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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

<u>SECOND DATA REQUEST OF COMMISSION STAFF TO JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES</u>

DATED FEBRUARY 9, 2007

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

Shelby Energy looks at two broad categories in reliability measurement: sustained interruptions (service outages) and momentary interruptions (voltage sags and "blinks"). Service outages are recorded, tracked and reported on an annual basis to the Rural Utilities Services of the United States Department of Agriculture (RUS). This value is measured and reported in "Average Hours Per Consumer" (SAIDI). Typically it is further separated by cause of interruption as follows: Power Supplier, Extreme Storm, Pre-Arranged (Planned), and Other for the purpose of reporting to RUS. (Refer to Exhibit 1-A, RUS Form 7A, Part G.) For operational purposes, outage or interruption reports are further broken down by nature and cause. (Refer to Exhibit 1-B, Shelby Outage Report Form.) This information is recorded, tracked, and analyzed for the purposes of making immediate to short-range system operating decisions and longer range engineering recommendations which are all focused on improving system reliability. (Refer to Exhibit 1-C Monthly Summary)

Momentary interruptions (voltage sags, recloser operations, and "blinks") are monitored at substation level and at line devices. Repetitive events and excessive operational device counts are promptly addressed and corrective action is taken. This process is not subject to a formal recording, tracking, and reporting procedure as is used in the case of sustained interruptions or outages.

Witness: Wayne Anderson
David Graham

USDA - RUS FINANCIAL AND STATISTICAL REPORT	BORROWER DESIGNATION KY0030
INSTRUCTIONS - See RUS Bulletin 1717B-2	PERIOD ENDED December, 2006

PART G. SERVICE INTERRUPTIONS

ITEM	AVERAGE HOURS PER CONSUMER BY CAUSE				TOTAL
	POWER SUPPLIER (*a*)	EXTREME STORM (*b*)	PREARRANGED (*c*)	ALL OTHER (*d*)	(*e*)
Present Year	.15	7.23	.02	1.58	8.98
2. Five-Year Average	.14	2.53	.02	1.23	3.92

SHELBY ENERGY INTERRUPTION REPORT

Exhibit 1-B

Oct.2004

SHELBY ENERGY MEMBER

OUTAGE TIME : ______ ☐ AM ☐ PM DATE :

LOCATION NUMBER

RESTORED TIME : ______ ☐ AM ☐ PM DATE :

ADDRESS

NATURE OF TROUBLE

POLE
- ☐ POLE (20)
- ☐ CROSS ARM (OR BRACE) (21)
- ☐ ANCHOR (OR GUY) (22)

TRANSFORMER
CIRCLE : CON CSP SP
- ☐ FAILURE (REPLACED) (50)
- ☐ FUSE OR BREAKER (51)
- ☐ LIGHTNING ARRESTER (52)

OH LINE
- ☐ CONDUCTOR (30)
- ☐ CLAMP OR CONNECTOR (31)
- ☐ SPLICE OR DEAD-END (32)
- ☐ JUMPER (33)
- ☐ INSULATOR (34)
- ☐ LIGHTNING ARRESTER (35)
- ☐ FUSE CUTOUT (36)
- ☐ OCR OR SECTIONALIZER (37)

SECONDARY AND SERVICES
- ☐ CONDUCTOR (60)
- ☐ METER OR METER LOOP (61)
- ☐ SECURITY LIGHT (62)

OTHER ☐ (SPECIFY BELOW)

UG LINE
- ☐ PRIMARY CABLE (40)
- ☐ SPLICE OR FITTING (41)
- ☐ SWITCH (42)
- ☐ LIGHTNING ARRESTER (43)
- ☐ SECONDARY CABLE OR FITTINGS (44)

CAUSE OF TROUBLE

EQUIPMENT
- ☐ EQUIPMENT FAILURE (30)
- ☐ INSTALLATION FAULT (31)
- ☐ CONDUCTOR SAG (CLEARANCE) (32)

SCHEDULED
- ☐ CONSTRUCTION (10)
- ☐ MAINTENANCE (11)

DETERIORATION
- ☐ DECAY (40)
- ☐ WOODPECKERS (41)
- ☐ CORROSION (42)
- ☐ CONTAMINATION (LEAKAGE) (43)
- ☐ MOISTURE (44)
- ☐ ELECTRICAL OVERLOAD (45)

PUBLIC (MEMBER)
- ☐ VEHICLES OR MACHINERY (70)
- ☐ AIRCRAFT (71)
- ☐ ACCIDENTS (OTHER) (72)
- ☐ VANDALISM (73)
- ☐ FIRE (74)

OTHER ☐ (SPECIFY BELOW)

WEATHER
- ☐ LIGHTNING (50)
- ☐ WIND (NOT TREES) (51)
- ☐ ICE, SLEET, FROST (NOT TREES) (52)
- ☐ TREES AND ICE (53)
- ☐ TREES (54)

ANIMALS
- ☐ SMALL ANIMALS OR BIRDS (SHORT CIRCUIT) (60)
- ☐ LARGE ANIMALS (AFFECTING POLE OR GUY) (61)

