing RUS Bulletin 1724E-204, Guide Specifications for Steel Single Pole and H-Frame Structures. In order to properly use the concrete pole specification, the user must develop loading trees, structure drawings and complete a list of specification options. Guide drawings and example loading trees are included.

The bulletin is divided into three parts: (1) instructions, (2) the specification, and (3) a commentary. The instructions to the user of this specification is actually a checklist which identifies: initial design considerations, information to be added to the technical specification, specification and technical information to be completed by the user, option or application requirements to be completed by the user, and information to be completed by the manufacturer.

The technical specification covers the technical aspects of design, material, manufacturing, inspection, testing, and concrete pole structures. Although this specification is orientated to single pole structures, it may be expanded to include H-frames.

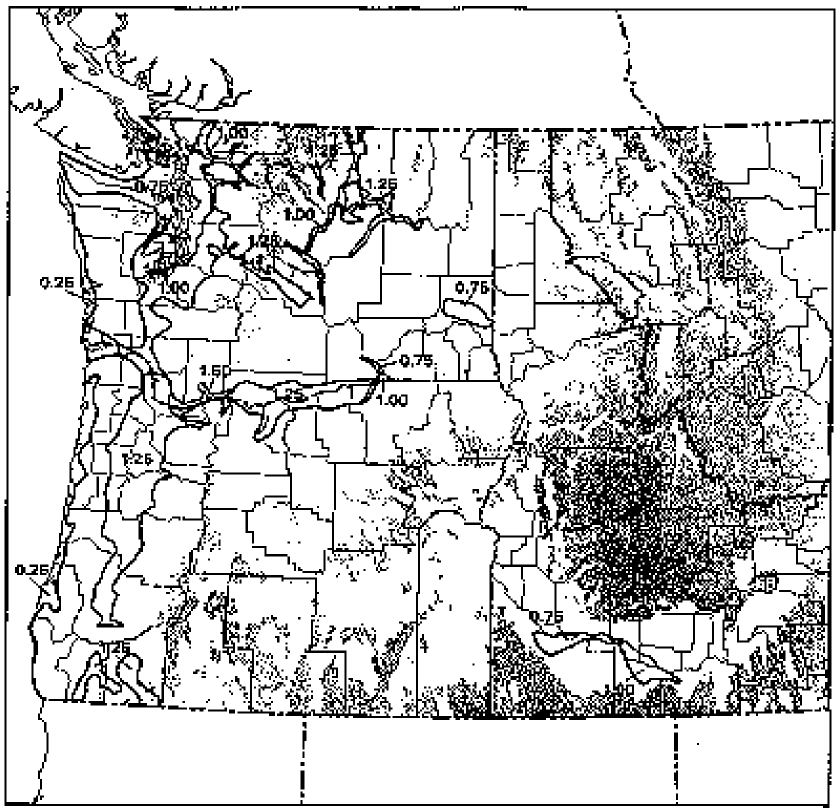
The commentary is intended to be an aid to the engineer. The commentary includes discussions on loads, point of fixity, cracking strength, p-delta effects, foundation rotation and deflection, air entrainment, and grounding. Example loading trees are also provided in the commentary.

Fig. C10-1. 50-yr mean recurrence interval uniform ice thicknesses due to freezing rain with concurrent 3-sec gust wind speeds: contiguous 48 states



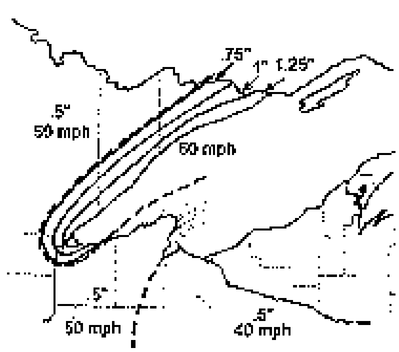
Notes:
1. In the Appalachian Mountains, indicated by crosshatching, ice loads may vary significantly over short distances.
2. Ice loads in the Shenandoah Valley in Virginia, on Signal and Lookout Mountains in Tennessee, and on the Parsleck Ridge and the edge of the Yazoo Basin in Mississippi may be higher than the mapped loads.
3. In the shaded region icing studies are incomplete. Consult other sources of information to determine design ice loads and wind speeds (see text). In areas where freezing rain is known to occur, a minimum uniform ice thickness of 0.5" with a 50-mph 3-sec gust wind speed should be considered.

FIG. C10 –2. 50-Year Mean Recurrence Interval Uniform Ice Thicknesses with Concurrent Wind Speeds Due to Freezing Rain: Pacific Northwest



NOTES:
1. Ice thickness is shown in inches.
2. Unless otherwise specified use 0.50 inch ice thicknesses.
3. Freezing rain is unlikely to occur in the shaded mountainous regions above 5,000 feet.
4. Apply a concurrent fastest-mile wind speed of 40 mph, a 3-second gust of 60 mph, to the appropriate ice thicknesses.

Fig. C10-3. 50-yr mean recurrence interval uniform ice thicknesses due to freezing rain with concurrent 3-sec gust wind speeds: Lake Superior



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RUS is grateful to the members of the Transmission Line Subcommittee of the NRECA Transmission and Distribution Engineering Committee. These members developed the basis for this bulletin.

B. On April 9, 1998, RUS amended its regulations by revising RUS Bulletin 50-2, "Transmission Specifications and Drawings 34.5 kV to 69 kV" and Bulletin 50-1, "Electric Transmission Specifications and Drawings 115 kV to 230 kV." These bulletins have been renumbered as Bulletin 1728F-810 and Bulletin 1728F-811 respectively. RUS made changes to improve and clarify bulletin content. RUS borrowers and other users of RUS electric transmission line specifications suggested corrections to several drawings. RUS and RUS borrowers have also provided suggested modifications to clarify and modify some of the drawings. These changes to the drawings are summarized below:

- Corrections were made to Crossarm Drilling Drawings TCD-11, TCD-15, TCD-20 and TCD-32. Several crossarm drilling dimensions were corrected on the crossarm drilling drawings. Crossarm types 81 and 83 (5 1/8" x 7 1/2") were eliminated on drawing TCD-40, since laminated arms are readily available in standard 9 3/8" x 3 5/8" sizes.

