Attachment 1

UES – Capital

Reliability Analysis and Recommendations 2013

Unitil Energy Systems - Capital

Reliability Study

2013

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September 9, 2013

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1. Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Capital system January 1, 2012 through December 31, 2012. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The reliability data presented in this report does not include Hurricane Sandy (10/29/12 2:00 to 10/31/12 12:00).

The following projects are proposed from the results of this study and are focused on improving the worst performing circuits as well as the overall UES-Capital system reliability. These recommendations are provided for consideration and will be further developed with the intention to be incorporated into the 2013 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
IRONWORKS SUB	33 LINE REMOTE FAULT INDICATION AND MOTOR OPERATORS AT IRON WORKS ROAD	$45,200
PLEASANT ST SUB	33 LINE REMOTE FAULT INDICATION AT PLEASANT STREET	$13,500
375 Line	TERRIL PARK 375J3 AUTOMATIC SECTIONALIZING	$38,000
37 Line	OVERBUILD A 35KV SUBSTRANSMISSION LINE ON 13W2 AS AN ALTERNATE FEED TO BOSCAWEN SUBSTATION	$2.2 Million
3H3	RECLOSER REPLACEMENT AT GULF ST SUBSTATION	$20,000
8X3	CREATE ALTERNATE MAINLINE	$1.7 Million

Note: estimates do not include general construction overheads

2. Reliability Goals

The annual corporate system reliability goals for 2012 have been set at 191-156-121 SAIDI minutes. These were developed through benchmarking Unitil system performance with surrounding utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire Capital system is used to identify future capital improvement projects and/or operational enhancements which may be required in order to achieve and maintain these goals.

3. Outages by Cause

This section provides a breakdown of all outages by cause code experienced during 2012, excluding Hurricane Sandy. Chart 1 lists the number of interruptions, and the percent of total interruptions, due to each cause. For clarity, only those causes occurring more than 5 times are labeled. Chart 2 details the percent of total customer-minutes of interruption due to each cause, only those causes contributing greater than 2% of the total are labeled.