- ☐ JOB ORDER SUBMITTED
- ☐ ACCIDENT REPORT SUBMITTED
- ☐ MEMBER BILLED

SUBSTATION ______ **FEEDER** ______

SECTIONALIZING STATION NUMBER ______

TOTAL TIME OF INTERRUPTION ______

PHASE ☐ **A** ☐ **B** ☐ **C**

NO. OF MEMBERS AFFECTED ______

☐ **INDIVIDUAL** ☐ **TAP**

SIGNED ______

APPROVED ______

Exhibit 1-C

Interruption I il for January-07

Date Off	Date On (if different)	Time Off	Time On	Elapsed Hours	No. Of Consumers	Consumer Hours	Map Reference	Sub	Fdr	Equip. Code	Cause Code	Comments
1/1/2007		12:05 PM	2:35 PM	2.50	31	77.50	33628011	2	2	37	60	squirrel
1/1/2007		4:30 PM	9:30 PM	5.00	1	5.00	32368036	4	1	20	70	car hit pole
1/2/2007		1:25 PM	2:15 PM	0.83	108	89.64	34272008	6	1	30	10	planned
1/2/2007		4:00 PM	4:25 PM	0.42	14	5.88	31775030	5	1	34	30	planned-insulator
1/3/2007		12:40 PM	1:20 PM	0.67	11	7.37	32922423	11	2	36	60	
1/4/2007		4:45 PM	7:10 PM	2.42	1	2.42	34272006	6	1	50	30	
1/5/2007		5:30 AM	6:30 AM	1.00	3	3.00	34115036	1	2	43	50	lightning arrester
1/5/2007		11:30 AM	1:00 PM	1.50	1	1.50	33093002	3	2	36	60	squirrel
1/5/2007		9:45 AM	2:15 PM	4.50	10	45.00	31767157	5	1	37	30	switch failed
1/8/2007		11:45 AM	11:55 AM	0.17	2	0.34	31767157	5	2	99	11	pull box
1/14/2007		9:30 PM	10:30 PM	1.00	1	1.00	34039043	1	3	51	30	
1/15/2007		6:15 AM	8:15 AM	2.00	1	2.00	34178004	1	3	60	54	
1/17/2007		1:30 AM	3:00 AM	1.50	12	18.00	33558004	2	1	37	52	line down
1/17/2007		1:30 AM	4:00 AM	2.50	9	22.50	33568001	2	1	32	53	line down
1/17/2007		1:30 AM	6:30 AM	5.00	36	180.00	33557004	2	1	37	52	line down
1/18/2007		11:00 AM	3:30 PM	4.50	1	4.50	31638066	7	2	50	30	
1/19/2007		8:15 PM	10:00 PM	1.75	3	5.25	32924022	3	3	22	70	vehicluar
1/20/2007		2:10 PM	2:30 PM	0.33	23	7.59	32374015	5	4	30	99	repair phase
1/20/2007		8:40 AM	10:30 AM	1.83	155	283.65	34115017	10	1	30	30	
1/20/2007		4:00 PM	6:30 PM	2.50	38	95.00	31756021	5	2	30	54	tree on phase
1/21/2007		8:00 AM	11:00 AM	3.00	46	138.00	32315017	5	2	35	30	lightning arrester
1/21/2007		9:00 AM	11:00 AM	2.00	41	82.00	34274024	2	4	30	52	ice
1/21/2007		9:09 AM	11:30 AM	2.35	30	70.50	43104014	99	1	0	99	tie line
1/21/2007		9:30 AM	2:30 PM	5.00	6	30.00	34076001	1	3	30	52	
1/21/2007		9:30 AM	1:00 PM	3.50	36	126.00	34067008	1	3	30	52	
1/21/2007		11:20 AM	10:30 PM	11.17	11	122.87	32928006	4	2	30	52	
1/21/2007		11:39 AM	5:45 PM	6.10	348	2122.80	32336017	5	2	30	59	ku transmission
1/21/2007		11:39 AM	6:05 PM	6.43	92	591.56	32377011	5	2	30	59	ku transmission
1/21/2007		11:39 AM	5:05 PM	5.43	75	407.25	32323/24/33	5	2	30	59	ku transmission
1/21/2007		11:24 AM	4:54 PM	5.50	30	165.00	32929002	4	2	30	52	ice
1/21/2007		11:39 AM	11:59 AM	0.33	1747	576.51		4		0	59	ku transmission
1/22/2007		3:50 AM	5:30 AM	1.67	5	8.35	34174401	10	2	36	60	buzzard
1/22/2007		4:10 PM	5:15 PM	1.08	1	1.08	33489042	1	4	99	30	m/b lugs
1/22/2007		12:20 AM	1:20 AM	1.00	60	60.00	32966008	11	1	42	30	
1/27/2007		11:40 AM	1:40 PM	2.00	1	2.00	33604002	3	2	33	51	jumper/trf
1/27/2007		1:40 PM	2:55 PM	1.25	4	5.00	33053006	3	1	36	99	unknown
1/30/2007		1:45 PM	2:00 PM	0.25	8	2.00	33464734	13	2	30	79	dynamite blast
1/30/2007		1:55 AM	3:30 AM	1.58	3	4.74	32315122	5	2	51	30	transformer c/o
MONTH TOTALS				**101.56**	**3005**	**5372.80**						

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

Shelby relies on the guidelines established by the RUS in determining a performance threshold or appropriate operating range relative to the measuring of reliability. The value of 5 hours/consumer annually and 1 hour/consumer annually by power supplier (SAIDI) is set forth in RUS bulletin 1730-1 as an acceptable level for rural electric distribution cooperatives.

Witness: Wayne Anderson
David Graham

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.

Shelby's electric distribution system performance is monitored and measured using a criterion that has as its basis not only reliability measures, but also compliance with applicable codes and industry accepted engineering and operational practices. Performance of circuits and line sections of the distribution system are analyzed periodically and those that fall outside the prescribed parameters of the "specific system criterion" (Refer to Exhibit 3-A) are nominated for corrective action in the form of specific construction work plan project work that may range from conductor and/or other line material replacements to extensive rebuilding, replacing and up-rating or upgrading of the circuit or line section. (Refer to Exhibit 3-B)

Witness: Wayne Anderson
David Graham

SPECIFIC SYSTEM CRITERIA
SHELBY ENERGY
CONSTRUCTION WORK PLAN

1. The minimum primary voltage on the system - referred to the 120 volt secondary - is 118 volts. Downline voltage regulation will be limited to one set of regulators for any given circuit.

2. Primary conductors will not be loaded over 75% of their thermal rating.

3. The following equipment will have a minimum loading not to exceed the nameplate percentages below:

a.	Distribution Transformers	130% winter; 100% summer
b.	Regulators	130% winter; 100% summer
c.	Step Voltage Transformers	130% winter; 100% summer
d.	Reclosers	80% winter; 80% summer
e.	Line Fuses	80% winter; 80% summer

4. Conversions to multiphase are to correct voltage drop and phase balance. Line sections operating at 12.5/7.2 kV with load currents exceeding 40 amps, 24.9/14.4 kV lines with load currents exceeding 35 amps and lines sections with greater than 60 customers will be considered for multiphasing. Operating and engineering practices used to develop the loading criteria are based on a single phase line interruption that may cause operation of the ground trip relay on three phase oil circuit reclosers.

5. Three phase tie points between substations should be equipped with air break switches.

6. Conductors and associated poles and hardware will be considered for replacement if any of the following conditions exist:

   a. More than 3 outages or 10 outage hours per year excluding major storms and power supplier for two out of the past three years.

   b. Conductors with an average of greater than one splice per phase per span in one mile increments.

   c. Ordinary replacement of old, deteriorated conductor on a systematic basis.

   d. A significant amount of load that is served by aged, faulty conductor will be considered for refeeding if a more efficient route on existing right of way can be found.

7. Poles and/or crossarms to be replaced if found to be physically deteriorated by visual inspection or testing.

8. Standard conductor sizes evaluated by economic conductor analysis. The standard conductor sizes include the following:

OVERHEAD	UNDERGROUND
#2 ACSR	1/0 ALUG
1/0 ACSR	4/0 ALUG
4/0 ACSR and 336.4 ACSR	

9. All new primary construction is to be overhead except where underground conductor is required to comply with governmental or environmental regulations, local restrictions, design necessities, or favorable economics.

10. All new construction is to be designed and built according to RUS standard construction specifications and guidelines.

11. Capacitors placed on the system to maintain 90% power factor during system peak with an emphasis on correction to 95% correction as economics dictate.

12. Conductors and associated poles and hardware will be rebuilt or relocated if they present a potential hazard, are found to be unsafe, or fail to meet the applicable NESC requirements.

13. Consider the installation of dual voltage, 7.2 X 14.4 kV transformers on all new construction in areas that are designated for voltage conversion within the next load block of the Long Range System Plan.

14. Adjoining substations should have reserve capacity equal to the peak projected load transfer between them.

15. All substations should be equipped with a low-side bypassing scheme that will allow any given circuit recloser to be bypassed for maintenance while an adjacent recloser feeds the circuit through the bus system.

16. New substations metering should be equipped with a bypassing mechanism.

17. EKP member distribution cooperatives and other foreign utility interconnections should be considered in fringe areas of the system as an alternative to other types of present and future system improvements. This will be coordinated through East Kentucky Power.

18. A transmission loop through the system should be continuously evaluated based on developing loads and historical power supplier outage data. This will be evaluated with East Kentucky Power.

19. Per the NESC requirements, idle services shall be maintained or retired. Services that have been idle for more than two years should be evaluated for future use. If no use is foreseen, the service should be retired.

20. Fused cutouts and lightning arresters should be added to all existing CSP transformers on the three phase portion of the system between the substation and the first set of downline circuit reclosers.

21. All single phase taps that are between a three phase circuit recloser and the first set of downline, single-phase reclosers should be fused.

22. All outgoing conductor from 12 kV substations will be 336 ACSR or larger.
All outgoing conductor from 25 kV substations will be 4/0 ACSR or larger.

23. When a new substation is constructed or a second substation transformer is placed in an existing substation site, additional circuits will be needed in order to adequately distribute the new and/or additional substation capacity.

SUMMARY OF CONSTRUCTION PROGRAM AND COSTS

Shelby Energy Cooperative's distribution system was analyzed in order to identify the construction requirements needed to adequately serve the projected CWP load of 117 MW. Improvements were identified based on voltage drop, conductor loading, system reliability improvement, economic conductor analysis and operational experience. A narrative list of system improvements is located in Section IV.

A breakdown of proposed construction projects by RUS 740C codes is listed below in Table I-C-1.