- Drawing TG-15 and TG-45 were revised to show the minimum thickness and width of the guying plate. Drawing TG-16 and TG-46 were revised to provide for a better ground connection between the guy wire and the pole ground wire. On drawing TG-17, a guying plate was added to TG-7D where the insulators attach to the pole and anchor shackles have been added to TG-7E. The anchor shackles are necessary to permit the attachment of light duty guy assemblies to the double-eye pole eye plate. The capacity of the swing angle bracket shown on drawing TG-18 was being clarified to show both allowable and ultimate capacities. Washers were being added on the clevis side of the clevis bolts. These washers will provide a bearing surface when tightening the nut to the clevis bolt. The dimensions of the connecting links to the pole bands were removed from drawing TG-26, Guy Attachments (Pole Bands) and TG-56, Pole Tie Assemblies (Pole Bands). The size of the link depends on the strength of the metal used by different manufacturers.

- Drawings TG-28 and TG-29, Bracket and Guy Attachment, were revised to show minimum sizes for the bracket, to clarify the notes by adding an allowable vertical load, and to define the ultimate load to be compatible with the TH-10 series structures and TG29. Antisplit bolts were added to drawings TG-35D and TG-35E, Heavy Duty Guying Ties. Several notes have been added to TG-36, Heavy Duty Pole Bands, so that problems associated with improper use of this unit are avoided. Since there are no suppliers for heavy duty pole eye plates, drawing TG-37 was eliminated. The pole tie assemblies shown in drawing TG-47 were modified to be similar to TG-45.

- Units TM-1B and TM-2B of drawings TM-1 and TM-2, Insulator Assembly Units, were modified in both bulletins to require the use of a Y-clevis ball instead of the anchor shackle and oval eye ball. The use of a Y-clevis ball will provide savings to RUS borrowers. It is a standard hardware item that has been used frequently on steel and concrete pole construction.

- The Pole Stability, Bearing, and Uplift Foundations drawings (TM-101, 102, 103) were revised to eliminate the compacted backfill below the pole for TM-101 unit, to eliminate unit TM-102B, and to add a note to the engineer on TM-103. All three drawings show the backfill at ground level in a more realistic manner. The reason for the elimination of unit TM-102B is the difficulty in compacting the soil below the top pair of pole bearing plates. The crossarm splice (TM-114A) was eliminated since laminated arms are readily available. Note 4 to Drawing TM-111 was revised for clarification. Drawing TM-115, Steel Upswept Arm Assembly, was revised to show Table 1, Required Dimensions and Swing Angle Clearances. A dimension for the 50,000 pound anchor shackle has been corrected on Drawing TM-120, Hardware.

- The higher capacity log anchors (TA-3L, 3LC, 5L, and 5LC) were eliminated from the log anchor drawings of both bulletins. The size of the washer required in these construction units limits the safety factor to a value which is below those designated for other assemblies. The other log anchor units remain in both bulletins (TA-2L and TA-4L). On these drawings, as well as drawing TA-2P, average soil was redefined as class 5 soil to be consistent with other RUS publications.

- The modification to existing drawings TA-1S through TA-24S, Anchors (Power Screw), in both bulletins was suggested by RUS borrowers and their consulting engineers. This revision simplifies defining unit costs for screw anchors. Screw anchor units are now composed of the basic helix section with a 5-foot extension. A bid unit will cover the number of extensions. The new drawing is designated TA-2H to 4H.

- Corrections were made to the list of materials for the TSS-9 structure in Bulletin 1728F-810 to show a 12' 0" arm for the lower crossarm instead of 9' 0" arm. The pole ground wire was relocated on the TS-1B, TS-1BX, TS-1C, TSZ-115B, TSZ-138B, TS-115B, and TS-138B in order to improve the BIL (Basic Impulse Insulation Level) of the structure.

- Drawings TPF-40 and TPF-50 were revised to reflect the option of using adjustable spacers with gained poles. A corresponding change is included in the list of options in the construction specifications.

If you would like more information or have any questions, please call Don Heald, Structural Engineer, Transmission Branch, at (202) 720-9102.

Composite Insulator Standards for Transmission Lines

The American National Standards Institute (ANSI) has recently approved and published ANSI C29.12, "Standard for Composite-Suspension Type Insulators." The standard covers non-ceramic insulators intended for use on overhead transmission lines 70 kV and above. The contents include materials, dimensions and characteristics, marking and sampling, inspection, and tests. This last category includes design test requirements, quality conformance tests, and routine tests. ANSI Standard C29.11 approved in 1989, describes the test to be conducted on non-ceramic suspension insulators for applications above 70 kV. ANSI C29.11 also establishes acceptance criteria. C29.12 refers to the tests found in C29.1 and C29.11.

The newly published C29.12 standard for non-ceramic suspension insulators establishes standard ANSI classes, similar to classes of insulators in standard C29.2, Insulators for Wet Process Porcelain and Toughened Glass Suspension Type. The ANSI classes for polymers are designated 60-1 to 60-14 for 20,000 or 25,000 lbs SML (specified mechanical load test) and 70-1 to 70-11 for 36,000 or 40,000 lbs SML. For each class of insulators, C29.12 defines a section length nominal dimension range, low frequency flashover electrical values, and critical impulse flashover electrical values. However, leakage distances have not been established for each class.

Low-frequency, dry flashover ratings are generally the most common flashover values referred to when comparing insulators because the values are the most easily and accurately tested. However, it is probably the least significant of the electrical characteristics of an insulator because flashover (60 Hz) of an insulator in service almost never occurs under normal dry operating conditions. For voltages up to 230 kV, the most severe stress on the insulation is usually caused by lightning. The most important flashover characteristic is the impulse flashover value as the front part of the wave shape applied during the test most closely imitates the shape of a lightning surge. For this reason, when non-ceramic insulators are requested for use instead of porcelain insulators, polymer insulators should be selected with comparable negative impulse flashover values.

