ATTACHMENTS TO MICHAEL D. CANNATA TESTIMONY

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Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 1

Received: May 14, 2010 Date of Response: May 21, 2010
Request No. Staff 1-25 Witness: Thomas P. Meissner, Jr.

Request

Reference Meissner testimony, page 178, lines 6-9. Please provide SAIDI, SAIFI and CAIDI data for each year from 2000-2009 broken down by the various types of causes of outages.

Response:

Please reference Staff Set 1-25 Attachment 1.pdf.

State of New Hampshire
Public Utilities Commission

Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 1
Received May 14, 2010

Cause Description	2000 SAIDI	2000 SAIFI	2000 CAIDI	2001 SAIDI	2001 SAIFI	2001 CAIDI	2002 SAIDI	2002 SAIFI	2002 CAIDI	2003 SAIDI	2003 SAIFI	2003 CAIDI	2004 SAIDI	2004 SAIFI	2004 CAIDI
Equipment Failure - Company	11.55	0.09	122.26	6.82	0.09	72.21	13.20	0.15	86.69	35.96	0.51	70.10	22.77	0.24	93.12
Equipment Failure - Customer	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	104.45	0.03	0.00	159.31	0.58	0.02	27.24
Overload	0.96	0.01	185.55	2.41	0.03	86.60	6.22	0.05	136.26	2.09	0.03	72.90	0.49	0.00	104.53
Improper Installation	0.00	0.00	38.00	0.04	0.00	75.00	6.83	0.03	250.70	3.03	0.02	151.54	0.00	0.00	0.00
Loose/Failed Connection	0.80	0.00	188.21	1.00	0.02	44.88	4.40	0.07	63.27	2.96	0.08	36.14	0.69	0.01	66.15
Scheduled, Planned Work	0.79	0.02	48.56	0.94	0.03	27.74	3.71	0.06	61.89	5.60	0.08	66.40	2.18	0.03	69.90
Lightning Strike	6.14	0.04	146.24	6.95	0.08	87.26	1.43	0.02	57.82	5.27	0.06	90.56	2.93	0.03	92.66
Corrosion/Contamination/Decay	2.16	0.04	59.30	2.94	0.02	190.37	2.36	0.03	87.57	0.16	0.00	92.48	0.34	0.00	140.18
Bird	1.00	0.01	73.80	0.02	0.00	39.84	0.82	0.01	102.17	0.12	0.00	60.36	1.18	0.02	51.09
Squirrel	1.30	0.02	70.12	8.59	0.12	73.47	17.23	0.12	148.11	7.68	0.08	97.02	19.14	0.14	132.50
Animal - Other	8.13	0.07	109.09	0.01	0.00	169.00	0.09	0.00	106.36	1.22	0.01	144.93	0.30	0.00	316.26
Power Supply Interruption/Disturbance	13.87	0.20	69.98	60.79	0.80	75.75	16.08	0.59	27.47	12.54	0.16	77.69	0.84	0.21	4.00
Operating Error/System Malfunction	0.01	0.00	125.00	0.00	0.00	0.00	2.26	0.03	83.10	0.02	0.00	66.92	0.61	0.02	34.06
Action by Others	0.90	0.02	38.14	0.54	0.01	62.14	5.63	0.10	57.70	0.82	0.01	91.49	0.21	0.00	71.39
Civil Emergency (fire, etc.)	0.00	0.00	275.00	0.89	0.01	159.67	0.24	0.00	108.84	0.01	0.00	127.57	0.00	0.00	58.00
Human Contact	0.00	0.00	37.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vandalism	0.00	0.00	0.00	0.00	0.00	0.00	0.59	0.01	108.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle Accident	8.21	0.05	152.44	2.39	0.01	165.38	7.32	0.08	94.94	1.05	0.02	64.18	12.53	0.13	95.26
Broken Tree/Limb	19.19	0.23	84.82	20.14	0.21	96.01	44.00	0.45	97.96	56.99	0.56	101.36	34.82	0.34	102.25
Tree/Limb Contact - Growth into Line	11.58	0.12	98.96	6.84	0.05	130.78	13.54	0.14	99.97	5.91	0.06	101.67	7.74	0.08	99.34
Patrolled, Nothing Found	5.59	0.06	95.77	3.86	0.05	71.32	5.27	0.06	84.26	5.35	0.07	78.27	10.64	0.10	109.49
Other	47.17	0.55	86.06	29.77	0.58	51.24	9.20	0.08	115.05	1.87	0.06	31.67	0.45	0.02	24.58
Totals	139.36	1.531		154.92	2.118		160.42	2.053		148.70	1.812		118.43	1.410	

Cause Description	2005 SAIDI	2005 SAIFI	2005 CAIDI	2006 SAIDI	2006 SAIFI	2006 CAIDI	2007 SAIDI	2007 SAIFI	2007 CAIDI	2008 SAIDI	2008 SAIFI	2008 CAIDI	2009 SAIDI	2009 SAIFI	2009 CAIDI
Equipment Failure - Company	26.70	0.20	130.49	25.68	0.27	94.14	14.96	0.14	105.28	29.54	0.17	177.19	21.26	0.34	61.69
Equipment Failure - Customer	0.20	0.00	158.21	0.01	0.00	73.89	0.78	0.01	140.00	0.00	0.00	11.25	0.00	0.00	0.00
Overload	2.38	0.02	125.85	1.22	0.02	78.88	1.62	0.01	122.19	1.41	0.01	146.65	0.20	0.00	94.82
Improper Installation	0.00	0.00	80.00	0.03	0.00	60.97	0.31	0.00	212.55	0.01	0.00	189.00	0.10	0.00	119.00
Loose/Failed Connection	5.33	0.03	174.93	9.45	0.15	64.18	1.97	0.04	44.51	3.06	0.04	85.64	11.51	0.07	164.78
Scheduled, Planned Work	4.52	0.05	94.29	4.92	0.10	48.55	4.39	0.05	85.60	6.43	0.07	91.76	7.10	0.12	60.60
Lightning Strike	8.42	0.13	66.75	12.68	0.08	152.75	14.70	0.10	151.41	17.87	0.21	84.75	2.34	0.02	105.55
Corrosion/Contamination/Decay	0.54	0.01	74.18	0.05	0.00	95.49	2.46	0.06	43.96	0.04	0.00	84.71	0.43	0.01	51.73
Bird	2.50	0.02	139.71	4.94	0.05	106.27	7.39	0.05	136.60	0.81	0.01	95.50	0.08	0.00	60.36
Squirrel	4.20	0.06	64.99	2.05	0.03	70.56	3.42	0.05	72.57	3.29	0.02	133.99	4.12	0.07	62.87
Animal - Other	3.20	0.02	211.93	1.41	0.04	31.41	0.00	0.00	0.00	1.32	0.01	106.42	2.63	0.01	196.98
Power Supply Interruption/Disturbance	1.49	0.08	18.00	0.00	0.00	0.00	9.04	0.39	23.12	0.00	0.00	0.00	9.30	0.45	20.51
Operating Error/System Malfunction	5.87	0.31	19.11	0.87	0.10	8.98	0.00	0.00	0.00	0.01	0.00	64.55	0.35	0.00	73.29
Action by Others	2.56	0.07	35.11	4.34	0.08	51.69	3.17	0.05	60.91	0.12	0.00	47.23	1.30	0.01	151.15
Civil Emergency (fire, etc.)	0.00	0.00	105.00	0.11	0.00	168.29	0.30	0.00	199.46	0.03	0.00	123.65	0.01	0.00	170.00
Human Contact	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00	87.00	0.00	0.00	0.00	0.00	0.00	0.00
Vandalism	1.50	0.01	110.65	3.79	0.04	84.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle Accident	11.05	0.07	165.64	9.24	0.09	105.22	13.31	0.07	179.49	11.68	0.08	149.98	17.12	0.17	101.21
Broken Tree/Limb	80.50	0.83	97.09	64.06	0.69	92.47	43.04	0.46	92.92	82.82	0.72	115.22	52.30	0.56	93.76
Tree/Limb Contact - Growth into Line	14.49	0.21	70.06	15.77	0.12	129.63	9.22	0.10	93.59	9.29	0.09	104.92	10.30	0.09	111.62
Patrolled, Nothing Found	15.01	0.13	112.41	11.67	0.13	92.49	15.23	0.15	100.71	12.84	0.11	122.18	12.26	0.10	117.67
Other	1.39	0.02	81.86	1.27	0.05	24.62	1.82	0.05	35.62	1.73	0.02	111.30	1.17	0.03	35.51
Totals	191.84	2.264		173.74	2.048		147.34	1.797		182.30	1.548		153.89	2.068	

Request

Reference Meissner testimony, page 181, lines 3-5. Please describe the actions UES has taken since 2000 to try to address declining reliability.

Response:

Unitil Energy conducts formal reliability analysis on an annual basis. Trouble report information is analyzed to identify poorly performing areas of the system. These areas are then analyzed through the use of GIS to plot historical trouble locations on a map. Engineers review these maps and develop reliability improvement projects to target these specific areas. Examples of projects resulting from this analysis include, but are not limited to: adding fuse locations; reconductoring with spacer cable; proactively replacing equipment with abnormally high failure rates; SCADA additions; tree trimming; or circuit transfers to name a few. All of the proposed projects are ranked based upon 1) cost per saved customer minute and 2) cost per saved customer interruption. This ranking is used during the capital budget process to identify the most beneficial projects.

Please reference Staff 1-26 Attachment 1.pdf, which identifies the specific reliability projects that have been completed since 2000.

State of New Hampshire
Public Utilities Commission
Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 1

Staff 1-26 Attachment 1

Year	Project
2000	Circuit 22W3 - Install Reclosers
2000	Circuit 8X3 - Install Grounding Bank
2000	Circuit 2H2 - Install Spacer Cable Equipment
2000	Circuit 8X3 - Install Recloser and Cutouts
2000	3356 Line - Insulator Replacements
2000	Circuit 47X1 - Install Cutouts
2000	Install Fault Indicators
2000	22X1 Reliability Project - Transfer to 56X1
2000	Circuit 23X1 - Install Cutouts
2000	Circuit 22X1 - Install Cutouts
2000	Circuit 18X1 - Install Cutouts
2001	Circuit 22W3 Install Reclosers
2001	Install Fault Indicators
2001	Circuit 6W1 - Install Cutouts
2001	Circuit 23X1 - Install Cutouts
2001	Circuit 2H3 - Install Cutouts
2001	Circuit 3H2 - Install Cutouts
2001	New Meadows Cable Injection
2001	Circuit 211A - Replace Underground Cable
2002	Hampshire Drive Cable Replacement
2002	Circuit 13W2 - Install Tree Wire
2002	Replace 6" Porcelain Suspension Disc Insulators
2002	Circuit 1X5 - Install Cutouts
2002	Circuit 13W2 - Install Cutouts
2002	SCADA Upgrade
2003	Replace Cutouts
2003	Guinea Substation SCADA Upgrades
2003	Replace 6" Porcelain Suspension Disc Insulators
2003	Bridge Street Substation - Bus Protection
2004	Brookwood Urd Upgrade
2004	Circuit 7W3 - Reconductor with Tree Wire
2005	Iron Works Substation - Install Animal Protection
2005	Circuit 22W3 - Reconductor Lewis Lane with Spacer Cable
2005	Circuit 13W2 - Install Sectionlaizer
2005	Westville Substation - Install Animal Protection
2005	East Kingston Substation - Install Animal Protection
2005	SCADA Upgrades (Master Station and 8 RTU Additions)
2005	Replace 6" Porcelain Suspension Disc Insulators
2006	Bow Junction Substation - Install Animal Protection
2006	Boscawen Substation - Install Animal Protection
2006	Circuit 8X3 - Install Recloser
2006	Circuit 22X1 - Install Fault Indicators
2006	Circuit 6W1 - Install Reclosure
2006	Circuit 58X1 - Install Reclosure
2006	Replace 25/27kV Cutouts

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State of New Hampshire
Public Utilities Commission
Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 1

Staff 1-26 Attachment 1

Year	Project
2006	Shaws Hill - Replace Post Insulators on Switch
2007	SCADA Upgrades (8 RTU Additions)
2007	Replace 25/27kV Cutouts
2007	Circuit 51X1 - Install Recloser on Winnicut Road
2007	Circuit 51X1 - Install Recloser
2008	375 Line Replace Shield Wire
2008	Installation of Tie Switch between 3354 and 3371 Line
2008	Exeter S/S - Replace 4kV switchgear with 2 circuit positions
2008	Guinea Station relaying
2009	Circuit 13W2 - Upgrade High St Recloser
2009	Circuit 22W3 - Install Recloser on Logging Hill Rd
2009	Circuit 22W3 - Birchdale Rd, Bow Install Spacer Cable
2009	Circuit 21W2 Install Reclosing on Main Street
2009	Circuit 58X1 Reconductor Pollard Road with Spacer Cable
2009	Circuit 21W1 Install Reclosing on Meditation Lane
2010	Circuit 13W2 Rebuild High St p. 83 to 110 on other side of the Street
2010	Circuit 22X1 Install a Recloser on Danville Road
2010	Circuit 18X1 Install a Recloser on Route 27
2010	Circuit 5H2 Install a Recloser on Sweet Hill Road
2010	Exeter Switching Install Automatic Transfer Scheme
2010	Circuit 7X2 S/S Recloser Replacement
2010	Circuit 23X1 Install a Recloser on Mill Lane
2010	Pollard Rd, Plaistow, Circuit 58X1

State of New Hampshire
Public Utilities Commission

Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 1
Received May 14, 2010

Data Request Staff 1-31:

Reference Meissner testimony, pages 223-227. Please provide copies of any UES and/or PSNH/NU studies detailing the system improvements being undertaken and the resulting need to rebuild and expand the Kingston and East Kingston substations.

Supplemental Response:

Please refer to Staff 1-31 Supplement Attachment 1 for an update to the proposed schedule for the Kingston Substation addition.

The schedule for this project had previously been identified in the 2009 PSNH/UES Joint Planning Recommendation Report provided as Staff 1-31 Attachment 2.

Person Responsible: Thomas P. Meissner Jr. **Date: October 29, 2010**

Request

Reference Meissner testimony, pages 224-226. Please provide support for UES' conclusion that the Unitil Energy load served by the Kingston and East Kingston substations will exceed planning criteria loading limits in the summer of 2012. Please explain how UES' load growth conclusion corresponds with the data provided regarding declines in energy sales (see, e.g., pp. 13-17).

Response:

The base case peak demand loading on the PSNH/NU Kingston substation transformer TB91 is expected to exceed its rating in the summer of 2010 (124% of the summer rating). Unitil Energy plans to implement an abnormal switching configuration during the summer months of 2010 and 2011 to decrease the loading on TB91 to below the thermal limit (96% of the summer rating). However, this alternate configuration only alleviates the loading on TB91 long enough to delay the in-service date of the proposed capacity expansion until 2012. By the summer of 2012 the loading on TB91 will exceed the thermal limit (101% of the summer rating) even with the alternate switching, absent the substation upgrade.

The peak demand loading for Circuit 6W1 out of East Kingston S/S is projected to reach 5,836 kVA (93% of the circuit rating) by the summer of 2010, and to increase to 6,142 kVA (98% of the circuit rating) by the summer of 2012. These projections are higher than earlier projections from the Unitil Energy Systems – Seacoast, Distribution System Planning Study 2010-2014. There are no alternatives to alleviate loading on this circuit other than the proposed project. In addition, this project provides reliability benefits as it will take a large circuit and split it into two smaller circuits, significantly reducing customer exposure.

Unitil Energy's load growth conclusion is based upon load, or peak demand, as measured in kilowatts (KW) or megawatts (MW). The data provided in the Company's testimony regarding declining energy sales (e.g., pp 13-17) pertains to energy consumed, as measured in kilowatt-hours (kWh). These two quantities can vary independently, and may in fact move in opposite directions. Energy (sales) and load (demand) are related to each other through the quantity known as Load Factor, which is defined as the average power divided by the peak power over a period of time. The average power consumed over a period of time is equivalent to energy sales consumed over that period of time divided by the time period (hours).

Declining energy sales would have the effect of decreasing the average power consumed over a period of time. This would in turn result in a decline in Load Factor if the peak demand does not decline in proportion to the decline in energy sales. In fact, this is exactly the pattern that Unitil Energy has experienced over an extended period of time. Load Factor on the Unitil Energy system has declined significantly. This can be attributed to penetration of summer cooling load (air conditioning) on the Unitil Energy system, which has resulted in a sharp spike in electrical demand without a commensurate increase in sales. The Unitil Energy system has become very "peaky", and experiences a sharp spike in demand on the hottest days of the year, though this load is not otherwise present the rest of the year.

The need for capacity additions at Kingston and East Kingston is driven by peaks in electrical demand that occur during heat waves in the summer. These peaks in demand do not correlate to the overall declining sales trend throughout the reminder of the year.

Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 3

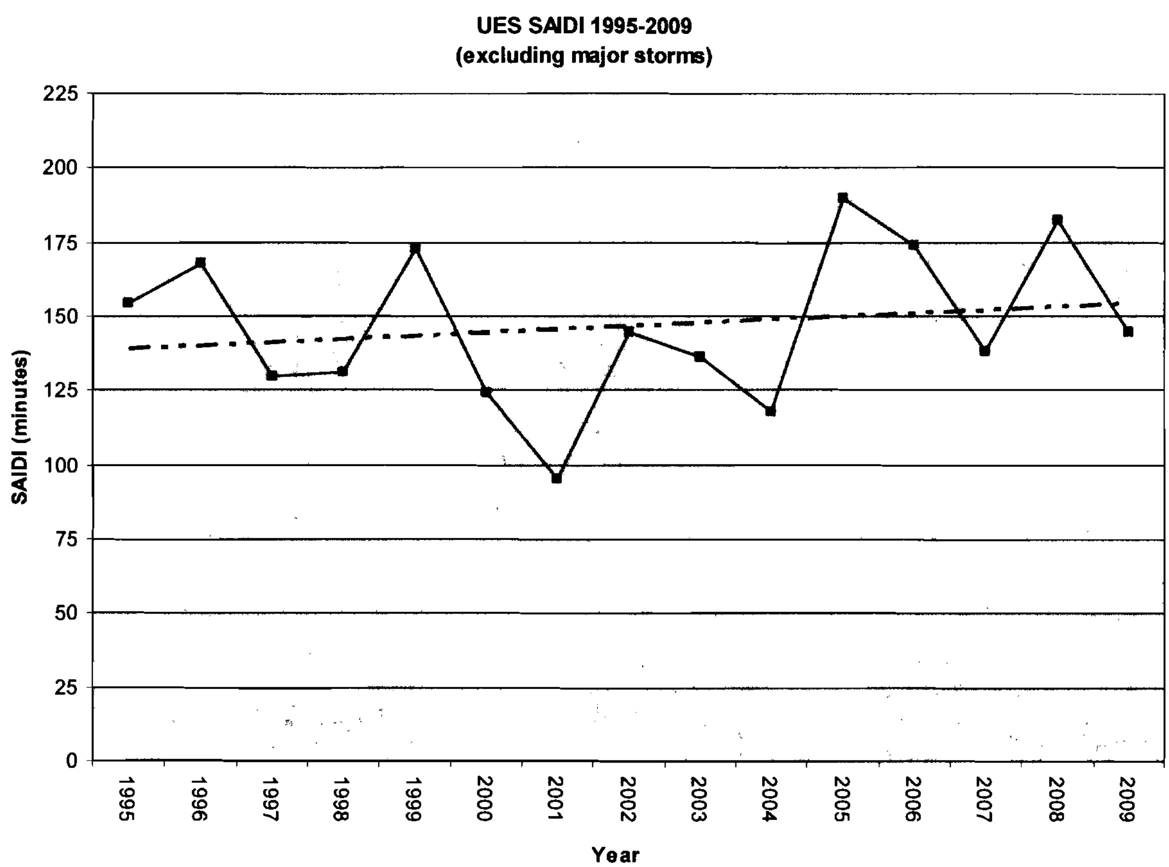
Received: July 1, 2010	Date of Response: July 15, 2010
Request No. Staff 3-27	Witness: Thomas P. Meissner, Jr.

Request:

Reference Meissner testimony, page 5 (Bates 0177), Figure TPM-2. Please supply Figure TMP-2 by operating company and including data from 1995 through 1999. As part of your response, please confirm that the data is for NH operating companies only and that major storm exclusions are based on the NHPUC definition of a major storm.

Response:

The chart below provides the annual SAIDI for UES including data from 1995 through 1999, with major storms excluded. The data is for New Hampshire only (UES); the major storm exclusions are based on the NHPUC definition of a major storm.



Request:

Reference Meissner testimony, page 8 (Bates 0180), lines 11-16. From 1995 through 2000, the UES operating companies stipulated to reliability improvement measures with Commission Staff as a result of reliability dockets. Please list the reliability improvement measures undertaken in that endeavor, describe UES actions during that 5-year period for each action, and state what UES action for each has been from 2000 through 2009.

Response:

For purposes of this response, the witness assumes that the referenced dockets were DE 96-128 (Concord Electric Company) and DE 96-129 (Exeter and Hampton Electric Company). A copy of the independent audit of the referenced dockets, prepared for the New Hampshire PUC by Barrington-Wellesley Group, Inc., and dated October 6, 2000, is provided as Staff Set 3-30 Attachment 1. The attachment lists the reliability improvement measures and actions taken during referenced 5-year period. The results and findings of the Barrington-Wellesley report were also reviewed in detail in a meeting with Commission Staff on July 11, 2002. The Company provided information and documentation at that meeting confirming compliance with each action in the settlement agreements.

The compliance obligations imposed by dockets DE 96-128 and DE 96-129 ended with the year 2000. However, the Company generally continued the practices identified in the referenced dockets as follows:

1. *Maintain or exercise funding that will support an average five-year distribution and transmission trimming cycle through the year 2000. Such trimming will be done according to the specifications which are as strict as those currently in effect.*
    - UES' original trimming cycles were differentiated by voltage class, and were specified as 5 years for subtransmission, 4 years for 34.5 kV, 5 years for 13.8 kV and 8 years for 4.16 kV. Clearances were defined above, adjacent and below conductors.
    - The trimming cycles remained in effect until February 1, 2007, when they were revised to differentiate between single phase and three phase construction, in addition to voltage.
    - The clearance specifications remained in effect until February 1, 2007, when they were revised to differentiate between single phase and three phase construction
    - The Company has maintained funding for its trimming program throughout the period of 2000 to 2009, though has been unable to increase funding sufficient to maintain the defined cycles in the face of increasing costs.

2. *By the end of the fourth quarter of 1998, re-evaluate the Distribution and Transmission Vegetation management Plan. Such a study to include the merits of establishing a different year cycle and other policies as appropriate.*
   - UES completed the study as required, by the fourth quarter of 1998.
   - A subsequent study was performed in 2000 to review and further enhance the vegetation management plan, and to incorporate performance measures. A new vegetation management policy (OP5.00) was developed and implemented January 2, 2001, which remained in effect until 2007.
   - In 2006, another study was performed to re-evaluate the distribution management plan. Clearances and cycles were revisited for single phase versus three phase construction. Changes to policy OP5.00 were implemented effective February 1, 2007.
   - In 2009 UES retained Environmental Consultants, Inc. ("ECI") to develop a comprehensive vegetation management program based on field workload surveys and tree re-growth studies from data gathered in the UES service area. Please refer to Meissner Testimony at page 37 (Bates 0209) beginning at line 20 for a description of the most recent study.
3. *Issue notifications in accordance with State regulations prior to the use of herbicides on its rights-of-ways. Inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work.*
   - The requirement to issue notifications in accordance with State regulations prior to the use of herbicides was incorporated into policy OP5.00 Vegetation Management as section 4.1.3.
   - UES subsequently curtailed the use of herbicides on its rights-of-ways, though this decision is being revisited as part of the most recent vegetation management study.
4. *Maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practices of its entire distribution system by the end of year 2000.*
   - UES completed the comprehensive engineering analysis and installed fusing or other protective devices on taps in accordance with the original agreement.
   - UES continues to fuse or otherwise protect circuit taps in accordance with good utility practice.
   - UES continues to perform comprehensive engineering analysis of all circuits on a cycle not to exceed three years. However, with advancements in GIS and the ability to seamlessly export circuit models to engineering analysis software, circuits are now generally reviewed annually.

5. *Provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reliability reporting requirements.*
   - UES continues to include data on device operations as part of its year-end reliability reporting to the Commission.

6. *Maintain the reliability of services to residential homes which in most cases, can be accomplished by limited trimming. Perform trimming required to make the service safe and reliable through coordination with the customer. If a customer requests trimming, assess each situation on a "case by case" basis. If a customer requests trimming over and above what is required to make the service safe and reliable, supply the customer with a list of private contractors to perform the work. Services will be reviewed at least once per distribution trimming system.*
   - UES has continued the same practices with regard to trimming of customer services, consistent with the compliance findings in the Barrington Wellesley report. These requirements are detailed in sections 4.2.4 and 4.2.5 of OP5.00 Vegetation Management.

7. *Commencing with its 1997 third quarter service reliability indices filing, provide data indicating reliability with and without off-system supply caused outages.*
   - UES continues to provide data indicating reliability with and without off-system supply caused outages as part of its quarterly and annual reliability reporting to the Commission.

8. *Maintain or exercise funding that will support a System Reliability Improvement Program to accomplish the types of projects as listed in, but not limited to, the 1996 through 2000, Five Year Capital Construction Budget.*
   - UES continues to maintain and exercise funding supporting a System Reliability Improvement Program as part of its annual capital planning and budgeting process, and continues to budget reliability projects in a manner consistent with the program described in the Barrington Wellesley report.
   - Reference Staff 3-33 for actual reliability improvement expenditures each year from 2000 through 2009.

PROJECT TITLE: State of New Hampshire
Electric Utility Reliability
An Independent Analysis

PREPARED FOR: State of New Hampshire
Public Utilities Commission
8 Old Suncook Road
Concord, NH 03301-7319

DATE: October 6, 2000

PREPARED BY: Barrington-Wellesley Group, Inc.
Management Consultants
P.O. Box 2390
New London, NH 03257-2390

SCOPE

The scope of this project is to provide an independent assessment of the electric utilities under the jurisdiction of the New Hampshire Public Utilities Commission (PUC) against the reliability docket for each utility. The utilities and the respective dockets are as follows:

UTILITY	DOCKET #
Granite State Electric Company (GSE)	DE 96-125
New Hampshire Electric Cooperative (NHEC)	DE 96-127
Connecticut Valley Electric Company (CVEC)	DE 96-126
Concord Electric Company (CECO)	DE 96-128
Exeter and Hampton Electric Company (E&H)	DE 96-129
Public Service Company of New Hampshire (PSNH)	DE 95-194 DE 97-034

Each docket relates to reliability issues relevant to each utility. In general, the Dockets cover such areas as vegetation management, system protection and fault isolation, reliability projects and (PUC) reporting requirements on reliability indices. The Docket for each utility was reviewed and the conformance with their Docket was used as the basis of the evaluation.

METHODOLOGY

Barrington-Wellesley Group, Inc. (BWG) completed site meetings along with PUC personnel of each utility on October 25 and 26, 1999. The purpose was to introduce BWG personnel and to allow them some time to assemble information relative to the Docket.

Based upon the respective Dockets, BWG then prepared a set of data requests that were sent to each utility contact person. The data requests solicited information relative to the utility practice on distribution system overcurrent protection and practices, details of the utility Vegetation Management Program and details on the utility reliability projects. The purpose was to acquaint BWG personnel with the particular utility system, its protection practices and to gather preliminary data relative to the reliability Docket. The intent was to assemble general information prior to site meetings so that a more focused approach could be accomplished in the meetings in order to minimize the amount of field time. The data request was sent to the respective utilities in early November.

Site meetings with the utilities were completed between December 1, 1999, and January 20, 2000. The information received from the data requests and the respective Docket was used to further probe compliance with the Docket. Depending upon a number of factors, the utility site meetings ranged from one to four day visits. The meetings consisted of interviews with engineering and operating personnel. The relevant personnel include distribution and project engineers, area operating superintendents, and vegetation management personnel. The areas relative to system protection and comprehensive overcurrent studies, reliability projects, and reliability indices were conducted with the distribution engineers and operating personnel. The area relative to vegetation management was conducted with operating personnel and vegetation management staff. The site meeting consisted of face-to-face meetings discussing the various aspects of the Docket and field trips to review samples of reliability projects and vegetation management practices.

Each utility was asked the same general questions relative to its Docket; each utility was free to support its position with documentation. This approach resulted in fair treatment among utilities without any preference of one utility over the other.

FINDINGS

The following section contains excerpts from the Dockets (italicized) of the relevant sections for each utility. The findings are detailed in regular type after each section.

OVERALL CONCLUSION

Essentially, all the utilities have increased their efforts to improve reliability. They have improved their Vegetation Management Program and increased their awareness and spending, on reliability. The expectation is that their reliability performance will improve directly due to these efforts.

It is recommended that as the utilities move forward they continue with these types of programs to improve their performance and not consider them to be a one-time requirement.

A concern of several of the utilities was the poor cooperation from Bell Telephone on joint use issues. They indicated that it was often difficult to get them to pay their fair share of work, namely tree trimming issues. Because of this, a bigger burden of the tree trimming costs is funded by the utilities.

NHPUC DOCKET DE 96-125

AGREEMENT

1. *Granite State Electric Company (GSE) will maintain or exercise funding that will support an average five-year trimming cycle through the year 2000. Such trimming will be done according to the specifications which are as strict as those currently in effect.*

In compliance -

- Tree trimming budget versus actual on par from 1995 – Present
- Detailed trimming specification in use
- Comprehensive pre-bid and bid evaluation in place
- Written documented audits in place
- 85-100% inspection of work
- Tree trimming crew evaluated on quarterly basis
- Program in place is well documented and tightly controlled

Granite State Electric Company (GSE) has made significant progress in its tree-trimming program. In both the Lebanon/Walpole and Salem districts, they are well into their second cycle of a five-year trimming cycle.

The progress on their tree-trimming program is as follows:

T&D Trimming Actual Dollars vs. Budgeted for the period covered in the Docket

Year	Actual	Budgeted
1995	$547,586	$522,200
1996	$640,457	$625,000
1997	$664,185	$685,000
1998	$612,842	$630,000
1999 (YTD)	$517,662	$630,000
2000		$630,000

Because of their proactive approach, they are now in a maintenance mode of tree trimming and feel that with levelized funding of the tree-trimming budget, they will maintain an optimum balance in customer reliability.

2. *Granite State Electric Company (GSE) will, by the end of the fourth quarter of 1998, re-evaluate the Vegetation Management Plan. Such a study to include the merits of establishing a different year cycle and other policies as appropriate.*

   In compliance -

   Granite State Electric Company (GSE) completed this report on November 11, 1998. The report evaluated the present five-year trim cycle against a four-year and a six-year trim cycle. The criteria against which the cycle change was evaluated were the issues of cost, productivity, budget requirements and customer outage times. The report concluded that the present five-year cycle is the optimum cycle. Based upon our review of the report, we are in agreement with the report conclusion of maintaining the five-year cycle. Their trimming costs per mile have stabilized; in fact they are expecting them to decrease.