Table I-C-1
System Additions and Improvements Summary

RUS Form 740C Category	Category Name	Estimated Cost
100	New Distribution Line	$5,250,000
300	Line Conversion & Replacement	$4,031,184
600	Misc. Equip & Poles	$4,203,640
700	Security Lights	$286,450
	2005-2009 CWP TOTAL	$13,771,274

100 – New Construction planned to serve 2,000 new services.

300 – 95 miles of conductor upgrading, replacement and feeder rehabilitation.

600 – Miscellaneous distribution equipment and pole changes. This includes voltage regulators, sectionalizing, meters, transformers, pole changes and increased service capacity upgrades.

700 – Other Distribution Items - Security Lights 702.

SHELBY CWP: I-C
Page 2

SHELBY ENERGY COOP 2005-2009 CWP
COST SUMMARY SPREADSHEET

NEW CONSTRUCTION -- RUS CODE 100

ITEM	RUS CODE	AVE. $/CONSUMER	# CONS.		EXT. COST	2005	2006	2007	2008	TOTAL
New Services	100	$2,625	2000		$5,250,000	$1,250,000	$1,287,500	$1,332,500	$1,380,000	$5,250,000
		TOTAL CODE 100:								

LINE CONVERSION / REPLACEMENT - RUS CODE 300

SUB - SECTION	RUS CODE	INST. COND/#-PH	$/MILES	# OF MILES	EXT. COST	2005	2006	2007	2008	TOTAL
Logan I - 486	301	#2 ACSR -1 Phase	$21,000	1.9	$39,900	$39,900				$39,900
Logan I - 430	302	#2 ACSR -1 Phase	$23,290	1.6	$37,264				$37,264	$37,264
Logan I - 477	303	#2 ACSR -2 Phase	$32,000	1.0	$32,000	$32,000				$32,000
Logan I - 473	304	#2 ACSR -2 Phase	$32,000	0.6	$19,200	$19,200				$19,200
Logan I - 476	305	#2 ACSR -1 Phase	$21,000	2.1	$44,100	$44,100				$44,100
Logan I - 489	306	#2 ACSR -2 Phase	$32,000	3.0	$96,000	$96,000				$96,000
Clayvillage - 360, 357-359	307	#2 ACSR -1 Phase	$22,500	3.7	$83,250			$83,250		$83,250
Clayvillage - 396, 896, 398 & 400	308	1/0 ACSR -3 Phase	$46,575	4.3	$200,273		$200,273			$200,273
Clayvillage - 397 & 399	309	#2 ACSR -1 Phase	$21,730	1.8	$39,114		$39,114			$39,114
Clayvillage - 422	310	336.4 ACSR - 3 Phase	$71,770	1.3	$93,300			$93,300		$93,300
Clayvillage - 361	311	#2 ACSR -2 Phase	$34,320	1.9	$65,208			$65,208		$65,208
Clayvillage - 313 & 314	312	#2 ACSR -1 Phase	$23,290	2.2	$51,238				$51,238	$51,238
Clayvillage - 309	313	#2 ACSR -1 Phase	$21,730	1.6	$34,768		$34,768			$34,768
Clayvillage - 625, 419 & 420	314	1/0 ACSR -3 Phase	$45,000	4.2	$189,000	$189,000				$189,000
Clayvillage - 345	315	#2 ACSR -2 Phase	$34,320	1.6	$54,912			$54,912		$54,912
Clayvillage - 393	316	#2 ACSR -2 Phase	$34,320	0.6	$20,592			$20,592		$20,592
Clayvillage - 341	317	#2 ACSR -1 Phase	$22,500	1.7	$38,250			$38,250		$38,250
Clayvillage - 364	318	#2 ACSR -1 Phase	$23,290	2.5	$58,225				$58,225	$58,225
Clayvillage - 757	319	#2 ACSR -1 Phase	$21,730	1.2	$26,076		$26,076			$26,076
Clayvillage - 366	321	#2 ACSR -1 Phase	$21,730	3.4	$73,882		$73,882			$73,882
New Castle - 303, 291, 293 & 294	322	DCT 336.4ACSR	$124,200	6.0	$745,200		$745,200			$745,200
New Castle - 284-287 & 289	323	336.4 ACSR - 3 Phase	$69,350	3.4	$235,790		$235,790			$235,790
New Castle - 306, 308, 929 & 830	324	1/0 ACSR -3 Phase	$46,575	3.9	$181,643		$181,643			$181,643
Campbellsburg - 220 & 221	325	#2 ACSR -1 Phase	$23,290	3.8	$88,500				$88,500	$88,500
Campbellsburg - 232 & 235	326	#2 CU Rehab	$12,000	3.6	$43,200				$43,200	$43,200
Campbellsburg - 150, 153, 154 & 158	327	#2 CU Rehab	$12,000	4.2	$50,400				$50,400	$50,400
Campbellsburg - 234	328	#2 CU Rehab	$12,000	2.0	$24,000				$24,000	$24,000
Bedford - 787, 89, 87 & 886	329	336.4 ACSR - 3 Phase	$67,000	3.8	$254,600	$254,600				$254,600
Bedford - 115	330	#2 ACSR -2 Phase	$35,480	1.5	$53,220				$53,220	$53,220
Bedford - 190 & 628	331	336.4 ACSR - 3 Phase	$67,000	1.8	$120,600	$120,600				$120,600
Southville - 506	332	#2 ACSR -1 Phase	$23,290	4.3	$100,147				$100,147	$100,147
Southville - 515 & 733	333	4/0 ACSR -3 Phase	$59,000	3.4	$200,600		$200,600			$200,600
Southville - 505, 547 & 498	334	#2 ACSR -2 Phase	$35,480	1.6	$56,770				$56,770	$56,770
Milton - 12, 629, 36, 38 & 40	335	336.4 ACSR - 3 Phase	$67,000	3.0	$201,000	$201,000				$201,000
Logan II - 449	336	#2 ACSR -1 Phase	$23,290	1.4	$32,606				$32,606	$32,606
Jericho - 541, 444, 446 & 731	337	336.4 ACSR - 3 Phase	$71,770	2.5	$179,425			$179,425		$179,425
Jericho - 931	338	#2 ACSR -2 Phase	$35,480	0.9	$31,932				$31,932	$31,932
Bekaert II - Katayama Feed	339	4/0 Cond. - 3 Phase	$75,000	1.8	$135,000			$135,000		$135,000
		TOTAL CODE 300:		95.1	$4,031,184	$996,400	$1,737,345	$669,937	$627,502	$4,031,184

CARRYOVER ITEMS

4. Why are momentary outages excluded?

Momentary outages (less than 5 minutes in duration) should not be included in reliability analysis since their causes typically arise from normal system operations such as a switching procedure or an oil circuit recloser operation in clearing a temporary line fault. However, excessive and/or repetitive momentary interruptions are indicative of problems on the distribution system that are considered power quality issues and very likely to cause reliability issues. For this reason, momentary interruptions are monitored and reviewed by Shelby in order to assure a high degree of power quality and take preemptive action against potential reliability issues.

Witness: Wayne Anderson
David Graham

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

Major storms are not excluded in Shelby's reporting of service interruptions to RUS on Form 7A, Part G (Refer to Exhibit 1-A). Major storms are however excluded from Shelby's internal analysis of service interruptions for the reason that a major storm whether ice, tornado or severe straight line winds are aberrations and inclusion of data from these aberrant events would skew the overall data to the extent that the overall data set would be corrupted and not be representative of normal system operating conditions.

Witness: Wayne Anderson
David Graham

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.**

Refer to Exhibit 6-A, RUS bulletin 161-1.

Witness: Wayne Anderson
David Graham

RUS BULLETIN 161-1

"Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems"

I. PURPOSE AND SCOPE

This bulletin provides guidance on recording and reporting service interruptions/outages, and the calculation of industry standard indices for measuring distribution system performance.