In general, RUS standard line designs have shown successful performance by specifying a leakage distance approximately twice the gap spacing of a comparable porcelain suspension string of insulators. In areas where there is atmospheric contamination, it may be necessary to increase the leakage surface. Although tests suggest that equivalent performance between non-ceramic and porcelain suspension insulators could be obtained with reduced leakage distances for the polymer insulator, it appears more prudent to adopt leakage distances comparable to what would be used for porcelain strings.

The NRECA T&D Transmission Subcommittee is currently preparing an extensive document on the use of non-ceramic insulators. This document, "Guide for the Application and Procurement of Non-Ceramic Insulators," will assist the user in developing specifications for procurement of non-ceramic insulators and will include a sample purchase specification. In addition, the guide will assist the user with application information, including recommended leakage distances based on environmental exposures, interchangeability with porcelain /ceramic/glass insulators, care and maintenance of non-ceramics, and recommended use of grading rings. This document should be available in 1999.

If you would like more information or have any questions, please call Don Heald, Structural Engineer, Transmission Branch, at (202) 720-9102.

OPERATIONS and MAINTENANCE

Downed Power Lines and Why They Can't be Detected

In 1989, the Power Engineering Society (PES) of the Institute of Electrical and Electronic Engineers (IEEE) published a paper entitled ***"Downed Power Lines: Why They Can't Always be Detected."*** It is an excellent layman's manual on the what, why, and wherefore's of downed power lines. It discusses the basic concepts of electric distribution and the causes of system faults. Its main point is the discussion on the limitations distribution utilities have in the detection of and protection system response to high resistance ground faults. It is an excellent booklet for the education of the public and those individuals that deal with such matters. It is also a significant resource for safety presentations and meetings.

Currently the booklet is out of print and the IEEE-PES has no plans to reprint. The NRECA T&D System Protection Subcommittee feels that the booklet is an excellent resource for rural electric cooperatives and has secured the rights for reprinting.

If you are interested in obtaining one or more or copies of this paper, please contact:

NRECA T&D System Protection Subcommittee
c/o Patterson & Dewar Engineers, Inc.
P.O. Box 1048
Decatur, GA 30031

Telephone: 404-296-5990
Fax: 404-299-3542

There will be a nominal charge for production, shipping, and handling.

If you would like more information or have any questions, please call Harvey Bowles, Chief, Distribution Branch, at (202) 720-5082.

Down Guy Insulators

RUS strongly recommends against the general practice of installing insulators in down guys to mitigate anchor rod corrosion for the following reasons:

- Isolating anchors does not eliminate the galvanic action and usually shifts the problems to other locations on the system. This practice may increase ground current, also called stray-current and stray-voltage, and spread them over larger areas, sometimes causing additional problems elsewhere. Also, this practice may cause steel buried at other locations to corrode more rapidly.

- Isolating anchors decreases the number of grounds on the distribution system and may adversely affects the integrity of an effectively grounded system neutral. This may cause more current (and voltage) on the neutral conductors, and could deteriorate instead of improve safety.

- Studies and experience has shown that the best way to solve the corrosion problem is to increase the buried steel to copper ratio and/or provide the galvanic cell with non-essential, less noble metals (sacrificial anodes), which will corrode instead of essential buried metal equipment.

It is essential that electric utilities contact pipeline companies in their service areas to coordinate cathodic protection of their respective systems. Wherever possible, the cathodic protection for the pipelines should be such that items like anchors, anchor rods, and bare concentric neutrals will not be detrimentally affected.

At certain isolated locations, such as where distribution lines cross or are tangent for a couple of spans to a corrosion protected pipeline, it may be desirable to install a guy strain insulator in one or two down guys to slow anchor corrosion. This is the only time that the use of a guy insulator is recommended. Care should be taken to ascertain that this action does not shift the problem elsewhere, or cause other related problems.

In areas where corrosion of anchor rods is a problem, it may help to replace copper-clad ground rods with steel ground rods and to add additional steel ground rods if necessary. Either stainless steel, galvanized steel, or stainless-clad steel ground rods, as shown in the List of Materials, are acceptable. This practice increases the ratio of buried steel to copper which in essence provides more ion donors (anodes) and fewer ion receivers (cathodes) resulting in less material being stripped off the anchor rods. In most cases, the use of steel ground rods is just as effective as using copper-clad ground rods. If grounding is not adequate, additional ground rod sections should be added and the ground rod driven deeper, or additional steel ground rods should be installed. This further improves the buried steel to copper ratio.

The best solution to the anchor rod corrosion problem is the one that fulfills the following criteria:

- Solves the problem, doesn't shift it elsewhere;
- Maintains or improves the safety and reliability of the system;
- Is economically favorable compared with the alternatives; and
- Is practical, feasible and straightforward.

Each corrosion problem in each area needs to be investigated individually and one or more of the recommended solutions above will need to be applied to mitigate the problem.

If you would like more information or have any questions, please call Trung Hiu, Electrical Engineer, Distribution Branch, at (202) 720-1877.

Keep Testing Your Underground Cable

In previous Items of Engineering Interest, we have discussed testing of new underground cable. The Underground Subcommittee of the NRECA's T&D Engineering Committee highly recommends that electric utility operators test underground cable they purchase. The Subcommittee's recommendation is founded on results of independent cable testing of cable samples conducted from 1993 through 1997. These samples were supplied by co-ops throughout the United States and represent samples of all eight major U.S. suppliers of medium voltage cable. The Subcommittee provided its testing results as an inducement to promote the independent testing of newly purchased cable.

The Subcommittee recommends that the following tests be conducted at a minimum:

1. Dimensional analysis of all cable components;
2. Microscopic examination for voids, contaminants and protrusions; and
3. Insulation shield stripping test.