3. *Granite State Electric Company (GSE) will issue public notifications in accordance with State regulations prior to the use of herbicides on its rights-of-ways. Granite State Electric Company (GSE) also agrees that it or its designated representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work. For property owners/occupants, said individual notification will also identify a Granite State Electric Company (GSE) contact to forward outstanding questions regarding the Vegetation Management Program and rights to alternative maintenance methods under RSA 374:2-a.*

   In compliance -

   Granite State Electric Company (GSE) prior to the docket maintained that they have always complied with the law. They had given notification and as a courtesy also went door to door.

4. *Granite State Electric Company (GSE) will maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practice of its entire distribution system by the end of the year 2000.*

   In compliance -

   - Policy in place for fusing distribution taps
   - Recloser application program undertaken in early 1990's
   - Review of distribution circuit loading and protection conducted annually
   - Significant reconstruction especially in Northern area resulted in present day line constructed system

It is the company policy to conduct annual distribution feeder equipment loading versus rating review. In addition, circuit reliability is reviewed annually. In the event of questionable circuit operation, the circuit is investigated and prior to any circuit configuration changes, the coordination is reviewed.

It is the company policy to apply sectionalizing fuses to all single and three phase taps where loading and coordination allows.

Their expanded review of reliability in the early 1980's and early 1990's resulted in additional data to support the increase in sectionalizing. This resulted in the additional fusing of taps. Because of this previous work, significant numbers of fuses were not added solely due to this docket. Several hundred line fuses were added in each of 1998 and 1999 and three reclosers were added in 1999. Most were not considered a reliability improvement. It is concluded that the company line study and coordination programs are in accordance with good utility practice.

5. *Granite State Electric Company (GSE) will provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reliability reporting requirements.*

In compliance -

- The utility has a small number of reclosers which makes the task manageable. In addition, the reclosers are electronic which simplifies field data gathering. Their automated customer information system (CIS) results in readily available data
- Covered conductor has contributed to reliability improvements.

The docket requires that by end of the third quarter of 1997, 1996 data on device operation shall be provided. A review of commission records and company records cannot accurately substantiate the date sent. In the early years of the docket, the report format was revised and the early reports may show separate reports for the Salem and Lebanon areas. Subsequent annual reports have been completed. Copies of the reports have been produced by Granite State Electric Company to Barrington-Wellesley Group, Inc. Granite State Electric Company feels that all information has been reported to the commission and reports it in a timely manner.

6. *Granite State Electric Company (GSE) is not required to routinely trim vegetation growth around services to residential homes, however, Granite State Electric Company (GSE) is responsible to maintain the reliability of services which in most cases, can be accomplished by limited trimming. Granite State Electric Company (GSE) will perform trimming required to make the service safe and reliable through coordination with the customer.*

If a customer requests trimming, Granite State Electric Company (GSE) will assess each situation on a "case by case" basis and may elect to perform trimming.

If a customer requests trimming over and above what is required to make the service safe and reliable, Granite State Electric Company (GSE) will supply the customer with a list of private contractors to perform the work.

Services will be reviewed at least once per distribution system trimming.

In compliance -

Prior to the docket, Granite State Electric Company indicated that services were trimmed if the customer required it or if it was observed that conditions warranted it. Moreover, Granite State Electric Company was concentrating upon the primary main line and since services were not a major problem, they were of a lower priority. The inclusion of services in the docket, has formalized their inclusion into the Vegetation Management Program. The cycle for services tree-trimming covers the period from 1997 – 2002. They are presently on schedule within the cycle.

7. *Granite State Electric Company (GSE) will also provide commencing with its 1997 third quarter service reliability indices filing data indicating reliability with and without off-system supply caused outages. The first filing will include data for the first and second quarters of 1997.*

   In compliance –

   The commission and company records cannot accurately substantiate the dates the reports have been sent to the commission. Copies of the reliability index reports have been furnished to BWG and it is the company's assertion that the reports are forwarded in a timely manner to the commission.

8. *Granite State Electric Company (GSE) will maintain or exercise funding through 2000, as part of the System Reliability Improvement Construction Program to accomplish the types of projects as listed in, but not limited to, the 1996 through 2000, Scheduled and Anticipated Reliability Projects. This effort includes the 1996/1997, $250,000 underground improvement project on Stiles Road, Salem, New Hampshire.*

   In compliance -

   - Inaccessible lines have been moved to the roadway
   - Load growth and highway construction contributed to major upgrades of the facilities

Granite State Electric Company (GSE) asserts that it has maintained funding during the docket for reliability projects as opposed to excise funding. They have specific budget categories for reliability projects. Some of the reliability projects are as follows:

- Stiles Road Underground System Upgrade
- Extend 2376 line Barron Ave. Sub. To Salem Depot Sub.
- 16L1 Getaway Upgrade Mt. Support
- 8L1/12L2 Improve Back up to Charlestown Sub.

Additionally, there is an annual blanket project category to cover year to year reliability improvement programs such as installing sectionalizing equipment, replacing open wire secondary, replacement of bare conductors with tree wire etc.

Granite State Electric Company (GSE) does not have a specific budgetary category for reliability; but the capital spending for the period covered in the docket has been:

1997	1998	1999	PROPOSED 2000
$2,935,000	$3,044,000	$3,358,000	$5,000,000

NHPUC DOCKET DE 96-127

AGREEMENT

1. *New Hampshire Electric Cooperative (NHEC) will maintain or exercise funding that will support, at a minimum, an average ten-year distribution and transmission trimming cycle. Such trimming will be done according to the specifications which are as strict as those currently in effect.*

   In compliance –

   - Consistent spending level
   - Wide r/w clearing floor to sky
   - Working toward ten year cycle
   - Each trimming job is reviewed two to three times per week
   - Each of the three company arborists keeps records on inspection
   - Formal bid evaluation in place
   - Use a mix of T&M, lump sum pricing

   During the period covered by the docket, New Hampshire Electric Cooperative has increased the spending on its ROW maintenance. The spending levels are as follows:

YEAR	DOLLARS	MILES MAINTAINED
1997	$2,190,596	419
1998	$2,151,658	444
1999	$1,680,442 *	429 (Est.)

*As of 3rd Quarter, Budgeted amount for 1999 is $2,094,645

   The spending levels have been accelerated over the years prior to the docket. The company is projecting that by the end of the Year 2000, only 25 miles will remain that has not been maintained within the ten-year cycle.

2. *New Hampshire Electric Cooperative (NHEC) will, by the end of the third quarter of 1999, re-evaluate its right-of-way and distribution vegetation maintenance programs. Such study to include the merits of establishing a different year cycle and other policies as appropriate.*

In progress -

- Outside consulting firm assisting with plan development.

As of this date, the plan has been written into the "New Hampshire Electric Cooperative Vegetation Management Program." Some specific recommendations from the consultant are being evaluated to determine if they will benefit the overall plan. The company is considering going to an average of eight-year cycle funding with some circuits trimmed to a six-year cycle and others to a twelve-year cycle. These considerations are tentative and internal discussions are continuing.

3. *New Hampshire Electric Cooperative (NHEC) will issue public notifications in accordance with State regulations prior to the use of herbicides on its rights-of-ways. New Hampshire Electric Cooperative (NHEC) also agrees that it or its designated representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work. For property owners/occupants, said individual notification will also identify a New Hampshire Electric Cooperative (NHEC) contact to forward outstanding questions regarding the Vegetation Management Program and rights to alternative maintenance methods under RSA 374:2-a.*

In compliance -

The company maintains that all notifications past and present strictly follow the policies of the NH Department of Agriculture, Division of Pesticide Control and the NHPUC. New Hampshire Electric Cooperative has produced various records, publications, and data to BWG in support of their assertion.

4. *New Hampshire Electric Cooperative (NHEC) will maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practice of its entire distribution system by 2000.*

In compliance –

- All distribution circuits recently updated
- Based upon three to five year cycle

New Hampshire Electric Cooperative has updated their single line diagrams showing the protective devices and the number of customers affected. They have formalized a database showing the sectionalizing/coordination study and the last update to the study.

The construction work plan has set some initial guidelines on the use of distribution sectionalizing devices. The company is in the process of formalizing an engineering protection manual.

The results of the system coordination studies did not result in additional line fuses being installed. The study verified that fuse/recloser coordination would operate properly. It has been the company policy since the mid-1970's to fuse all taps to the extent consistent with good utility practice.

BWG reviewed a small area of the New Hampshire Electric Cooperative service territory. The fusing of taps from the main line appeared reasonable and consistent with utility practices; however, the service area is large and the area reviewed cannot be considered a representative sample. Given the rural nature of cooperatives, it is important that coordination and the fusing of taps be considered a priority.

5. *New Hampshire Electric Cooperative (NHEC) will provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reliability reporting requirements.*

In compliance –

- A significant amount of reclosers especially hydraulic requires significant commitment

New Hampshire Electric Cooperative does not have the dates available as to when the reports were sent to the commission. Commission data is not fully available to substantiate the date that the reports were received by the commission. New Hampshire Electric Cooperative has provided BWG with a copy of the reports and maintains that the reports are sent in a timely manner.

6. *New Hampshire Electric Cooperative (NHEC) is not required to routinely trim vegetation growth around services to residential homes, however, New Hampshire Electric Cooperative (NHEC) is responsible to maintain the reliability of services which in most cases, can be accomplished by limited trimming. New Hampshire Electric Cooperative (NHEC) will perform trimming required to make the service safe and reliable through coordination with the customer.*

If a customer requests trimming, New Hampshire Electric Cooperative (NHEC) will assess each situation on a "case by case" basis and may elect to perform trimming.

If a customer requests trimming over and above what is required to make the service safe and reliable, New Hampshire Electric Cooperative (NHEC) will supply the customer with a list of private contractors to perform the work.

Services will be reviewed at least once per distribution system trimming.

In compliance -

New Hampshire Electric Cooperative has not changed its practice for trimming services. The company checks services when doing cycle mainline clearing/trimming and services are trimmed, if needed, to maintain service integrity.

7. *New Hampshire Electric Cooperative (NHEC) will also provide commencing with its 1997 third quarter service reliability indices filing data indicating reliability with and without off-system supply caused outages. The first filing will include data for the first and second quarters of 1997.*

In compliance -

The information is forwarded to the commission in a timely manner. Commission records support this.

8. *New Hampshire Electric Cooperative (NHEC) will maintain or exercise funding through 1999, as part of the System Reliability Improvement Construction Program to accomplish the types of projects as listed in, but not limited to, the Three Year (1997, 1998, and 1999), Proposed Construction Work Plan.*

In compliance –

New Hampshire Electric Cooperative has funded the construction work plan reliability projects consistent with the budget as follows. The budgeted dollars consist of all the reliability projects contained in the work plan.

YEAR	$ BUDGETED	$ SPENT
1997	4,741,500	4,535,209
1998	3,368,900	3,653,870
1999	3,772,515	4,071,034

9. *New Hampshire Electric Cooperative (NHEC) will commence in 1997, a three-year program of approximately $8 million to eliminate all 207 miles of remaining amerductor, and at the same time where appropriate relocate the facilities to the roadside.*

Substantially in compliance –

- 95% complete at end of 1999
  NHEC Amerductor Elimination Program Miles of Line Remaining Chart –
  See Attachment

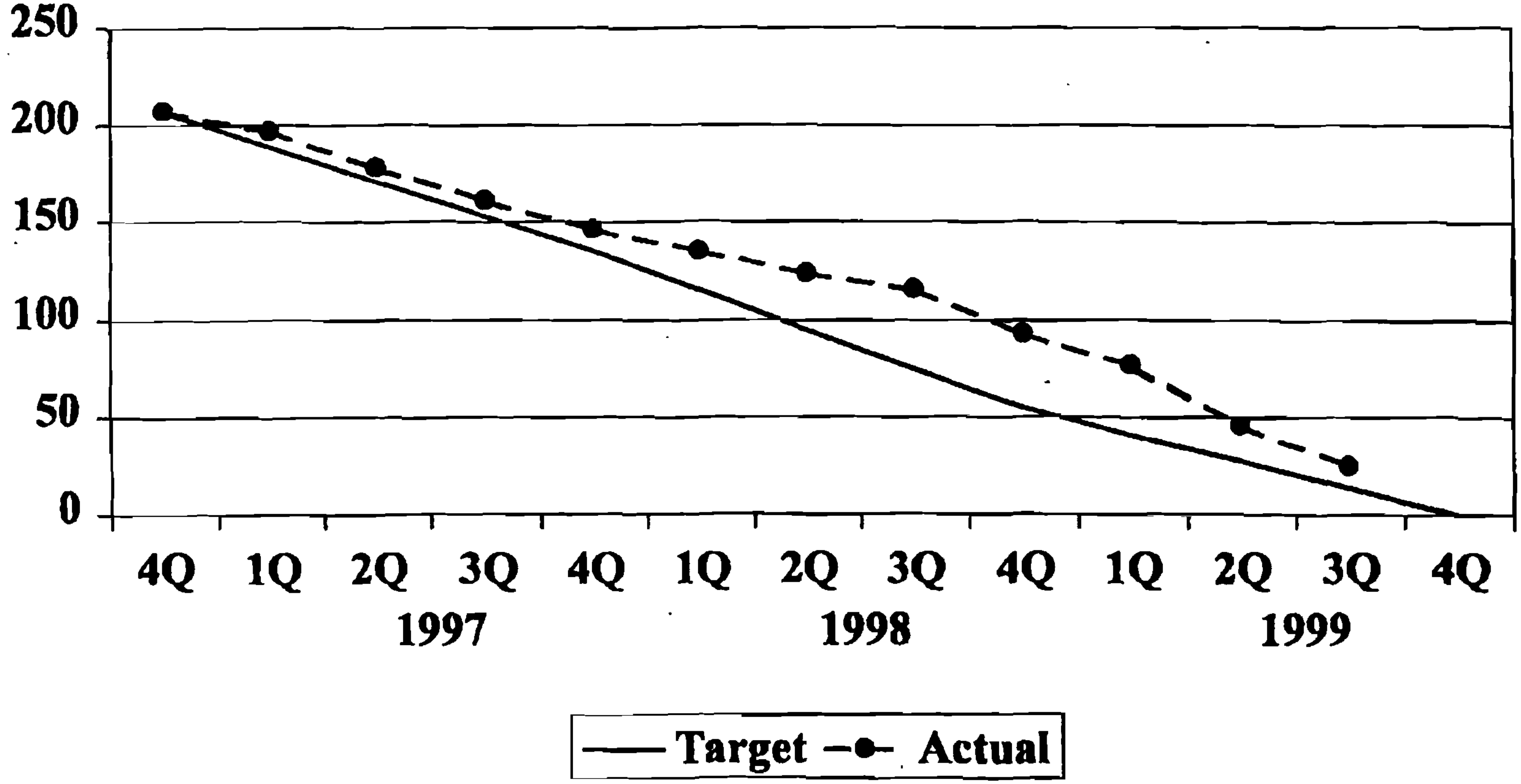
10. New Hampshire Electric Cooperative (NHEC) will, by the end of the third quarter of 1997, install and have operational a minimum of 1500 momentary outage monitoring devices as part of a reliability improvement program.

Compliance in part -

- 1500 devices were purchased in 1997 and 820 installed. The devices experienced numerous problems and the installation was discontinued.
- Different devices were purchased in early 1999. To date, approximately 300 of the new devices are installed. The performance of the new devices is much better.

The new devices required an NT computer platform. The new devices are being installed as labor is available. Several hundred of the original devices are to remain in service. The company estimates that by the end of 2000, 600 of the new devices will be in service.

NHEC Amerductor Elimination Program
Miles of Line Remaining



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NHPUC DOCKET DE 96-126

AGREEMENT

1. ***Connecticut Valley Electric Company (CVEC) will maintain or exercise funding that will support an average five-year transmission and seven year distribution trimming cycle through the year 2000. Such trimming will be done according to specifications which are as strict as those currently in effect.***

   In compliance -

   - Dollars spent consistent over period
   - Deferment for 1999 resulting in lower spending
   - Comprehensive trimming policy
   - Use a mix of T&M, lump sum tree trimming
   - Crew productivity evaluated weekly by company arborist
   - Formal and informal crew evaluation
   - Wide right of way trimming

Connecticut Valley Electric Company has maintained a five-year transmission cycle for the past 30 years. The next five-year cycle will be due in 2002.

In the late 1980's Connecticut Valley Electric Company started to get their trimming into about a seven-year distribution cycle. They are able to maintain this average cycle with essentially levelized funding. In 2000, they are expecting to trim 90–95 miles. This will project them well within the seven-year cycle.

The tree trimming progress is closely monitored by the forestry department and the information is plotted on the system line maps to serve as a permanent record.

The statistics of the tree-trimming program is as follows:

CVEC DISTRIBUTION
CONTRACTOR DOLLARS

YEAR	TRIM $	DNGR TRS $	HERBICIDE $	TOTAL $
94	203,185	4,349	12,788	220,322
95	249,721	6,756	11,176	267,653
96	208,767	6,770	11,109	226,646
97	196,381	5,275	12,308	213,964
98	202,793	9,876	13,108	225,777
99	87,464	2,962	1,031	91,457

YEAR	TRM.MI.	#DGR TRS	HERB.AC.
94	58.56	21	21.72
95	63.93	29	28.94
*96	78.98	41	48.64
*97	74.40	26	27.06
*98	58.77	34	36.10
*99	18.96	11	2.42

* SECOND CYCLE TRIMMING BEGAN IN 1996.

2. *Connecticut Valley Electric Company (CVEC) will, by the end of the fourth quarter of 1998, re-evaluate the Distribution Vegetation Management Plan. Such study to include the merits of establishing a different year cycle and other policies as appropriate.*

   In compliance -

   Connecticut Valley Electric Company re-evaluated its distribution Vegetation Management Plan and provided a report to the commission on December 28, 1998. Connecticut Valley Electric Company reviewed the oldest growth in the system against the fastest growing species of trees given their existing seven-year cycle. Connecticut Valley Electric Company has concluded that the seven-year average cycle is appropriate for their system. BWG has reviewed their Vegetation Management Plan and observed various trimming year growth and is in agreement with Connecticut Valley Electric Company conclusion. The length of a tree trim cycle is directly related to the aggressiveness of trimming. The seven-year cycle is reasonable provided that the trimming is consistent with the regrowth rate.

3. *Connecticut Valley Electric Company (CVEC) will issue public notifications in accordance with State regulations prior to the use of herbicides on its rights-of-ways. Connecticut Valley Electric Company (CVEC) also agrees that it or its designated*

representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way proposed herbicide treatment work. For property owners/occupants, said individual notification will also identify a Connecticut Valley Electric Company (CVEC) contact to forward outstanding questions regarding the Vegetation Management Program and rights to alternative maintenance methods under RSA 374:2-a.

In compliance -

Prior to the docket Connecticut Valley Electric Company notified each landowner of the intent to treat the ROW. Town managers were notified with a letter in accordance to the NH notification requirements.

4. *Connecticut Valley Electric Company (CVEC) will maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practice of its entire distribution system by the end of the year 2000.*

In compliance -

- Ten year average cycle unless major changes
- Recent rebuilds in Clairmont result in updating of studies

In 1996, the circuits in the Claremont area were upgraded to 12 Kv. During that period the line studies were updated and a switching plan was developed. At this time, the fuse coordination was addressed and taps fused as appropriate.

There are 13 circuits in the Connecticut Valley Electric Company service area and seven circuits are presently under review for the comprehensive engineering analysis. The study will add fuse taps and/or reclosers to isolate the tap from the main line. The field data survey was started in the fourth quarter of 1999 and the engineering and fuse/recloser installation is scheduled to be completed by the end of 2000.

It is Connecticut Valley Electric Company policy to fuse all taps as appropriate.

5. *Connecticut Valley Electric Company (CVEC) will provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reporting requirements.*

   In compliance -

   Connecticut Valley Electric Company has provided the dates when the reports have been sent to the commission. The company dates are in agreement with commission records. The company is supplying the information in a timely manner.

6. *Connecticut Valley Electric Company (CVEC) is not required to routinely trim vegetation growth around services to residential homes, however, Connecticut Valley Electric Company (CVEC) is responsible to maintain the reliability of services which in most cases, can be accomplished by limited trimming. Connecticut Valley Electric Company (CVEC) will perform trimming required to make the service safe and reliable through coordination with the customer.*

   If a customer requests trimming, Connecticut Valley Electric Company (CVEC) will assess each situation on a "case by case" basis and may elect to perform trimming.

   If a customer requests trimming over and above what is required to make the service safe and reliable, Connecticut Valley Electric Company (CVEC) will supply the customer with a list of private contractors to perform the work.

   Services will be reviewed at least once per distribution system.

   In compliance -

   Prior to the docket, Connecticut Valley Electric Company trimmed services only if trees and limbs were lying on them and they posed a safety hazard or there was a potential for physical damage. Tree crews trimmed them when they were working in the vicinity.

   Since the docket, the only change has been to incorporate the general practice on policy into the Vegetation Management Plan.

7. *Connecticut Valley Electric Company (CVEC) will also provide commencing with its 1997 third quarter service reliability indices filing data indicating reliability with and without off-system supply caused outages. The first filing will include data for the first and second quarters of 1997.*

Connecticut Valley Electric Company has provided the dates when the reports have been sent to the commission. The company dates are in agreement with commission records. The company is supplying the information in a timely manner.

8. *Connecticut Valley Electric Company (CVEC) will maintain or exercise funding through 2000, as part of the System Reliability Improvement Construction Program to accomplish the types of projects as listed in, but not limited to, the 1996 through 2000, Proposed Construction Projects. This effort includes relocating Line 5 from the Wells River Substation to, and throughout the Town of Bath, new Hampshire and reconstructing the line along roadways so that the lines are accessible to line crews and line vehicles, such construction scheduled to be completed in 1999.*

In compliance -

- Recent rebuilds in Clairmont area resulted in facilities on par with present day construction

A representative listing of reliability projects is as follows:

1997

- Reconstruct main line between Lafayette Sub and Maple Ave. Sub
- Reconstruct line 5 Bath and move out to the roadway
- Install new OCR line 39 Haverhill
- Fuse coordination Wells River circuit 13

The approximate spending on reliability projects in this year is $497,600.

1998

- Reconstruct Line 3 Unity
- Station Service and Relay upgrade Joy Sub
- Install bird guards line 39
- Fuse coordination Newbury 12, Thetford 16, Ely 41

The approximate spending on reliability projects in this year is $164,700.

1999

- Temple Inland Substation Upgrade
- Fuse Coordination Bradford 63

The approximate spending on reliability projects in this year is $177,000.

9. *Connecticut Valley Electric Company (CVEC) will by the end of the third quarter of 1997, evaluate remote, fast response facilities, for example, satellites located in New Hampshire. Results and recommended action will be forwarded to the New Hampshire Public Utilities Commission (NHPUC).*

In compliance –

BWG reviewed the report dated September 30, 1997. The report concluded that the customer response would be improved if crews were located in New Hampshire. Central Vermont Public Service Company (CVPS) had started plans to find a suitable location for the crews. Several locations were evaluated and after some time a suitable site was proposed. As of this time, the project was put on hold due to the financial problems that Connecticut Valley Electric Company (CVEC) is experiencing. Although the present financial problems may defer this project, it is hoped that Connecticut Valley Electric Company (CVEC) will take other appropriate measures as necessary to insure that customer reliability continues to improve.

NHPUC DOCKET DE 96-128

AGREEMENT

1. *Concord Electric Company (CECO) will maintain or exercise funding that will support an average four-year distribution and transmission trimming cycle through the year 2000. Such trimming will be done according to the specifications which are as strict as those currently in effect.*

In compliance -

- Changed cycle to five years – letter on file with PUC
- Spending consistent with budgeted dollars during period
- Tree trimming standards in place
- Approximately two – three crews on site full-time
- System is small, urban and easily manageable

Concord Electric Company (CECO) has completed one cycle of the five-year transmission trimming cycle. A new cycle started in 1999. A maintenance cycle includes flat cut and side trimming for an average of 52 acres per year.

Concord Electric Company (CECO) completed one cycle of the five-year distribution trimming cycle. A new cycle started in 1999. A maintenance cycle includes 65 pole miles per year.

Concord Electric Company (CECO) has increased their expenditures per year over the previous years since 1997.

TREE TRIMMING COSTS

Distribution Trimming	Budget	Actual
1997	$222,000	$222,578
1998	$228,866	$228,886
1999	$189,976	$233,162

Transmission Trimming	Budget	Actual
1997	$33,600	$33,957
1998	$34,634	$34,663
1999 (as of 10/99)	$25,998	$40,086

2. *Concord Electric Company (CECO) will, by the end of the fourth quarter of 1998, re-evaluate the Distribution and Transmission Vegetation Management Plan. Such a study to include the merits of establishing a different year cycle and other policies as appropriate.*

   In compliance

   In 1998, a committee was formed at the Unitil level to re-evaluate the Vegetation Management Program for both Concord Electric Company (CECO) and E&H. Specific changes and recommendations were made at that time to the Vegetation Management Control Program and incorporated into each company guidelines. A formal report was not prepared; therefore, the specific proposals could not be reviewed by BWG.

   In 2000, a committee was formed at the Unitil level to review the Vegetation Management Plan and to develop guidelines and performance measures. The committee was formed to further enhance the Vegetation Management Plan.

3. *Concord Electric Company (CECO) will issue public notifications in accordance with State regulations prior to the use of herbicides on its rights-of-ways. Concord Electric Company (CECO) also agrees that it or its designated representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work. For property owners/occupants, said individual notification will also identify a Concord Electric Company (CECO) contact to forward outstanding questions regarding the Vegetation Management Program and rights to alternative maintenance methods under RSA 374:2-a.*

   Not applicable

   Concord Electric Company (CECO) does not use herbicides nor treat stumps. Concord Electric Company only uses herbicides for weed control in substations. Concord Electric Company is aware of the regulations required by the docket and the requirements of State law.

4. *Concord Electric Company (CECO) will maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practice of its entire distribution system by the end of the year 2000.*

   In compliance –

   - Three year cycle
   - Added reclosers and fused taps to improve reliability
   - Significant amount of 4KV distribution contributes to reliability

   Circuits are analyzed at the Unitil level. The review includes a comprehensive circuit analysis which also takes into account reliability issues.

5. *Concord Electric Company (CECO) will provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reliability reporting requirements.*

   In compliance

   The dates reported by the company records are in agreement with commission records.

6. *Concord Electric Company (CECO) is not required to routinely trim vegetation growth around services to residential homes, however, Concord Electric Company (CECO) is responsible to maintain the reliability of services which in most cases, can be accomplished by limited trimming. Concord Electric Company (CECO) will perform trimming required to make the service safe and reliable through coordination with the customer.*

   If a customer requests trimming, Concord Electric Company (CECO) will assess each situation on a "case by case" basis and may elect to perform trimming.

   If a customer requests trimming over and above what is required to make the service safe and reliable, Concord Electric Company (CECO) will supply the customer with a list of private contractors to perform the work

   Services will be reviewed at least once per distribution system trimming.

   In compliance

   No changes have been made with respect to service tree trimming as a result of the docket.

7. *Concord Electric Company (CECO) will also provide commencing with its 1997 third quarter service reliability indices filing data indicating reliability with and without off-system supply caused outages. The first filing will include data for the first and second quarters of 1997.*

In compliance

The dates reported by the company are in agreement with the commission records.

8. *Concord Electric Company (CECO) will maintain or exercise funding that will support a System Reliability Improvement Program to accomplish the types of projects as listed in, but not limited to, the 1996 through 2000, Five Year Capital Construction Budget.*

In compliance

Unitil has initiated its own initiatives and goals relative to reliability irrespective of the docket. Prior to 1999, reliability projects were budgeted on a case-by-case basis not as part of a separate reliability budgeted item. Because of this, it would be more difficult for Concord Electric Company (CECO) to detail the 1998 and 1997 reliability dollars and projects. Since Concord Electric Company (CECO) has demonstrated compliance with the Docket and they have initiated separate reporting for reliability projects, BWG did not request the previous years data. Concord Electric Company (CECO) indicated that if the information was requested, they will devote the resources to furnish the data.

The reliability projects for 1999 included additional and enhanced fusing, installation of reclosers, and installation of surge arrestors.

The 2000 budget includes carryover reliability projects, the replacement of spacers, and enhanced tree trimming.

The cost data for 1999 and 2000 is as follows:

1999	Budget	$128,700
1999	Actual	$47,999[3]
2000	Carryovers	$44,780[4]
2000	Budget	$94,645

The 2000 budget reflects both capital and O&M projects.

[3] Recloser delivery delay pushed this project into 2000. The recloser is scheduled for delivery in May. The project should be complete in late May or early June.
[4] Three of the 1999 projects were performed for less than their budget amount. The total amount <u>below</u> the budget estimate was $22,965 (17.8%)

NHPUC DOCKET DE 96-129

AGREEMENT

1. *Exeter and Hampton Electric Company (E&H) will maintain or exercise funding that will support an average five-year distribution and three-year transmission trimming cycle through the year 2000. Such trimming will be done according to specifications which are as strict as those currently in effect.*

Compliance progressing -

a. Comprehensive vegetation management program
b. One and one-half tree trimming crews per year
c. Majority of system along roadways
d. Significant amount of 4KV circuits
e. Small system easily manageable

Exeter and Hampton Electric Company (E&H) has completed one full transmission vegetation control cycle since the date of the docket.

Exeter and Hampton Electric Company (E&H) indicated that they have maintained their cycle schedule (average five-year cycle) for those areas they have identified requiring tree trimming maintenance in order to preserve increased levels of reliability.

TRIMMING COSTS

Description	1996	1997	1998	1999
Distribution Trimming Budget	$187,800	$193,404	$175,500	$180,228
Transmission Trimming Budget	$ 29,050	$ 33,444	$ 36,108	$ 38,676
Distribution Actual Spent	$152,905	$147,875	$166,931	$209,742
Transmission Actual Spent	$ 1,264	$ 44,831	$ 31,159	$ 36,963

DOES NOT INCLUDE STORM ACCOUNT

2. *Exeter and Hampton Electric Company (E&H) will, by the end of the fourth quarter of 1998, re-evaluate the Distribution and Transmission Vegetation Control Procedures. Such study to include the merits of establishing a different year cycle and other policies as appropriate.*

   In compliance -

   In 1998, a committee was formed at the Unitil level to re-evaluate the Vegetation Management Program for both Concord Electric Company (CECO) and E&H. Specific changes and recommendations were made at that time to the Vegetation Management Control Program and incorporated into each company guidelines. A formal report was not prepared; therefore, the specific proposals could not be reviewed by BWG.

   In 2000, a committee was formed at the Unitil level to review the Vegetation Management Plan and to develop guidelines and performance measures. The committee was formed to further enhance the Vegetation Management Plan.