II. DEFINITIONS

AMR (Automated Meter Reading)

Interruption: A loss of electricity for any period longer than 5 minutes.

IEEE: The Institute of Electrical and Electronics Engineers.

IVR: Interactive Voice Response.

Outage: 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 o fservice to customers, depending on system configuration. This definition does not apply to generation outages.

SAIDI: System Average Interruption Duration Index.

SCADA: Supervisory Control and Data Acquisition.

Power Supply Interruption: Any interruption coming from the transmission system or the substation (even if the distribution system owns the substation or transmission system). If a distribution system owns a sub-transmission system, it and the sub-transmission to distribution substations are considered part of the distribution system. Not included are any substation breakers that go to lockout because of a fault on the distribution system. If there a delivery point is on the distribution system, interruptions caused by something on the source side of the delivery point would be considered a "power supply" outage.

Major Event: This is defined in IEEE Standard 1366-2004 and in Appendix 5 of this document. A major event represents an interruption or group of interruptions caused by conditions that exceed the design and operational limits of the system.

Major Event Day: A day in which the daily SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Stitistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

Prearranged Interruption: Any interruption scheduled by the distribution system in order for it to safely perform routine maintenance.

All Other Interruptions: All interruptions excluding power supply, major storm, and prearranged.

III. INTERRUPTION REPORTING

A. The Trouble Ticket

The generation of a trouble ticket is the first step in interruption reporting. The first goal of the trouble ticket is to get as much information as possible about the interruption and to pass this information along quickly to the people or systems that need it.

A trouble ticket is traditionally the result of a telephone call from a member reporting a service problem or interruption. These telephone calls have historically been taken by a customer service representative (CSR) using a manual "trouble ticket" form. However, with newer technology, cooperatives can automate this process and render the traditional trouble ticket paperless.

Cooperative personnel should give thought to the process of interruption data-gathering, reporting, and analysis and make a determination of the point at which this data should enter into an electronic format. Because of the flexibility of software systems and the advent of services and products like call centers and interactive voice response systems, the cooperative has many choices to improve its performance in this area.

1. Manual Trouble Ticket
The simplest interruption reporting is the use of a form as shown in Appendix 1. A cooperative employee could fill out this type form manually as they talk to the member on the phone. This same form could be used to dispatch crews and report the cause of the interruption and other pertinent information, making a complete record of the interruption report. It would be used to generate any interruption analysis or reports the cooperative may find useful.

2. Automated Trouble Ticket
Technology available today provides faster response to larger call volumes and allows for interruption data to be quickly assimilated into a computerized outage management system. The result is faster response and restoration times, as well as increased customer satisfaction. There are several methods for generating the

automated trouble ticket, including, but not limited to, the use of SCADA, AMR, IVR and call centers. For more discussion on these options, see Appendix 3 on page 17.

B. The Interruption Report

The interruption report is used to document a service interruption. Typically, an interruption report is completed each time a sectionalizing device opens permanently for the purpose of clearing a fault or de-energizing a section of line for construction or maintenance.

The report should provide enough information to comply with RUS and the state's public service commission reporting requirements for service reliability/continuity. Additionally, the form should capture information that will enable the Coop to calculate industry standard reliability indices, as well as to determine the effectiveness of various maintenance activities performed by the Cooperative.

A sample Interruption Report is included in Appendix 2.

C. Reports to RUS

Cooperatives that borrow funds from RUS are required to report the system average annual interruption minutes per consumer on Form 7 and Form 300. Shown below is Part G of Form 7 (Figure 1). The value used in this report is called SAIDI, System Average Interruption Duration Index. It is defined in detail in the Definitions Section of this Bulletin.

Part G. Service Interruptions					
Item	SAIDI (in minutes)				
	Power Supply (a)	Major Event (b)	Planned (c)	All Other (d)	TOTAL (e)
1. Present Year					
2. Five-Year Average					

Figure 1 – RUS Form 7 Part G

Form 7 calls for four separate SAIDIs as well at the total interruption time. The definitions of the terms used in Part G can be found in Part II, "Definitions".

IV. INTERRUPTION ANALYSIS

In addition to RUS reporting requirements, it is recommended that Cooperatives track additional information about service interruptions for more detailed analysis. The purpose of additional analysis is to provide feedback to the Coop's employees, management and board on how well the distribution system is serving the members.

There have traditionally been two codes associated with interruption reporting: cause codes and equipment codes. Every interruption has a cause, but not every interruption results in damaged or failed equipment, such as a recloser properly de-energizing a feeder when contacted by a tree limb. It is important to recognize the distinction between the cause of an interruption other than failed equipment, and a particular piece of equipment that is damaged or needs to be replaced. In the case where no equipment was damaged, the corresponding code in Figure 4, "0999, No Equipment Failure" would be used. Therefore, every interruption will have a cause code and an equipment code associated with it even when no equipment is at fault. Recommended cause codes are shown in Figure 3, and equipment codes are shown in Figure 4.

Weather Condition Codes indicate the conditions that existed when the interruption occurred; it is not to be confused with the cause code that indicates a weather component that might have initiated it. These are shown in Figure 5.

Voltage Level Codes can be used to identify system behavior that is a function of the operating voltage on the damaged components at the time of the interruption. The table in Figure 6 indicates the phase-to-phase voltage level, as some systems operate "Wye" configurations and others operate "Delta" configurations. It is generally accepted that higher voltage systems are more susceptible to lightning damage because of different Basic Insulation Levels (BIL). The cooperative engineer may be able to determine other improvements based on this data as well.

The codes are formatted such that summary and high level reports are easy to produce based on the data in the interruption report. The cooperative may choose to use additional codes for more detailed information and analysis. It is important to note that these tables link together the codes that the cooperative may use, as in the first column, and the codes prescribed by RUS and by IEEE.

Cause Codes			
Coop Code	**RUS FORM 7, Part G, Column**	**IEEE CODE**	**Description**
			Power Supply[1]
000	a	4	Power Supply
			Planned Outage
100	c	3	Construction
110	c	3	Maintenance
190	c	3	Other prearranged

[1] This cause code is used for outages caused by something on equipment not owned by the Distribution Cooperative. If an interruption is caused by something on the cooperative's own transmission system, then a specific cause should be used.

[2] This cause code should only contain those major event days that are determined using the IEEE "Beta Method" described in Part C of this section.

[3] Interruptions marked as "Cause Unknown" should be further investigated to try to determine probable cause.

			Equipment or Installation/Design
300	d	1	Material or Equipment Fault/Failure
310	d	10	Installation Fault
320	d	10	Conductor Sag or Inadequate Clearance
340	d	10	Overload
350	d	10	Miscoordination of Protection Devices
360	d	10	Other Equipment Install/Design
			Maintenance
400	d	1	Decay/Age of Material/Equipment
410	d	1	Corrosion/Abrasion of Material/Equipment
420	d	6	Tree Growth
430	d	6	Tree Failure from Overhang or Dead Tree without ice/snow
440	d	6	Trees with ice/snow
450	d	1	Contamination (Leakage/External)
460	d	1	Moisture
470	d	6	Cooperative Crew Cuts Tree
490	d	10	Maintenance Other
			Weather
500	d	2	Lightning
510	d	7	Wind Not Trees
520	d	7	Ice, Sleet, Frost Not Trees
530	d	7	Flood
590	d	10	Weather Other
			Animals
600	d	8	Small Animal/Bird
610	d	8	Large Animal
620	d	8	Animal Damage – Gnawing or Boring
690	d	8	Animal Other
			Public
700	d	5	Customer-Caused
710	d	5	Motor Vehicle
720	d	5	Aircraft
730	d	5	Fire
740	d	6	Public Cuts Tree
750	d	5	Vandalism
760	d	10	Switching Error or caused by construction/maintenance activities
790	d	10	Public Other
			Other
800	d	10	Other
			Unknown[3]
999	d	9	Cause Unknown