The Subcommittee also recommends that optional testing of Tree-Retardant Cross-Linked Polyethylene (TR-XLPE) and Cross-Linked Polyethylene (XLPE) insulated cables include a Hot Oil Test. The Subcommittee does <u>not</u> recommend conductor shield and insulation shield resistivity tests because they consistently test well below maximum specifications.

Subcommittee recommended typical sampling rates are to test one sample, each, from the first and last reel on orders of 50,000 feet (15,240 meters) or less and one sample for each additional 50,000 feet of cable ordered.

The Subcommittee recommends that purchasers instruct manufacturers to cut samples and send them to the selected testing laboratory, or the purchaser can cut the samples upon arrival of the shipment. The Subcommittee further recommended that purchasers notify suppliers in advance that cable testing will be conducted and purchasers should establish responsibilities and procedures in case of a failure, such as: Any evidence of noncompliance with the enclosed specifications shall be justification for:

1. Further testing at manufacturer's expense (each shipping reel);
2. Rejection of the tested reel and possibly the reels preceding and following in the manufacturing process; and
3. Rejection of the entire order, depending on the severity and frequency of noncompliance.

A partial list of possible independent testing laboratories provided by the Subcommittee includes:

Cable Technology Laboratories, Inc.
P.O. Box 708
690 Jersey Ave.
New Brunswick, NJ 08903
(201) 846-3220

Forster Electrical Engineering, Inc.
550 North Burr Oak Ave.
Oregon, WI 53575
(608) 835-9009

NEETRAC
62 Lake Mirror Road, Building 3
Forest Park, GA 30050
(800) 762-6522

All of these laboratories participate in the Cable Acceptance Testing Program promoted by NRECA's T&D Underground Subcommittee. The inclusion of a laboratory in this list does not imply endorsement by RUS. The testing laboratories listed above have voluntarily agreed to collect electric cooperative test data and provide it to the NRECA Underground Subcommittee annually for information and publication. To have your data included, note on your purchase order "INCLUDE IN COOPERATIVE DATA FILE." Cooperative names will not be published and participation is voluntary.

The NRECA T&D Underground Subcommittee has compiled data supplied by Cable Technologies Laboratory, Forester Engineering and NEETRAC on the results of cable acceptance testing of newly manufactured cable samples from 1993 through 1997. These cables were supplied by coops throughout the United States and represent samples of all major U.S. suppliers of medium voltage cable. Sample failures are reported only if they failed AEIC or RUS specifications, and not individual specifications. No attempt has been made to evaluate the severity or short/long-term effects these failures would have on the life of the cable.

This information is being provided not as an endorsement nor as a criticism of any cable manufacturer, but rather as an inducement to promote the independent testing of newly purchased cable. The tabulation should alert you to the fact that no construction, no factory, and no manufacturer is infallible. It is in your best interest to test your cable to help insure that you are getting what you pay for and what you specify - a long life cable.

The following tables summarize results of the 1996 and 1997 testings (the 1993, 1994, and 1995 testings including 35, 30, and 45 co-ops, respectively, are summarized in the 1995 and 1996 Items of Engineering Interest):

1996 TEST RESULT (53 CO-OPS)

CABLE TYPE	TR-XLPE*			EPR**			TOTAL
INSULATION LEVEL	15 kV	25 kV	35 Kv	15 kV	25 kV	35 kV	
TOTAL TESTED	146	74	4	132	42	0	398
NUMBER FAILED CONTAMINANTS	2			1			3
NUMBER FAILED DIMENSIONAL					1		1
NUMBER FAILED LOW STRIP TENSION	3						3
NUMBER FAILED AMBER		2					2
NUMBER FAILED SHIELD PICKOFF				6	1		7
PROTRUSIONS	1						1
SHIELD RESISTANCE				2	2		4
PERCENT FAILURES	4.1%	2.7%	0.0%	6.8%	9.5%	0.0%	5.3%

1997 TEST RESULT (50 CO-OPS)

CABLE TYPE	TR-XLPE*			EPR**			TOTAL
INSULATION LEVEL	15 kV	25 kV	35 kV	15 kV	25 kV	35 kV	
TOTAL TESTED	144	96	10	106	60	0	416
NUMBER FAILED CONTAMINANTS				1			1
NUMBER FAILED DIMENSIONAL		1		3	4		8
NUMBER FAILED LOW STRIP TENSION							0
NUMBER FAILED SHIELD RESISTANCE				1			1
NUMBER FAILED NEUTRAL TOUCHING		1		1			2
NUMBER FAILED SHIELD PICKOFF	1						1
NO EXTERNAL MARKINGS							0
PERCENT FAILURES	0.7%	2.1%	0.0%	5.7%	6.7%	0.0%	3.1%

* Tree-Retardant Cross-Linked Polyethylene ** Ethylene Propylene Rubber

If you would like more information or have any questions, please call Trung Hiu, Electrical Engineer, Distribution Branch, at (202) 720-1877.

ENVIRONMENTAL MATTERS

Raptor Protection Video

Raptor electrocution continues to be one of the major wildlife concerns of the U.S. Fish and Wildlife Service (USFWS), especially in states west of the Mississippi River. Raptors (birds of prey) are a group of birds, which includes eagles, falcons, owls, kites, osprey and vultures. The USFWS Division of Law Enforcement has documented the electrocution of 1,030 migratory birds from the states of Colorado, Kansas, Montana, Nebraska, North Dakota, South Dakota, Utah and Wyoming. These birds of prey are protected through several laws, which include the Eagle Protection Act, the Endangered Species Act and the Migratory Bird Treaty Act. Violations of these laws can result in fines and/or imprisonment. The Western Area Power Administration (Western) has been asked by some of its customers for guidance on raptor electrocution prevention.

Western has formed the Raptor Protection Video Group consisting of concerned individuals, wildlife organizations, utilities and Federal agencies. Partners include several consulting firms and utilities, the North American Falconers Association, the Audubon Society, the Avian Power Line Interaction Committee, the RUS, the USFWS, and Western.