3. *Exeter and Hampton Electric Company (E&H) will issue public notifications in accordance with State regulations prior to the use of herbicides on its transmission line rights-of-ways. Exeter and Hampton Electric Company (E&H) also agrees that it or its designated representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work. For property owners/occupants, said individual notification will also identify a Exeter and Hampton Electric Company (E&H) contact to forward outstanding questions regarding the Vegetation Management Program and rights to alternative maintenance methods under RSA 374:2-a.*

   In compliance -

   Exeter and Hampton Electric Company (E&H) uses herbicides on transmission ROW and some stump treatment. Prior to the docket, Exeter and Hampton Electric Company (E&H) adhered to all State regulations. They have not changed their practice after the docket since they already were following the stipulations.

4. *Exeter and Hampton Electric Company (E&H) will maintain or exercise funding to accomplish a comprehensive engineering analysis resulting in the installation of fusing of circuit taps or installation of other protective devices in accordance with good utility practice of its entire distribution system by the end of the year 2000.*

   In compliance –

   a. Three year cycle
   b. Fusing of taps appear reasonable
   c. Small manageable system
   d. 4KV system dated but in good condition
   e. Distribution engineering seems to closely monitor line studies

   The first three-year cycle is scheduled to be completed by the end of 2000. The company does a detailed analysis of their line studies which includes a review of the circuit reliability. They maintain that they apply protective devices based upon their review in accordance with good utility practice.

5. *Exeter and Hampton Electric Company (E&H) will provide by the end of the third quarter of 1997, 1996 data on device operations, and annually thereafter, to approximate momentary interruptions as part of reliability reporting. Subsequent annual reports shall be made with year-end reliability reporting requirements.*

   In compliance –

   The company data on the date reports sent to the commission is consistent with commission data.

6. *Exeter and Hampton Electric Company (E&H) is not required to routinely trim vegetation growth around services to residential homes, however, Exeter and Hampton Electric Company (E&H) is responsible to maintain the reliability of services which in most cases, can be accomplished by limited trimming. Exeter and Hampton Electric Company (E&H) will perform trimming required to make the service safe and reliable through coordination with the customer.*

   If a customer requests trimming, Exeter and Hampton Electric Company (E&H) will assess each situation on a "case by case" basis and may elect to perform trimming.

   If a customer requests trimming over and above what is required to make the service safe and reliable, Exeter and Hampton Electric Company (E&H) will supply the customer with a list of private contractors to perform the work.

Services will be reviewed at least once per distribution system trimming.

In compliance -

Exeter and Hampton Electric Company (E&H) made a change after the docket relative to customer requests. After the docket, Exeter and Hampton Electric Company (E&H) followed the more conservative approach as outlined in the PUC docket by assessing each situation on a case-by-case basis while maintaining a safe and reliable service.

7. *Exeter and Hampton Electric Company (E&H) will also provide commencing with its 1997 third quarter service reliability indices filing data indicating reliability with and without off-system supply caused outages. The first filing will include data for the first and second quarters of 1997.*

In compliance -

The company data on the date reports sent to the commission is consistent with commission data.

8. *Exeter and Hampton Electric Company (E&H) will maintain or exercise funding through 2000, as part of the System Reliability Improvement Construction Program to accomplish the types of projects as listed in, but not limited to, the 1996 through 2000, Planned and Proposed Construction Projects.*

In compliance

Exeter and Hampton Electric Company (E&H) provided BWG with copies of their system reliability budget, cost summaries, and construction authorizations for the years 1999 and 2000. Prior to 1999, reliability projects were budgeted on a case-by-case basis and not as specific reliability budgeted items. Because of their own initiatives to improve reliability and due to their internal management objectives, the reliability projects were more readily available than previous years. Since they have demonstrated compliance with the Docket, BWG felt that this representation was adequate. The company indicated that if data for 1998 and 1997 was requested, they would be more than willing to devote the resources to produce the information.

The dollars relative to reliability projects are as follows:

1999	Budget	$267,084
1999	Actual	$90,954[1]
2000	Carryovers	$95,500[2]
2000	Budget	$253,334

[1] Replacing all the post insulators on the 3356 line was deferred until 2000 because of line crew availability: cost $95,500. This project was completed in February.

[2] The installation of tree wire on 13W2 ($106,400) was deferred pending closer analysis. Ultimately the objective of reducing tree related outages was accomplished by performing tree trimming on this portion of the circuit in 2000 for a cost of $6,750. The original cost of the 13W2 tree wire project and tree trimming project were not included in this adjusted total.

The 1999 capital projects included projects such as installing or revising the fusing on circuits, extending the three-phase circuit and fusing unprotected taps.

The 2000 capital projects include line insulator replacement, revising the fusing on a circuit, and the installation of fault indicators. The 2000 budget includes enhanced tree trimming for reliability improvement.

NHPUC DOCKET DE 95-194

AGREEMENT

1. *Public Service Company of New Hampshire (PSNH) will, by the end of the year 2000, complete the distribution trimming of its entire distribution system which it began in 1995. Such trimming will be done according to the specification which is currently in effect with added focus on vertical trimming.*

In compliance –

- Eight to nine tree trim contractors with 90 to 100 crews on site typically
- Bids completed on a circuit basis with about 80% lump sum
- Four arborists inspect all work and keep their own informal notes
- End of each job contractors are evaluated
- Evaluating enhanced tree trimming
- Recognize need to improve transmission side trimming – requesting additional budgeting
- Typically were required to select lowest bidder but;
- Developing data base and criteria to provide additional contractor ratings in evaluating bids

Since 1995, Public Service Company of New Hampshire has consistently planned and completed between 1,600 and 2,000 miles of trimming. In 2000, 2,031 miles are planned which will result in the completion of one cycle within the time as specified in the docket.

Public Service Company of New Hampshire has prepared a transmission plan for ROW side trimming. The plan consists of a 15/10-year cycle. The plan also includes emergency hot spot side trimming.

A priority approach on the transmission system was prepared to include the work on the highest priority circuits for the next three years. Recognizing Public Service Company of New Hampshire and the commission's concern for the transmission system, we are in agreement with the commission staff that this area be included in the docket.

Commission order no. 22, 690 dated August 25, 1997, asserted the importance of trimming of the transmission system. This proposed transmission plan should be fully funded to achieve the goal of the program.

2. *Public Service Company of New Hampshire (PSNH) will, by the end of the first quarter of 1998, develop a cyclical approach to managing its distribution trimming program which takes into consideration voltage levels, growing conditions and other factors as appropriate.*

   In compliance –

   Public Service Company of New Hampshire has prepared a comprehensive plan and submitted the report within the time specified.

   Public Service Company of New Hampshire is presently managing their Vegetation Management Plan consistent with this document.

3. *Public Service Company of New Hampshire (PSNH) will investigate the merits of conducting pilot mowing tests to evaluate the effectiveness of various mowing practices and will initiate such tests if deemed feasible.*

   In compliance -

   Public Service Company of New Hampshire is in the process of conducting pilot mowing techniques along side of another project to assess the merits of sheep grazing along the ROW. The project was originally planned to be evaluated by the manager of the sheep-grazing project. In late 1999, Public Service Company of New Hampshire felt that the program would be better served by a third party. The project is now being evaluated on the university level by UNH. The project will be evaluated twice a year over the next five years.

4. *Public Service Company of New Hampshire (PSNH) will issue public notifications in accordance with State regulations prior to the use of herbicides on its transmission line rights-of-ways. Public Service Company of New Hampshire (PSNH) also agrees that it or its designated representative (contractor) shall inform right-of-way property owners/occupants and abutters with homes within 200 feet of the right-of-way of proposed herbicide treatment work. For landowners, said individual notification will also identify a Public Service Company of New Hampshire (PSNH) contact to forward outstanding questions regarding the Integrated Vegetation Management (IVM) Program and rights to alternative maintenance methods under RSA 374:2-a.*

In compliance -

Public Service Company of New Hampshire has not used herbicides for distribution line stump treatment since 1993. However, Public Service Company of New Hampshire contractors are licensed to apply herbicides, and Public Service Company of New Hampshire has a special permit to apply herbicides in the year 2000. There are ongoing discussions regarding stump treatment in conjunction with 'enhanced tree trimming', but no final decision has been made. If Public Service Company of New Hampshire decides to move forward with this practice, or at any time in the future decide to use herbicides, Public Service Company of New Hampshire understands that it must provide proper notification.

5. *Public Service Company of New Hampshire (PSNH) will include information on device operations as part of reliability reporting to the Commission. Such information will be gathered on an annual basis and will be similar to that which was developed in this docket to approximate momentary interruptions.*

In compliance -

- Present system requires significant man hours to compile report
- Problem is compounded by large number of overhead hydraulic reclosers

Public Service Company of New Hampshire is in the process of implementing handheld devices for field gathering the data. They are also evaluating additional changes to the SCADA and CIS (Customer Information System) to attempt to minimize the amount of labor to prepare the report.

Public Service Company of New Hampshire has been submitting the reports in a timely manner.

6. *Public Service Company of New Hampshire (PSNH) will spend $4 million over the period 1996 through 2000 as part of a reliability improvement program. Said program may include, but shall not be limited to, such projects as voltage conversions, moving sections of line onto the road, construction distribution circuit backup facilities, purchasing additional distribution backup equipment, replacing or removing equipment or material that presents reliability risks, installing reliability enhancing equipment or material, and removal of danger trees in conjunction with municipalities or landowners Monies expended and projects undertaken under this section shall be in addition to average spending levels for similar projects during the period 1991 to 1995 which was approximately $900,000 per year. A listing of projects and their respective costs shall be included with the year-end reliability report as currently submitted to the New Hampshire Public Utilities Commission (NHPUC).*

In compliance -

- Base and additional expenditures from 1996-1998 were averaging $2.2M. This is above the requirement.
- Expected 2000 expenditures should be achievable because of increased spending in previous years.
- Public Service Company of New Hampshire has submitted project lists and cost data and has worked with commission staff on project issues.

STATUS	YEAR	'BASE' EXPENDITURES	'ADDITIONAL' EXPENDITURES	TOTAL
Completed	1996	$1,032,851	$1,290,288	$2,323,139
Completed	1997	$1,571,641	$1,185,564	$2,757,205
Completed	1998	$553,090	$932,830	$1,485,920
Completed	1999	$717,533	$481,281	$1,198,814
	AVERAGE/YEAR	$968,779	$972,491	$1,941,270
	TOTAL	$3,875,115	$3,889,963	$7,765,078
Required	2000	$624,885	$110,037	$734,922
	Projects Expenditures Goal	$4,500,000	$4,000,000	$8,500,000

Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 3

Received: July 1, 2010	Date of Response: July 15, 2010
Request No. Staff 3-51	Witness: Thomas P. Meissner, Jr.

Request:

Reference Meissner testimony, page 20 (Bates 0192), Table TPM-4. Please provide supporting detail demonstrating how UES arrived at the conclusion that the capital requirement for the System Hardening component of the REP is $750,000 per year for 5 years and that the capital requirement of the Asset Replacement component of the REP is $1 million per year for 5 years assuming that capital costs are included in rate base as proposed.

Response:

Please refer to Staff 3-51 Attachment 1. The attached schedules were used in the development of Collin testimony, Schedule MHC-12, page 1 of 1 (Bates 0068). Refer also to the response to Staff 1-27.

As shown in the attached schedules, historical spending for asset replacement and system hardening were detailed for each of the past five years, and were then projected forward for the next five years based on Unitil Energy's current five year capital budget.

- The $750,000 System Hardening estimate for the REP is consistent with the average spending on reliability improvement projects over the past two years, and anticipates an increase in spending on automation projects in the next five years. Overall, it assumes that recent spending on reliability will continue in future years. It is not an exact calculation, and is based on judgment given past, current and projected spending.

- The $1 million Asset Replacement estimate for the REP is consistent with past and projected spending for asset replacement activities, but with a modest increase of approximately $200,000 – $250,000 annually to begin focusing on cable replacement and other asset replacement programs. Again, it is not an exact calculation, and is based on judgment given past, current and projected spending.

Unitil Energy expects to submit detailed activities and targeted expenditures and investments for Staff's review prior to implementation. These plans and associated investment levels may vary from the levels proposed under the REP as a result of Unitil Energy's annual submission and Staff's review of the proposed plans. Only investments made in accordance with the REP would be eligible for cost recovery under the REP Capital Investment Allowance. Reference Meissner testimony, Schedule TPM-1, page 4 of 4 (Bates 0232).

Unitil Energy Systems, Inc.
Reliability Enhancement Capital Expenditures
Historical Costs 2005-2009 - Projected Costs 2010 - 2014

(In thousands)

	Capital	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	Pole Replacement	$ 132.80	$ 78.50	$ 544.80	$ 498.40	$ 387.30	$ 260.59	$ 290.28	$ 298.05	$ 231.39	$ 253.64
2	Underground Cable Replacement	-	39.50	-	-	-	-	-	-	-	-
3	Automation	179.00	(11.80)	43.80	(12.60)	-	42.98	276.31	74.24	44.25	176.96
4	Reliability Projects - Specific	260.30	33.40	-	-	210.40	205.73	127.40	130.28	98.88	108.39
5	Other	25.70	65.90	97.20	30.40	1,407.20	2,339.53	-	-	-	-
6											
7	Subtotal	$ 597.80	$ 205.50	$ 685.80	$ 516.20	$ 2,004.90	$ 2,848.83	$ 693.99	$ 502.58	$ 374.52	$ 538.98
8											
9	Seacoast	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
10											
11	Pole Replacement	$ 32.10	$ 52.00	$ 78.90	$ 82.20	$ 314.50	$ 524.22	$ 457.74	$ 512.33	$ 535.20	$ 434.24
12	Underground Cable Replacement	-	-	-	-	-	-	-	-	-	-
13	Automation	15.10	22.90	8.20	(6.40)	1.60	21.86	72.25	-	-	-
14	Reliability Projects - Specific	15.80	101.30	72.40	-	351.60	780.65	109.14	108.58	108.14	121.19
15	Other	72.00	24.40	-	-	661.60	273.24	-	-	-	-
16											
17	Subtotal	$ 135.00	$ 200.60	$ 159.50	$ 75.80	$ 1,329.30	$ 1,599.96	$ 639.12	$ 620.91	$ 643.34	$ 555.43
18											
19	Total Combined UES	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
20											
21	Pole Replacement	$ 164.90	$ 130.50	$ 623.70	$ 580.60	$ 701.80	$ 784.81	$ 748.01	$ 810.38	$ 766.59	$ 687.88
22	Underground Cable Replacement	-	39.50	-	-	-	-	-	-	-	-
23	Automation	194.10	11.10	52.00	(19.00)	1.60	64.84	348.57	74.24	44.25	176.96
24	Reliability Projects - Specific	276.10	134.70	72.40	-	562.00	986.37	236.54	238.86	207.02	229.58
25	Other	97.70	90.30	97.20	30.40	2,068.80	2,612.77	-	-	-	-
26											
27	Combined Total	$ 732.80	$ 406.10	$ 845.30	$ 592.00	$ 3,334.20	$ 4,448.79	$ 1,333.11	$ 1,123.48	$ 1,017.86	$ 1,094.41

Unitil Energy Systems, Inc.
RELIABILITY ENHANCEMENT AND VEGETATION MANAGEMENT PLAN
Historical Costs 2005-2009 - Projected Costs 2010 - 2014

(In thousands)

	Combined Capital Reliability Budget	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	Pole Replacement	$ 164.90	$ 130.50	$ 623.70	$ 580.60	$ 701.80	$ 784.81	$ 748.01	$ 810.38	$ 766.59	$ 687.88
2	Underground Cable Replacement	-	39.50	-	-	-	-	-	-	-	-
3	Automation	194.10	11.10	52.00	(19.00)	1.60	64.84	348.57	74.24	44.25	176.96
4	Reliability Projects - Specific	276.10	134.70	72.40	-	562.00	986.37	236.54	238.86	207.02	229.58
5	Other REP [1]	97.70	90.30	97.20	30.40	2,068.80	2,612.77	-	-	-	-
6											
7	UES Capital Subtotal	$ 732.80	$ 406.10	$ 845.30	$ 592.00	$ 3,334.20	$ 4,448.79	$ 1,333.11	$ 1,123.48	$ 1,017.86	$ 1,094.41
8											
9	REP Capital Groupings										
10	"Feeder Hardening" Activities	567.90	236.10	221.60	11.40	2,632.40	3,663.98	585.10	313.11	251.27	406.53
11	Asset Replacement	$ 164.90	$ 170.00	$ 623.70	$ 580.60	$ 701.80	$ 784.81	$ 748.01	$ 810.38	$ 766.59	$ 687.88
12											
13	UES Capital Subtotal	$ 732.80	$ 406.10	$ 845.30	$ 592.00	$ 3,334.20	$ 4,448.79	$ 1,333.11	$ 1,123.48	$ 1,017.86	$ 1,094.41
14											
15	REP O&M Expenses										
16	Augmented tree trimming and clearing	-	-	-	-	-	-	200.00	200.00	200.00	200.00
17	Inspection and Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ 100.00	$ 100.00	$ 100.00	$ 100.00
18											
19	UES Capital Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 300.00	$ 300.00	$ 300.00	$ 300.00
20											
21	VPM Expenses Base Funding										
22		-	-	-	-	-	-				
23	Tree Trimming and Vegetation Management	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,250.00	$ 2,250.00	$ 2,250.00	$ 2,250.00
24											
25	UES Capital Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,250.00	$ 2,250.00	$ 2,250.00	$ 2,250.00

Unitil Energy Systems, Inc.
RELIABILITY ENHANCEMENT AND VEGETATION MANAGEMENT RATE PLAN
Proposed Funding 2011 - 2015

(In thousands)

		2011	2012	2013	2014	2015
1	Recommended Funding for REP and VMP Rate Plans					
2	(In thousands)	2011	2012	2013	2014	2015
3						
4	REP Capital Investment					
5	"Feeder Hardening" Activities	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00
6	Asset Replacement	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00
7						
8	REP Capital Total	$ 1,750.00	$ 1,750.00	$ 1,750.00	$ 1,750.00	$ 1,750.00
9						
10	REP O&M Expenses					
11	Inspection and Maintenance	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00
12	Augmented tree trimming and clearing	$ 200.00	$ 200.00	$ 200.00	$ 200.00	$ 200.00
13						
14	REP Expense Total	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00
15						
16	VPM Baseline O&M					
17	VMP Base Funding Expense	$ 2,250.00	$ 2,250.00	$ 2,250.00	$ 2,250.00	$ 2,250.00
18						
19	REP and VPM Expense Baseline	$ 2,550.00	$ 2,550.00	$ 2,550.00	$ 2,550.00	$ 2,550.00

[1] Excludes budgeted costs associated with the Kingston Substation project for which separate step adjustment is being proposed

Unitil Energy Systems, Inc.
Docket No. DE 10-055
PUC Staff Information Requests – Set 3

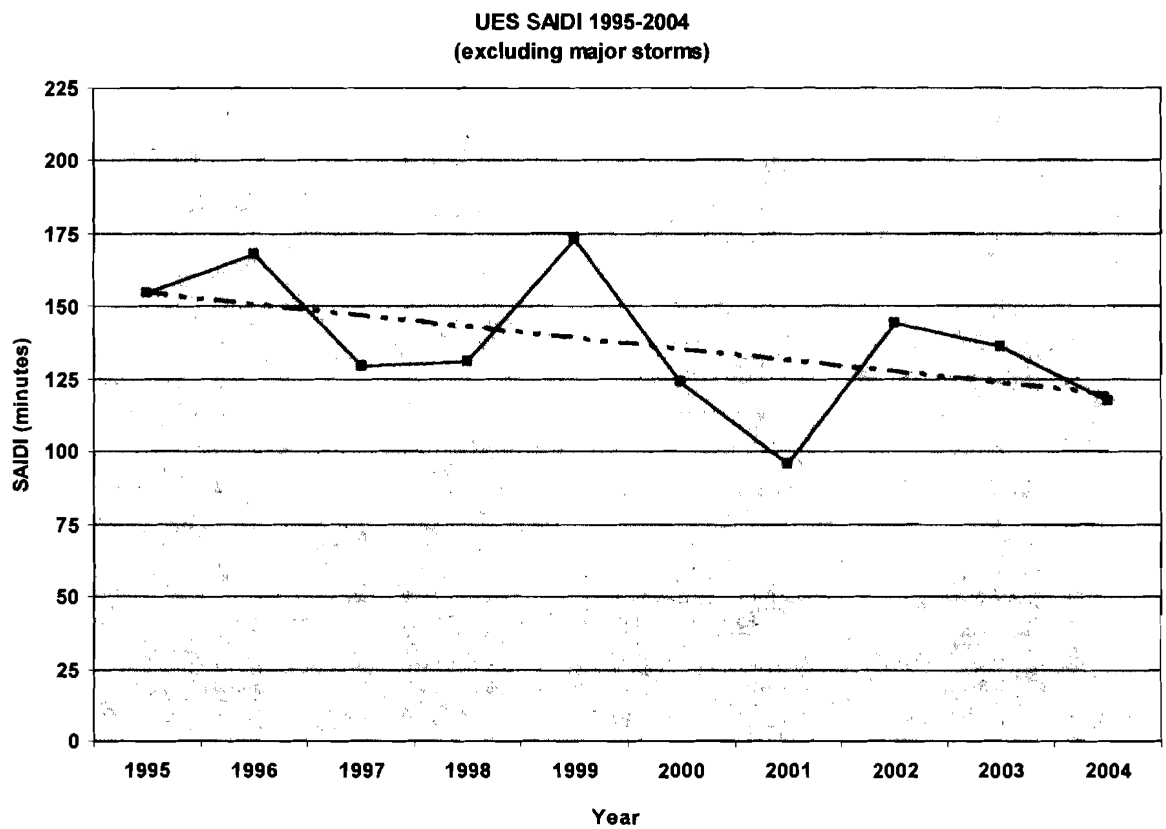
Received: July 1, 2010 Date of Response: July 15, 2010
Request No. Staff 3-59 Witness: Thomas P. Meissner, Jr.

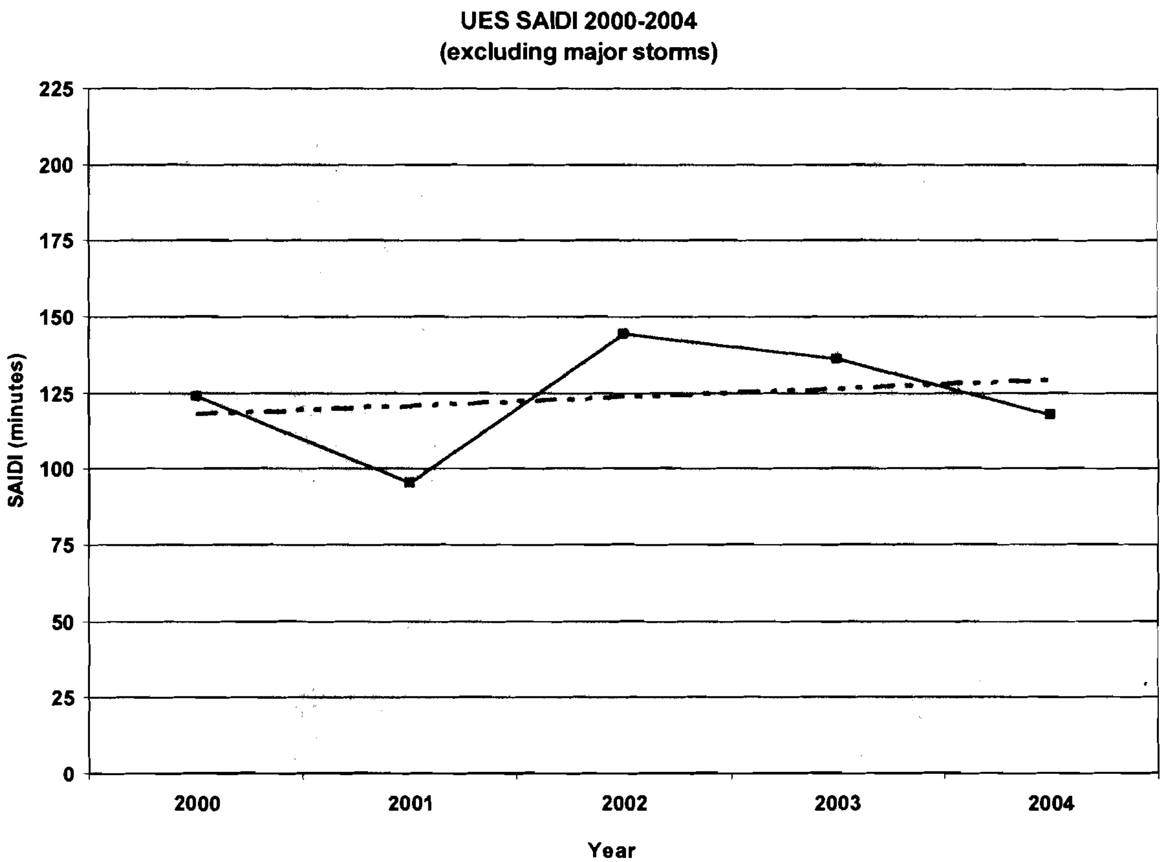
Request:

Reference Meissner testimony, page 33 (Bates 0205), lines 13-16 and Meissner testimony, page 5 (Bates 0177), Figure TPM-2. Please reconcile the referenced statement on page 33 of your testimony with the data that were available to UES in 2006 including the reliability data of the previous five years that were presented in Figure TPM-2.

Response:

UES last filed a rate case on November 4, 2005. At that time, reliability data was available through 2004. Below are graphs showing both the ten year trend and the five year trend through year-end 2004. It was only during the most recent five years (2005 through 2009) that a discernable uptrend in SAIDI became evident. Please refer to Staff 3-27 for the full 15 year trend.




UES SAIDI 2000-2004
(excluding major storms)
SAIDI (minutes)
225
200
175
150
125
100
75
50
25
0
2000
2001
2002
2003
2004
Year

Request:

Reference Meissner testimony, page 54 (Bates 0226), lines 10-12. Please supply a copy of UES' reliability planning standards. Please also supply a copy of UES' policies and procedures for dropping load for contingencies on its distribution system.

Response:

UES' reliability planning standards are provided as attachment Staff 3-67 Attachment 1. UES' policies and procedures for dropping load for contingencies on its distribution system are provided in section 3.9 (pages 6-7) of this document.

Staff 3-67
Attachment 1

Unitil

Unitil Service Corp.

Electric System Planning Guide

Unitil Service Corp.

Original Issue: April 2000
Revised: December 19, 2003
Revised: January 12, 2004

TABLE OF CONTENTS

1 OBJECTIVE

The objective of this guide is to define study methods and design criteria used to assess the adequacy of Unitil transmission, subtransmission, and substation systems; and to provide guidance in the planning and evaluation of modifications to these systems. The purpose is to ensure appropriate and consistent planning and design practices to satisfy applicable criteria and reasonable performance expectations.

2 INTRODUCTION

All Unitil facilities which are part of the Bulk Power System (Pool Transmission Facilities, PTF) shall be designed in accordance with the latest versions of the Northeast Power Coordinating Council (NPCC) policies, the New England Power Pool (NEPOOL) standards, and all applicable Unitil policies. The fundamental guiding documents are the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Reliability Standards for the New England Power Pool" (NEPOOL Document PP3), and this document.

All Unitil facilities which are not considered PTF but are part of the Unitil systems shall be designed in accordance with the latest version of this document.

Detailed design of facilities may require additional guidance from industry or technical standards which are not addressed by any of the documents referenced in this guide.

Systems should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- Utilization of standard components to facilitate availability of spare parts
- Minimization of post contingency switching operations
- Minimization of the use of Special Protection Systems (SPS)

Regulatory Requirements

All Unitil facilities shall be designed and operated in accordance with all applicable state regulatory requirements as specified in the State of New Hampshire's "Code of Administrative Rules" or the Commonwealth of Massachusetts "Code of Massachusetts Regulations."

3 PLANNING CRITERIA

Unitil transmission, subtransmission, and substation systems should be planned and designed for safe, economical and reliable performance, with consideration for normal and reasonably foreseeable contingency situations, load levels, and generation.

3.1 Allowable Equipment Loading

Thermal ratings for system equipment are established to obtain the maximum use of the equipment accepting some defined, limited loss of life or loss of strength. These ratings are based on the Unitil "Electrical Equipment Rating Procedures Guide". The principal variables used to derive these ratings include specific equipment physical parameters and design, maximum allowable operating temperatures, seasonal ambient weather conditions, and representative daily load cycles.

Normal ratings describe the allowable loading to which equipment can operate for normal, continuous load cycling up to peak demands at the indicated **Normal Limit**. Emergency ratings allow brief operation of equipment to higher peak demand limits for emergency situations.

The following listing summarizes Unitil equipment thermal ratings:

Rating	Allowable Duration before Relief
Summer Normal Limit	continuous
Summer Long-Time Emergency (LTE) Limit	12 hours
Summer Short-Time Emergency (STE) Limit	15 minutes
Winter Normal Limit	continuous
Winter Long-Time Emergency (LTE) Limit	4 hours
Winter Short-Time Emergency (STE) Limit	15 minutes

Equipment loaded at or below its **Normal Limit** is operating within normal loading conditions. Equipment loaded above its **Normal Limit** is operating at emergency loading conditions, and may be experiencing higher than normal loss of life or loss of strength.

Equipment loaded above its **Normal Limit** and at or below its **Long-Time Emergency Limit** is operating at a long-time emergency load level. Long-time emergency loading may be sustained for a single, non-repeating load cycle where the **Normal Limit** is exceeded for no more than the allowable duration.

Equipment loaded above its **Long-Time Emergency Limit** and at or below its **Short-Time Emergency Limit** is operating at a short-time emergency load level. Short-time emergency loading must be relieved to normal or LTE conditions within 15 minutes. Unitil systems should be planned and designed to avoid short-time emergency loading. However, it is acceptable for equipment to be loaded to short-time emergency conditions following a loss-of-element contingency, provided automatic or remote actions are in place to relieve the loading within the specified time.

Equipment loaded beyond its **Short-Time Emergency Limit** is operating at a **Drastic Action Level (DAL)**, and immediate relief is required including the shedding of load if necessary. If a facility operates at this level for more than five minutes, equipment may suffer unacceptable damage. Unitil systems shall not be planned for equipment to reach DAL loadings.

3.2 Allowable System Voltages

System voltage ranges are established to obtain adequate operating voltages for system customers, maintain proper equipment performance, avoid over-excitation of transformers or under-excitation of generators, and preserve system stability. Unitil systems should be planned and designed to sustain steady-state operating voltages at **Non-Distribution points** within a minimum limit of 90% of nominal (108 V on a 120 V base) and a maximum limit of 105% of nominal (126 V on a 120 V base). Unitil systems should be planned and designed to sustain steady-state operating voltages at **Distribution points** within a minimum limit of 97.5% of nominal (117 V on a 120 V base) and a maximum limit of 104.2% of nominal (125 V on a 120 V base).