Chart 1
Number of Interruptions by Cause

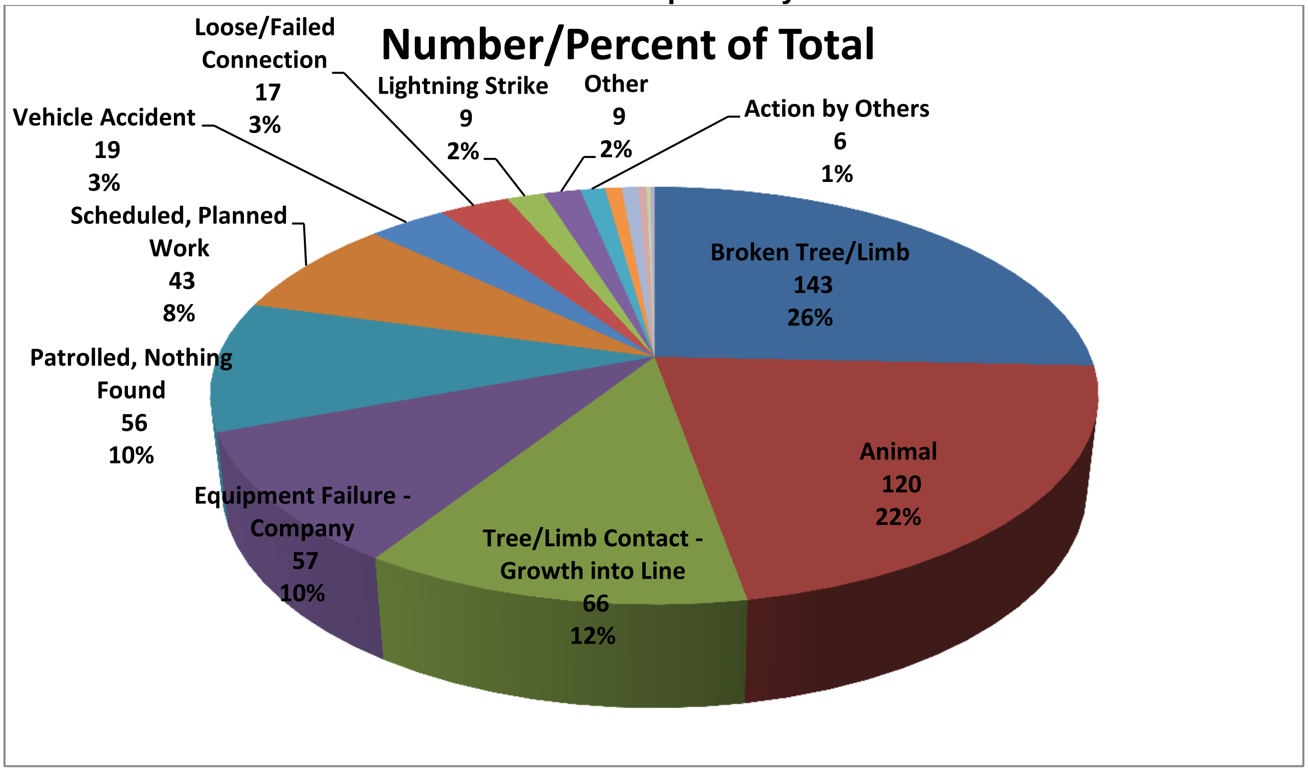
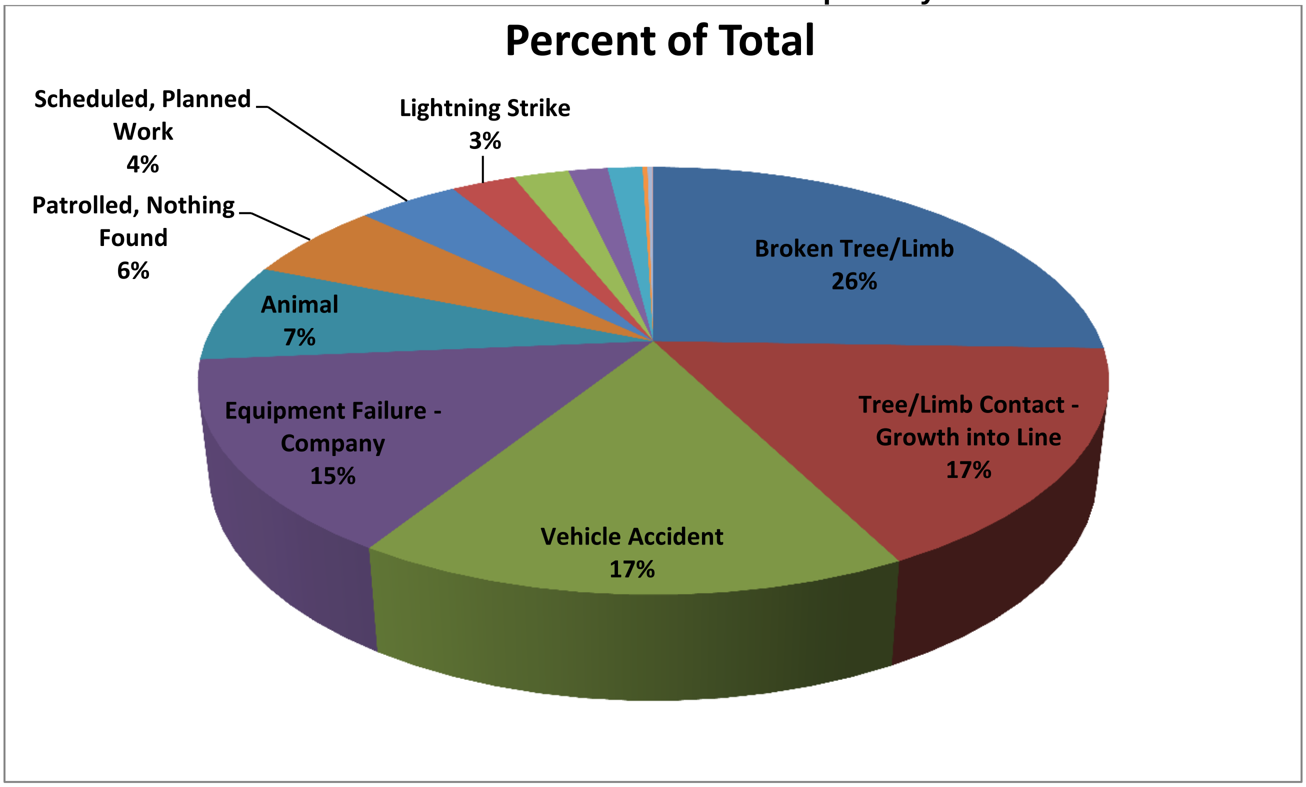