The purpose of the video will be to educate the public and the industry about this issue. The video format will consist of three parts. The first part will identify birds of prey and seek to develop an appreciation for these birds not only in an aesthetic sense, but also their importance to the ecosystem. The second part will discuss the problems of raptor electrocutions. Siting problems including locations of facilities, which entice the birds to perch and/or nest, and design of structures which cause electrocutions and possible outages will be discussed. The Federal laws and regulations and associated penalties that protect these birds will also be identified and discussed. The third part will focus on the solutions to the problems including pre-construction design solutions and post-construction retrofit solutions in problem areas.

The group is looking for additional partners who will be given credit for their participation in the development of the video. It is anticipated that the cost of the video will be between $60,000 and $65,000 including the use of some existing film footage. Some organizations have already pledged money and resources to the project. The completion of the video is scheduled for the summer of 1999.

If you would like more information or have any questions, please call Dennis Rankin, Environmental Protection Specialist, Engineering and Environmental Staff at (202) 720-1953, E-mail: drankin@rus.usda.gov.

Raptor Electrocution/Collision Prevention Information

Several publications concerning raptor electrocution prevention, bird collision mitigation and animal caused outages are available. These publications include:

> "Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996." Avian Power Line Interaction Committee (APLIC)/EEI/Raptor Research Foundation, 1996. This publication is available from the Raptor Research Foundation, Jim Fitzpatrick, Director, Carpenter St. Croix Valley Nature Center, 12805 St. Croix Trail, Hastings, MN 55033. Cost is $30.00 plus $5.00 postage and handling.)
>
> "Mitigating Bird Collisions with Power Lines: The State of the Art in 1994." APLIC/EEI, 1994. This publication is available from EEI, 701 Pennsylvania Avenue, NW, Washington, D.C. 2004-2696. Cost is $40.00 plus $6.50 handling for non-members and $32.00 plus $6.50 handling for members.)
>
> The Avian Power Line Interaction Committee (APLIC) is also developing two videos which will complement the above publications. These videos will be available through EEI in the future.
>
> "Animal-Caused Outages." RER Project 94-5, NRECA, 1996. This publication is available from NRECA, 4301 Wilson Boulevard, Arlington, VA 22203-1860, telephone (703) 907-5500.

If you would like more information or have any questions, please call Dennis Rankin, Environmental Protection Specialist, Engineering and Environmental Staff at (202) 720-1953, E-mail: drankin@rus.usda.gov.

ADMINISTRATIVE and OTHER

What is Y2K?

The “Year 2000 Problem”, “Y2K”, and the “Millennium Bug” are all terms being used interchangeably to identify a problem expected to occur at the turn of the next century. The problem is caused by a shortcut used in programming – software applications and microchip code. By using two digits (98) to record a year instead of four digits (1998), programmers could save valuable memory space and product designers did not need to add the electronics necessary for the third and fourth digits. However, as we approach the new millennium, these conservation measures become a potential programming nightmare, as the Year 2000 could be misinterpreted by software and microchip code as 1900.

There are software fixes on the market and programmers are frantically reviewing and correcting (rewriting) their programs to change from the two-digit to a four-digit date designation.

The bigger problem, however, appears to be in embedded microchips – 80 billion are currently in use. The only way to fix microchips that are not Year 2000 compliant is to replace them, and the problem is further exacerbated because it is difficult to ascertain which chips are compliant or Y2K ready.

The implications are enormous. One example not needing much imagination is banking where finance charges could be accrued on an account when 2000 is read as 1900. In the power industry, there is the possibility that switches will fail to operate when required or that some non-compliant interconnection will cause a system to shut down, when a date is not recognized. It is difficult to access behavior of many systems – and only through testing will problems be revealed and consequently corrected.

Dialogue with manufacturers is important to determine their level of readiness and their products that must be upgraded. Not only is it important to look at software and embedded chips of products used in your systems, but the systems used by manufacturers in production must be compliant to assure quality control.

The federal government is taking an active role in ascertaining the problem and its impacts on the various business sectors. The White House has appointed a Council, Congress has formed a special committee which has started holding hearings with various business leaders, and individual departments of the executive branch have been working with the White House Council to look at their own systems and those individuals they serve. RUS has named John J. Schell of the Telecommunications Standards Division as the RUS Year 2000 Compliance Coordinator. If you have general questions concerning 2000 issues, please contact John Schell at (202) 720-0671 or by E-mail at jschell@rus.usda.gov. RUS is actively working within the structures of government to ensure Year 2000 compliance on all systems. All RUS systems are either Year 2000 compliant now or are in the process of achieving compliance. In addition, RUS/USDA is preparing contingency plans in the event of any problems.

Electric cooperatives will receive surveys from many of their business associates, including NRECA, RUS, CFC, and others. In addition to providing information to the surveying parties, the surveys provide an opportunity for vital self-evaluation. While the implications of non-compliance are unknown, chances are there will be some shutdowns, and it is our intention to heighten awareness of the potential problems.

In a letter to all Electric and Telecommunications Borrowers dated July 15, 1998, RUS provided a summary of the results of our first borrower survey and requested additional survey responses. We also provided two background articles concerning Y2K. In the near future, the RUS website will provide information and links to assist you. Currently, the NRECA website lists some helpful links for assessing and solving the Y2K problem.

If you would like more information or have any questions, please call Fred Gatchell, Deputy Director, ESD, at (202) 720-1398, or Sharon Ashurst, Public Utility Specialist, Energy Forecasting Branch, at (202) 720-1925

RUS Technical Publications

RUS has published several items recently of interest to the rural electric engineering community. These publications include:

RULES:

- **7 CFR 1724, "Electric Engineering, Architectural Services and Design Policies and Procedures."** This rule, published on June 29, 1998, contains RUS requirements on engineering and architectural services and system design. These policies and procedures are presently contained in seven RUS bulletins, which will be rescinded after this regulation becomes effective. This rule simplifies RUS requirements relating to architectural and engineering services and the planning and design of electric distribution, transmission, and generation systems and facilities owned by RUS borrowers, and substantially reduces the number of engineering documents that must be submitted to RUS.