Figure 3 – Cause Codes

Equipment Failure Codes	
Coop Code	**Description**
	Generation or Transmission
010	Generation

020	Towers, poles and fixtures
030	Conductors and devices
040	Transmission substations
090	Generation or Transmission other
	Distribution Substation
100	Power transformer
110	Voltage regulator
120	Lightning arrester
130	Source side fuse
140	Circuit breaker
150	Switch
160	Metering equipment
190	Distribution substation Other
	Poles and Fixtures, Distribution
200	Pole
210	Crossarm or crossarm brace
220	Anchor or guy
290	Poles and Fixtures Other
	Overhead Line Conductors and Devices, Distribution
300	Line Conductor
310	Connector or clamp
320	Splice or deadend
330	Jumper
340	Insulator
350	Lightning arrester line
360	Fuse cutout (damaged, malfunction, maintenance)
370	Recloser or sectionalizer (damaged, malfunction, maintenance)
390	Overhead line conductors and devices, distribution other
	Underground Line Conductors and Devices, Distribution
400	Primary Cable
410	Splice or fitting
420	Switch
430	Elbow arrester
440	Secondary cable or fittings
450	Elbow
460	Pothead or terminator
490	Underground other
	Line Transformer
500	Transfromer bad
510	Transformer fuse or breaker
520	Transformer arrester
590	Line transformer other
	Secondaries and Services
600	Secondary or Service Conductor
610	Metering equipment
620	Security or street light

690	Secondary and service other
	No Equipment Damaged
999	No Equipment Failure

Figure 4 – Equipment or Material Responsible for Interruption

Weather Codes	
010	Rain
020	Lightning
030	Wind
040	Snow
050	Ice
060	Sleet
070	Extreme Cold
080	Extreme Heat
090	Weather Other
100	Clear, calm

Figure 5 – Weather Codes

Voltage Level Codes	
001	< KV(Secondary/Low Voltage)
002	5 KV
003	15 KV
004	25 KV
005	35 KV
006	60 KV
007	> 60 KV

Figure 6 – Voltage Level Codes

A. Use and Analysis of Interruption Data

The time spent collecting the data described above will be wasted unless it is analyzed and the results used as a tool to improve the distribution system performance.

There are many ways the data can be useful. For example, interruption records, which included data on equipment failures, led utilities to discover that two lightning arrester manufacturers had bad batches of arresters which were resulting in premature failures. Another utility used information on lightning damage and location to determine lightning prone areas in their territory. They then selectively improved the grounding only in these areas. This resulted in a least-cost reduction in interruptions due to lightning and also reduced equipment damage.

The goal of all of this is to reduce the number and duration of interruptions. To determine if you are spending your money wisely and truly reducing interruptions, you must keep consistent data over many years to show trends.

B. Definition And Use of the Major Indices

In this section we will discuss the definition of the most significant interruption-related indices and calculations. The following three indices should be calculated:

SAIDI-- System Average Interruption Duration Index
SAIFI-- System Average Interruption Frequency Index
CAIDI-- Customer Average Interruption Duration Index

The IEEE Standard 1366-2004[3] defines SAIDI as the total duration of interruption for the average customer during a predefined period of time (usually one calendar year). It is measured in customer minutes.

$$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Durations (over the period desired)}}{\text{Total Number of Customers Served}}$$

As stated above, SAIDI is usually calculated for a calendar year or "year-to-date", but for major event calculations, **daily** SAIDI values should be recorded. The starting time for the duration of the interruption calculation is determined by the time the cooperative knows about the interruption either by automated means or by the first phone call from the affected area. Interruptions where the customer indicates that the repair can be scheduled for a later date should be counted as an interruption, but with a duration being the estimated amount of time required to repair the problem, including travel time.

The total number of customers served is the average number of customers served over the defined time period. (The sum of the monthly customer count divided by the number of months.) This number should be the same as on the RUS Form 7 except that Public Street and Highway Lighting should not be included. (Security or safety lights, billed to a residential customer, should not be counted on the Form 7)

SAIFI is the number of interruptions that the average customer experiences during the year (or month or day). Interruption recovery time has no effect on this index.

$$\text{SAIFI} = \frac{\text{Total number of customers interrupted}}{\text{Total number of customers served}}$$

CAIDI is the average amount of time that a customer is without power for a typical interruption. It is primarily determined by response time to a reported interruption. However, the number of customers affected by an interruption can affect CAIDI because

[3] Guide for Electric Power Distribution Reliability Indices. IEEE P1366-2004, Copyright © 2003 by the Institute of Electrical and Electronic Engineers, Inc.

the distribution system has limited resources to respond to an interruption that covers an extensive portion of their territory.

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

C. Determination of a Major Event

There are certain things that are beyond the control of the distribution system, primarily natural disasters. Form 7 requires that the SAIDI for these interruptions be reported separately in Part G, Column (b), "Major Event" and not be included in Part G, Column (d), "All Other".

To date there has been no hard and fast rule of what constitutes a major event. It was usually defined as an event that lasted a specified period of time and which caused an interruption for at least a specified number of customers.

For example, an ice storm that results in interruptions of up to ten days and causes an interruption for 80% of customers is clearly a major event. In this case, the interruption records would be kept separately for this event. In calculating the SAIDI for the year, the interruptions from this event should be included in Column b.

What about a severe thunderstorm that caused some customers interruptions of up to 25 hours and where 5% of the customer experience some kind of interruption because of it? Is this a major event or not? Some distribution systems would say yes and others would say no.

It is very desirable to be more consistent across the nation and to take into account the fact that distribution systems with lower SAIDI's should have a lower threshold for what constitutes a "Major Event". The IEEE Working Group on System Design within the Distribution Subcommittee has carefully analyzed the situation and has developed a statistical approach to determine a threshold daily SAIDI level that determines a "Major Event Day". They have defined a major event as a interruption or series of interruptions that exceeds reasonable design and or operational limits of the electric power system. With the issuance of this Bulletin, RUS encourage all cooperatives to start using this approach: All outages that occur during a day determined to be a Major Event Day should be reported in RUS Form 7, Part G, Column (b).

This methodology is fully described in IEEE 1366, "Guide for Electric Power Distribution Reliability Indices" and in Appendix A of this Bulletin. The calculation involves taking the daily SAIDI values for the last five years and taking the natural logarithm of each value in the data set. For those who have an automated system of recording reliability information, this calculation should be easily obtainable. For those who use a manual system, RUS has developed a simple Access Database Form to determine the threshold level for major event days. The form is available to download from the RUS web site http://www.usda.gov/rus/electric/forms/index.htm.

The Interruption Reporting Form (Appendix A) is utilized to calculate the values required on RUS form 7, Part G. No other analysis is performed by this database.

D. Step Restoration Process

When service is restored in several steps, the calculations should be made separately and then added together. The explanation used by the IEEE can be found in appendix 5.

V. SERVICE CONTINUITY OBJECTIVES

A. Demand For Good Service

Rural electric systems now provide power to everything from the peanut farm to the computer network server farm. As utility service entities, cooperatives should strive to provide the level of service needed by the load, consistent with the cost the customer is willing to bear. Approaching reliability from the customer's perspective will help cooperative personnel develop appropriate levels of service for the customer's benefit. A goal may be to improve the CAIDI for a feeder by 20 minutes, or it may be to reach an "Average System Availability Index (ASAI) of "four nines" (99.99%).

In some instances, extreme levels of reliability may be needed which are beyond the cooperative's ability to provide when considering such things as feeder lengths or degree of environmental exposure, frequency of storms, extreme terrain, cost, etc. A joint approach may be used that involves adding facilities on the customer's premises that are owned and maintained by the customer, to achieve these high requirements. The cooperative may agree to meet a minimum reliability number supplemented by customer-owned backup equipment.