Chart 2
Percent of Customer-Minutes of Interruption by Cause



4. 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2012 through December 31, 2012 are summarized in Table 1 below.

Table 1
Worst Ten Distribution Outages

Circuit	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI
8X3	1/27/2012 Vehicle Accident	2,266	210,738	7.08	0.076
13W2	5/15/2012 Broken Tree/ Limb	562	174,220	5.86	0.019
13W1	10/19/2012 Tree/ Limb Contact (Growth into Line)	2,041	164,193	5.52	0.069
13W2	7/6/2012 Vehicle Accident	1,291	143,267	4.82	0.043
4X1	4/28/2012 Equipment Failure- Company-Cable	1,150	140,300	4.72	0.039
18W2	7/27/2012 Equipment Failure-Company-Hardware (Brackets, Pins)	1,067	100,298	3.37	0.036
8X3	8/10/2012 Lightning Strike	403	92,480	3.11	0.014
21W1A	8/11/2012 Equipment Failure-Company-Connector	692	88,611	2.98	0.023
21W1P	6/2/2012 Tree/ Limb Contact (Growth into Line)	413	86,730	2.92	0.014
13W2	7/20/2012 Bird	1,292	77,803	2.62	0.043

Note: This table does not include substation, sub-transmission or scheduled planned work outages.

5. Sub-transmission Line Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Capital system from January 1, 2012 through December 31, 2012.

All substation and sub-transmission outages ranked by customer-minutes of interruption during the time period from January 1, 2012 through December 31, 2012 are summarized in Table 2 below.

Table 3 shows the circuits that have been affected by sub-transmission line outages. The table illustrates the contribution of customer minutes of interruption for each circuit affected by a sub-transmission outage.

Table 2
Sub-transmission and Substation Outages

Line/Substation	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI
33 Line	6/25/2012 Patrolled Nothing Found	1,048	40,468	1.36	0.035

Table 3
Contribution of Sub-transmission and Substation Outages

Circuit	Substation / Transmission Line Outage	Cust-Min of Interruption	% of Total Circuit CMI	Circuit SAIDI Contribution	Number of Events
33X5	33 Line	99	100.0%	33	1
33X6	33 Line	33	100.0%	33	1
33X3	33 Line	67	100.0%	67	1
6X3	33 Line	38,025	39.0%	39	1
33X4	33 Line	2,244	100.0%	33	1

6. Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures. All circuit reliability data presented in this section includes subtransmission or substation supply outages unless noted otherwise.

6.1. Worst Performing Circuits in Past Year

A summary of the worst performing circuits during the year of 2012 is included in the tables below. Table 4 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The SAIFI and CAIDI for each circuit are also listed in this table. Table 5 provides detail on the major causes of the outages on each of these circuits. Customer-minutes of interruption are given for the six most prevalent causes during 2012.

Circuits having one outage contributing more than 75% of the Customer-Minutes of interruption were excluded from this analysis.