- **7 CFR 1730, "Electric System Operation and Maintenance"** (O&M). This rule, published on January 23, 1998, contains RUS requirements on electric system O&M and the policy on RUS' review and evaluation of borrowers' O&M practices. It also includes revisions to RUS Form 300, Review Rating Summary, and replaces RUS Bulletin 161-5, Electric System Review and Evaluation. See Bulletin 1730-1 for additional guidance.

- **Bulletin 1728F-803, "Specifications & Drawings for 24.9/14.4 kV Line Construction"** (incorporated by reference). The proposed rule covering the revision of this bulletin was published on August 26, 1997. The proposed revision includes a new drawing assembly designation system as well as a number of clarifications, modifications, and updates to these drawings. Public comments on this proposed rule have been received and are now being incorporated into the final rule.

- **Bulletin 1728F-806, "Specifications & Drawings for Underground Electric Distribution"** (incorporated by reference). The proposed rule covering the revision of this bulletin was published on April 8. 1998. The proposed revision includes a number of clarifications, modifications, and updates to these drawings. Public comments on this proposed rule have been received and are now being incorporated into the final rule.

- **Bulletins 1728F-810 and 1728F-811, "Electric Specifications and Drawings for 34.5 kV through 230 kV Transmission Lines"** (incorporated by reference). The final rule covering the revision of these bulletins was published on March 10, 1998. RUS has made editorial changes and changes to improve clarity of these bulletins. RUS borrowers and other users of RUS electric transmission line specifications have proposed corrections to several drawings. RUS and RUS borrowers have also suggested modifications to clarify and modify some of the drawings. RUS also has renumbered and reformatted these bulletins in accordance with the agency's publications and directives system. These bulletins were formerly known as RUS Bulletins 50-1 and 50-2.

GUIDANCE DOCUMENTS:

- **Bulletin 1724D-104, "An Engineering Economics Computer Workbook Procedure,"** dated February 3, 1998. This guide bulletin describes a computerized engineering economics procedure developed by RUS to assist borrowers and others in their construction project planning process.

- **Bulletin 1724E-204, "Guide Specification for Steel Pole and H-Frame Structures,"** dated June 6, 1997. This guide specification, which replaces REA Bulletin 62-12, "Guide Specifications for Steel Pole Structures" (June 1983), is to provide RUS borrowers with a basis for procuring adequate single pole and H-frame steel transmission line structures. Use of this specification should help eliminate ambiguities that might arise in the evaluation process of competitively bid steel pole procurements.

  This suggested purchase specification covers the technical aspects of design, materials, welding, inspection, delivery, and protective coatings of single circuit steel pole and steel H-frame structures, 115 kV to 230 kV. This specification does not include contract (front-end) documents or specifications for construction. This specification may be expanded to include double circuit structures and structures over 230 kV.

  The Transmission Line Subcommittee of the NRECA T&D Engineering Committee contributed significantly to the revision of this bulletin.

- **Bulletin 1724E-206, "Guide Specification for Prestressed, Spun, Concrete Poles,"** dated December 22, 1997. This guide specification provides a basis for procuring prestressed, spun, concrete poles. This purchase specification covers the technical aspects of design, materials, manufacturing, inspection, testing, and delivery of prestressed, spun concrete poles.

  The Transmission Line Subcommittee of the NRECA T&D Engineering Committee developed the basis of this bulletin.

- **Bulletin 1724E-301, "Guide for the Evaluation of Large Power Transformer Losses,"** dated December 19, 1997. This bulletin provides guidelines for evaluating transformer losses and for including such losses in bid evaluations.

- **Bulletin 1730-1, "Electric System Operation and Maintenance (O&M),"** dated January 26, 1998. This bulletin provides guidelines for borrowers regarding O&M records, practices, etc., as well as RUS standard practices on review and evaluation of borrowers O&M. It also contains a rating guide for RUS Form 300, giving guidance about conditions normally needed to justify a rating of 3.

- **IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers,"** published in July 1998, and its quarterly supplements. This document provides a convenient listing of the materials and equipment that have been accepted by RUS.

If you need any of these publications, please contact RUS' Program Development and Regulatory Analysis staff at (202) 720-8674. Many RUS publications are also available via the Internet at:

http://www.usda.gov/rus/

PUBLICATIONS IN PROGRESS

<u>**Timber Specifications:**</u> RUS is in the process of revising the following three bulletins that cover pressure treating poles and crossarms, and their respective quality control:

- **1728F-700, "RUS Specification for Wood Poles, Stubs and Anchor Logs,"**
- **1728H-701, "RUS Specification for Wood Crossarms (Solid and Laminated) Transmission Timbers and Pole Keys"** (7 CFR 1728.201), and
- **1728H-702, "RUS Specification for Quality Control and Inspection of Timber Products"** (7 CFR 1728.202).

Topics currently being considered for revision include:

1. Elimination of the requirement for borrowers to notify RUS of their timber product purchases during the previous year,
2. Reinstatement of the acceptance and listing of inspection agencies in the RUS List of Materials,
3. Requirement for a heat sterilization during kiln drying or steam conditioning of poles,
4. Requirement for inspection agencies to have their company designation branded or tagged on the pole face,
5. Elimination of the 10 percent allowance of preservative retention reduction at the time of shipment to the borrower,
6. Requirement for all independent inspectors and plant quality control personnel to be trained and certified by x-ray fluorescence instrument manufacturer,
7. Requirement for treating plants and inspection agencies to maintain certain levels of liability insurance and errors and omission insurance, and

8. Include butt treating of cedar poles as an acceptable method of treatment for poles.

RUS is soliciting input from electric borrowers and others as to necessary changes to these bulletins. Comments or suggestions should be sent to H. Robert Lash, Chief, Transmission Branch, RUS, Stop 1569, 1400 Independence Ave, SW, Washington, DC 20250-1569, E-mail: blash@rus.usda.gov. All comments are welcome.