In this context, **Non-Distribution points** indicate locations that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are **Non-Distribution**, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Correspondingly, **Distribution points** indicate locations that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

It is acceptable for steady-state voltage excursions beyond these limits to occur immediately following a contingency event and while corrective actions are in progress. However, Unitil systems should be planned and designed to limit the extent and duration of such excursions. Furthermore, Unitil systems shall not be planned to accept unchecked voltage collapse.

There are no design limits on the amount of change in operating voltages from initial pre-contingency to immediate post-contingency levels.

3.3 System Configuration

Unitil systems shall be planned and designed to meet applicable criteria utilizing specific normal and emergency configurations of system elements.

The **Normal Configuration** shall describe the intended arrangement of the system when all normally in-service elements are available. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges when in the **Normal Configuration** at all normally anticipated load levels.

The arrangement of system elements may be temporarily altered to a non-emergency configuration for routine operating and maintenance purposes. An acceptable non-emergency configuration should also satisfy normal ratings and voltages. It is not a requirement that Unitil systems be planned or designed for every possible non-emergency configuration.

A **Contingency Configuration** describes a modified arrangement of the system in response to emergency conditions. Unitil systems should be planned and designed to be promptly arranged into prescribed **Contingency Configurations** when necessary to attain acceptable conditions following specific contingent emergencies, and to operate within specified equipment ratings and voltage ranges when in these configurations.

3.4 System Load

Unitil systems shall be planned and designed to meet applicable criteria up to specific normal and emergency load levels.

3.4.1 Peak Design Load

The **Peak Design Load** describes the benchmark load level that system adequacy is measured against. It shall be the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. The **Peak Design Load** is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Peak Design Load**.

3.4.2 Extreme Peak Load

Load levels above the established **Peak Design Load** are considered a contingency event under which emergency conditions may be accepted. The **Extreme Peak Load** describes a maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Extreme Peak Load** with all elements available.

3.5 Load Power Factor

Load Power Factor in each area should be consistent with the limits set by the requirements developed under NEPOOL criteria, rules, and standards #30 (CRS-30) for that area.

3.6 System Generation

The operation of generating plants not directly under Unitil control may be determined by a competitive market bidding system where plant availability and dispatch may not include consideration of system support or reliability needs. Unitil systems shall be planned and designed to meet applicable criteria under reasonably foreseeable generation dispatch, taking into account uncertainties in unit status and future availability.

3.6.1 Generation Dispatch

For planning purposes, typical historical performance for each unit may be used as the initial basis for generation dispatch assumptions. These assumptions should take into account factors for seasonal variations, demonstrated forced-outage rates, operating limits, and expected performance during system disturbances.

The planning and operation of generating plants outside of Unitil systems is not typically within the scope of Unitil planning requirements unless they have a direct impact on system adequacy. The impact of generation inside or within the immediate vicinity of Unitil systems should be taken into account. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges during the outage of any utility-owned generating plant.

3.6.2 Non-Utility Generation

The adequacy of system infrastructure to meet Unitil's end-use load obligations necessitates that it be self-sufficient to a certain extent from internal, non-utility generation. Unitil systems are to be planned and designed to operate within specified equipment ratings and voltage ranges with at least one-half of all internal, non-utility generating facilities that presently exist being out of commission in the future.

3.6.3 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a system disturbance. As a general practice, generation rejection or ramp down should not be included in the planning and design of the Unitil systems.

3.6.4 Priority

Serving load has priority over generation. Therefore, if there is an option to trip generation or trip load, the plan will be to trip generation.

3.7 Normal Conditions

Unitil systems shall be planned and designed to operate within normal equipment ratings and voltage ranges for the following normal conditions:

- all normally in-service elements available, and
- load levels up to the established **Peak Design Load**, and
- typical seasonal generation dispatch.

Additionally, the impact of the following generation conditions should be taken into account:

- outage of any utility-owned generating plant inside or within the immediate vicinity of the system, and
- outage of up to 50% (cumulative output) of internal non-utility generating plants.

3.8 Contingency Conditions

Unitil systems shall be planned and designed to meet applicable criteria for specific, pre-determined emergency scenarios.

Design Contingencies describe the pre-determined emergency scenarios that system adequacy is measured against. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges following actions in response to the following **Design Contingencies**:

- loss of any **Non-Radial Line** element, or
- loss of any **Radial Line** element with no backup tie, or
- loss of any **System Supply Transformer**, or
- **Extreme Peak Load** with all elements available.

3.9 Allowable Loss of Load

The objective of planning and designing the system to meet **Design Contingency** criteria is to utilize system elements up to their maximum allowable capabilities to carry or restore as much load as possible. It is understood and accepted that many system fault or equipment failure events, including loss-of-element **Design Contingencies**, may result in the temporary loss of customer load until damaged components are isolated and restoration switching is performed. However, limited loss of customer load for more extended periods of time are acceptable design compromises for specific circumstances where other alternatives are not practical or economical.

3.9.1 Loss-of-Element Contingency

To provide continuity or immediate restoration of service to all portions of system load for all reasonably foreseeable contingencies requires fixed infrastructure with spare capacity or redundancy for each element. This level of design may be inefficient and cost-prohibitive to cover the contingent loss of certain major elements. The loss of limited portions of system load for limited periods of time may be tolerated under defined circumstances as part of prudent, cost-effective alternatives to fixed infrastructure. These alternatives are traditionally either of two choices: (1) the interruption of load while repairs are being made to an element that cannot be backed up; or (2) the interruption of load while mobile or spare equipment is made available from another location, transported and placed into service where needed.

The Unitil system is designed to accept loss of load during the following specifically identified **Design Contingencies**, subject to the indicated conditions and limits:

Table 3.9.1-1 Allowable Loss of Load

Design Contingency	Allowable Loss of Load	Allowable Duration
Loss of a radial line element with no backup tie	≤ 30 MW	≤ 24 hours
Loss of a system supply transformer	≤ 30 MW	≤ 24 hours

Under these contingencies, it is understood that remaining system elements will be utilized up to their maximum allowable capabilities to carry or restore as much load as possible. Allowable Loss of Load refers to a collection of customers within the system that cannot be restored after these automatic or manual actions. This load is the peak coincident demand of this collection of customers, and not the net sum of power flow that may be seen if offset by sources within the affected portions of the system. The allowable impact is limited to these affected customers, not the overall load level at any given time. If actual load at the time is not at peak conditions, it is not acceptable to extend interruptions to a wider collection of customers by summing the demands at that time up to the same numerical limit.

3.9.2 Extreme Circumstances

Widespread outages or catastrophic failures resulting from contingencies more severe than defined **Design Contingencies** may acceptably result in loss of customer load in excess of the limits given here.

3.9.3 Regional Load Shed

NEPOOL and NPCC require that each member have load shedding capability to prevent a widespread system collapse. The types of conditions that could result in these emergencies are unusually low frequencies, equipment overloads, or unacceptable voltage levels in an isolated or widespread area of New England. These conditions may require load shedding. The specific requirements associated with the load shedding are specified in NEPOOL Operating Procedure No. 7 "Action In An Emergency".

3.10 Exceptions

These planning criteria do not apply if a customer receives service from Unitil and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, Unitil has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

Unitil is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, Unitil does not have to provide redundant transmission supplies.

4 PLANNING STUDIES

4.1 Basic Types of Studies

System planning studies based on steady-state power flow simulation shall be routinely conducted to assess conformance with the criteria and standards cited in this guide. These studies will review present and future anticipated system conditions under normal and contingency scenarios. The scale and composition of the Unitil electric system does not typically warrant routine analysis of its dynamic behavior. Transient stability analyses (and other forms of study) are conducted as needs arise.

4.2 Study Period

The lead-time required to plan, permit, license, finance, and construct transmission, subtransmission or substation upgrades is typically between one and ten years depending on the complexity of the project. As a result, system planning studies should examine conditions at various intervals covering a period of ten-years to identify potentially long-term projects.

4.3 Modeling and Assessment for Steady-State Power Flow

The modeling representation for steady-state power flow simulation should include the impedance and admittance of lines, generators, reactive sources, and any other equipment, which can affect power flow or voltage (e.g. capacitors or reactors). The representation should include voltage or angle taps, tap ranges, and control points for fixed-tap, load-tap-changing, and phase shifting transformers.

Specific issues related to the study, which need to be addressed, are discussed below.

4.3.1 Element Ratings

Thermal ratings of each load-carrying element in the system are determined to obtain the maximum use of the equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers and switches). Models will include three (3) rating limits for each season's case:

Summer models- Summer Normal, Summer LTE, and Summer STE.
Winter models - Winter Normal, Winter LTE, and Winter STE.

4.3.2 Modeled Load

Load development is extremely important to the creation of an effective model. The summer and winter forecasted **Peak Design Loads** and **Extreme Peak Loads** should be obtained annually from the appropriate department for a period of ten years. Modeled loads for each load center should be developed in sufficient detail to distribute the active and reactive coincident loads (coincident with the system's total peak load) throughout the system such that the net effect of loads and losses matches expected power flows and the overall **Peak Design** or **Extreme Peak** load for each case.

4.3.3 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, studies may require modeling several load levels. Minimum requirements call for study of peak load levels (**Peak Design** or **Extreme Peak**). Where high voltage issues or unusual reactive power flows are a concern, or the degree of consequences and exposure to risks must be quantified, lesser load levels may be studied. The basis for the these loads can be either summer or winter conditions, whichever is the worst case scenario for the system. In some areas, both seasons should be studied.

4.3.4 Balanced Load

Balanced, three-phase, 60 Hz ac loads should be assumed at each load center unless specifically identified by an area or circuit study. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load of the other phases.
- The voltage unbalance between the phases, measured phase–to–phase, is less than 3%.
- Harmonic voltage distortion is within limits recommended by the current version of IEEE Std. 519.

4.3.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the system and, when appropriate, located on the low voltage side of substation transformers. Reactive compensation on distribution feeders and circuits are assumed to be included within the modeled loads.

4.3.6 Generation Dispatch

Analysis of system sensitivity to variations in generation dispatch is necessary during a study. The intent is to test the adequacy of the Unitil system as much as can be reasonably anticipated against the end-use loads which it is obligated to serve.

The basis for modeling should begin with initial assumptions of generating unit outputs at their typical seasonal levels. Cases may then be modified to reflect intended criteria and assumptions for future conditions.

In modeling the system, no more than one-half of internal, non-utility generation should be considered as being in commission and operational for the future study period. This may be modeled conservatively by taking the most significant facilities for a portion of the system out of service until the sum total of internal non-utility generation has been reduced by at least fifty percent (50%) from their typical historical output. Remaining units may be modeled at their historical output. This may result in additional units being reduced or off-line if that has been their typical history (e.g. hydro generation during periods of low river flow).

4.3.7 Facility Status

Initial conditions assume all existing facilities normally connected to the system are available and operating as designed or expected.

Studies should not consider presently planned improvements or modifications to be assured to be implemented for future system models. Instead, these improvements should be updated and reaffirmed through the study process as being necessary and the most cost-effective options available. Risks, consequences, and exposure levels should be determined in the event that projects are not completed as planned.

4.4 Modeling For Stability Analysis

4.4.1 Dynamic Models

Dynamic models are required for generators and their associated equipment, HVdc terminals, and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained in cooperation with NEPOOL and NPCC.

4.4.2 Load Level and Load Models

Stability studies within NEPOOL typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed with a bulk power system load level of 45% of peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch within a specific area or system.

System loads within NEPOOL are usually modeled as constant admittances for both active and reactive power, but other load models can be used as needed. Loads outside NEPOOL are modeled consistent with the practices of the individual areas. Appropriate load models for other areas are available through NEPOOL and NPCC.

4.4.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched economically. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

4.5 Addressing System Deficiencies and Constraints

System studies should clearly identify results that fail to satisfy criteria or constrain performance. To the extent that supporting information is available, these deficiencies or constraints should be quantified in terms of severity, extent of impact, duration and periods of exposure.

4.6 Development and Evaluation of Alternatives

If the performance or reliability of the forecasted system does not conform to the applicable criteria, then alternative solutions based on performance, reliability, technical preference, economics, and capacity need to be developed and evaluated. The evaluation of alternatives leads to a recommendation, which is summarized concisely in a report.

4.6.1 Performance

The system performance with the proposed alternatives should meet or exceed all applicable planning criteria.

4.6.2 Reliability

This guide assesses reliability deterministically by defining conditions which the system must be capable of withstanding. This deterministic approach is consistent with NEPOOL and NPCC practice. The system is designed to meet these deterministic criteria to promote reliability and efficiency.

The level of reliability provided through this approach may vary on the bulk system. To some degree this is acceptable due to inherent factors such as differences in local area load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, service requirements, and class and vintage of equipment. When the level of reliability provided to an area is significantly lower than other areas, alternatives are developed to improve the reliability.

When assessing local area reliability, the engineer compares the reliability of comparable areas at different locations on the system. This comparison considers factors such as age, condition, style, and failure rates of equipment. The cause of poor reliability also influences the recommended action. Therefore, the engineer must assess the specific conditions affecting the reliability of service to particular customer(s).

If remedial actions are taken, historical performance data over an appropriate period of time may need to be re-established prior to assessing the need for additional remedial actions.

4.6.3 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement.

4.6.4 Economics

Initial and future investment cost estimates should be prepared for each alternative identified during the course of a study. An engineering economic analysis, as defined in the Unitil Economic Evaluation Procedures, is required to compare the total unit cost of each alternative. The analysis should include the annual charges on investments, losses, and all other expenses related to each alternative.

4.6.5 Capacity

All equipment should be sized based on economics, operating requirements, standard sizes, and engineering judgment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a rough guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without additional major modifications for at least ten (10) years.

4.7 Recommendation

Every study that identifies potential violations of design criteria shall propose recommended actions. The recommended actions should be based on factors such as the forecasted performance, reliability, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, environmental impacts of facilities, and complexity to license and permit.

4.8 Reporting Study Results

A system planning study should culminate in a professional report clearly describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

5 TERMINOLOGY

Bulk Power System

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant effect outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Contingency Configuration

A modified arrangement of the system to attain acceptable conditions following a contingency event.

Design Contingency

A pre-determined emergency scenario that system adequacy is measured against.

Distribution Point

Locations on a system that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

Drastic Action Level (DAL)

Any loading of an element above its STE limit. DAL loading requires immediate relief, including the shedding of load if necessary, to avoid the likelihood of unacceptable or catastrophic damage to equipment..

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, phase angle regulating transformer, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its current transformer(s).

Extreme Peak Load

A maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes.

Interface

A collection of transmission lines connecting two areas of the transmission system.

Load Cycle
Refers to the varying facility loading over a 24-hour period.

Long-Time Emergency (LTE) Limit, Summer or Winter
Allowable peak loading to which equipment can operate for a single, non-repeating load cycle due to emergency circumstances, accepting the possibility of higher than normal loss of life or loss of strength.

Loss of Load
Loss of service to one or more customers excluding automatic switching time.

NEPOOL
The New England Power Pool, formed in 1971, is a voluntary association of electric utilities in New England who established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region.

Non-Distribution Point
Locations on a system that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are non-distribution, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Non-Radial Line
A transmission or subtransmission line, or portion of a line, with more than one possible sending end. A non-radial line may operate radially by being open at one or more ends or intermediate switching locations. However, a radially operating line is still considered non-radial if it has been designed with the intent of utilizing its alternate sending ends to carry or deliver power.

NPCC
The Northeast Power Coordinating Council is an electric regional reliability council, which was formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. The NPCC area includes the following U.S. states and Canadian provinces: Massachusetts, Connecticut, Rhode Island, New York, Vermont, New Hampshire, Maine, Ontario, Quebec, New Brunswick, and Nova Scotia.

Normal Configuration
The intended arrangement of a system when all normally in-service elements are available.

Normal Limit, Summer or Winter
Allowable peak loading to which equipment can operate during normal, continuous load cycling and prescribed seasonal conditions.

Peak Design Load

The benchmark load level that system adequacy is measured against. The **Peak Design Load** is the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. It is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources.

Radial Line

A transmission or subtransmission line, or portion of a line, with only one effective sending end and no back up ties to carry or deliver power.

Scheduled Switching

Any planned switching which is scheduled in advance of any work. This does not include work that occurs as a result of a contingency.

Short-Time Emergency (STE) Limit, Summer or Winter

One-time peak loading which can be sustained by equipment for up to 15 minutes while corrective actions are underway following a contingency emergency, and accepting the likelihood of higher than normal loss of life or loss of strength.

Special Protection Systems

A Special Protection System (SPS) is a protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding is not considered an SPS.

System Supply Transformer

Transformers that deliver power into a system from its external transmission supply.

System

The collection of electric transmission, subtransmission and substation elements that receive electric power supplied from internal and external sources and transport and deliver it to distribution systems. The system is generally a continuous infrastructure in a certain operating area.

Unitil owns and operates systems in three areas: Unitil Energy Systems – Capital (in the region of Concord, NH), Unitil Energy Systems – Seacoast (in the region of Exeter and Hampton, NH), and Fitchburg Gas and Electric Light (Fitchburg, MA).

Transfers

The flow of electrical power across a transmission circuit or interface.

Table 1. Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading Limit[1]	Allowable Element Loading Duration	Allowable Loss of Load Limit	Allowable Loss of Load Duration
Normal Configuration – all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ up to half of internal, non-utility generating units out of service	≤ Normal	---	none	---
Normal Configuration – outage of generating plant			≤ Normal	---	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
Contingency Configuration – loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Contingency Configuration – loss of system supply transformer			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load		≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle, (W) = Winter load cycle

Table 2. Voltage Range Summary

Condition	Low Limit (p.u.)	High Limit (p.u.)
Non-Distribution points	0.90	1.05
Distribution points	0.975	1.042

[1] STE loading is acceptable following a loss-of-element contingency, provided actions are available to relieve the loading within 15 minutes.

Request:

Reference Meissner testimony, Schedule TPM-2, page 1 (Bates 0233), Section 3. Please describe in detail what weather conditions PDI levels 1 through 4 represent and how they relate to the NHPUC definition of a Major Storm.

Response:

PDI levels are indices developed by Unitil's weather forecast provider - WSI Corporation of North Andover, MA. A PDI level is a qualified indicator of both the possibility and severity of impact of a particular event that results in the potential for customer outages. Although the PDI level is an established predictive tool used for pre-event planning purposes, there remains the need for professional judgment in the storm preparation process. The detailed weather conditions related to PDI levels are:

- A PDI of 0 – Isolated, general storms are possible but not probable with little or no lightning and wind gusts less than 30 miles per hour (mph). The potential for customer outages is unlikely.
- A PDI of 1 – Scattered, strong storms are possible with moderate lightning or limited icing (< 1/4 inch accretion) and isolated wind gusts between 30 and 50 mph. The potential for customer outages is minor.
- A PDI of 2 – Strong storms with isolated yet severe pockets are possible with moderate to severe lightning or icing between 3/8 to ¾ inch accretion or < 6 inches of wet snow, soil moisture > 6 g/kg, sustained winds 30 to 40 mph and many wind gusts between 40 to 50 mph with a few in excess of 50 mph. The potential for customer outages is moderate.
- A PDI of 3 – Severe storms are possible with moderate to severe lightning or icing between ¾ to 1 inch accretion or between 6 and 12 inches of heavy, wet snow and widespread damaging wind gusts in excess of 50 mph with a possibility of tornados. The potential for customer outages is heavy.
- A PDI of 4 – A severe and widespread storm is imminent with intense lightning or icing in excess of 1 inch accretion or an excess of 12 inches of heavy, wet snow and hurricane force wind gusts (> 75 mph). The potential for customer outages is severe.

Based upon these definitions, and based on a review of historical data comparing PDI levels to past major storms at UES, the Company relates these conditions to the NHPUC definition of a major storm as follows:

- PDI 0 and PDI 1 are unlikely to result in weather capable of causing widespread damage or customer outages corresponding to a Major Storm.
- PDI 2 *may* result in weather capable of causing widespread damage and customer outages corresponding to a Major Storm, and *may* escalate to a higher PDI level as the timeframe for the predicted weather approaches and the forecast improves.
- PDI 3 and PDI 4 are highly likely to result in weather capable of causing widespread damage and customer outages corresponding to a Major Storm.

The decision to begin advance preparations at a PDI level 2, including procurement of resources, depends on a variety of factors. For example, the weather associated with a PDI 2 covers a wide range. At the low end of the range, the predicted weather would not be expected to result in significant problems; at the higher end of the range, weather-related damage could be significant and the event could easily escalate to a more severe PDI level. These and a variety of other factors, combined with the professional judgment of the weather forecasting service, and the experience and judgment of managers involved in emergency management, determine the extent of the response (if any) in advance of a pending PDI 2 event.

Request:

Reference Staff 1-29. Please provide a copy of the UES vegetation management practices and program currently in use.

Response:

A copy of the current UES vegetation management program is provided as attachment Staff Set 3-75 Attachment 1.

Staff 3-75
Attachment 1

Unitil

Operations Bulletin #OP5.00

Subject: Vegetation Management

Effective: January 1, 2001

Revised: February 1, 2007

Issued by: R. Letourneau

1.0 Purpose

To establish a standardized vegetation management program for the Unitil system companies in order to insure consistency and the best practices approach in achieving reliable operation of the overhead T&D systems in accordance with Unitil's Strategic Plan.

2.0 Scope

This bulletin applies to the vegetation management program for all Unitil electric distribution systems and provides the required guidelines, necessary standards, and performance measures necessary for a continuing assessment of the effectiveness of the program.

3.0 Table of Contents

4.0 Methods

Vegetation management methods apply to both Unitil's Transmission system and Distribution system. Transmission methods and frequency differ from distribution methods due to the fact our transmission system is, for the most part, off-road and located within rights-of-way. The topography, land-use, the company's rights, and the fact our transmission system is the backbone of a reliable energy delivery system dictate more aggressive trimming methods and also various types of vegetation control. The Distribution methods, although not as aggressive as Transmission, still require minimum line clearance specification, however with less variation in trimming methods. The following sections describe approved methods of vegetation control.

4.1 Transmission Vegetation Control

Transmission vegetation control is defined as the process and methods utilized to maintain the company's rights-of-way. Because the transmission system is an integral component of a reliable energy delivery system, and because of the higher voltages of our transmission lines, tree and limb contact must be completely eliminated through inspection and trimming programs. The higher voltages are less tolerant to tree and/or limb contact and added clearance is preferred. Added clearance is also preferred to speed transmission foot patrols during routine maintenance inspections or during outage situations where a fault has occurred and the ability to quickly isolate the fault is necessary to sectionalize the line or begin immediate repair work in order to minimize outage time to our customers.

Several methods will be described in this bulletin. Although not any one single method is the most effective, the distribution company shall endeavor to deploy the most efficient and effective method of vegetation control based upon the topography of the land, types of vegetation in terms of growth rates, the company's rights, state and federal law, and any other regulations which may apply.

4.1.1 Transmission Cycle

Transmission vegetation control shall be completed on a 5-year cycle. This results in the maintenance of one-fifth of the transmission system on an annual basis. The determination of the amount of trimming may be calculated based upon the pole miles of transmission line or acreage. Since many of our rights-of-way have more than one line, and because many rights-of-way can accommodate more than the existing facilities, the preferred unit of measure shall be acres. The acres unit of measure accommodates varying line configurations as well as varying widths of right-of-way. Therefore all planning and reporting of transmission vegetation control shall utilize acres as the standard unit of measure.

4.1.2 Selective Trimming

Selective trimming is defined as tree removal in the transmission right-of way employing conventional methods. Conventional methods include the identification of the tallest vegetation within the right-of-way and removal of such vegetation utilizing various saws and chippers/shredders. This method has several benefits including no restrictions on topography since personnel often walk the right-of-way, transporting all the required equipment by hand.

4.1.3 Herbicide Applications

The spraying of herbicides by certified contractors has shown to be a cost effective vegetation management tool. Increased regulation in this area has resulted in an increased administrative burden. However at this time the additional responsibilities have not outweighed the resulting benefits. Therefore this method continues to be a preferred method of transmission vegetation control for Unitil Companies.

Careful planning and accurate records are required in order to properly execute a successful herbicide program. Knowledge of federal and state laws as well as local ordinances need to be researched to determine proper application. Because laws between Massachusetts and New Hampshire could vary, this Operations Bulletin will not address one specific method. Instead the bulletin will outline the steps currently utilized by one New Hampshire DOC. These steps are as follows:

1. Obtain herbicide permit from the NH Department of Environmental Services. This is the responsibility of the certified contractor performing the spraying.
2. By means of certified mail, notify the selectmen, mayor, or town manager in the city or town where the rights-of-way are located (refer to Appendix A for copy of sample letter).
3. Notification to the public through the use of notices in one newspaper of statewide circulation and in all newspapers of local circulation (refer to Appendix B for copy of sample notice).
4. Notification through billing stuffers, by telephone, or in person each abutter along the right-of-way where herbicides are to be applied. Abutters shall be offered alternative vegetation management, i.e. mechanical clearing. This is New Hampshire state law (RSA 374:2-a) and the wishes of the landowner shall take precedence.
5. Posting signs every 200 feet along the perimeter of the right-of-way where herbicides are to be applied.

New Hampshire State law further stipulates the format of the newspaper advertisements, including specific information required for publication as well as a requirement that the advertisement be a "coupon" that may be clipped and mailed back to the utility.

The information provided in this Operations Bulletin shall be used as a guideline and is **not intended to be all-inclusive.**

Herbicide applications are not practical for all applications. For example, rights-of-way that include a large percentage of farmlands, or rivers/streams would not be conducive to herbicide use. However for many applications, herbicide use continues to be an efficient, cost-effective method of controlling growth along Unitil's rights-of-way.

4.1.4 Mowing

The mowing of transmission rights-of-way is defined as the mechanical removal of vegetation using various motorized apparatus that may be attached to off-road equipment. The topography must be free of rivers and large streams since the equipment is unable to cross such obstacles. Several vendors have become proficient in this method and Unitil has contracted with them with favorable results.

4.1.5 Side-Cutting

Side cutting is defined as vegetation control at the edge of the right-of-way. Side cutting shall be utilized in conjunction with other forms of vegetation control and is therefore not a practical transmission vegetation control method on a stand-alone basis. In other words, side–cutting supplements transmission vegetation control methods utilized to control vegetation within the right-of-way.

Tree limbs that grow from outside the actual right-of-way can jeopardize the integrity of the transmission system and therefore must be removed. Furthermore, dead and danger trees also pose risks. Dead trees may fall into adjacent trees at the edge of the right-of-way, leaning towards the transmission line posing a threat to the transmission line itself. Danger trees, defined as dying trees that have weak limbs or trunks, may also pose similar risks. Side cutting is designed to eliminate these threats.

4.2 Distribution Vegetation Control

Distribution vegetation control is defined as the systematic removal of vegetation growth along Unitil's distribution circuits. The majority of distribution circuits are along the roadway and unlike transmission methods, distribution methods are not as varied and are usually performed from a bucket truck using various sawing techniques. In addition to trimming trees, the identification and removal of danger trees is also a significant part of vegetation control.

Distribution vegetation control shall be scheduled through a combination of circuit SAIDI, circuit SAIFI and a predetermined cycle by circuit and voltage class.

4.2.1 Conductor clearances

The goal of distribution vegetation control is to limit the opportunity for tree contact while trimming a reasonable volume of vegetation. The following clearance guideline should be followed to whenever possible.

	Multi-Phase	Single Phase
Clearance above primary conductors	15 foot minimum plus danger trees and dead wood	6 foot minimum above plus danger trees and deadwood
Clearance adjacent to primary conductors	8 foot minimum plus 20 foot minimum clearance for danger trees and deadwood	6 foot minimum plus 20 feet minimum clearance for danger trees and deadwood
Clearance below lowest attachment point on pole	Ground cut or four (4) feet below lowest telephone cable.	Ground cut or four (4) feet below lowest telephone cable.

The specifications listed above and further detailed in Appendix C shall be strictly followed. However, it is recognized that, from time to time, proper permissions may not be granted from property owners. In addition, scenic road designations may preclude the achievement of specified clearances. Permission problems and/or scenic road designations shall be well documented on daily timesheets (See Section 6.3, Performance Metrics) for auditing purposes.

4.2.2 Distribution Cycle

Distribution vegetation control shall be completed on a cycle according to the following table:

Voltage Class	Cycle	
	Three Phase	Single Phase
4 kV	8 years	10 years
13.8 kV	5 years	7 years
34.5 kV	4 years	5 years

The determination of the amount of trimming shall be calculated based upon the pole miles of distribution circuits, by voltage class, excluding secondaries and services. These figures shall be determined based upon the annual statistical report compiled by individual distribution operation centers (DOCs).

4.2.3 Danger Trees and Deadwood

Danger trees and deadwood are defined as dead or dying trees or limbs that pose a threat to distribution circuits upon their failure. These dead trees or limbs may break away at any time, fall into the circuit and result in damage to our facilities. Managing dead trees and limbs requires identification and removal at the earliest possible stage. Methods for removal include flat cutting the entire tree or removal of the problem branches. The objective is to ensure that if the tree failed, the integrity of the distribution circuit will be maintained.

Third party participation shall be pursued in all danger tree removals prior to commencement of the program. Participation is based upon the current Intercompany Operating Procedure as detailed in Section 4.2.5 of this Operating Bulletin. Reimbursement provides significant payment to Unitil allowing for further funding of the Vegetation Management Program. Refusal of participation shall be properly documented.

4.2.4 Maintaining Services

Services shall be reviewed for trimming on the same cycle and concurrently to the distribution primary circuit. Services and secondary pole lines shall not be trimmed unless a tree/branch is directly in contact with the conductor. For the purpose of record keeping and metric evaluation, services and secondary pole lines trimmed shall be categorized as unscheduled work.

4.2.5 Customer Trimming Requests

Customer requested service trimming requires careful assessment and management. These requests, if not handled properly, may result in a significant resource commitment both in terms of dollars and administrative labor without a proportional benefit to outage and/or damage prevention. In addition, improperly managed requests may result in negative customer sentiment.

Each request shall be individually reviewed in the field after a discussion with the customer reveals that a potential problem exists. Only those services that have significant contact with vegetation and/or are in harms way due to danger trees shall be trimmed. All other service shall not be trimmed. The customer shall receive notification as to the position of the company and shall also receive a complete explanation as to the decision.

4.2.6 Intercompany Operating Procedures

The purpose of the Intercompany Operating Procedure (IOP) is to establish a definite method of allocating costs of trimming associated with both construction and maintenance of joint pole lines.

Maintenance trimming shall be done on a joint basis. This joint participation is dependent upon the individual IOP's established with each telephone company however the division of costs are typically either 75% Unitil and 25% telephone or 80% Unitil and 20% telephone.
Heavy storm work shall be handled immediately without prior review. The parties agree to a reciprocal acceptance of each other's tree contractors for heavy storms on a 50%/50% basis, provided field representatives, as soon as practicable after a major storm, meet to communicate cities/towns, streets, and lines trimmed as a result of said storm. Subsequent bills to include the same information.