Table 4
Worst Performing Circuits by Customer-Minutes

Circuit	No. of Customers Interruptions	Worst Event (% of CI)	Cust-Min of Interruption	Worst Event (% of CMI)	SAIDI	SAIFI	CAIDI
13W2	11,043	5.09%	948,203	18.37%	817.42	9.520	85.86
8X3	6,306	35.93%	684,424	30.79%	244.18	2.250	108.54
4X1	3,029	37.97%	308,508	45.48%	129.46	1.271	101.85
18W2	2,567	41.57%	240,082	41.78%	223.12	2.386	93.53
13W1	2,332	20.37%	204,020	24.45%	425.04	4.858	87.49
7W3	2,229	40.11%	175,812	30.51%	193.92	2.459	78.87
21W1P	1,239	33.33%	155,820	55.66%	381.91	3.037	125.76
15W1	1,993	46.71%	148,241	28.15%	152.67	2.053	74.38
22W3	1,971	31.46%	124,864	28.30%	80.98	1.278	63.35
4W3	1,627	28.76%	103,008	24.99%	76.70	1.211	63.31

Note: all percentages and indices are calculated on a circuit basis

Table 5
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption					
	Animal Combined	Broken Tree/Limb	Equipment Failure - Company	Patrolled, Nothing Found	Tree/Limb Contact - Growth into Line	Vehicle Accident
13W2	112,145	305,317	2,841	12,646	255,642	183,191
8X3	29,642	124,535	15,677	63,283	68,416	280,538
4X1	364	84,634	140,472	13,110	40	1,098
18W2	16,596	47,569	101,840	8,247	17,902	47,621
13W1	2,736	63,500	874	360	60,622	0
7W3	2,400	65,849	42,506	1,405	330	45,675
21W1P	0	0	12,741	0	86,730	0
15W1	1,656	87,879	560	13,297	28,573	16,171
22W3	16,865	52,296	482	6,669	23,671	23,080
4W3	44,573	885	25,740	574	14,358	3,227

6.2. Worst Performing Circuits of the Past Five Years (2008 – 2012)

The annual performance of the ten worst circuits in terms of SAIDI and SAIFI for the past five years is shown in the tables below. Table 6 lists the ten worst circuits ranked by SAIDI performance. Table 7 lists the ten worst performing circuits ranked by SAIFI.

The data used in this analysis includes all system outages except those outages that occurred during the 2012 Hurricane Sandy, 2011 October Nor'easter, Hurricane Irene, 2010 Windstorm and the 2008 Ice Storm.

Table 6
Circuit SAIDI

Circuit Ranking	2012		2011		2010		2009		2008	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	13W2	817.42	13W1	887.09	8X3	1,037.0	13W1	797.86	211A	1,655.4
2	13W1	425.04	13W2	835.67	211A	650.29	13X4	444.00	13W2	1,071.9
3	211P	381.91	37X1	797.25	13W1	648.23	13W2	443.03	13W1	575.6
4	211A[1]	270.00	13W3	660.07	13W2	487.15	18W2	369.36	22W3	434.3
5	8X3	244.17	18W2	593.77	13W3	417.67	13W3	349.28	4W3	396.1
6	18W2	223.12	22W3	421.91	2H4	414.01	211A	330.29	1H3	351.1
7	7W3	193.84	17X1	388.00	2H2	353.25	37A	269.61	22W2	291.3
8	34X2[2]	165.00	13X4	369.00	37X1	304.57	22W3	246.30	15W1	288.9
9	15W1	152.67	21W1A	361.90	3H2	298.00	4W3	245.64	13W3	233.1
10	15W2	135.36	38W	359.61	18W2	293.13	15W1	210.10	1H4	194.0

Table 7
Circuit SAIFI

Circuit Ranking	2012		2011		2010		2009		2008	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	13W2	9.520	13W3	10.379	13W1	5.956	211A	8.614	13W2	9.98
2	13W1	4.858	13W2	8.942	8X3	5.847	13W1	6.091	211A	7.01
3	21W1P	3.037	37X1	7.660	13W3	5.561	13W2	3.881	13W1	6.28
4	7W3	2.458	13W1	7.500	13W2	4.638	22W1	3.240	22W2	5.04
5	18W2	2.386	22W3	6.440	37X1	4.391	4W3	3.051	14X3	5.00
6	6X3	2.283	38W	5.428	211A	4.365	13W3	2.748	22W3	4.58
7	8X3	2.250	13X4	5.000	1H5	4.235	22W2	2.720	15W1	3.08
8	15W1	2.053	22W2	4.881	1H3	4.135	15W1	2.277	1H3	3.00
9	22W1	2.000	3H1	3.245	1H4	4.127	18W2	2.004	4W3	2.88
10	13W3	1.834	4X1	3.100	3H2	4.000	37A	1.702	22W1	2.36

[1] This is an underground circuit slated for review to determine a long term improvement plan
[2] This circuit has not been on this list prior to 2012 and has one outage in all of 2012.