RUS is also working on the following publications:

- **7 CFR 1710, Subpart E, "Load Forecasts and Market Analysis."** This proposed rule will change the existing load forecasting regulations. The changes are intended to reduce the overall administrative burden of reporting load forecasts to RUS. The changes will also allow RUS to accept less detailed analysis for smaller borrowers. For further information, please contact Georg Shultz at (202) 720-1920.

- **RUS Bulletin 1724D-112, "The Application of Shunt Capacitors to the Rural Electric System."** This bulletin will examine the application of shunt capacitors on rural distribution systems and serve as a general guide for capacitor applications to RUS borrowers and others. The System Planning Subcommittee of NRECA's T&D Committee has been instrumental in the development of this bulletin. For further information, please contact Chris Tuttle at (202) 205-3655.

- **RUS Bulletin 1724D-114, "Voltage Regulator Application on Rural Distribution Systems."** This bulletin will examine the application of voltage regulators on rural distribution systems and serve as a general guide for voltage regulator applications to RUS borrowers and others. For further information, please contact Jim Bohlk at (202) 720-1967.

RUS 1998 Electric Engineering Seminar

On March 4, 1998, RUS held a seminar on rural electric distribution and transmission system engineering and operation. The program included presentations on various topics of interest to the rural electric engineering community.

In addition to the formal presentations, this seminar provided an opportunity for the participants from around the country to share experiences and ideas of mutual interest. Over 250 distribution system managers, engineers, and line superintendents as well as personnel of consulting engineering firms and RUS attended this seminar. The seminar was held in conjunction with NRECA's "TechAdvantage 98."

If you would like more information or have any questions, please call Fred Gatchell, Deputy Director, ESD, at (202) 720-1398.

Transmission and Distribution Engineering Committee

In 1991, NRECA established its Transmission and Distribution Engineering Committee (T&D Committee) to work with REA (now RUS) in the development and maintenance of electric transmission and distribution standards and specifications, and the exchange of engineering information of mutual interest to rural electric utilities. The T&D Committee is composed of some of the most dedicated and talented individuals from NRECA and from electric cooperatives all across the United States. These individuals routinely donate several weekends and considerable amounts of other personal time each year to fulfill their commitments to the Committee.

We want to use this opportunity to thank these individuals and the organizations that sponsor their participation. See Appendix B for the T&D Committee Roster.

If you would like more information or have any questions, please call Don Heald, Acting Chair, Technical Standards Committee "A" (Electric), at (202) 720-0980.

APPENDIX A

RURAL UTILITIES SERVICE ELECTRIC STAFF DIVISION

Office of the Director

George J. Bagnall Director
(202) 720-1900 gbagnall@rus.usda.gov

Donna B. Howdershelt Secretary
(202) 720-1900 dhowders@rus.usda.gov

Fred J. Gatchell Deputy Director
(202) 720-1398 fgatchel@rus.usda.gov

Vacant Chair, Technical Standards Committee “A”
(202) 720-0980 tscae@rus.usda.gov

Michelle D. Lew Technical Committee Assistant
(202) 720-0980 mlew@rus.usda.gov

Marshall D. Duvall Staff Engineer
(202) 720-0096 mduvall@rus.usda.gov

Robin L. Meigel Finance Specialist
(202) 720-9452 rmeigel@rus.usda.gov

William Procopiow Architect
(202) 720-9090

Energy Forecasting Branch

Georg A. Shultz Chief
(202) 720-1920 gshultz@rus.usda.gov

Vacant Secretary
(202) 720-1920 @rus.usda.gov

Sharon E. Ashurst Public Utility Specialist
(202) 720-1925 sashurst@rus.usda.gov

Christopher L. Tuttle Economist
(202) 205-3655 ctuttle@rus.usda.gov

Distribution Branch

Harvey L. Bowles Chief
(202) 720-5082 hbowles@rus.usda.gov

Anjunette A. Lyles Secretary
(202) 720-5082 alyles@rus.usda.gov

James L. Bohlk Electrical Engineer
(202) 720-1967 jbohlk@rus.usda.gov

Trung V. Hiu Electrical Engineer
(202) 720-1877 thiu@rus.usda.gov

George L. Keel Equipment Specialist
(202) 690-0551 gkeel@rus.usda.gov

Stephen Jones Electrical Engineer
(202) 720-1792 sjones@rus.usda.gov

Transmission Branch

H. Robert Lash Chief
(202) 720-0486 blash@rus.usda.gov

Betty Sharpe Secretary
(202) 720-0486 bsharpe@rus.usda.gov

Donald G. Heald Structural Engineer
(202) 720-9102 dheald@rus.usda.gov

Mike Eskandary Electrical Engineer
(202) 720-9098 meskanda@rus.usda.gov

Ted V. Pejman Electrical Engineer
(202) 720-0999 tpejman@rus.usda.gov

Updated August, 1998

APPENDIX B

NRECA TRANSMISSION & DISTRIBUTION ENGINEERING COMMITTEE

MEMBER	ORGANIZATION	LOCATION
Committee Chairman		
Overt L. Carroll	Clark RECC	Winchester, KY
NRECA Staff Coordinator		
Steve Lindenberg	NRECA	Arlington, VA
David Altman	Lumbee River EMC	Red Springs, NC
Dominic Ballard	East Kentucky Power Co-op	Winchester, KY
Alan Blackmon	Blue Ridge EC	Pickens, SC
Gregory Broussard	Jackson EMC	Jefferson, GA
John Burch	Florida Keys EC	Tavernier, FL
James Byrne	Poudre Valley REA	Fort Collins, CO
Jim Carter	NRECA - WQC	Spartanburg, SC
Steve Cress	Tipmont REMC	Linden, IN
James Crouch	Fairfield EC	Winnsboro, SC
Russ Dantzler	Mid-Carolina EC	Lexington, SC
Berl Davis	Palmetto EC	Hilton Head, SC
Bruce Dreyer	Middle Tennessee EMC	Murfreesboro, TN
Herman Dyal	Clay Electric Co-op	Keystone Heights, FL
Charles Emerson	Trico EC	Tucson, AZ
Doug Emmons	Hoosier Energy REC, Inc.	Bloomington, IN
Mark Evans	Upper Cumberland EMC	Carthage, TN
Ronnie Frizzell	Arkansas EC Corp.	Little Rock, AR
David Garrison	East Central Oklahoma EC	Okmulgee, OK
David Gebhardt	LaPlata EA	Durango, CO
Phil Gelhorn	East Central EA	Braham, MN
Ed Giesler	Tri-County EC	Portland, MI
Allan Glidewell	Southwest Tennessee EMC	Brownsville, TN
Weldon Gray	Concho Valley EC	San Angelo, TX
Ron Gunnell	Randolph EMC	Asheboro, NC
Steven Gwin	Middle Tennessee EMC	Murfreesboro, TN
Charlene Ham	Rusk County EC	Henderson, TX