Lastly, removal of danger trees including large limbs that threaten both parties' facilities shall be removed on a 50%/50% basis, subject to prior field review wherever possible (see Section 4.2.2 of this Operating Bulletin).

5.0 Standards

Standards refer to required conductor clearances relative to vegetation growth. In all cases these standards shall be realized unless designated scenic roads and /or appropriate permissions from landowners can not be obtained.

Please refer to Appendix C for a pictorial view of standards.

6.0 Performance Metrics

In order to measure the effectiveness of the trimming program, data shall be collected on a continuous basis and performance metrics shall be calculated and published, by DOC, on the Operations Systems web page. Comparative analysis shall allow for continued improvement in vegetation control methods and techniques. Responsibility for the collection of data, accurate and timely reporting, and comparative analysis shall rest with the DOC's respective Manager of Electric Systems or their designee. Performance metrics shall be updated no less than once per month.

6.1 Effectiveness Measures

In order to monitor the effectiveness of the transmission trimming program, each DOC shall record the **total number of momentary or permanent outages** experienced on our transmission system on a monthly basis. Only those momentary and permanent outages related to tree or limb contact are utilized for this metric. Additionally, only those trees and limbs that are within the trim zone shall be included. The metric is expressed as follows:

Transmission Effectiveness = Total number of momentary or permanent outages

The logic behind the measure is that an effective transmission trimming program shall have the objective of minimizing these types of interruptions.

In order to monitor the effectiveness of the distribution trimming program, each DOC shall record the **number of tree-related outages, by voltage class,** on a monthly basis. This number shall be divided by the **total number of pole miles per respective voltage class** in the DOC as described in Section 4.2.1. The quotient, expressed as follows, shall comprise the effectiveness measurement for distribution vegetation control:

$$\textbf{Distribution Effectiveness} = \frac{\textbf{Number of tree-related outages (by voltage class)}}{\textbf{Total number of pole miles (by voltage class)}}$$

The logic behind the measure is that an effective trimming program shall have the objective of minimizing tree-related outages.

6.2 Efficiency Metrics

Efficiency metrics are designed to compare costs and ensure that resources are deployed in a manner that achieves the greatest amount of trimming for the dollars expended.

For Transmission efficiency, each DOC shall record **dollars expended** and **acres maintained**. The quotient, expressed as follows, shall comprise the effectiveness measurement for transmission vegetation control:

$$\textbf{Transmission Efficiency} = \frac{\textbf{Total dollars expended}}{\textbf{Total acres maintained}}$$

For Distribution, each DOC shall record **dollars expended** and **sections of primary conductor trimmed**. The quotient, expressed as follows, shall comprise the effectiveness measurement for distribution vegetation control:

$$\textbf{Distribution Efficiency} = \frac{\textbf{Total dollars expended}}{\textbf{Number of sections trimmed}}$$

The **number of sections trimmed** shall also include services. In other words, one service is equal to one section.

The logic behind this measurement is that the most efficient crews shall be more productive and able to achieve the lowest cost per section of circuit trimmed.

6.3 Daily Timesheet Information

All vendors performing maintenance or construction trimming shall complete daily timesheets. See Appendix D for a copy of the timesheet.

This timesheet is designed to collect the necessary data that will be utilized to process vendor invoices and to calculate performance metrics. It shall be the responsibility of the Manager, Electric Systems or their designee to ensure the timesheets are completed daily, and that all required information is included.

Information on the daily timesheet includes:

General Information:

- Date
- Street
- Town

- Circuit
- Voltage

Pole Numbers
- Company pole number
- Telephone pole number

Quantity of work:
- Number of sections trimmed
- Number of services trimmed

Type of work:
- Scheduled work
- Unscheduled work
- Construction related
- CWO number
- Storm work
- Other trouble
- Customer Trim Request

Type of Clearing:
- Trees trimmed – L (light), M (medium), H (heavy)
- Ground Cut
- Dead/Hazardous trees or limbs removed

Type of Construction:
- 1 – Single Phase, 2 – Two Phase, 3 – Three Phase
- Secondary Only
- Service Only

Time:
- Labor
- Equipment/Vehicle

Telephone Participation
- Trimmed for Telephone Y/N
    - See individual IOP's for division of participation.

6.4 Monthly Reports & Map Updating

Monthly progress reports shall be available. These reports shall provide specific information regarding the status of individual DOC vegetation management programs. Information shall include annual schedules for transmission and distribution programs, scheduling status, and performance metrics. The report will be completed by individual DOC and then rolled into one single, Unitil system report. Please see Appendix E for format of report.

It shall be the responsibility of the Manager, Electric Systems or their designee to update the Operations System web site no less than once per quarter.
In addition, each DOC shall utilize circuit maps as a means to track circuit trimming. These maps shall detail the specific locations that our facilities were trimmed along with appropriate dates. These maps shall remain on file for at least one complete cycle.

6.5 Supervision

The Manager, Electric Systems or their designee shall be responsible for developing schedules and monitoring the progress of said schedules. The Manager, Electric Systems, shall be responsible for monitoring the efficiency and effectiveness of the contract crews, ensuring that their productivity and quality are as expected.

Any knowledgeable DOC employee may perform monitoring of the contract crews. Monitoring includes live field visits and post-audit inspections. The results of these field visits and audits shall be reported to the Manager, Electric Systems.

7.0 Budgeting Criteria

Transmission and Distribution Trimming budgets shall be completed annually based upon the scheduled cycle, volume of trimming, as well as an estimate of unscheduled work. On an annual basis, Unitil engineering shall review reliability performance on a circuit by circuit basis (SAIDI and SAIFI). Operations shall use this information to develop the trimming schedule for the year. In addition, Engineering will make recommendations on problem areas with the ultimate objective of improving the System Average Interruption Duration Index, or SAIDI. This analysis shall be completed during the annual capital budgeting process. Operations shall endeavor to complete the identified trimming projects as early as possible in the fiscal year so that the SAIDI benefit may be realized as soon as possible.

7.1 Annual Costs

Annual costs shall be based upon the volume of work required for that cycle year and the amount of expected trimming, including both scheduled and unscheduled work. Either acres (for Transmission) or pole miles (for Distribution) shall be utilized in conjunction with the costs recorded for the performance metrics detailed in Section 6.0. It is also necessary to pre-select trimming methods, i.e. side-cutting, herbicide application, mowing, etc., before commencement of a budget.

7.2 Determining Volume of Work

In order to determine the volume of work, the amount of vegetation growth needs to be established. The type of clearing (Light, Medium, and Heavy) can only be determined by field inspection. Prior to budgeting, the areas to be trimmed shall be inspected to determine vegetation growth. The information from this inspection shall then be utilized to calculate required resources for the cycle year.

In an area where it is anticipated that work shall be placed out to bid, Unitil shall endeavor to perform such bidding in advance of the actual budgeting process. This will allow for more accurate budgeting.

7.3 Vendor Selection

Criteria for vendor selection shall be based upon cost and performance. It is also strongly recommended to select a vendor that is able to provide additional resources during storm events.

On a routine basis, Unitil shall solicit request for proposals from local tree contractors. These proposals shall include a listing of personnel and equipment, along with any ancillary services the vendor may provide. Other selection criteria include the safety record of the vendor and minimum insurance requirements as set fourth in Unitil Policies. The DOC management will then evaluate the proposal and select an appropriate vendor.

7.4 Competitive Bidding

Competitive bidding is an effective method for performing either maintenance trimming or construction trimming. Not all work is conducive to bidding. In most cases, the best utilization of competitive bidding is for work that is confined to a definitive scope. Work included is this is as follows:

- Complete circuit trimming
- Off-road trimming
- Long line extensions along public way
- Major system improvements such as voltage conversions
- Specialty trimming (mowing, herbicide application)

Competitive bid documents shall be developed to request various different staffing alternatives. Three different approaches to bidding shall be used:

1. Per circuit – Not to exceed cost
2. Per hour cost based upon known schedule
3. Alternative approach
    a. Minimum of 1 crews on site bid on a per hour cost
    b. 1 crew on site as required bid on a per mile basis

Considerations should be given to limit the age of equipment used by the contract tree crews. Alternatively, maintenance time for contract tree equipment should not be included in the bid.

7.5 Hot Spot Trimming

From time to time "hot spot" trimming (unscheduled work sections) is required due to tree contact and or multiple outages as a result of tree contact. This usually happens off cycle as a result of increased vegetation growth or non-compliance with standards during normal cycle maintenance.

It is important that hot spot trimming is carefully managed as this practice is inefficient and results in increased costs. It is recognized that hot spot trimming is a necessary part of vegetation control, but its use shall be minimized to the extent possible.

7.6 Emergency Trimming

It is reasonable to assume that contract tree crews will be required to assist with outage restoration throughout the year. Tree trimming during outage restoration conditions should follow the same standards as described in this document.

Appendix A

Unitil

Exeter & Hampton
Electric Company

Current Date

Town of Plaistow
Board of Selectman
145 Main Street
Plaistow, NH 03865

RE: Vegetation Control Program on Transmission Lines

Dear Selectman:

I am writing to inform you that Exeter & Hampton Electric Company will be conducting our vegetation control program on our transmission lines in parts of your town, scheduled to begin ______________. Please refer to the enclosed map of the area in which we will be working.

The general treatment method will be selective foliage treatment using Monsanto's Herbicide "Accord", and Dupont's "Krenite". The Accord and Krenite will be used for the full width of the right-of-way to control vegetation and if trees are too tall to be sprayed, they will be cut down and the stumps treated to prevent sucker growth.

All work will be done in compliance with applicable Federal and State of New Hampshire rules and regulations.

A Notification Request Coupon is enclosed for individuals who own property over which the right-of-way passes, or whose property abuts the right-of-way and who wish to be notified in writing thirty (30) days prior to any treatment. Coupons must be received no later than____________. Requests after this date will not be granted until the next treatment cycle. As we have done in the past, we will also notify all abutters along our transmission line by telephone.

Exeter & Hampton Electric Company will be working very closely with all parties involved and any questions or concerns you may have may be directed to me at the number below between 7:00 AM and 3:30 PM, Monday through Friday.

Very Truly Yours,

Safety & Facilities Coordinator

Business Office

114 Drinkwater Road
Kensington, NH 03833

Phone: 603-777-5500
Fax: 603-777-5600

Email: ehec@unitil.com

Appendix B

Public Notice - Right-Of-Way Maintenance Schedule

To ensure safety and service reliability to its customers, Exeter & Hampton Electric Company will be conducting maintenance on a portion of its transmission rights-of-way from mid-August into September. Herbicides will be used to treat certain species of fast-growing trees while leaving undisturbed low-growing grasses and other vegetation. Accord and Krenite are approved by the U.S. Environmental Protection Agency and the N.H. Division of Pesticide Control, and will be applied by licensed professionals with hand-held application tools.

Right-of-Way Number	Approx. Treatment Commencement Date	Location
3358	August 18 - 22	Plaistow
3345, 3356	August 25 - 29	Plaistow, Kingston
3343, 3354	September 2 - 6	E. Kingston, Kingston, Kensington, Hampton Falls

Further information can be obtained Monday - Friday 8:00 a.m. - 3:30 p.m. by contacting: Daivid R. O'Brien, Supervisor
Unitil/Exeter & Hampton Electric
114 Drinkwater Road, Kensington NH 03833
603/772-5916 or 1-800-582-7276

A Notification Request Coupon is provided below for individuals who own property over which the right-of-way passes, or whose property abuts the right-of-way and who wish to be notified thirty days prior to any treatment. Coupons must be received no later than July 18, 1997. Requests received after this date will not be granted until the next treatment cycle.

Rights-of-way are gnerally located away from streets and may be identified by the metal tag on a pole or structure with a number on it. The Division of Pesticide Control has marked all known public water supplies along that rights-of-way and these areas will be avoided. It is the responsibility of each landowner or resident to make Exeter & Hampton Electric Company aware of the location of a potential water supply and any environmentally sensitive areas where herbicide application ought to be avoided.

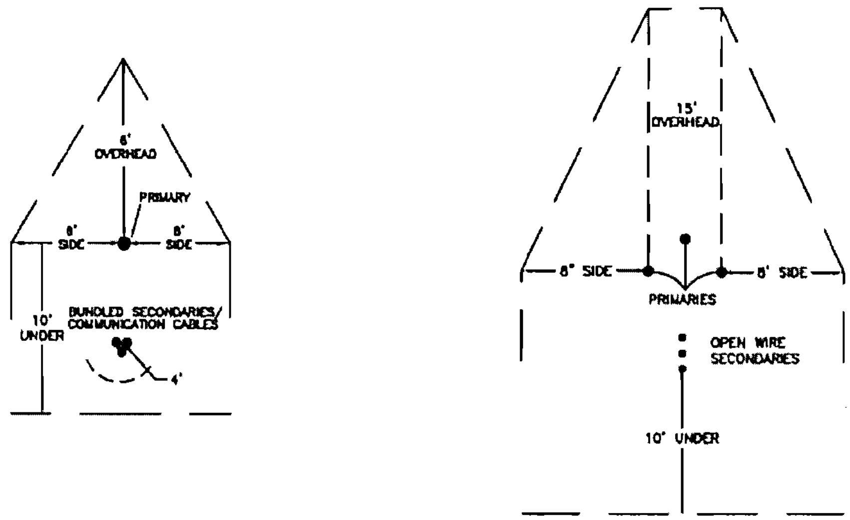
NOTIFICATION REQUEST COUPON

Name:____________________ Town/City of InvolvedProperty: ____________
Street Address:______________________________ Ph (Home) __________
Town: ______________________________ Ph: (Work)__________
State:________ Zip Code _________ Ok to use Work No: __Yes__No
Property of Concern: ______________________________
Sensitive Areas: ______________________________
Name of Utility Company: ______________________________
Approximate Line and Pole Numbers: ______________________________
For further information call (603) 772-5916 or (NH) 1-800-582-7276
Return by July 18, 1997

Unitil
Exeter & Hampton Electric Company

Appendix C

MINIMUM CLEARANCE ZONE DIMENSIONS FOR ELECTRICAL CONDUCTORS AND COMMUNICATION CABLES



NOTES:

OVERHEAD CLEARANCE SHALL BE MEASURED VERTICALLY UPWARD FROM THE HIGHEST PRIMARY OR OPEN WIRE SECONDARY.

SIDE CLEARANCE SHALL BE MEASURED HORIZONTALLY OUTWARD FROM THE OUTERMOST PRIMARY OR OPEN WIRE SECONDARY.

UNDER CLEARANCE SHALL BE MEASURED VERTICALLY DOWNWARD FROM THE LOWEST PRIMARY OR OPEN WIRE SECONDARY.

NORMALLY REMOVE ALL BRANCHES WITH THE MINIMUM CLEARANCE ZONE BOUNDED BY THE DASHED LINE PERIMETER.

IF THE EXISTING CLEARANCE IS LESS THAN THE MINIMUM REQUIRED CLEARANCE BETWEEN THE TREE TRUNK OR LARGE HEALTHY LIMB (WITH STRONG CROTCH) AND WIRES, LEAVE THEM AND REMOVE ALL OTHER BRANCHES WITHIN THE MINIMUM CLEARANCE ZONE.

REV.	DESCRIPTION	BY	DATE	CHK	APR
A	UPDATED WITH BULLETIN REVISIONS	MP	02/05/08	NS	NS

REVISIONS

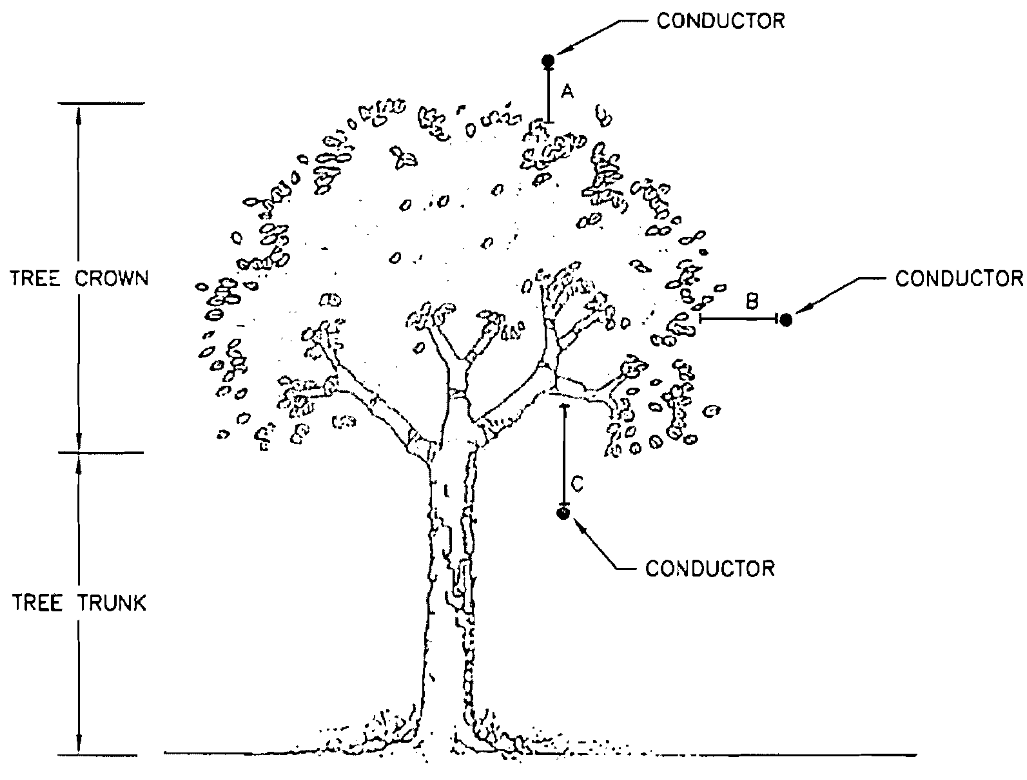
DRAWN: M.L.C.
CHECKED: SW
APPROVED: SW

Unitil
Unitil Service Corp.

Unitil Service Corp.

TREE TRIMMING CLEARANCES FOR ELECTRICAL CONDUCTORS AND COMMUNICATION CABLES

SCALE	DATE	SHEET	DRAWING NO.
N/A	11/30/00	1 OF 1	UAG0004



CLEARANCE	TYPE OF TRIMMING	SINGLE-PHASE MINIMUM CLEARANCE	MULTI-PHASE MINIMUM CLEARANCE	BUNDLED SECONDARY/ COMMUNICATION CABLE MINIMUM CLEARANCE
A	UNDER TRIMMING	10 FEET	10 FEET	4 FEET
B	SIDE TRIMMING	6 FEET	8 FEET	4 FEET
C	OVERHEAD TRIMMING (REMOVE OVERHANG SITUATIONS WHERE POSSIBLE)	6 FEET	15 FEET	4 FEET

REV.	DESCRIPTION	BY	DATE	CHK	APR
A	UPDATED WITH BULLETIN REVISIONS	MP	02/05/09	NS	NS

REVISIONS

DRAWN: MLC
CHECKED: SW
APPROVED: SW

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Unitil Service Corp.

Unitil Service Corp.

TREE TRIMMING CLEARANCES FOR ELECTRICAL CONDUCTORS AND COMMUNICATION CABLES

SCALE	DATE	SHEET	DRAWING NO.
N/A	11/30/00	1 OF 1	UAG0005

000420

SPECIFICATION FOR LOCAL DISTRIBUTION LINE CLEARANCE

1. SCOPE OF WORK

This specification covers the trimming and removal of trees and brush along the urban and rural overhead electrical lines owned by Unitil.

2. LINE CLEARANCE OBJECTIVES

A) The tree position (relative to the wires), species and condition of the tree determine the type of trimming required. It is the contractor's responsibility to be knowledgeable about and to instruct his crews in various techniques necessary for trimming individual trees. Clearance shall be sufficient all around primary and open wire secondary conductors to keep them free of tree contacts for at least five (5) years. All dead, decayed or insect-damaged limbs are a hazard to the lines and shall be removed.

B) In case of ornamental trees, care must be taken when trimming and done in such a manner that the final shape of the tree is evenly proportioned.

3. PRIMARIES AND OPEN WIRE SECONDARIES

A) Minimum conductor clearances relative to various primary and open wire secondary positions are shown in the table below and in Figures 1 and 2.

	Multi-Phase	Single Phase
Clearance above primary conductors/ open wire secondaries	15 foot minimum plus danger trees and dead wood	6 foot minimum above plus danger trees and deadwood
Clearance adjacent to primary conductors/ open wire secondaries	8 foot minimum plus 20 foot minimum clearance for danger trees and deadwood	6 foot minimum plus 20 feet minimum clearance for danger trees and deadwood
Clearance below	Ground cut or the greater of four (4) fee below lowest telephone cable or 10 feet below primary conductors/open wire secondaries	Ground cut or the greater of four (4) fee below lowest telephone cable or 10 feet below primary conductors/open wire secondaries

B) Figure 2 shows the minimum clearance zone around the conductors. It explains how to deal with situations in which tree trunks or large limbs are within the minimum clearance zone.

4. OPEN WIRE SERVICE DROPS

Minimum clearance normally shall be two (2) feet around. If the existing clearance is less than two (2) feet between a tree trunk, leader, or large limb and conductors, remove all other small branches within two (2) feet all around the conductors. If a tree trunk or large limb is rubbing against conductors, report the condition to Unitil for a decision as to whether tree work or line work will be performed to correct the condition.

5. SECONDARY CABLE SERVICE DROPS

During scheduled maintenance, all services will be inspected along trim route and any service where there is hard rubbing should be trimmed to a minimum of two (2) feet all around to prevent chafing which could cause cable failure.

Service trims should be performed by one crew member while the other is performing other ground work such as position the bucket truck or paperwork. However, each crew member shall be within visual contact of the other at all times in order to maintain safe work practices.

6. LINE EXTENSION: PRIVATE PROPERTY

A) Before the initial installation of wires, maximum efforts shall be made to remove all tree species in a trip centered on the new pole line as follows:

Single phase primaries and/or secondaries:
10 feet each side of pole line center

Three phase primaries:
14 feet each side of pole line center

B) Outside of the defined trip, tree removal and tree trimming shall be performed as necessary in conformance with the major articles immediately following.

C) NOTE: Line clearing for the initial installation of overhead conductors in a development or on private property shall be paid for or provided by the developer or customer and the tree contractor shall be advised accordingly.

7. LINE EXTENSIONS: PUBLIC WAY

A) Follow IOP with applicable telephone company.

Appendix D

Unitil

Year: ____

Vegetation Control Report

Week Ending: ____

						Qty of Work		Type of Work						Type of Clearing			Construction			Time		Tel Co.
Date	Street & Town	Circuit #	Voltage	Unitil Pole # From - To	Fair Point Pole #	# Sections Trimmed	# Services Trimmed	Scheduled Maintenance	Unscheduled Maintenance	CWO #	Storm Work	**Clear / Open**	Customer Trim Request	Trimming - Light, Medium, Heavy - (L,M,H)	Ground Cut	Dead/Hazardous/Tree Limb Removed	1 - 1 Phase 2 -2 Phase 3 - 3Phase	Secondary Only	Service Only	Labor	Equipment / Vehicle	Trimmed for Tel Co Y/N
	Totals:																					

Tree Contractor: Asplundh Tree Expert

Workers: ____

____

Equipment / Vehicle: ____

Tailboard Conference: Yes No

Foreman Initials:

Comments -

Unitil Rep. Signature ____

000424

Appendix E

Unitil System

Plan and Progress Reporting

Transmission	*Scheduled Work - Acres*	
	Scheduled Work Complete - Acres	
	Cumulative Schedule Accuracy	
Distribution	*4 kV Scheduled Work - Sections*	
	4 kV Scheduled Work Complete - Sections	
	13.8 kV Scheduled Work - Sections	
	13.8 kV Scheduled Work Complete - Sections	
	34.5 kV Scheduled Work - Sections	
	34.5 kV Scheduled Work Complete - Sections	
	Unscheduled Work - Sections	
	Total Work - Sections	
	Cumulative Schedule Accuracy	

Effectiveness Metrics

Transmission	*Number of permanent outages*	
	Number of momentary outages	
Distribution	*4 kV tree-related outages*	
	4 kV pole miles	
	4 kV cumulative tree outages per mile	
	13.8 kV tree-related outages	
	13.8 kV pole miles	
	13.8 kV cumulative tree outages per mile	
	34.5 kV tree-related outages	
	34.5 kV pole miles	
	34.5 kV cumulative tree outages per mile	

Efficiency Metrics

Transmission	*Total Dollars Expended*	
	Actual Work - Acres	
	Cumulative Expense Per Acre	
Distribution	*Total Dollars Expended*	
	Total Work - Sections	
	Cumulative Expense Per Section	

Request:

Reference Staff 1-29, pages 1-6 through 1-7 and page 5.4-2. Please provide your initial thoughts regarding the option 1 and option 2 hazard tree removal programs with regard to cost and reliability benefits.

Response:

Option I provides a reasonable improvement in overall reliability while maintaining relatively low long-term annual costs. This is the primary reason Unitil believes this option is most beneficial for our customers.

Conversely, Option II provides the same reliability improvements, however the benefit is achieved in a much shorter time-frame and at a significantly higher annual cost. The main reason this option is less desirable is due to the logistical implementation of the hazard tree program. Based upon the survey performed by ECI, our vegetation control consultant, the UES system has 31,521 hazard trees; 9,176 on three phase requiring removal and mitigation based on our proposal. A 3-year program would therefore require the removal of over 3,000 trees annually. Many of these trees are located on private property and will require significant customer communication and education. Attempting to remove this significant amount of hazard trees in a 3 year period is impractical.

Request:

Reference Staff 1-29, page 3-9 and page 5.6.2. Do the current UES vegetation management practices and program incorporate the requirements of NESC Section 218 B (Mislabeled A)? If not, why not?

Response:

NESC Section 218B is not directly addressed in UES' current vegetation management policy. However, our normal vegetation management practices meet the requirements of NESC 218B.

Request

Reference response to STAFF 3-33. For the years 2004 through 2009, please supply the list of reliability improvement projects identified including benefit rank and show how the "knee of the curve" was used to determine which projects were constructed. In your response, please indicate which projects were actually constructed or, in the case of 2010, planned to be constructed.

Response:

Refer to Staff Set 4-46 Attachment 1 for a list of all reliability projects proposed for budget consideration for the years 2004-2010. Projects constructed are shown in bold text unless otherwise noted. Note that the total project costs shown in this attachment are budgetary estimates without general construction overheads and will not align with the actual total annual expenditures provided in the previous response to Staff 3-33.

Recommended 2004 Reliability Project Ranking

Budget Number	Description	Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM
SEA DRB03	**Cemetery Ln. Animal Protection**	**$5,058**	**1,213**	**189,303**	**1**	**1**
SEA DRB02	**6" Al Disk Replacement**	**$117,667**	**15,344**	**928,170**	**2**	**3**
FGE DRB03	**Circuit 39W19 recloser addition**	**$6,234**	**360**	**35,872**	**3**	**4**
CAP DRB02	**Circuit 7W3 tree wire**	**$15,000**	**691**	**131,792**	**6**	**2**
SEA DRB04	**Cutout Replacement**	**$49,936**	**2,334**	**84,350**	**5**	**8**
FGE DRB05	**Circuit 22W1 vacuum switch**	**$38,339**	**955**	**164,161**	**8**	**6**
SEA DRB05	Recloser 3359	$48,577	2,582	74,393	4	10
SEA DRB01	FC Indicator	$5,208	0	25,351	12	5
CAP DRB01	Circuit 13W2 recloser addition	$48,589	274	92,675	11	7
FGE DRB02	S/S animal protection at Sawyer Passway & Pleasant St	$96,873	1,859	149,404	9	9
FGE DRB04	Circuit 31W37 recloser addition	$18,892	669	25,441	7	12
FGE DRB01	Circuit 15W16 spacer cable & recloser addition	$152,000	897	149,038	10	13
SEA DRB06	SCADA at 3347 Line Tap	$27,389	0	41,849	13	11
	TOTALS	$232,234	20,897	1,533,648		

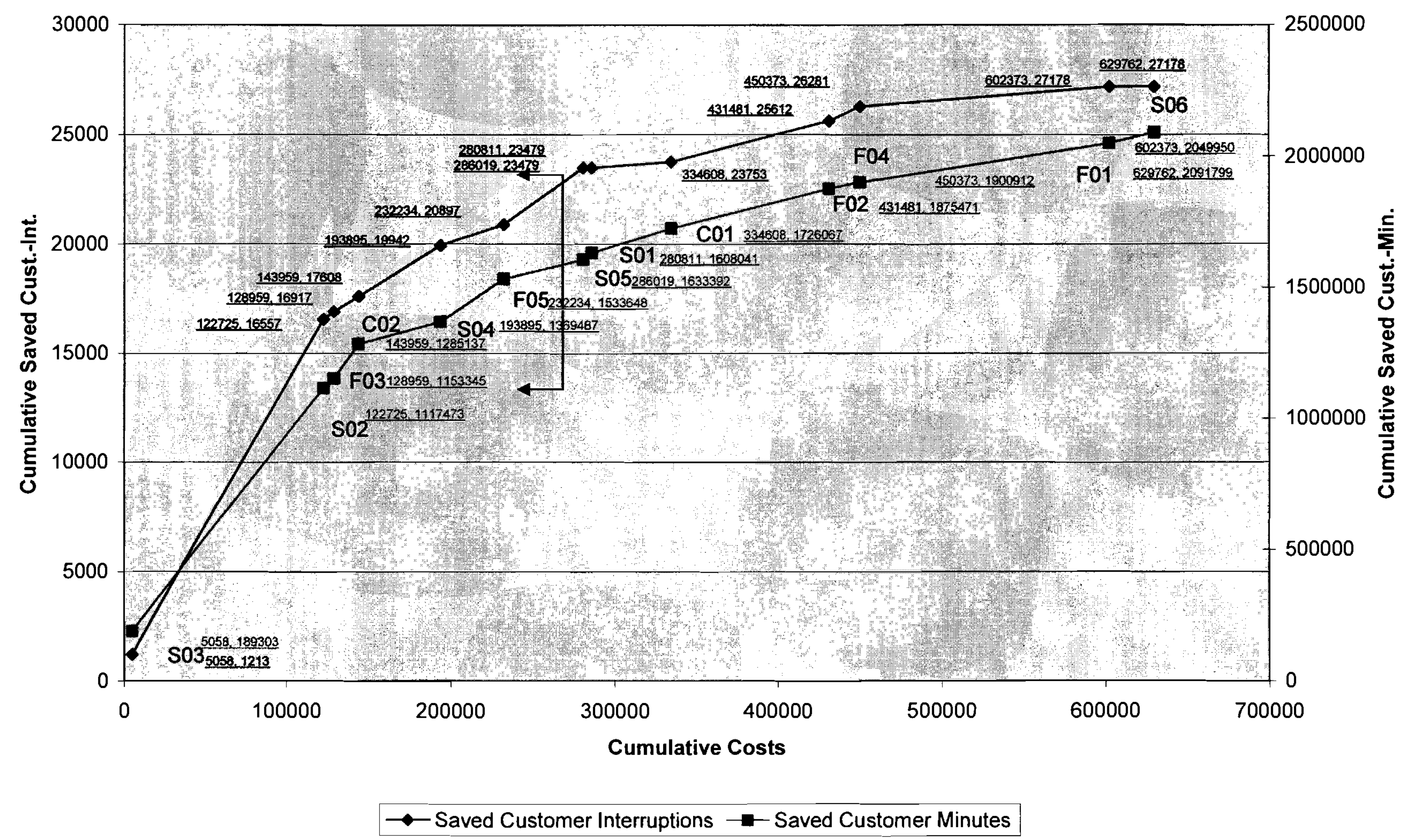
NOTES:

1) Projects in bold indicate recommended projects to meet corporate reliability goals.