RUS guidelines for service reliability should take into consideration those areas that are controllable by the individual borrower and those items that are not. All interruption categories should be analyzed to determine if they are acceptable with regard to customer expectations. The cooperative should look at each category when determining/modifying operating and design practices/criteria. The Power Supplier should be consulted if Power Supply interruptions are excessive. For RUS Form 300, Part II, 7(a), the "All Other" classification will be the primary category for evaluation. The table below shows the current RUS guideline:

Description	All Other SAIDI, In Minutes
Satisfactory (rating of 3)	200 or less
Should Be Explained (rating of 2 or less)	More than 200

B. Establishing Reliability Objectives

When the cooperative sets a goal of reliability, personnel can then take a proactive role in bringing it about through system planning and budgeting. A thorough analysis of interruption causes, number of accounts affected, and durations can tell the engineering and operations staff where to concentrate their efforts. Listed below are several areas to consider for review:

Right-of-Way Clearing	Sectionalizing Scheme
Level of Lightning Protection	Response Time
System Grounding	Personnel Deployment
Pole Treatment/Maintenance	Use of Wildlife Guards
Construction Practices	Loading Levels for Ice and Wind
Level of System Automation	Line Patrolling Activities

By prioritizing likely contributors of interruptions, the engineer is better able to target capital expenditures for the near term to improve the system's overall performance. Long-term benefits of pursuing a continuous improvement in reliability include increased customer satisfaction, lower maintenance expenses, lower demands on operations personnel, better system performance during extreme weather events, and improved safety for lineworkers and the general public. Specific action to be taken by the cooperative to achieve or maintain a satisfactory interruption level should be addressed in the Construction Work Plan.

3. Other Indices

There are several other indices that the cooperative might want to use. Three of these-- SAIFI, SAIDI, and CAIDI-- were discussed above. One other that might be considered is MAIFI (Momentary Average Interruption Frequency Index). This is a measure of the number of breaker operations that do not go to lock-out. This could be used as means to measure system coordination. It might also be used as one measure of the quality of the power supply by recording momentary transmission interruptions.

4. Normalization For Weather

The weather varies across the country. It also varies from year to year. Most thunderstorms are not considered major events but they can have a dramatic effect on the number of customer interruptions throughout the year. By normalizing the interruption data to a "typical" year with regards to lightning, it is possible to see more clearly the condition of the system. A plot of the number of customer interruptions versus the number of cloud-to-ground lightning strikes may illuminate a system's improvement in protection, or decline if arrestors and grounding are not maintained.

Appendix 1

Manual Trouble Ticket

TROUBLE TICKET			
DATE	TIME	RECEIVED BY	
ACCOUNT NO.	REPORTED BY	PHONE NO.	TIME POWER WENT OFF
☐ SERVICE OFF ENTIRELY ☐ NEIGHBORS ALSO OFF ☐ SERVICE DROP DOWN ☐ LIGHTS DIM ☐ CHECKED FUSES	ADDRESS CAUSE LOCATION OF CAUSE		
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

Appendix 2

Interruption Report

INTERRUPTION REPORT					REPORT NO.		
DATE		TIME	RECEIVED BY				
LOCATION OR SWITCH NO.			REPORTED BY			TIME POWER WENT OFF	
SUBSTATION							
FEEDER			CAUSE				
DISTRICT			LOCATION OF CAUSE				
			ASSIGNED TO		TIME	TRUCK NO.	
ACTION TAKEN							
RESTORED SERVICE TO	DATE		TIME	NO. CUSTOMERS		CUSTOMER-MINUTES	
RESTORED SERVICE TO	DATE		TIME	NO. CUSTOMERS		CUSTOMER-MINUTES	
RESTORED SERVICE TO	DATE		TIME	NO. CUSTOMERS		CUSTOMER-MINUTES	

		TOTAL CUSTOMERS	TOTAL CUSTOMER-MINUTES	
MATERIAL OR EQUIPMENT	CODES			
	CAUSE	EQUIP	WEATHER	RUS FORM 7
REVIEWED BY				
Dispatcher	Superintendent	Engineer		

Appendix 3

Call Centers, SCADA, and IVR

Call Center

Call Centers have grown out of a need by cooperatives to handle larger call volumes with a person rather than a machine. The call center can either be staffed in-house by cooperative employees or outsourced to a call center at a different location. Due to economics or the desire to have high volume call handling capabilities with live customer service representatives out-sourcing may be the way to go for many cooperatives. In either case, the customer service representative will talk to the member gathering information needed to identify the member and the location of the interruption, including any other information the member may have about the interruption. The customer service representative may also be able to share information about the interruption with the member if they are already aware of the interruption. Call centers could then electronically forward this information to the appropriate operating personnel for dispatching and service restoration or as input to an interruption management system. In some cases, if properly equipped, the call center may actually dispatch the trouble ticket to the crew doing restoration.

Successful operation of a call center involves being sure the customer service representatives are trained to provide a positive image of the cooperative. The member should not be able to tell if the customer service representative (CSR) is a cooperative employee or an employee of an outsource call center. These CSRs should have fast reliable access to a customer database that will quickly provide account location and status (i.e., off for non-payment). This database should be updated at least daily. Theses CSRs should also have access to information concerning status of interruptions so they can keep members informed as the interruption progresses.

Interactive Voice Response Systems (IVR)

If a cooperative is willing to use advance call answering technologies they may want to investigate the use of an IVR system. These systems use electronic voice messaging to handle large call volumes fast and efficiently. These systems are especially attractive if the cooperative is using an automated interruption management system. Again, as in the call center application, these systems can either be implemented in-house or outsourced to third party vendors. Often this decision is based on a cooperative's ability to size their incoming phone lines to handle the phone traffic needed on large interruptions. For example, the existing cooperative capability may be only 12 – 24 incoming lines, while third party facilities may be capable of over 500 incoming lines. This increased call handling capability is especially critical if the cooperative is using an automated interruption management system. The cooperative may also consider using an emergency overload system where the calls go to the third party only after a set call volume is reached.

An IVR system works very similar to a call center except the customer is talking to a machine and not a live person. However, with advance speech recognition systems becoming more common, these systems are becoming more and more member friendly.

IVR systems require access to a current customer database giving account location and status (i.e. off for non-payment). Most IVR systems use member phone numbers for account recognition. This can be done using caller ID systems or by the member entering their phone number in response to a request from the IVR. Using phone numbers as account recognition requires cooperatives to be diligent in keeping phone numbers current for all accounts and in the case of multiple accounts the IVR system must have a method of distinguishing which account is actually out. This can be done by the IVR using text messaging of some account location field, which would uniquely identify the location to the member; or the IVR, using speech recognition, could ask the member to leave a message describing the proper location. If both of these methods failed the IVR could simply forward the member to a live person for resolution.

IVR systems also have the ability, when tied to an interruption management system, to give members feedback on interruption status and restoration time.

Appendix 4

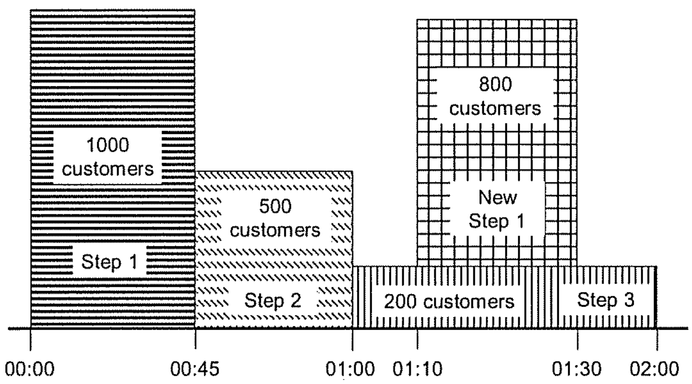
The Step Restoration Process and Example

The following case illustrates the step restoration process. A feeder serving 1,000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. The table shows the times of each step, a description and associated customer interruptions and minutes they were affected in a time line format.