6.3. Improvements to Worst Performing Circuit (2011-2013)

Projects completed from 2011 to 2013 that are expected to improve the reliability of the ten worst performing circuits are included in table 8 below.

Table 8
Improvements to Worst Performing circuits

Circuits	Year of Completion	Project Description
37 Line[1]	2012	Implemented Source Transfer Scheme with 4X1
Boscawen S/S[1]	2012	Circuit Exit Rebuilt and Extensive Tree Removal around Substation
13W1	2013	Forestry Review / Mid Cycle Review / SRP[2]
13W2	2012	Fuse and Recloser Setting Changes
		Hazard Tree Mitigation / Mid Cycle Review
	2013	Grey Spacer Cable Replacement[3]
		Cycle Pruning
13W3	2011	Forestry Review
	2012	Transferred load to 4X1
	2013	Grey Spacer Cable Replacement[3]
		Hazard Tree Mitigation
15W1	2011	Forestry Review
	2013[4]	Hazard Tree Mitigation / Hot Spot Pruning
15W2	2013	Mid Cycle Review
18W2	2011	Hot Spot Pruning
	2013	Hazard Tree Mitigation / SRP
22W3	2011	Cycle Pruning / Hazard Tree Mitigation
	2012	Installed squirrel guards on all transformers in trouble areas
	2013	Mid Cycle Review
4W4	2012	Installed Recloser on Lake View Drive
		Forestry Review

[1] The 37 line radially supplies Boscawen Substation (13W1, 13W2, 13W3)
[2] Storm Resiliency Pilot
[3] For more detail refer to section 10.1
[4] This work was not in the 2013 VMP Report but instead was in response to outages in the Shaker Road area

Circuits	Year of Completion	Project Description
4W3	2011	Installed Recloser on Sewalls Falls Road
	2012	Cycle Pruning / Hazard Tree Mitigation
4X1	2013	Hazard Tree Mitigation / SRP
6X3	2011	Hazard Tree Mitigation
7W3	2012	Hazard Tree Mitigation / Mid Cycle Review
	2013	SRP
8X3	2011	Hot Spot Pruning
	2012	Cycle Pruning / Hazard Tree Mitigation

7. Tree Related Outages in the Past Year (1/1/12-12/31/12)

This section summarizes the worst ten performing circuits by tree related outages during 2012. This section is used by the forestry department to help come up with future tree trimming plans.

Table 9 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table. Circuits having less than three outages were excluded from this table.

All streets on the Capital System with three or more tree related outages are shown in Table 10 below. The table is sorted by number of outages and customer-minutes of interruption.

Table 9
Worst Performing Circuits – Tree Related Outages

Circuit	Cust-Min of Interruption	Customer Interruptions	No. of interruptions
13W2 [1,2,3,4]	560,959	6,640	48
8X3 [2,5]	192,951	1,461	31
13W1 [1,3]	124,122	1,318	25
15W1 [1,5]	116,452	1,692	12
4X1 [1]	84,674	740	8
22W3 [1,3,5]	75,967	948	16
7W3 [1,2]	66,179	1,069	10
18W2 [1,5]	65,471	556	14
13W3 [1,3,4,5]	24,829	316	9
4W4 [2,3]	19,167	257	8

[1] Tree trimming efforts are being completed in 2013
[2] Tree trimming efforts were completed in 2012
[3] Reliability improvement projects benefiting this circuit were completed prior to 2013
[4] Reliability improvement projects benefiting this circuit are going to be completed in 2013
[5] Tree trimming efforts were completed in 2011