2) Totals listed above include only the recommended projects (bold).

000434

2004 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings



000435

Recommended 2005 Reliability Project Ranking

NO.	Budget Number	Description	Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM
1	SEA DRB03	**Westville Substation - Install Animal Protection**	**$5,603**	**412**	**46,189**	**1**	**1**
2	SEA DRB04	**East Kingston Substation - Install Animal Protection**	**$3,952**	**282**	**31,324**	**2**	**2**
3	CAP DRB03	**Iron Works Rd S/S, Concord - Animal Protection**	**$8,059**	**483**	**31,000**	**3**	**4**
4	FGE DRB00 (DRB01)	**Lunenburg S/S Animal Protection**	**$9,296**	**491**	**49,157**	**5**	**3**
5	FGE DRB00 (DRB03)	**31W38 to 30W30 Install Circuit Tie Switch**	**$17,113**	**957**	**28,500**	**4**	**7**
6	CAP DRB01	**22W3 Re-Conductor (Lewis Lane / Clinton St.)**	**$73,569**	**3,706**	**160,336**	**6**	**6**
7	FGE DRB00 (DRB02)	**Circuit 11W11 Recloser Additions**	**$37,033**	**1,074**	**106,111**	**7**	**5**
8	CAP DRB02	**13W2 Sectionalizer Replacement / Recloser Installation**	**$7,577**	**110**	**11,764**	**9**	**8**
9	SEA DRB01	Cir 6W1 - Install Reclosers on South Rd.	$12,566	190	19,007	8	9
10	SEA DRB02	Cir 51X1 - Install Reclosers on Depot Ln.	$9,669	119	9,038	10	11
11	SEA DRB05	Cir 22X1 - Install Spacer Cable on No. Main St., Danville	$130,000	1,254	181,028	11	10
		TOTALS	$162,202	7,515	464,381		

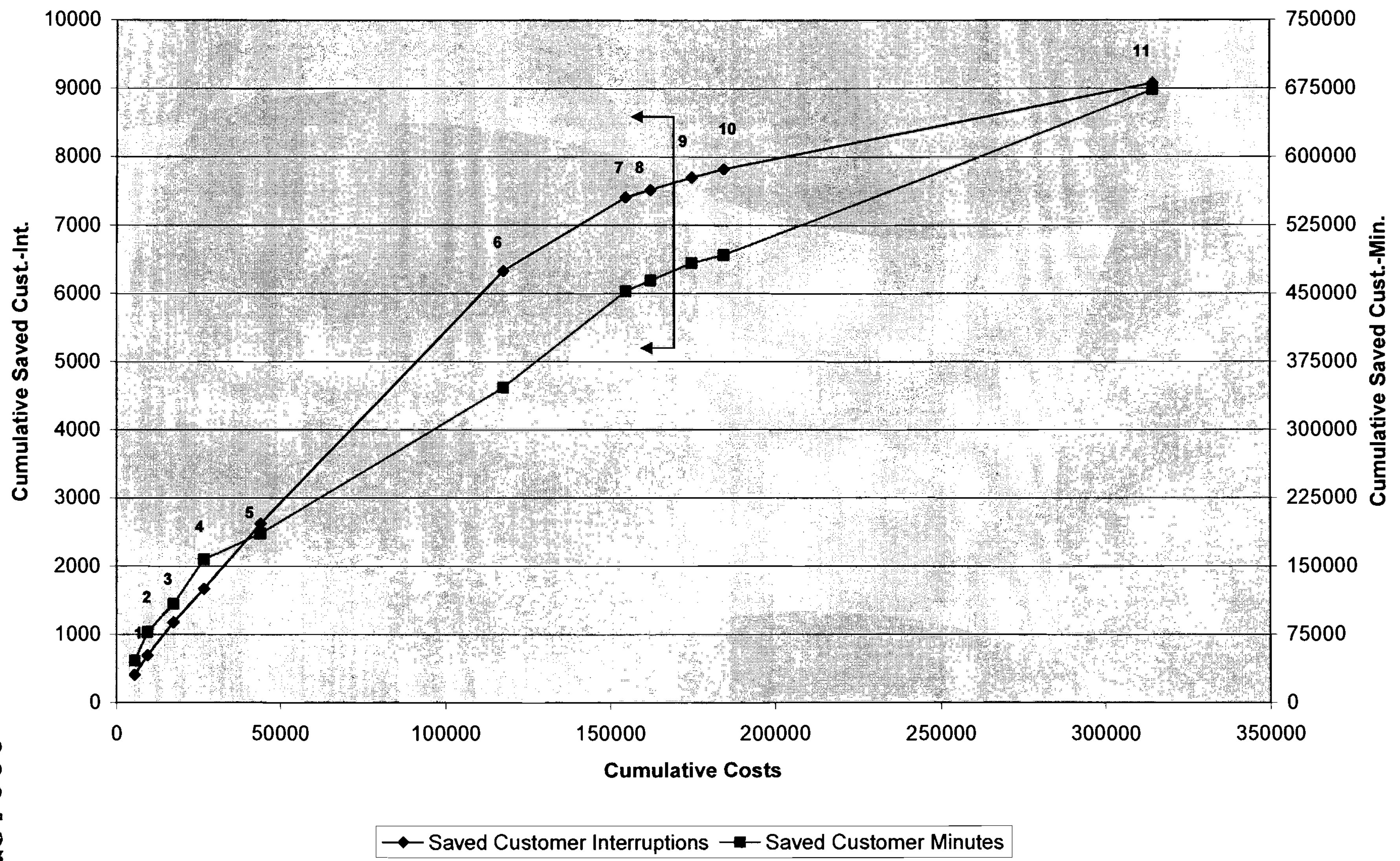
NOTES:

1) Projects in bold indicate recommended projects to meet corporate reliability goals.

2) Totals listed above include only the recommended projects (bold).

000436

2005 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings



Recommended 2006 Reliability Project Ranking

NO.	Budget Number	Description		Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM	
1	**CAP DRB00 (DRB02)**	**Install Animal Protection - Bow Jct.S/S**		**$4,715**	**209**	**45,472**	**1**	**2**	
2	**FGE DRB02**	**30W30 to 30W31 Load Transfer**		**$34,418**	**1,353**	**248,013**	**2**	**4**	
3	**SEA DRB00 (DRB03)**	**23X1 - Install Reclosers - Amesbury Rd.**		**$14,165**	**244**	**105,367**	**6**	**3**	NOTE 3
4	**FGE DRB01**	**50W51 to 50W56 Tie Switch and Insulate Bus**		**$84,607**	**2,674**	**407,989**	**4**	**6**	
5	**FGE DRB03**	**Eliminate Wallace Road Substation**		**$53,939**	**1,370**	**350,133**	**5**	**5**	
6	**CAP DRB00 (DRB01)**	**Install Animal Protection - Boscawen S/S**		**$7,073**	**270**	**15,751**	**3**	**8**	
7	**SEA DRB00 (DRB05)**	**22X1 - Installation of Fault Indicators**		**$1,889**	**1**	**66,000**	**11**	**1**	
8	**CAP DRB00 (DRB03)**	**8X3 - Install Reclosers - Rt. 28 South**		**$9,000**	**145**	**24,240**	**7**	**7**	
9	**SEA DRB00 (DRB04)**	**58X1 - Install Reclosers - Pollard Rd.**		**$27,165**	**413**	**50,261**	**8**	**9**	
10	SEA DRB00 (DRB01)	6W1 - Install Spacer Cable - South Rd.		$280,000	1,825	298,809	9	11	
11	SEA DRB26	59X1 - Installation of GOAB Switch		$13,201	1	15,000	12	10	
12	SEA DRB00 (DRB02)	13W2 - Install Spacer Cable - Crane's Crossing Rd.		$390,000	2,254	245,686	10	13	
13	SEA DRB00 (DRB06)	59X1J7X2 - Install Motor Operator and SCADA Control		$24,586	1	24,620	13	12	
			TOTALS	$236,971	$6,679	$1,313,226			

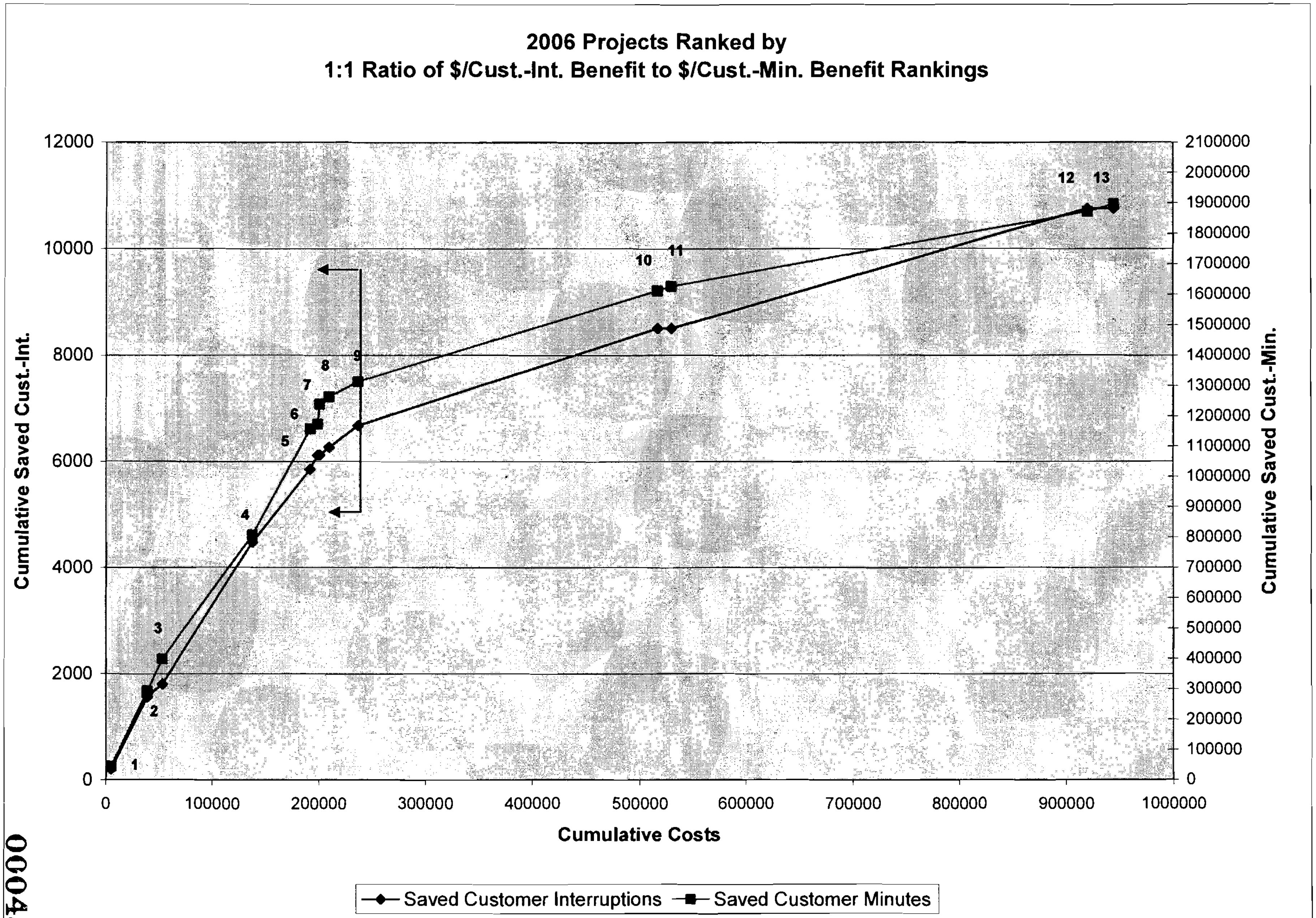
NOTES:

1) Projects in bold indicate recommended projects to meet corporate reliability goals.

2) Totals listed above include only the recommended projects (bold).

3) The recloser installation location was revised to circuit 6W1 - South Road following further analysis subsequent to the initial budget submission concluding that this location provided greater reliability benefit.

000438



2006 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings
Cumulative Saved Cust.-Int.
Cumulative Saved Cust.-Min.
Cumulative Costs
Saved Customer Interruptions
Saved Customer Minutes

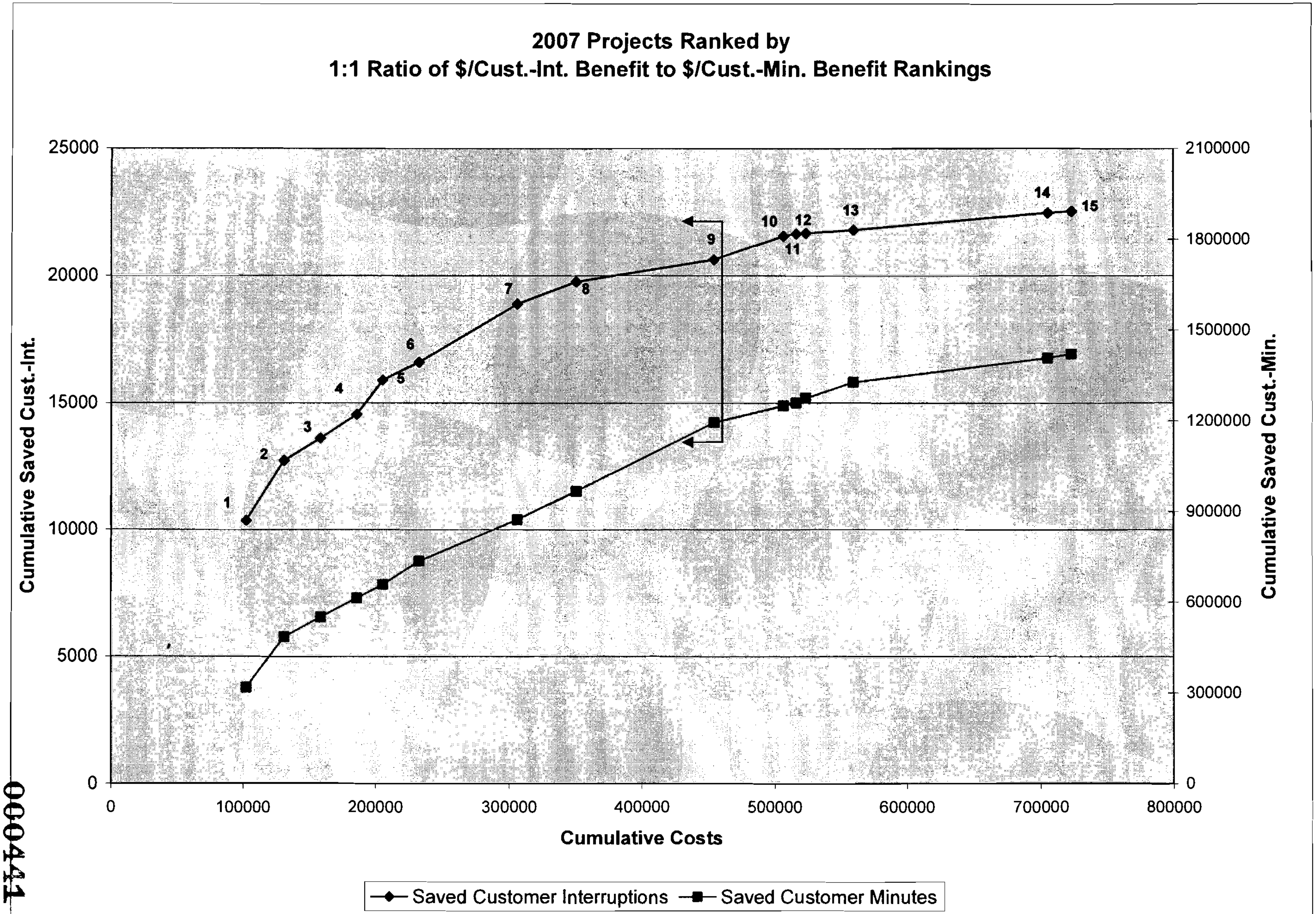
0004439

Recommended 2007 Reliability Project Ranking

NO.	Budget Number	Description	Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM	
1	SEA DRB00 (DRB01)	**Exeter Switching Automation**	$102,500	10,366	317,237	1	2	NOTE 3
2	FGE DRB00 (DRB05)	**Reinsulate Nockege S/S**	$28,617	2,357	168,942	2	1	
3	SEA DRB00 (DRB03)	**51X1 - Install Recloser - Winnicutt Road**	$27,425	885	64,932	5	4	
4	SEA DRB00 (DRB04)	**51X1 - Install Recloser - Union Road**	$27,425	931	63,154	4	5	
5	FGE DRB00 (DRB06)	**Circuit 30W30 Install Spacer Cable Page Street**	$19,332	1,354	43,328	3	6	
6	SEA DRB00 (DRB02)	**21W2 - Install Recloser - Main Street**	$27,425	704	77,704	7	3	NOTE 3
7	FGE DRB00 (DRB01)	**Reinsulate the 01 Tap and the 02 Tap to Beech Street**	$73,493	2,298	137,872	6	10	
8	FGE DRB00 (DRB02)	**Circuit 30W30 Install Spacer Cable Reservoir Road**	$44,570	874	93,918	8	9	
9	CAP DRB00 (DRB03)	**Circuit 13W2 Rebuild on Other side of High Street**	$103,453	861	227,959	11	7	NOTE 3
10	FGE DRB00 (DRB04)	Circuit 39W19 Install Spacer Cable Wheeler Road	$52,408	933	55,594	9	12	
11	CAP DRB00 (DRB01)	Circuit 13W1 Pickard Road Protection Improvement	$9,543	89	9,100	10	13	
12	CAP DRB00 (DRB04)	Circuit 13W2 Recloser Installation - Warner Road	$7,329	21	15,621	15	8	
13	FGE DRB00 (DRB03)	Circuit 39W18 Replace Turnpike Road Underground Cable	$35,859	120	52,622	13	11	
14	CAP DRB00 (DRB02)	Circuit 13W2 Spacer Cable Installation - High Street	$145,606	679	80,311	12	15	
15	CAP DRB00 (DRB05)	Circuit 15W1 Recloser Installation - Mountain Road	$17,953	58	13,480	14	14	
		TOTALS	$454,240	20,630	1,195,046			

NOTES:
1) Projects in bold indicate recommended projects to meet corporate reliability goals.
2) Totals listed above include only the recommended projects (bold).
3) This project was cancelled during the capital budget development.

000440



2007 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings
Cumulative Saved Cust.-Int.
Cumulative Saved Cust.-Min.
Cumulative Costs
0
5000
10000
15000
20000
25000
300000
600000
900000
1200000
1500000
1800000
2100000
100000
200000
300000
400000
500000
600000
700000
800000
1
2
3
4
5
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12
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14
15
Saved Customer Interruptions
Saved Customer Minutes

000441

Recommended 2008 Reliability Project Ranking

NO.	Budget Number	Description	Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM
1	**FGE DRB00 (DRB01)**	**Circuit 1W2 - Install Recloser - Shea Street**	**$27,076**	**2,085**	**692,331**	**1**	**2**
2	**FGE DRB00 (DRB02)**	**Load Transfer - Circuit 1W4 to Circuit 40W4**	**$16,596**	**1,532**	**194,572**	**2**	**1**
3	**FGE DRB00 (DRB03)**	**Circuit 39W18 - Install Recloser - Main Street**	**$27,076**	**1,110**	**93,285**	**4**	**3**
4	**SEA DRB00 (DRB04)**	**Circuit 47X1 - Install Recloser - Guinea Road**	**$28,787**	**780**	**136,000**	**3**	**5**
5	**CAP DRB00 (DRB04)**	**Circuit 13W1 - Pickard Road Protection improvement**	**$8,758**	**113**	**27,053**	**5**	**10**
6	**CAP DRB00 (DRB01)**	**Circuit 13W2 - Rebuild poles 83 - 120, High Street, Boscawen**	**$95,724**	**1,321**	**242,943**	**6**	**9**
7	**SEA DRB00 (DRB05)**	**Install recloser 54X1 and 22X1**	**$57,575**	**805**	**144,840**	**7**	**8**
8	**SEA DRB00 (DRB02)**	**Circuit 21W2 - Install Recloser - Main Street**	**$28,787**	**550**	**64,000**	**9**	**7**
9	**SEA DRB00 (DRB03)**	**Circuit 22X1 - Install Recloser - Kingston Road**	**$28,787**	**900**	**45,000**	**12**	**4**
10	**FGE DRB00 (DRB04)**	**Circuit 39W19 - Install spacer cable - Wheeler Road**	**$46,058**	**1,061**	**63,930**	**13**	**6**
11	**CAP DRB00 (DRB03)**	**Circuit 13W2 - Recloser Installation - Warner Road, Salisbury**	**$6,880**	**26**	**16,615**	**8**	**13**
12	**SEA DRB00 (DRB01)**	**Circuit 21W1 - Install Recloser - Meditation Lane**	**$28,787**	**370**	**53,000**	**10**	**11**
13	CAP DRB00 (DRB02)	Circuit 13W2 - Install spacer cable - Water Street, Boscawen	$100,537	376	163,831	11	14
14	CAP DRB00 (DRB05)	Circuit 22W3 - Install spacer cable - Birchdale Road, Bow	$33,848	301	36,610	14	12
		TOTALS	$400,891	10,653	1,773,569		

NOTES:
1) Projects in bold indicate recommended projects to meet corporate reliability goals.
2) Totals listed above include only the recommended projects (bold).
3) All reliability improvement projects were cancelled during the capital budget development.

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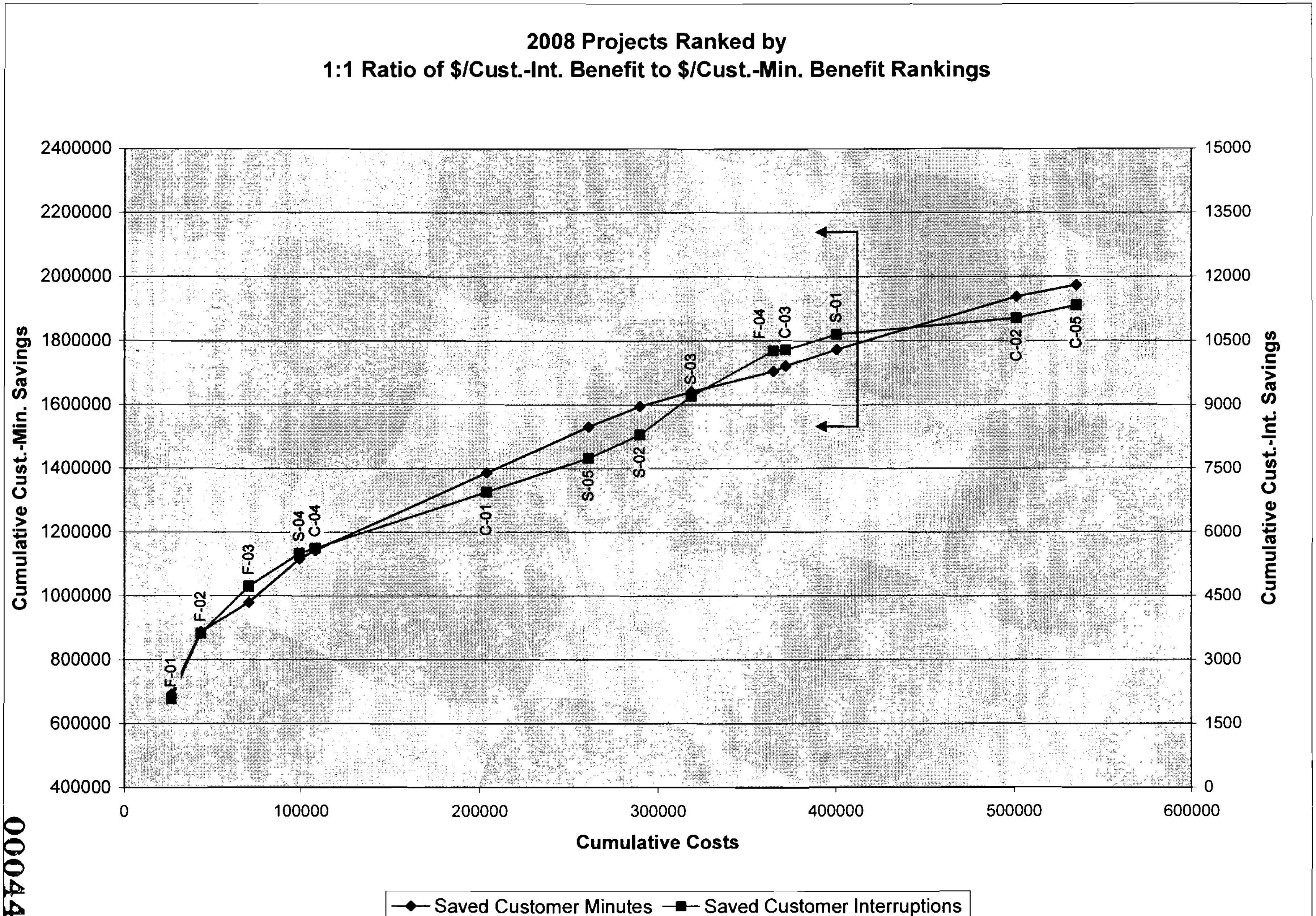


2008 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings
Cumulative Cust.-Min. Savings
Cumulative Cust.-Int. Savings
Cumulative Costs
2400000
2200000
2000000
1800000
1600000
1400000
1200000
1000000
800000
600000
400000
15000
13500
12000
10500
9000
7500
6000
4500
3000
1500
0
100000
200000
300000
400000
500000
600000
F-01
F-02
F-03
S-04
C-04
C-01
S-05
S-02
S-03
F-04
C-03
S-01
C-02
C-05
Saved Customer Minutes
Saved Customer Interruptions

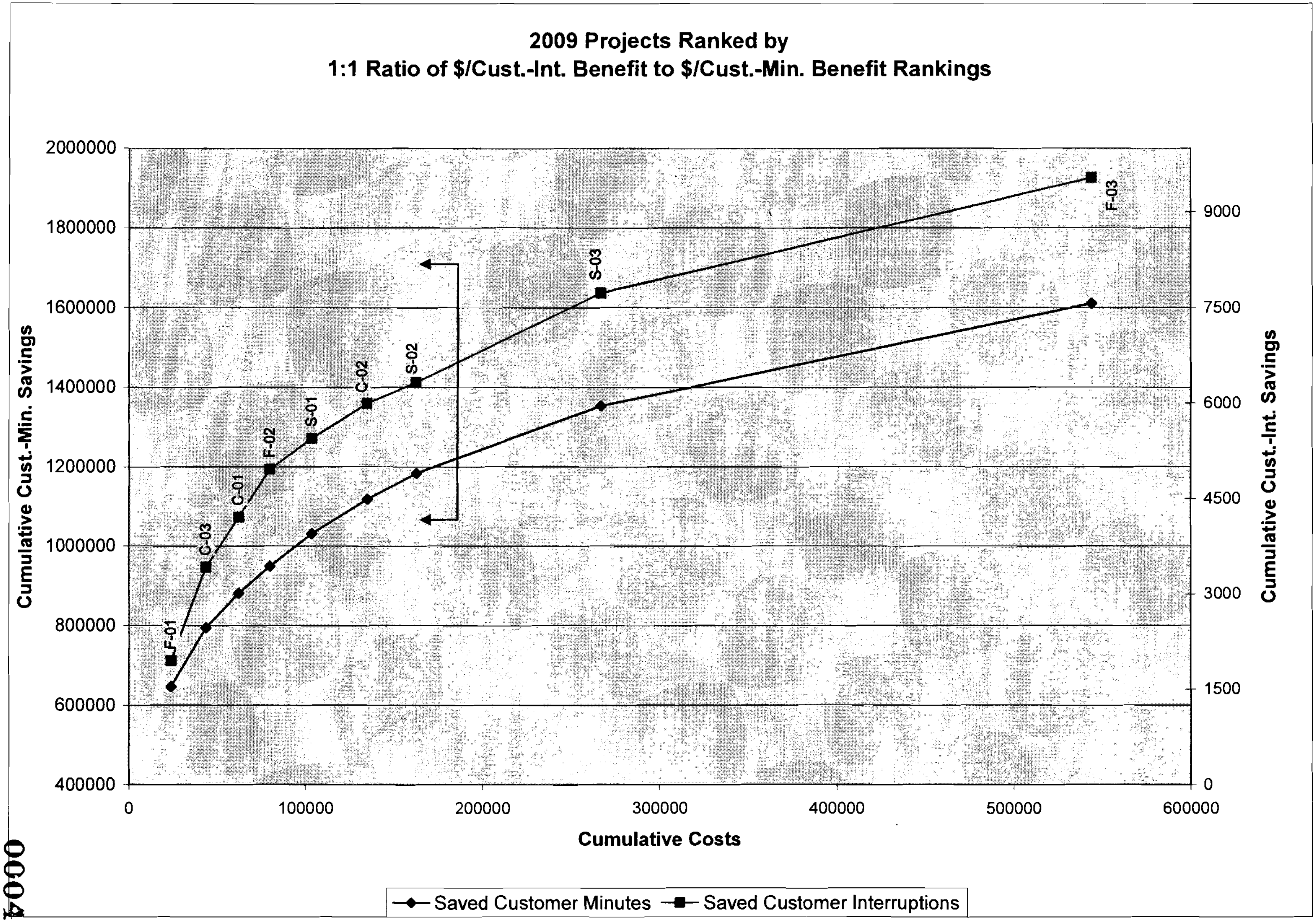
000443

Recommended 2009 Reliability Project Ranking

NO.	Budget Number	Description	Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM
1	FGE DRB00 (DRB01)	Circuit 1W2 - Install a Recloser on Shea Street	$24,077	1,947	646,293	1	1
2	CAP DRB00 (DRB03)	Circuit 22W3 - Install Recloser on Logging Hill Rd.	$19,720	1,474	148,236	3	4
3	CAP DRB00 (DRB01)	Circuit 13W2 - Replace High Street Recloser, Boscawen	$18,670	788	86,676	5	6
4	FGE DRB00 (DRB02)	Load Transfer Circuit 1W4 to Circuit 40W4	$17,606	756	68,796	6	8
5	SEA DRB00 (DRB01)	Circuit 21W1 - Install Reclosing on Meditation Lane	$23,656	481	81,295	8	7
6	CAP DRB00 (DRB02)	Circuit 22W3 - Install Spacer Cable, Birchdale Rd., Bow	$31,141	552	87,266	7	5
7	SEA DRB00 (DRB02)	Circuit 21W2 - Install Reclosing on Main Street	$27,656	327	65,013	9	9
8	SEA DRB00 (DRB03)	Circuit 58X1 - Reconductor Pollard Road with Spacer Cable	$104,780	1,408	169,816	4	3
9	FGE DRB00 (DRB03)	Circuit 30W30 - Install Spacer Cable on Lancaster Avenue	$276,721	1,804	257,882	2	2
		TOTALS	$544,027	9,537	1,611,273		

NOTES:
1) Projects in bold indicate recommended projects to meet corporate reliability goals.
2) All projects listed above were completed.