Relative Time	Description	Customers	Duration (Minutes)	Customer-minutes of Interruption
00:00	1,000 customers interrupted.			
00:45	500 customers restored; 500 customers still out of service.	500	45	22,500
1:00	Additional 300 customers restored; 200 customers still out of service.	300	60	18,000
1:10	Feeder trips again, 800 previously restored customers interrupted again. (200 remained out and were not restored at this time.)			
1:30	800 customers restored again.	800	20	16,000
2:00	Final 200 customers restored. Event ends.	200	120	24,000
Totals:		1,800		80,500

Example SAIFI = 1,800/1,000 = 1.8 interruptions
Example CAIDI = 80,500/1,800 = 44.7 minutes
Example SAIDI = 80,500/1,000 = 80.5 minutes

The graph below shows the steps as they happened:



Appendix 5

Calculation of Major Event Days

The following process ("Beta Method") is used to identify major event days (MEDs). Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. This approach supercedes previous major event definitions.

A major event day is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the major event days, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period as follows:

1. Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical date are available, use all available historical data until five years of historical data are available.

2. Only those days that have a positive SAIDI/Day value will be used to calculate the T_{MED}. Exclude the days that have no interruptions.
3. Take the natural logarithm, (ln) of each daily SAIDI value in the data set.
4. Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
5. Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
6. Compute the major event day threshold, T_{MED}, using the equation below.

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

7. Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a major event day.

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

Shelby's approach to outage response and service restoration has its basis in the general principle of prioritizing outage situations or instances by:

1. Risk to public safety
2. Critical governmental and/or public health operations affected
3. Number of consumers affected

This is evident in the Service Restoration Procedure (Refer to Exhibit 7-A) and Description of Trouble Call Reporting and Dispatching Procedure (Refer to Exhibit 7-B). Developed for inclusion in the "Threat Alert System and Cyber Response Guidelines for the Electricity Sector" as directed by North American Electric Reliability Council (NERC).

Witness: Wayne Anderson
David Graham

SERVICE RESTORATION PROCEDURE

In order to assure that service is restored as quickly as possible in the most effective manner, the following priorities have been established for restoring service following a major interruption.

1 SUBSTATIONS

2 MAIN THREE PHASE FEEDERS

3 REMAINING THREE PHASE LINES AND TAPS

4 SINGLE AND TWO PHASE LINES

5 SHORT SINGLE PHASE TAPS

6 TRANSFORMERS

7 SERVICE WIRES

In addition, every effort will be made to expedite service to:

1 HOSPITAL(S)

2 NURSING HOME(S)

3 PUBLIC FACILITIES (Governmental and Public Use Facilities)

4 Individuals with special care needs who have registered in advance with the cooperative and provided substantiating documentation.

Outages that are potentially dangerous to the public (downed lines, low clearances, etc.) are given top priority when identified.

DESCRIPTION OF TROUBLE CALL REPORTING AND DISPATCHING PROCEDURES

When consumer calls to report an outage or downed power lines:

1 Record caller/consumer name.

2 Take phone number.

3 Road name or street address.

4 Any details they can give us about trouble.

5 While consumer is on the line - account number is confirmed.

6 This information is transferred to an outage report and given to dispatcher.

7 The dispatcher then will identify the area on the map and mark it.

8 The outage report is then arranged with the other outage reports and put in a priority according to the situation and severity.

9 The outages are called by two-way radio to the crews that are working.

10 The area where the crews are working is marked on the map. The dispatcher keeps a record of where each crew is and what line they are working on at all times.

11 When the crew calls the dispatcher that the line is back on service, the dispatcher records the time and trouble on the outage report, then dispatches the crew to a new location.

8. Refer to the RUS drawing M1.30G "Right-of-Way Clearing Guide" (ROW Guide), a copy has been provided in Appendix A.

a. 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?

Yes, the RUS Right-of-Way Clearing Guide M1.30G (Refer to Exhibit 8A-1) with the clearance requirements prescribed therein is appropriate for most all areas of Shelby's electric distribution system. Exceptions and exclusions should be considered in areas of operation of greater population density (ie: Subdivisions and other urban areas). Exceptions are also made for tall, off right-of-way trees that are considered a potential risk to the distribution line. Language in the Cooperative's right-of –way easement makes provisions for such exceptions. (Refer to Exhibit 8A-2).

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

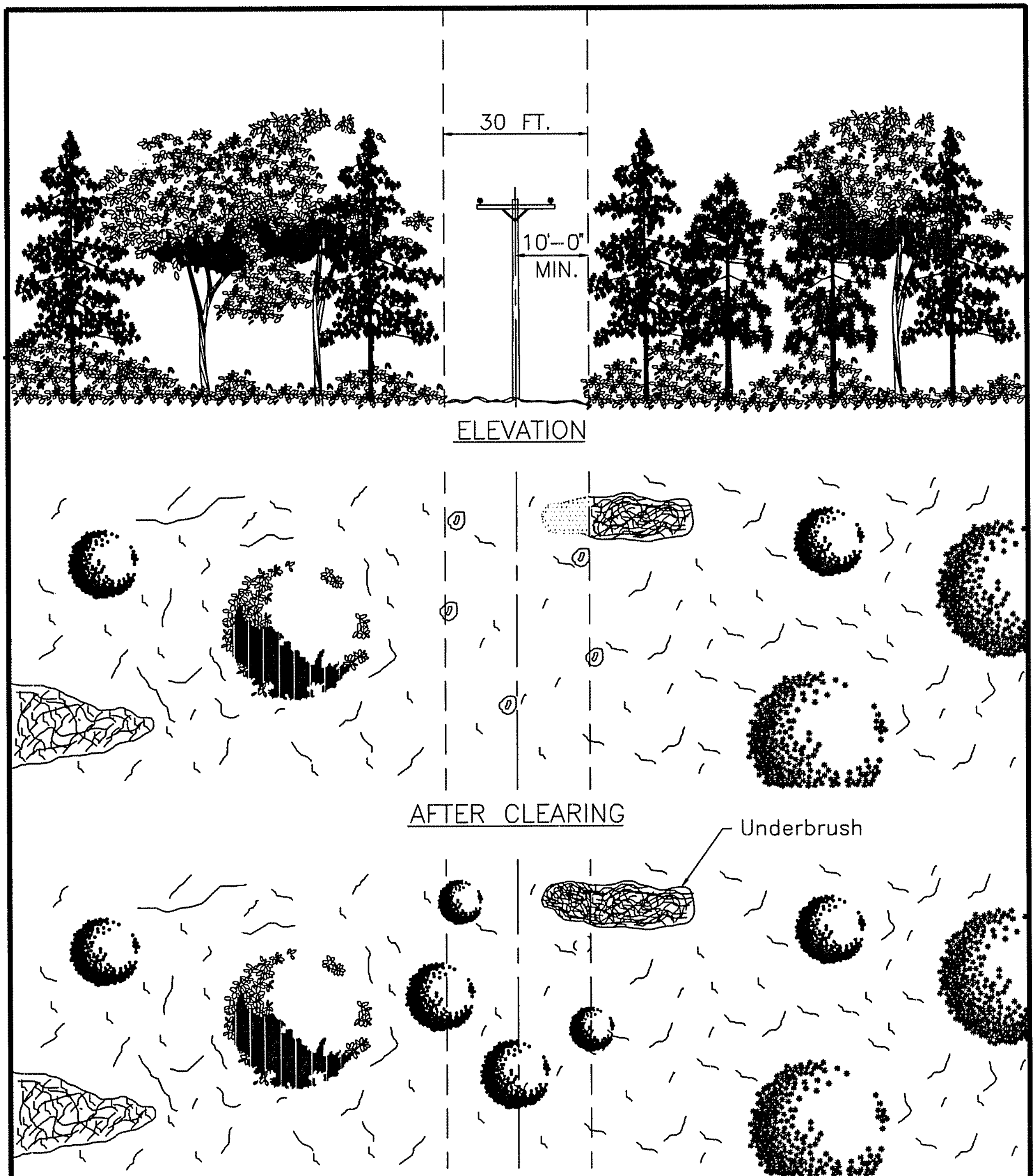
N/A

Witness: Wayne Anderson
David Graham

RIGHT-OF-WAY CLEARING SPECIFICATIONS

The right-of-way shall be prepared by removing trees, clearing underbrush, and trimming trees so that the right-of-way is cleared close to the ground and to the width specified. However, low growing shrubs, which will not interfere with the operation or maintenance of the line, shall be left undisturbed if so directed by the owner. Slash may be chipped and blown on the right-of-way if so specified.