APPENDIX B

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MEMBER	ORGANIZATION	LOCATION
Wayne Henson	East Mississippi EPA	Meridian, MS
Bill Hetherington	Lee County EC, Inc.	North Ft. Myers, FL
Vince Heuser	Nolin RECC	Elizabethtown, KY
Jon Hodge	Trinity Valley Electric Co-op	Athens, TX
Tom Hoffman	Agralite Electric Co-op	Benson, MN
Jerrod Howard	Central Electric Power Co-op, Inc.	Columbia, SC
Robert Johnson	Arkansas EC Corp.	Little Rock, AR
Joseph Joplin	Rutherford EMC	Forest City, NC
Allan Kunze	Lower Colorado River Authority	Austin, TX
Wally Lang	Minnkota Power Co-op, Inc.	Grand Forks, ND
Terry Lee	South Mississippi EPA	Hattiesburg, MS
Carl Liles	Western Farmers EC	Anadarko, OK
Gregory Lindsly	Dixie EMC	Baton Rouge, LA
Troy Little	Four County EPA	Columbus, MS
Charles Lukkarila	United Power Assn.	Elk River, MN
Bil Kahanek	Lower Colorado River Authority	Austin, TX
Charles (Bubba) McCall	Georgia Transmission Corp.	Tucker, GA
John Mitchell	Rappahannock EC	Fredericksburg, VA
David Moore	Johnson County EC	Cleburn, TX
Ken Murphy	Tallapoosa River EC	LaFayette, AL
William Murray	Berkeley EC	Moncks Corner, SC
Tom Myers	Berkeley EC	Moncks Corner, SC
Ace Necaise	Singing River EPA	Lucedale, MS
Stuart Nelson	Lower Colorado River Authority	Austin, TX
Jim Newberg	Missoula EC, Inc.	Missoula, MT
Rod Nikula	Wright-Hennepin CEA	Rockford, MN
David Obenshain	Piedmont EMC	Hillsborough, NC
Bob Oldham	Southern Maryland EC	Hughesville, MD
Michael Pehosh	Ozarks EC	Fayetteville, AR
Chris Perry	Nolin RECC	Elizabethtown, KY
Peter Platz	Coast Electric Power	Bay St. Louis, MS

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NRECA TRANSMISSION & DISTRIBUTION ENGINEERING COMMITTEE

MEMBER	ORGANIZATION	LOCATION
John Rodgers	Nodak EC, Inc.	Grand Forks, ND
Terry Rosenthal	Laclede EC	Lebanon, MO
Paul Rupard	East Kentucky Power Co-op	Winchester, KY
Glenn Sell	Union Rural EC	Marysville, OH
Lewis Shaw	Brunswick EMC	Shallotte, NC
Robert Siekas	Cherryland EC	Grawn, MI
Jim Skeen	Plumas-Sierra Rural EC	Portola, CA
Gordon Sloan	Sulphur Springs Valley EC	Willcox, AZ
Thomas Slusher	Union EMC	Monroe, NC
Michael Smith	Singing River EC	Lucedale, MS
Paul Spears	Tri-County EC	Azle, TX
Gary Stein	Wabash Valley Power Assn.	Indianapolis, IN
Blaine Strampe	Federated REA	Jackson, MN
Vernon W. Strickland	Intercounty ECA	Licking, MO
Tom Suggs	Natchez Trace EPA	Houston, MS
Fred Terwilliger	Central EC, Inc.	Parker, PA
Brian Tomlinson	Denton County EC, Inc.	Corinth, TX
David Turner	Lower Colorado River Authority	Austin, TX
John Twitty	Alabama EC	Andalusia, AL
Scott Wehler	Adams Electric Co-op	Gettysburg, PA
John Westby	Verendrye EC, Inc.	Velva, ND
Kenneth Winder	Moon Lake Electric	Roosevelt, UT

APPENDIX B

NRECA TRANSMISSION & DISTRIBUTION ENGINEERING COMMITTEE

MEMBER	ORGANIZATION	LOCATION
CONSULTANT MEMBERS		
Jim Bardwell	SGS Witter, Inc.	Albuquerque, NM
Keith Bartels	Martin & Associates, Inc.	Mitchell, SD
George Chapman	Patterson & Dewar Engineers, Inc.	Decatur, GA
Peter Daly	Power System Engineering, Inc.	MADISON, WI
Bob Dew	Southern Engineering Company	Atlanta, GA
William Dorsett	Booth & Associates	Raleigh, NC
Don Gray	SGS Witter, Inc.	Albuquerque, NM
Joseph Jones	McCall-Thomas Engineering Co.	Orangeburg, SC
Joe Perry	Patterson & Dewar Engineers, Inc.	Decatur, GA
Art Smith	Patterson & Dewar Engineers, Inc.	Decatur, GA
Gene Smith	SGS Witter, Inc.	Lubbock, TX
Mike Smith	SGS Witter, Inc.	Albuquerque, NM
James Stewart	Stewart Engineering, Inc.	Anniston, AL
Ed Thomas	Utility Electrical Consultants	Raleigh, NC
Mike Waters	Utility Electrical Consultants	Raleigh, NC