000444


2009 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings
Cumulative Cust.-Min. Savings
Cumulative Cust.-Int. Savings
Cumulative Costs
2000000
1800000
1600000
1400000
1200000
1000000
800000
600000
400000
9000
7500
6000
4500
3000
1500
0
100000
200000
300000
400000
500000
600000
F-01
C-03
C-01
F-02
S-01
C-02
S-02
S-03
F-03
Saved Customer Minutes
Saved Customer Interruptions

S-000445

Recommended 2010 Reliability Project Ranking

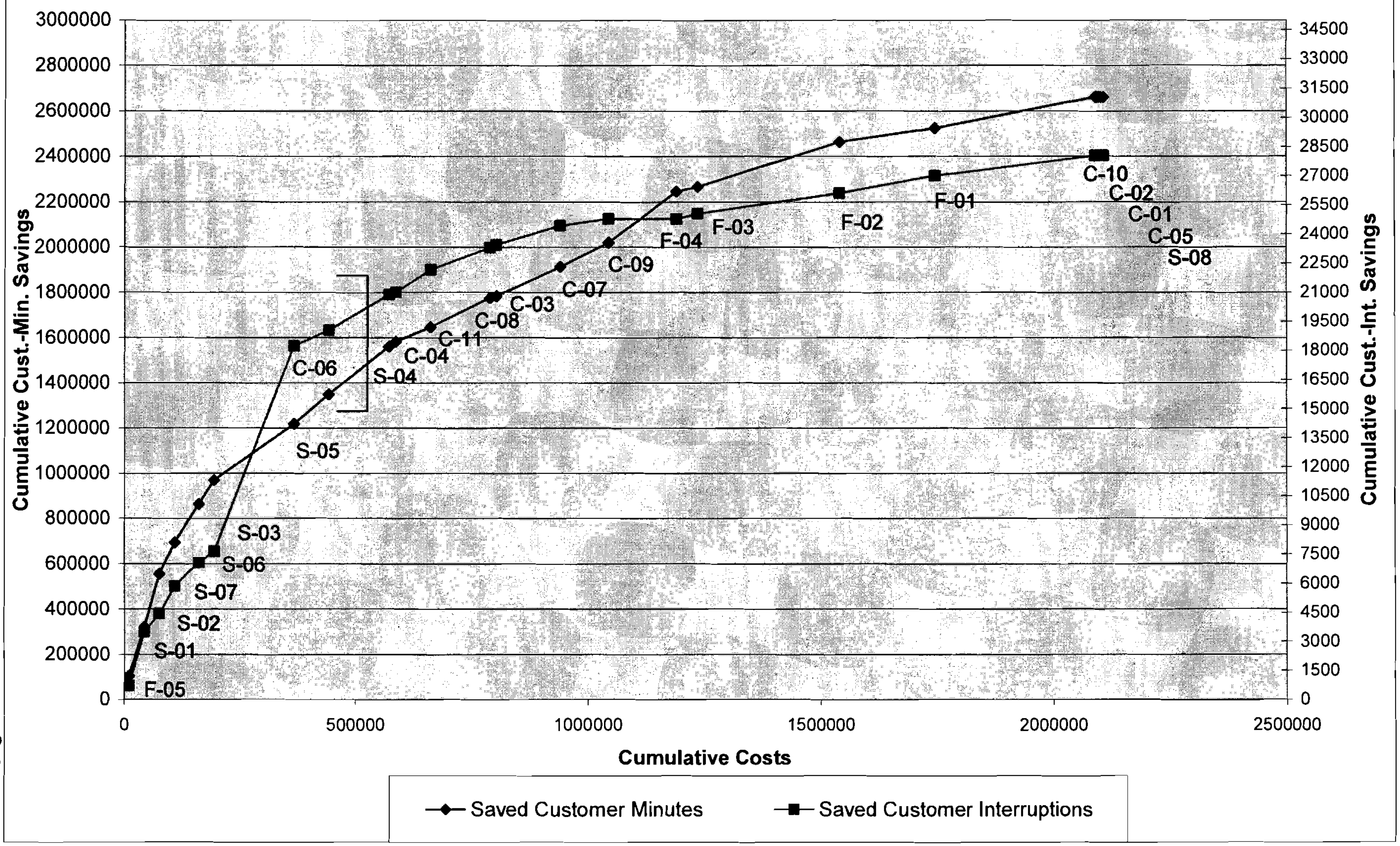
NO.	Budget Number	Description	Cost	Cumulative Cost	Cust-Inter Saved	Cust-min Saved	Rank by $/CI	Rank by $/CM
1	FGE DRB05	INSTALL ANIMAL PROTECTION AT W TOWNSEND S/S	$9,895	$9,895	722	104,137	14	15
2	SEA DRB01	CIR. 22X1 - INSTALL RECLOSER ON DANVILLE RD.	$33,290	$43,185	2,779	215,496	2	4
3	SEA DRB02	CIR. 18X1 - INSTALL RECLOSER ON RT. 27	$33,290	$76,475	916	234,878	11	2
4	SEA DRB07	CIR. 23X1 - INSTALL RECLOSER ON MILL LN.	$33,290	$109,765	1,427	139,746	4	8
5	SEA DRB06	CIR. 7X2 - S/S RECLOSER REPLACEMENT	$52,102	$161,867	1,223	170,358	5	7
6	SEA DRB03	CIR. 5H2 - INSTALL RECLOSER ON SWEET HILL RD.	$33,290	$195,157	572	105,020	15	14
7	SEA DRB05	EXETER SWITCH. - INSTALL AUTO. TRANSFER SCHEME	$172,570	$367,727	10,599	248,909	1	1
8	CAP DRB06	CIR. 13W2 - REBUILD HIGH ST. P. 83 - P. 110	$74,647	$442,374	800	130,910	13	10
9	SEA DRB04	TIMBERLANE S/S - INSTALL AUTO. TRANSFER SCHEME	$129,570	$571,944	1,857	211,650	3	5
10	CAP DRB04	CIR. 8X3 - INSTALL RECLOSERS ON SWAMP RD.	$14,697	$586,641	119	21,235	19	18
11	CAP DRB11	37 LINE - RECONDUCTOR WITH SPACER FROM P. 20 TO P.33X	$74,576	$661,217	1,143	64,737	7	16
12	CAP DRB08	CIR. 13W2 - INSTALL SPACER CABLE ON WATER ST. P. 71 - P. 122	$127,724	$788,941	1,151	127,948	6	12
13	CAP DRB03	CIR. 4W3 - INSTALL RECLOSERS ON SEWALLS FALLS RD.	$13,848	$802,789	145	9,089	18	20
14	CAP DRB07	CIR. 13W2 - INSTALL SPACER CABLE HIGH ST. TO WATER ST.	$138,105	$940,894	994	130,066	10	11
15	CAP DRB09	CIR. 13W2 - INSTALL SPACER CABLE WATER ST. TO LONG ST.	$103,662	$1,044,556	353	106,069	16	13
16	FGE DRB04	INSTALL TIE SWITCH BETW. CIR. 21W36 & CIR. 40W40	$143,607	$1,188,163	1	226,836	20	3
17	FGE DRB03	CIR. 11W11 - INSTALL RECLOSER AND SECTIONALIZER ON ROLLSTONE RD.	$45,654	$1,233,817	267	19,711	17	19
18	FGE DRB02	CIR. 39W18 - INSTALL SPACER CABLE ON FITCHBURG RD.	$305,808	$1,539,625	1,050	196,892	8	6
19	FGE DRB01	CIR. 30W31 - INSTALL SPACER CABLE ON HIGHLAND ST.	$205,114	$1,744,739	884	60,762	12	17
20	CAP DRB10	CIR. 13W2 - INSTALL SPACER CABLE HIGH ST. TO OLD TURNPIKE RD.	$345,264	$2,090,003	1,039	138,484	9	9
21	CAP DRB02	CIR. 4W3 - INSTALL SECTIONALIZERS ON PENACOOK ST.	$3,193	$2,093,196	121	23,638	20	21
22	CAP DRB01	CIR. 15W1 - INSTALL RECLOSER ON EASTMAN ST.	$3,790	$2,096,986	259	32,080	20	21
23	CAP DRB05	CIR. 13W2 - INSTALL RECLOSER ON WARNER RD.	$4,273	$2,101,259	26	8,124	20	21
24	SEA DRB08	CIR. 58X1 - INSTALL CUTOUT MOUNTED SECTIONALIZERS ON N MAIN ST.	$6,000	$2,107,259	302	77,916	20	21
		PROPOSED PROJECT TOTALS (NO.'s 1 - 8)	$442,374		19,038	1,349,454		

NOTES:
1) Projects in bold indicate recommended projects to meet corporate reliability goals.
2) Totals listed above include only the recommended projects (bold).
3) Projects 21 - 24 to be included under T&D blanket

000246

Printed 8/12/2010

2010 Projects Ranked by
1:1 Ratio of $/Cust.-Int. Benefit to $/Cust.-Min. Benefit Rankings



Request

Reference response to STAFF 3-71. Please supply sample weather forecasts used by UES in determining PDI event levels. Please include any information regarding confidence levels of the forecasts.

Response:
Please refer to Staff 4-51 Attachment 1 and Staff 4-51 Attachment 2. These forecasts are provided for the February 25, 2010 windstorm and are illustrative of the forecasts used by Unitil Energy to prepare for severe weather events. As shown in Staff 4-51 Attachment 1, the initial forecast for February 25, 2010 was for a PDI level 2 event with a high confidence level. As shown in Staff 4-51 Attachment 2, the forecast escalated to a PDI level 3 in Seacoast as the event occurred, with a high confidence level. The escalation in forecast demonstrates the importance beginning pre-storm preparations at a PDI level 2. It should be noted that the February 25, 2010 wind storm was the second worst storm in state history, and was forecast as a PDI level 2 in Seacoast up until the time the storm actually occurred, and never exceeded a level 2 in Capital according to forecasts.

As shown in the attached forecasts, each is assigned a Confidence level. Confidence levels are characterized as Low, Medium or High and is a measure of certainty in the forecasted weather occurring. Confidence levels are a function of time and become more accurate as the event draws nearer. Therefore a PDI level 2 with a "High" Confidence level provides a high degree of certainty that trouble will occur.

Data Request OCA 2-52:

On p. 52 (Bates p. 224), at lines 20-22 of his testimony, Mr. Meissner states: "NU, PSNH and Unitil have determined that Unitil Energy load served by Kingston substation will exceed planning criteria loading limits for the 115kV line and 115kV-34.5kV transformer in the summer of 2012." What alternatives to the proposed Kingston substation investment did the Company consider (e.g., distributed generation), to avoid having to spend the $2,446,960 on the substation? See Meissner testimony, p. 53 (Bates p. 225), at lines 12-13.

Response:

Unitil has evaluated several distributed energy resource alternatives including PV generation (with and without battery storage), wind generation, utility landfill gas generation, utility natural gas generation, and thermal energy storage (to displace air conditioning load). An economic analysis was performed on each of these technologies and it was determined that these alternatives are not practical, feasible, or economical to meet the additional capacity required of the Kingston substation expansion project.

In addition to the DER alternatives, Unitil considered the following construction alternatives:

- Construct a new 345 – 34.5kV substation supply in the Kingston area. This alternative would provide more capacity and better system support but is more costly and the construction timeframe is longer which adds the risk of missing the need date of 2012.
- Construct a new 34.5kV sub-transmission line in existing ROW from Hampton to Kingston. This alternative is less costly but is not technically feasible since the majority of the load being served is beyond Kingston substation resulting in unacceptable voltages during peak conditions due to the distances involved. ROW constraints would also require this construction to be double circuit configuration. This is not a desirable configuration from a reliability standpoint since single contingencies could create outages on two lines.

PSNH/NU considered the following construction alternatives:

- A new 20MW generation station in the Kingston area. This alternative would provide the necessary capacity requirements but is more costly and the construction timeframe is longer which adds the risk of missing the need date of 2012.

Person Responsible: Thomas P. Meissner, Jr. **Date:** July 20, 2010

State of New Hampshire
Public Utilities Commission

Unitil Energy Systems, Inc. Rate Case
Docket No. DE 10-055
Office of Consumer Advocate Second Set of Information Requests

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Data Request OCA 2-53:

On p. 54 (Bates p. 226), at lines 11-12 of his testimony, Mr. Meissner states: "The load on the circuit is expected to exceed the planning criteria loading limits of the substation equipment in the 2012 timeframe." What alternatives to the proposed East Kingston substation investment did Unitil consider in order to avoid spending the $1,362,171 estimated on the substation? See Meissner testimony, p. 55 (Bates p. 227), at lines 1-2.

Response:

Unitil has evaluated several distributed energy resource alternatives including PV generation (with and without battery storage), wind generation, utility landfill gas generation, utility natural gas generation, and thermal energy storage (to displace air conditioning load). An economic analysis was performed on each of these technologies and it was determined that these alternatives are not practical, feasible, or economical to meet the additional capacity required of the East Kingston substation expansion project.

In addition to the DER alternatives, Unitil considered the following construction alternatives:

- Transferring a portion of the circuit load to an adjacent circuit. This alternative is not a desirable alternative since the circuit transfer project is costly and it only slightly defers the need for additional capacity in this area. In addition, this alternative does not provide any reliability improvement.

Person Responsible: Thomas P. Meissner, Jr. **Date:** July 20, 2010

State of New Hampshire
Public Utilities Commission

Unitil Energy Systems, Inc. Rate Case
Docket No. DE 10-055
Office of Consumer Advocate Third Set of Information Requests

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Data Request OCA 3-2:

Please refer to Schedule MHC-12 (Bates p. 0068). Please revise this schedule to reflect the amounts recommended by the Company's consultant, ECI.

Response:

See *NH OCA 3-2 Attachment 1 MHC-12.xls*. The information highlighted in yellow has been revised to reflect the amounts recommended by the Company's consultant, ECI.

Person Responsible: Mark H. Collin **Date:** August 13, 2010

Unitil Energy Systems, Inc.
RELIABILITY ENHANCEMENT AND VEGETATION MANAGEMENT RATE PLAN
2011 - 2015

Line		2011	2012	2013	2014	2015
1	Recommended Funding for REP and VMP Rate Plans					
2	(In thousands)	2011	2012	2013	2014	2015
3						
4	REP Capital Investment					
5	"Feeder Hardening" Activities	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00
6	Asset Replacement	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00
7						
8	REP Capital Total	$ 1,750.00	$ 1,750.00	$ 1,750.00	$ 1,750.00	$ 1,750.00
9						
10	Full Annual Carrying Costs at 17.68%[1]	$ 309.40	$ 309.40	$ 309.40	$ 309.40	$ 309.40
11						
12						
13	REP O&M Expenses					
14	Inspection and Maintenance	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00
15	Augmented tree trimming and clearing	$ 200.00	$ 200.00	$ 200.00	$ 200.00	$ 200.00
16						
17	REP Expense Total	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00
18						
19	VPM Baseline O&M					
20	**VMP Base Funding Expense**	**$ 2,634.80**	**$ 2,634.80**	**$ 2,634.80**	**$ 2,634.80**	**$ 2,634.80**
21	Amounts Currently in Rates (2009)	$ 735.74	$ 735.74	$ 735.74	$ 735.74	$ 735.74
22	**Test-Year Proforma Adjustment**	**$ 500.00**	**$ 500.00**	**$ 500.00**	**$ 500.00**	**$ 500.00**
23						
24	Incremantal Step Adjustment for VMP	$ 1,399.06	$ 1,399.06	$ 1,399.06	$ 1,399.06	$ 1,399.06
25						
26	REP and VPM Expense Baseline (lines 17 & 20)	$ 2,934.80	$ 2,934.80	$ 2,934.80	$ 2,934.80	$ 2,934.80
27						
28	Illustrative Incremental Step Adjustments	$ 2,008.46	$ 309.40	$ 309.40	$ 309.40	$ 309.40
29						
30	[1] *After tax carrying charge rate = Pre-tax ROR (12.06%) + Average Depreciation Rate (4.00%) + Property Taxes (1.62%)*					

000458

State of New Hampshire
Public Utilities Commission

Unitil Energy Systems, Inc. Rate Case
Docket No. DE 10-055
Office of Consumer Advocate Third Set of Information Requests

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Data Request OCA 3-18:

Data request OCA 2-52 asked: "What alternatives to the proposed Kingston substation investment did the Company consider (e.g., distributed generation), to avoid having to spend the $2,446,960 on the substation?" The response discussed DER alternatives but no other alternatives (*e.g.*, interruptible rates or other targeted peak load reduction actions). Please explain all other alternatives evaluated by the Company to delay the need for the Kingston substation investment.

Response:

The Company has not evaluated interruptible rates, targeted peak load reduction actions, or other customer demand response programs as a means to delay the Kingston substation investment.

Person Responsible: Thomas P. Meissner, Jr. **Date:** August 13, 2010

Received: September 30, 2010 Date of Response: October 14, 2010
Request No. 5 Witness: Mark H. Collin

Request
Comparing OCA 3-2 to Schedule MHC - 12, please reconcile the delta (change) with regard to VMP proposed expenditures.

Response:
The following cost estimates support the amounts included in the revised MHC-12 provided in response to OCA 3-2:

System Arborist (SG 18 w/ OH's)[1]	$93,800
Vegetation Management Coordinator (SG 17 w/ OH's)[2]	$126,000
Distribution Trimming	$2,344,000
Sub-Transmission Trimming	$80,000
Total Annual UES Vegetation Management	$2,634,800

The original estimate included in MHC-12 was based upon the best information available when prepared but did not include the level of detail available from the ECI Consultants report.

[1] System Arborist time will be split 67% UES and 33% FG&E based upon primary pole miles of distribution.
[2] There will be one Vegetation Coordinator for FG&E, and one for UES.

Received: September 30, 2010 Date of Response: October 14, 2010
Request No. 7 Witness: Thomas P. Meissner, Jr.

Request
Please provide the justification for not trimming single phase as frequently as three phase distribution lines from both an economic and reliability perspective. In your discussion on reliability, please consider the base level of reliability seen by the customer.

Response:
Unitil's VMP proposal to extend the single phase maintenance cycle and to shorten the three-phase cycle is based upon research and evidence that determined how trees cause interruptions. This research concludes that in practical terms, single-phase lines represent a lower interruption risk than multi-phase construction for several reasons, most notably the voltage gradient created across a branch when in contact with a conductor. One such research document, presented at the 2004 IEEE Power Conference in Scottsdale, Arizona, by Paul J. Appelt[1] and John W. Goodfellow, is attached to this response as Attachment 1.

By focusing on the vegetation that causes the greatest risk of interruptions, i.e. three-phase construction, it is anticipated that we will minimize tree related outages overtime and ultimately improve system reliability. Given that the research further concludes that there is minimal risk of an interruption when a tree contacts one phase of a multiphase system, extending the single phase cycle provides economic benefits without compromising system reliability.

[1] Paul J. Appelt is President of ECI, the firm contracted by Unitil to perform a vegetation control study in 2010.

Conference Papers

Research on How Trees Cause Interruptions- Applications to Vegetation Management

Paul J. Appelt,Consulting ServicesECI
John W. Goodfellow, Research Consultant

Paper No.
04 C6

0-7803-8298-6/04/$20.00 ©2004IEEE

Research on How Trees Cause Interruptions- Applications to Vegetation Management

2004 IEEE Rural Electric Power Conference in Scottsdale, Arizona.

by Paul J. Appelt[i] and John W. Goodfellow[ii]

Abstract. ECI and others have conducted applied practical research to the question of how trees cause sustained as well as momentary interruptions. This research has led to the development of a conceptual model of tree-initiated faults on overhead distribution systems. Information gained from this newfound understanding into distribution system construction, tree species, and voltage impacts on fault risk has implications for tree maintenance programs and construction standards. ECI has used this understanding to help utilities optimize maintenance cycles to reduce annual asset maintenance costs, while reducing interruptions associated with tree growth.

Understanding How Trees Cause Interruptions

Introduction

Trees are frequently among the top causes of electric distribution system service interruptions and tree maintenance expenditures typically account for one of the largest line items in an electric utility operating and maintenance budget. Gaining a better understanding of how trees cause interruptions is an important step towards identifying effective mitigation strategies that can provide the greatest improvements in reliability for the least cost. Trees cause distribution system interruptions through two fundamental mechanisms: (1) by failing structurally, causing physical damage to overhead utility infrastructure (mechanical failure mode), or (2) by providing a fault pathway between conductors and/or ground, resulting in a low impedance, high fault-current (electrical failure mode).

ECI has conducted research that explored how trees cause interruptions and some of the dynamics of electrical faults through trees. Through an understanding of the dynamics of tree-related interruptions it became evident that the relationships between system design, construction and protection were significant contributors to the overall risk of sustained tree-caused interruption on a distribution system. Findings from initial investigations into the electrical mode of sustained tree-caused interruptions have also led to challenging questions about the possible role of trees in momentary interruptions. ECI has also conducted investigations into the potential for trees to be causal agents for momentary service interruptions.

Through improved understandings of the mechanisms behind tree-caused electrical mode of system failure, innovative solutions to vegetation management problems have been developed which have, where implemented, resulted in reductions in annual asset maintenance expenditures related to vegetation control.

Research History

Why does a tree limb cause an electrical mode of system failure in some cases and not in others? Past research concerning this subject has been undertaken by various groups in an attempt to answer this question.

Baltimore Gas & Electric (BG&E) conducted some of the earliest publicized field demonstrations of electrical fault pathway development[1]. This work, begun in 1992, identified the formation of a carbon path across a tree limb as a condition for the operation of electrical protective devices, both in laboratory and field tests. Later, Florida Power Corporation performed some similar evaluations.

In 1997 under contract with Allegheny Power System (APS), ECI conducted some high voltage testing in a controlled laboratory experiment as part of a formal investigation into the factors influencing the creation of fault pathways through tree limbs. Subsequent high voltage research was completed in 1998 and 1999 for Niagara Mohawk Power Corporation (NiMo) and Portland General Electric. This research included investigations into the fault characteristics of tree limbs subject to voltage stress and influences of the following conditions:

- Voltage gradient
- Branch diameter
- Surface moisture
- Branch condition (living or dead)
- Branch origin (normal vs. "sucker" growth)
- Internal wood moisture content
- Seasonal variation and effect on impedance
- Species variation on impedance (eleven species)

This work resulted in development of a conceptual model for the mechanism of electrical modes of failure through trees. ECI conducted an engineering study and completed proof of concept field validations testing of the earlier laboratory studies on the APS and NiMo distribution systems in 2000[2]. In this phase, additional research data was acquired as trees and branches were introduced to energized primary voltage distribution lines under normal operations in the field. This work helped assess the relationship between incidental tree contact with a conductor and momentary interruptions.

Continued research into the variations in electrical fault characteristics among additional tree species subject to various voltage gradients continued in 2003, supported by the Tree Trust and individual utility cooperators including Illinois Power, Central Vermont Public Service, Black Hills Power and Keyspan.

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[1] Rees, Wm. T. Jr., T.C. Birx, D. L. Neal, C. J. Summerson, F.L Tiburzi Jr., and J.A. Thurber, PE. "Priority Trimming to Improve Reliability". Unpublished manuscript. BG&E. 1993.
[2] ECI. "Understanding the Way Trees Cause Power Interruptions". Private research report. 1998.

The Tree Fault Pathway Model

The body of research conducted by ECI and others has led to the creation of a tree fault pathway model for development of interruptions through the electrical mode of failure. The tree fault pathway model identifies four primary factors that influence whether or not a tree branch crossing two primary distribution phases (or phase and neutral) will result in an interruption. These factors include:

- Voltage gradient (voltage plus distance)
- Branch diameter
- Tree species
- Internal moisture content (living vs. dead limbs).

The multiple research efforts conducted by ECI confirmed that the formation of the carbon path is essential for the electrical fault to occur. Without a completed carbon path no fault occurs. However, once a carbon path is fully developed across a branch bridging two phases or a phase and a neutral, overcurrent protective devices will detect what has become a low-impedance fault, and operate as designed, creating an interruption.

Species Specific Variation in Impedance Testing

Background

The goal of ECI's 1998 study was to replicate some of the previous work in a controlled laboratory environment, where a large number of tree limb samples could be tested with multiple replications. Eleven species were tested within 4 different diameter classes. Subsequent testing in 2003 more than doubled the initial number of tree species tested. Time to fault and current measurements were recorded for each specimen as well as sample diameter and moisture content.

Experimental Design

The design allowed a predetermined test voltage level to be impressed uniformly across a fixed distance, achieving the desired voltage stress gradient. The voltage gradient impressed on each specimen was controlled, and varied for different sample lots by varying the voltage input.

The project involved two related but different experimental efforts. In the first phase of testing, branch specimens were subjected to fixed high-voltage gradients. The voltage stress gradients tested impressed relatively high voltage stress gradients of 2kV/ft, 3kv/ft and 5kV/ft. Tests were made on 48 specimens (4 replications x 4 diameter classes x 3 voltage gradients).

The second phase of the high-voltage laboratory work subjected individual specimens to decreasing fault gradients until a level was reached that did not result in a short circuit fault. The voltage gradient was stepped down 300 Volts between tests. The number of test specimens used in the second phase of the experiment varied, and was a function of the researcher's ability to estimate a starting voltage gradient close to the fault/no fault threshold.

Both phases of testing were conducted in a controlled high-voltage laboratory setting. Individual test specimens were placed between two conductor segments positioned a fixed distance apart. This configuration permitted the branch specimens to be consistently positioned for each testing sequence.

A variable output AC high potential test transformer provided a means of voltage control. A 60:1 power transformer with a maximum rated output of 15 kilovolts was used as a high voltage source. An instantaneous current sensing trip coil of a protective relay protected the test circuit. The relay was set to interrupt at a fault current level of 275 mA. Test set instrumentation provided for a continuous record of time and current, as well as real time observations of current, time, and voltage.

Results - Phase-to-Phase or Phase-to-Neutral Faults Through Tree Branches
Upon contact with two energized conductors (or between an energized conductor and grounded object or neutral), an electrical stress is imposed on the branch. While the gradient is relatively uniform, it is greatest at the point of contact due to the unequal potential of the bark and wood. Arcing at the points of contact oxidizes organic compounds in the branch into elemental carbon. The arcing fronts move in the direction of the gradient, increasing the stress as illustrated in Figure 1. If the voltage gradient between the two electrodes is high enough, the carbon path continues to form and grow together until the gap between the areas of unequal potential is bridged and the fault occurs.

Figure 1. Creation of a Carbon Path

Of all the variables studied, voltage gradient, branch diameter and species have been found to have the greatest affect on fault current levels. Voltage gradient is a function of both the voltage differential between two points, and their distance apart.
All testing conducted to date indicates that formation of a complete carbon pathway is essential to transition from a high-impedance to a low-impedance condition and for a

fault to occur at distribution voltages. However, wood has certain insulating properties and the formation of the carbon path becomes a race between the push of the voltage gradient and the drying affect and increasing resistance of the wood itself. If the voltage gradient is high enough, the carbon path will form faster than the drying wood increases its resistance, and a fault will occur. But, if the voltage gradient is low enough, the drying effect increases the wood's resistance faster than the carbon path can form – and a fault will NOT occur. Effectively, the voltage gradient is not high enough to push the carbon path across the limb and completely bridge the gap. This helps explain why utility operations personnel often see limbs on the lines without adverse impact to system operation, especially at lower voltages.

A developing fault may also be interrupted when the limb that falls across phases, or across a phase and neutral, is actually so small that the branch burns through at one of the contact points before the carbon path fully develops. At high voltage gradients, however, the carbon path may develop before even a very small branch burns through.

Table 1. Common Line Types and Voltage Gradients

Line Type	**Voltage Gradient**
3 Ø 34kV on 10 foot arms	11.5 kV per foot
3 Ø 24.9kV on 8 foot arms (center ϕ on pole top insulator)	6.2 kV per foot
3 Ø 34kV on 10 foot arms	11.5 kV per foot
3 Ø 12.5kV on 8 foot arms	5.16 kV per foot
3 Ø 12.5kV on 10 foot arms	4.16 kV per foot
1 Ø 24.9 kV (14.4kV) on pole top insulator with neutral	2.4 kV per foot
1 Ø 12.5kV (7.2kV) on pole top insulator with neutral	1.2 kV per foot
3 Ø 4.2kV on 8 foot arms (center ϕ on pole top insulator)	1.0 kV per foot
1 Ø 4.2kV (2.4kV) on pole top insulator with neutral	0.4 kV per foot

Table 1 illustrates typical voltage gradients for the design and construction criteria common in the industry. As voltage increases and distance between potential points of contact decrease (arm length or distance to neutral), voltage gradient increases. While each utility has some differences in specific framing standards and slight operation voltage differences, Table 1 contains the general range of voltage gradients likely to be encountered. Figure 2 illustrates the relationship between voltage gradient and time to fault for trees based on all species in the initial studies. The "no fault" zone is different for individual tree species and the location of the curve will shift to the left or right as additional species are added through future research results.

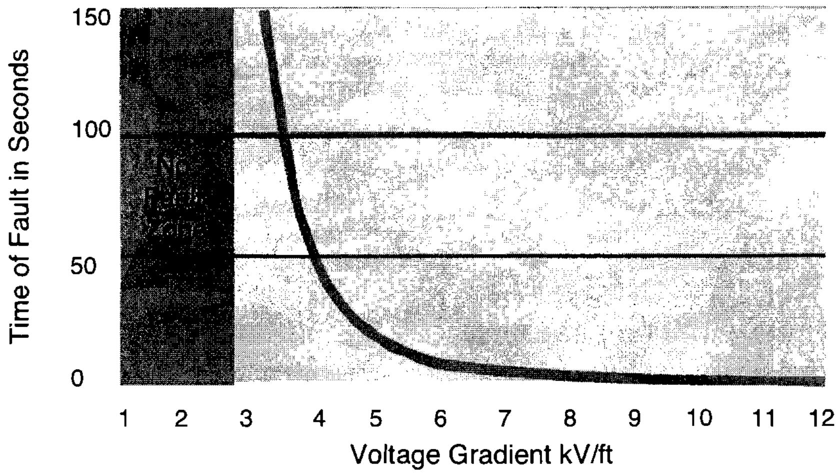

Figure 2 Influence of Voltage Gradient on Fault

Differences in Calculated Impedance: Rho
A final empirical approach to assessing differences in impedance made use of quantitative data collected in both experimental phases.