The landowner's written permission shall be received prior to cutting trees outside of the right-of-way. Trees fronting each side of the right-of-way shall be trimmed symmetrically unless otherwise specified. Dead trees beyond the right-of-way which would strike the line in falling shall be removed. Leaning trees beyond the right-of-way which would strike the line in falling and which would require topping if not removed, shall either be removed or topped, except that shade, fruit, or ornamental trees shall be trimmed and not removed, unless otherwise authorized.



NOTE:
Change suffix of drawing number to designate clearing width. (e.g. M1.30G specifies 30 foot wide clearing).

RIGHT-OF-WAY CLEARING GUIDE		
DEC 1998		
RUS		M1.30G

Shelby Energy Cooperative, Inc.
Shelbyville, Kentucky

RIGHT OF WAY EASEMENT

Map Location No. ____________________

Work Order No. ________________

In consideration of **One Dollar ($1.00)** and other good and valuable considerations, receipt of which is hereby acknowledged, the undersigned hereby grant unto **Shelby Energy Cooperative, Incorporated** (hereinafter called the Cooperative), its successors and assigns, a perpetual right of way easement to construct, operate, maintain, add to and/or remove electric, telephone and cable distribution lines, together with such poles and equipment as are necessary and appropriate therewith, upon, over and/or under a thirty (30) foot wide strip across the lands of the undersigned which are located on the ____________ side of the ________________ Road about ______ miles _____________ of the town of ______________________, ____________ County, Kentucky; which lands were conveyed to the undersigned, and are more specifically described in the deed dated ____________________, ________, of record in the ____________ County Clerk's Office in Deed Book _______, Page ______ .

The said easement shall extend fifteen (15) feet on each side of the distribution line which shall be constructed according to the following course:____________________________

____
____
____
____
____
____
____
____ as shown on the attached drawing(s).

It is understood and agreed that no buildings or structures may be erected within the limits of this easement. The Cooperative is granted the right of ingress and egress over the lands of the undersigned to and from said distribution line(s) in the exercise of this easement and the right to do all trimming and removal of trees and branches which in the discretion of the Cooperative is necessary for the proper clearance of said lines.

The Cooperative shall promptly compensate the undersigned for damage to fences, crops, or animals caused by the Cooperative's use of the easement.

IN TESTIMONY WHEREOF, witness the signature(s) of the undersigned, this ________ day of _______________, ________.

____

____

____

____

STATE OF KENTUCKY
SCT
COUNTY OF SHELBY

The foregoing instrument was signed and acknowledged before me by _____________ ____ this _____ day of ___________, _______.

____
NOTARY PUBLIC, Kentucky State-at-Large
My Commission Expires: ________________

This instrument was prepared by Mathis, Riggs, Prather and Dean, P.S.C., 500 Main Street, P.O. Box 1059, Shelbyville, Kentucky 40066-1059, (502) 633-5220.

By: __________________________
Donald T. Prather

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

a. 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.

As a rural electric distribution cooperative, Shelby is obligated by its loan agreements with the Rural Utilities Services of the United States Department of Agriculture (RUS), to comply with its specifications, standards and guide lines relative to the design, construction, operation and maintenance of the electric distribution system. Given this, Shelby is satisfied with the RUS Right-of-Way Guide, M1.30. Additionally, the NERC Standard FAC-003-1is intended for electric transmission system applications where operating voltage levels are significantly higher than those found on distribution systems. This introduces the issue of potential flash over in the operation of these systems that is not found with the operation of an electric distribution system. There is also the matter of scope of effect that is significantly greater with the operation of an electric transmission system as opposed to an electric distribution system. A more strict standard for the maintenance of right-of-way is reasonable to apply to an electric transmission system where not only the operating voltage level is significantly higher, but also its scope of effect is more regional in nature, plus the interconnectivity of the regional transmission systems demands a higher degree of standard to ensure continuity of operation.

This is not to say however, that the FAC-003-1 Standard is not entirely applicable to the electric distribution system. An electric distribution utility should have a formal vegetation management plan (VMP), defining and delineating: the objectives, practices, approved procedures and work specifications involved therein. It is also crucial that personnel involved in meeting the objectives of the VMP have the proper training to safely and effectively carry out the tasks necessary in meeting these objectives.

Shelby does feel strongly however, that the level of reporting accountability as delineated in Part B, Paragraph R3 of the FAC-003-1 while entirely appropriate for the operation of an electric transmission system it is not appropriate for an electric distribution utility

Witness: Wayne Anderson
David Graham

9. (con't)

b. 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?

Shelby is capable of meeting the reporting requirement of NERC Standard FAC-003-1, R3. Shelby currently has in place and is using an interruption reporting system that logs all service interruptions by: date and time of occurrence, substation, feeder, line section and phase affected, nature and cause of interruption, number of consumers affected and the time service was restored. This data is summarized monthly for reporting to the Cooperative's Board of Directors and management staff and annually to RUS. Interruptions caused by vegetation (typically trees) is a category that is logged and tracked separately in this system. (Refer to Exhibit 1-C)

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

The Shelby Energy electric distribution system experienced a total of 81 sustained outages attributed to trees (or vegetation) during the calendar year 2006.

Witness: Wayne Anderson
David Graham

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

Shelby Energy has adopted the RUS M1.30G (Refer to Exhibit 8A-1) as its preferred right-of-way maintenance standard. Practice has been to apply this standard with some exceptions over Shelby's entire electric distribution system on a four year cycle. This practice has proven to be reasonably successful. Shelby is committed to the notion of continuous improvement and realizes the potential benefits of having a formalized vegetation management program. This will be further addressed in future annual cooperative work plans.

Witness: Wayne Anderson
David Graham

Questions 11-43 and 48-52 are not applicable to Shelby Energy.

Witness: Wayne Anderson
David Graham

44. Can Shelby Energy monitor SAIDI, SAIFI and CAIDI in addition to the measures noted in response to Staff's First Data Request?

Yes, Shelby monitors and records outages or interruptions in terms of SAIDI for reporting on an annual basis to RUS (Refer to Exhibit 1-A, RUS Form 7A, Part G). SAIFI and CAIDI indices can both be derived from this basic data.

Witness: Wayne Anderson
David Graham

45. Why doesn't Shelby Energy exclude any outages from its reliability measures?

Shelby does not exclude any outages from its reporting to RUS. The outage hours are categorized however by cause as follows: Power Supplier, Extreme Storm, Prearranged or Planned and Other. The first two categories (Power Supplier and Extreme Storm) represent causes that are beyond the control of most reliability efforts that the utility can reasonably be expected to implement on its system. Shelby does exclude the outage hours that result from these causes that are extraordinary from its internal reliability measures.

Witness: Wayne Anderson
David Graham

46. How many substations are equipped with SCADA? How many are not?

Twelve distribution substations are SCADA equipped on Shelby's system, one is not. The remaining substation to be SCADA equipped is scheduled for SCADA equipment installation by 2008.

Witness: Wayne Anderson
David Graham

47. How many reclosers beyond SCADA-equipped substations are equipped with SCADA?

Shelby has no distribution line devices SCADA equipped at this time and there is presently no plan in place to do so in the near term.

Witness: Wayne Anderson
David Graham