Current recordings were automatically recorded once every 0.88 seconds of each test. While fault impedance has been shown to evolve (change) throughout the course of each test, data immediately following energization of the specimen is believed to be an accurate indication of the initial impedance of the specimen.

After assembling a data set of initial impedance it was necessary to normalize each observation for the effect of the varying diameters of the test specimens. The calculated resistivity (Rho) of individual tree species does vary significantly between species as seen in Figure 3.

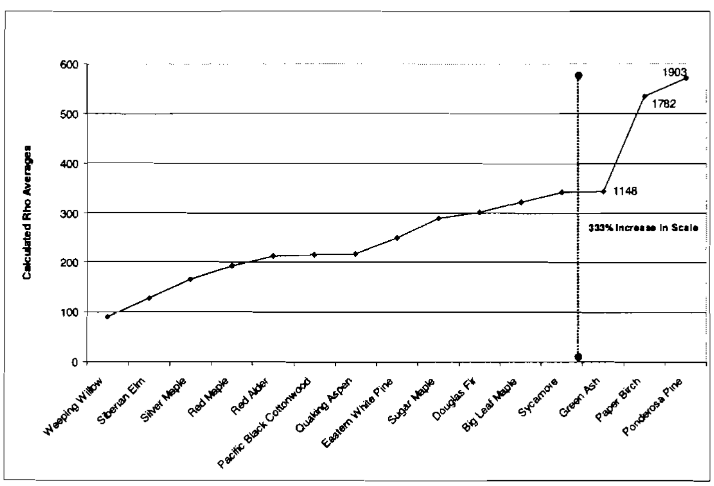

Figure 3 Calculated Rho Averages by Species

It should be noted that calculated Rho for green ash, paper birch and ponderosa pine were orders of magnitude greater than for the other species tested. For purposes of clarity, the Figure 3 scale was compressed artificially to accommodate these large values in order to also demonstrate the large differences in Rho among the other species.

Influence of Branch Diameter

Larger diameter branches are more conductive than small branches. Additional work is required to understand the exact electrical pathway through branches, although, there is speculation suggesting that xylem fibers play a major role as conductive pathways with layers of varying dielectric strengths.

Incidental Contact Between Trees and Conductors

In an effort to better understand the impact of incidental tree-to-conductor contact on momentary interruptions, ECI completed two separate field studies in 2000 designed to assess the relationships between tree-to-conductor contact and momentary interruptions[3]. These studies built on previous work and helped create additional understanding about what happens when a tree comes into contact with a single energized distribution conductor. These studies were conducted for and with the assistance of APS and NiMo.

Experimental Design

The NiMo project design included a single-phase, 7,620-volt tap off of a 13.2 kV line with maximum calculated fault current available to the site of 853 amperes. A 10K fuse was installed to isolate the tap and power quality monitoring equipment was installed on the customer side of the system.

The tap itself consisted of URD cable running down the pole, across the ground and up into the trees. A section of copper clad conductor was spliced onto the end of the URD cable and then placed in contact with test trees. The conductor made contact with multiple branches to simulate a line running out through the trees in an overgrown condition.

Data loggers and AC Current Probes were used to measure current flowing through the test trees. Digital Voltmeters (Figure 4) were placed at one-meter intervals down the tree and out in the soil away from the tree along major roots to measure voltage gradient down through the tree to the earth.

[3] ECI. "Assessing the Relationship Between Tree-Conductor Contact and Momentary Outages at Niagara Mohawk Power Corporation". Private research report. 2000.

Figure 4 Voltmeters in Test Tree

Field Results

The levels of fault current observed in all tests were low. This result was consistent with both the engineering studies and experimental work. All of these field tests could be described as "high impedance faults". The fault current levels observed ranged in the order of 100mA, with the exception of a worst-case scenario test that resulted in fault current of nearly 500mA.

This worst-case test involved continuous contact with the main stem of an aspen tree 17 cm in diameter at the point of contact. Previous research efforts suggest that both the larger tree stem diameter in conductor contact and the shorter distance to ground (no lateral branches for current to flow through) contributed to the higher measured fault current. Even after over an hour of observation, fault current levels remained relatively stable and constant, did not exceed 0.5 Amperes and likely would have remained a high impedance fault if the test were not ended. It should be clear that the fault current levels at no time, in any of the tests, approached levels remotely high enough to have been detected by an overcurrent protection system.

Research Conclusions

Based on the laboratory testing and field demonstrations completed, it is evident that tree contact with single-phase conductors on 15kV class distribution circuits represents very low risk of causing a sustained or momentary interruption. Nor will incidental tree contact with a single-phase line cause a significant voltage sag or dip. Power quality measurements completed in the field demonstrations indicated no degradation in power quality.

It may be safe to conclude that there is minimal risk of an interruption when a tree on a typical distribution line contacts one phase of a multiphase distribution circuit. There is a risk of an interruption when a tree (or branch) provides a fault pathway between energized phases or between an energized phase and system neutral. It should be noted that this discussion applies only to the electrical failure mode through tree limbs and not mechanical failure.

These understandings of how trees cause outages create significant opportunities for both cost savings and reliability improvements through changes in scheduling and certain tree maintenance work selection criteria and guidelines.

Applying the Results

Based on the enhanced understandings of how trees cause interruptions as described in this paper, there is considerably different risk of interruption due to tree contact with conductors when construction types reflect high voltage gradients. In practical terms, single-phase lines or lines constructed with longer crossarms and lower-voltage lines represent lower interruption risk than multi-phase construction on short crossarms or higher voltage lines.

There is also different interruption risk associated with different tree species and with different size tree limbs in close proximity to conductors. ECI has utilized this understanding of risk variability to modify line clearance scheduling and maintenance practices to improve reliability and lower maintenance costs.

One case study includes program changes made at Kansas City Power and Light Company (KCP&L) that reduced overall distribution vegetation maintenance costs by over 13 percent while reducing tree-related interruption duration by over 50 percent.

The key to realization of these improvements was the reallocation of tree maintenance expenditures toward those locations on the system and those activities that represented a higher risk of tree-related interruptions. These resource reallocations included:

- Extending the single-phase maintenance cycle
- De-emphasizing trimming trees for service lines
- Shortening the three-phase backbone inspection and maintenance cycle, effectively placing greater emphasis on this critical element of the circuit.
- Emphasizing selective removal of hazardous trees and trees at higher risk of causing interruptions adjacent three-phase lines
- Implementing a highly prescriptive approach to work selection, prior to work assignment to line clearance crews, through tree assessments by individuals trained in an understanding of tree-related interruption risk

By extending the tree maintenance cycle for single-phase portions of circuits, a significant number of trees grow into the conductor by the time line clearance work is scheduled. As projected by the research, however, this intermittent contact has not had any detrimental impact on system reliability. Furthermore, KCP&L was able to reinvest some of the savings associated with cycle extension on single-phase lines to decrease the inspection cycle on 3-phase backbones and to selectively increase tree maintenance levels on these portions of the distribution system most at risk of interruption from trees.

Table 2 illustrates the theoretical potential savings associated just through cycle extension of single-phase construction on a 5,000-mile system with 50 percent single-phase construction.

Table 2. Potential Savings Example Associated with Cycle Extension

1ϕ Cycle Length	Est. 1ϕ Cycle Cost/ year	1ϕ System % Savings	3ϕ Cycle Length	Est. 3ϕ Cycle Cost/ year	Total Annual Cost	Total System % Savings
4	$1,250,000		4	$1,250,000	$2,500,000	
5	$1,000,000	20%	4	$1,250,000	$2,250,000	10%
6	$833,333	33%	4	$1,250,000	$2,083,333	17%
7	$714,286	43%	4	$1,250,000	$1,964,286	21%
8	$625,000	50%	4	$1,250,000	$1,875,000	25%

New information gathered on outage risk associated with the electrical impedance of different tree species is expected to result in further reliability improvements at KCP&L through modification of tree removal criteria based on those differences.

Additional interruption risk reduction can be realized through modification of construction standards, especially in areas of high tree density or where trees are highly subject to breakage. Changes to construction standards that result in reduced voltage gradients exposed to trees can help reduce interruption risk.

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Request
Please reconcile whether the prediction intervals or confidence intervals are 90/10 or 95/5 in terms of the confidence that the load will be BELOW the upper interval bound and what the upper interval bound is in each case.

Response:

Reference TS-8 Response Attachment 1 - System Load Forecast Description.

Unitil - System Load Forecasting Process Description

Unitil publishes a 10-year system load forecast annually establishing three specific forecast load levels; Average Peak, Peak Design, and Extreme Peak. The development of the 10-year load forecasting model is essentially a two step process 1) develop a load versus temperature model and 2) develop the load forecast model.

The first step is to develop a load-versus-temperature model of the previous year and then to forecast future load levels based upon the historical load-versus-temperature models of the previous ten years. The basis for the load-versus-temperature models are the daily peak loads (kW) and the corresponding daily average temperature for the summer months (June-September). The load-versus-temperature models are constructed using the Boltzmann sigmoid function which estimates a predicted load level for any given temperature based upon the actual load-versus-temperature experienced.

Once the model for the previous summer is developed, it is compiled with the historical models of the previous nine years. Future load forecasting is not performed by trending these load-versus-temperature models. Rather, the year-to-year variation in these models establishes the historical basis for future load forecasting.

The second step of the process is to develop the load forecast model. The process utilized for future load forecasting is a Monte Carlo simulation using random variables for the highest daily average temperature that could be experienced in any given year and specific parameters used in historical load-versus-temperature models from the previous 10 years. The three published load levels are assigned to the percentile ranks indicated below:

- 50th percentile = Average Load Forecast
- 90th percentile = Peak Design Forecast
- 96th percentile = Extreme Peak Forecast

The percentile ranks (not confidence or prediction intervals) corresponding to each forecast load level were chosen to roughly equate to a probability level. For example, the 50th percentile was assigned to the Average Load Forecast such that there is equal chance every year that the actual load experienced will be above or below the Average Load Forecast. Similarly, there is a 1-in-10 chance every year that the Peak Design Forecast could be exceeded and a 1-in-25 chance every year that the Extreme Peak Forecast could be exceeded. Unitil does not utilize confidence intervals or prediction intervals in its load forecasting model. Note that only the Peak Design and Extreme Peak forecasts are used for planning electric system infrastructure improvements.

Each step in the process is described in more detail below:

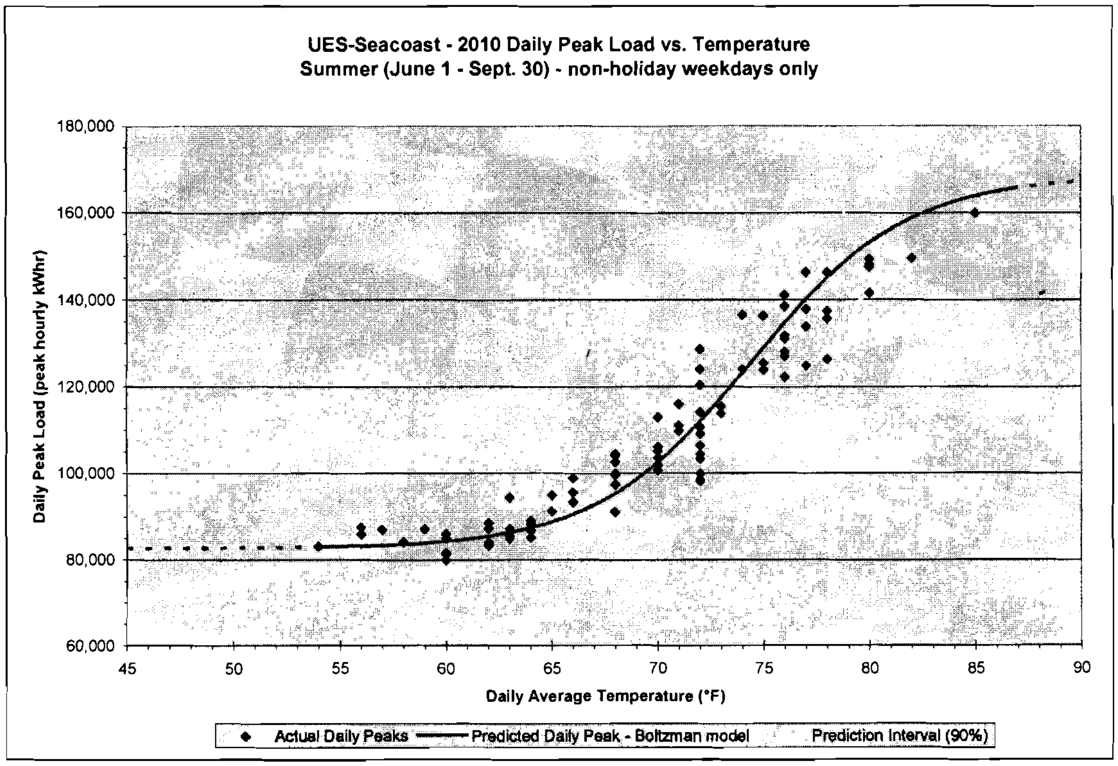
Step 1: Develop Load-vs-Temperature Model

Develop Load-vs-Temperature Models for Previous Year

The load-versus-temperature model is developed by tabulating the actual daily peak loads (kW) and the respective daily average temperatures experienced for the time period of June-September. Weekends and holidays are ignored. The Excel Solver add-in is used during this process to optimize the constants used in Unitil's load-vs-temperature model such that the coefficient of determination is maximized. This maximizes the "best fit" of the model.

From this data, a predicted load (Y_p) is calculated using the Bolzmann sigmoid function for discrete daily average temperatures up to 100°F. In addition, a standard deviation for each discrete temperature (S_{ind}) is also calculated. A 90% prediction interval estimate for each discrete temperature is calculated from the predicted load ± the margin of error. The margin of error for each discrete temperature is represented by the product of the standard deviation at the respective temperature and the t-value of the distribution[1]. The prediction interval is only used to illustrate the fit of the model as shown in the chart below and is not used to develop the actual load forecast. This chart shows the actual load and temperature experienced on non-holiday weekdays from June 1st – September 30th, 2010. The solid magenta line indicates the discrete predicted loads for every temperature. The dashed yellow lines indicate the 90% prediction interval estimates which are plotted only to assist in visually examining the fit of the load-vs-temperature model and do not influence future load projections.

[1] A t-distribution is used since the sample size is small and, therefore, the population standard deviation is unknown.



Compile Load-vs-Temperature Models for Previous Ten Years

The model developed for the previous year is compiled with the models constructed for the prior 9-years. This establishes a 10-year historical load-versus-temperature model. The year-to-year incremental changes in the optimized constants used in these models are calculated and used as input data for the future load forecasting model.

Step 2: Develop Load Forecast Model

As previously indicated, Unitil's load forecasting model utilizes a Monte Carlo simulation to calculate 5,000 random load projections for each future forecast year. The load projections are calculated using the same methodology used in the historical load-vs-temperature models. However, the parameters of temperature and the model constants are randomized and weighted based on historical data. This randomization is described in detail below:

- 5,000 random daily average temperatures for each forecast year are generated within the range of actual highest daily temperatures experienced for the past 20 years and weighted based upon the actual frequency of occurrence. For example, if the highest daily average temperature of 84°F occurred 4 times in the past twenty years, the probability of the model generating a temperature of 84°F is 0.2.

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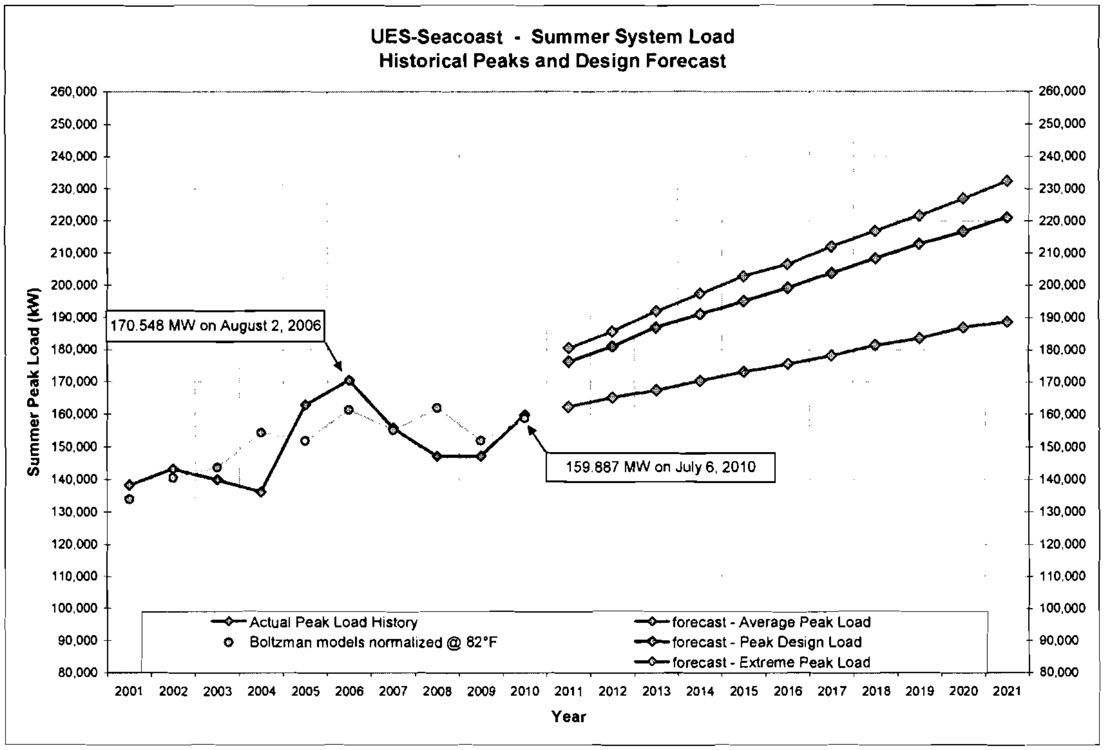
- 5,000 random model constants for each forecast year are generated based on the actual year-to-year incremental changes in the optimized constants observed in the 10-year historical load-versus-temperature model. The randomization of these constants is weighted such that more recent years have a greater influence as does the year of the all time system peak. The reasoning behind this weighting is to sensitize the model to recent changes in the system configuration, customer base, and evolving customer habits in electricity usage.

The tables and charts below represent the most recent load forecasts for UES-Seacoast and UES-Capital for the years 2011-2021.

UES-Seacoast Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2011	162.4	176.3	180.4
2012	165.2	181.0	185.7
2013	167.6	186.9	192.0
2014	170.5	191.1	197.4
2015	173.1	195.2	202.9
2016	175.6	199.2	206.7
2017	178.3	204.0	212.2
2018	181.5	208.5	216.9
2019	183.7	213.0	221.8
2020	186.9	216.7	226.9



UES-Capital Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2011	126.8	135.2	138.5
2012	127.6	137.2	140.9
2013	128.5	139.1	143.0
2014	129.4	140.7	144.7
2015	130.4	142.5	146.6
2016	131.5	144.3	148.8
2017	132.2	145.5	150.6
2018	133.4	147.4	152.7
2019	134.4	149.2	155.3
2020	135.2	150.7	156.3

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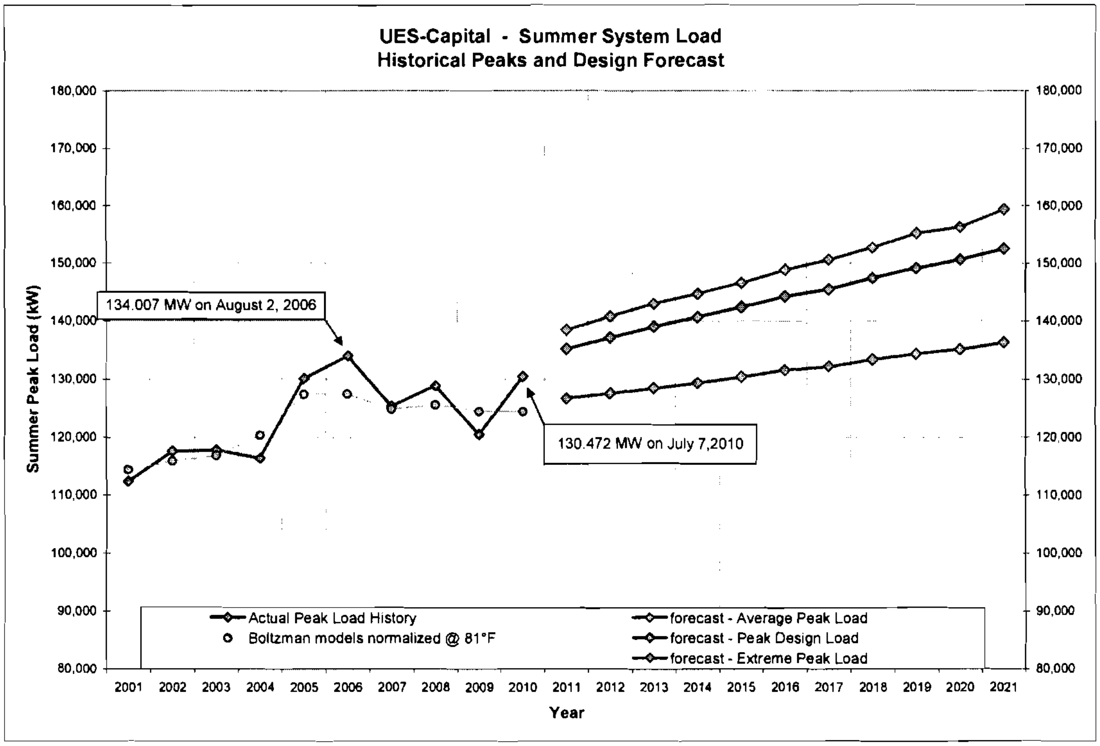


By inspection of the charts above, it is observed that the slope of the Extreme Peak and Peak Design forecasts are much steeper than the Average Load forecast. It has also been observed that the slope of the Average Peak Load forecast is not as steep as in previous years. The divergence of the slope of the Average Peak Load and the Peak Design Load is due to the probability distribution of the of the Monte Carlo simulation results. One explanation of this observed trend is that the system has experienced several years with out a new system peak and a slowing rate of growth. This is reflected in the temperature normalized curve plotted on these charts. In addition, the UES system load factor has been decreasing during this same time period.

Received: September 30, 2010 Date of Response: October 14, 2010
Request No. 11 Witness: Thomas P. Meissner, Jr.

Request
What is PSNH's cost, NU's cost, Unitil's cost and the combined PSNH/NU/Unitil cost for Kingston substation? Please provide a copy of the final one-line diagram. Please also provide an updated step adjustment calculation in the form distributed at the technical conference.

Response:

Unitil, NU and PSNH held a meeting on October 4th to discuss the most recent revision to the PSNH Kingston Oneline. Unitil expressed at this meeting that it does not agree with the proposed design for the PSNH substation noting that it greatly duplicates the equipment located in the Unitil substation. The costs of this proposed design are shown below. Unitil and PSNH are still in discussion about this proposed design and Unitil has not approved this design

	Project Cost
NU Transmission	$12.0 million
PSNH Distribution	$ 7.10 million
Unitil	$ 3.95 million
Total	**$23.05 million**

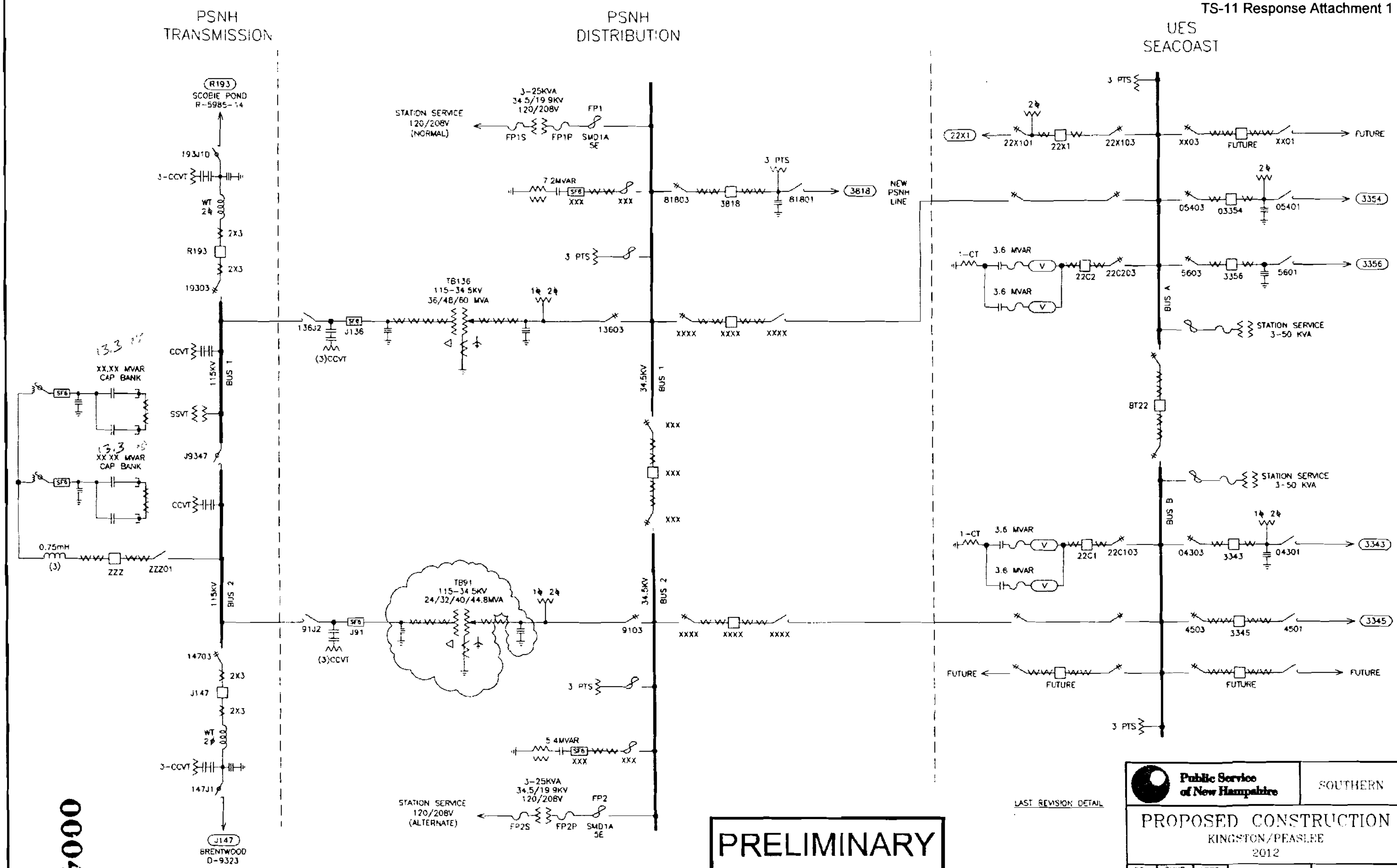
The NU Transmission portion includes costs for improvements to the 115kV system that are not directly related to the Kingston addition. This cost will be allocated at the transmission level either through LNS or RNS rates depending upon the ISO determination on PTF.

The PSNH distribution costs are charged to Unitil through the Distribution Service Agreement as part of the NU OATT. The costs will be allocated to Unitil and PSNH based upon a load ratio share calculation.

Reference TS-11 Response Attachment 1 for the draft one-line diagram PSNH presented at the meeting.

Reference TS-11 Response Attachment 2 for an updated step adjustment calculation in the form distributed at the technical conference.

TS-11 Response Attachment 1



PRELIMINARY

LAST REVISION DETAIL

Public Service of New Hampshire	SOUTHERN
PROPOSED CONSTRUCTION KINGSTON/PEASLEE 2012	
DRN. LJG / CHKD. / APPR. / 10/1/10	SKT-AS-KINGSTON

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Unitil Energy Systems, Inc.
Docket No. DE 10-055
Request No. Tech Session 11 - Attachment 2
Schedule MHC-11 Updated

Unitil Energy Systems, Inc.
PROJECTED LARGE CAPITAL PROJECT STEP ADJUSTMENT
Proposed Funding 2012

LINE NO	(1) DESCRIPTION	(2) AMOUNT
1	NET UTILITY PLANT	
	KINGSTON SUBSTATION	$ 3,950,000
	EAST KINSTON SUBSTATION	1,362,200
	TOTAL NET UTILITY PLANT	5,312,200
2	LESS: ACCUMULATED DEFERRED INCOME TAXES	39,000
3	RATE BASE	5,273,200
4	PRE-TAX RATE OF RETURN	12.06%
5	RETURN AND RELATED INCOME TAXES	635,948
6	ANNUAL BOOK DEPRECIATION @ 4.06% DEPRECIATION RATE	215,675
7	ANNUAL PROPERTY TAXES @ 1.62% TAX RATE	86,058
8	TOTAL STEP ADJUSTMENT REVENUE REQUIREMENT	937,681

Unitil Energy Systems, Inc.
Docket No. DE 10-055
Technical Session Data Requests

Received: September 30, 2010 Date of Response: October 14, 2010
Request No. 13 Witness: Thomas P. Meissner, Jr.

Request
Referencing Staff 4-61, state in the 2009 format the trimming cycles contained in Staff 1-29.

Response:
Please see TS-13 Response Attachment 1.

VMP Proposal 7 year cycle 1-phase, 4 year cycle 3-phase, and 7 year hazard tree	4 kV		13.8 kV		34.5 kV		
	1Ø	3Ø	1Ø	3Ø	1Ø	3Ø	Totals
Total in-service miles	273.3	120.49	300.80	158.69	57.6	138.0	1048.8
Scheduled pruning miles	39.0	30.1	43.0	39.7	8.2	34.5	194.5
Reliability enhancement miles							15.4
Mid-cycle trimming miles							21.2
Unscheduled miles							6.1
Total miles trimmed							237.2
Annual expenditures							$2,643,800

VMP Enhanced Proposal 5 year cycle 1-phase & 3-phase, and 5 year hazard tree	4 kV		13.8 kV		34.5 kV		
	1Ø	3Ø	1Ø	3Ø	1Ø	3Ø	Totals
Total in-service miles	273.3	120.49	300.80	158.69	57.6	138.0	1048.8
Scheduled pruning miles	54.7	24.1	60.2	31.7	11.5	27.6	209.8
Reliability enhancement miles							14.3
Mid-cycle trimming miles							22.9
Unscheduled miles							5.7
Total miles trimmed							252.7
Annual expenditures							$3,184,800