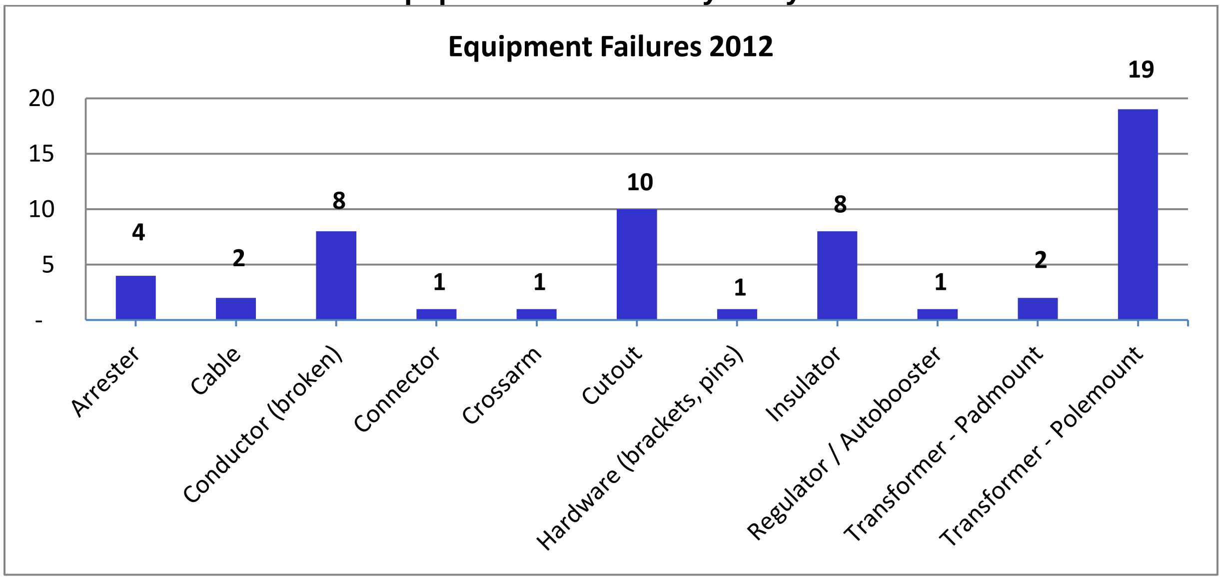
Table 10
Multiple Tree Related Outages by Street

Circuit	Street	# of Outages	Customer Interruptions	Customer Min. of Interruptions
13W2 [1,2,3,4]	Mutton Rd	8	115	16,214
4X1[1]/13W3 [1,3,4,5]	Queen St	7	263	29,672
13W2	Battle St	5	211	18,484
13W1[1,3]	Old Tilton Rd	5	121	10,072
13W2	Warner Rd	5	197	15,870
15W1[1,5]	Oak Hill Rd	4	202	21,954
13W2	Old Turnpike Rd	4	534	41,486
13W2	Hensmith Rd	4	95	12,924
13W2	West Salisbury Rd	4	281	25,830
13W2	High St	3	2958	107,018
18W2 [1,5]	Bow Bog Rd	3	121	14,043
4W4 [2,3]	Lake View Dr	3	73	6,026
8X3 [2,5]	Sanborn Hill Rd North	3	28	3,263

8. Failed Equipment in the Past Year

This section is intended to clearly show all equipment failures throughout the year of 2012. Chart 3 shows all equipment failures throughout the study period. Chart 4 shows each equipment failure as a percentage of the total failures within this same study period. Chart 5 shows the top four types of failed equipment within the study period with five years of historical data.

Chart 3
Equipment Failure Analysis by Cause



[1] Tree trimming efforts are being completed in 2013
[2] Tree trimming efforts were completed in 2012
[3] Reliability improvement projects benefiting this circuit were completed prior to 2013
[4] Reliability improvement projects benefiting this circuit are going to be completed in 2013
[5] Tree trimming efforts were completed in 2011

Chart 4
Equipment Failure Analysis by Percentage of Total Failures

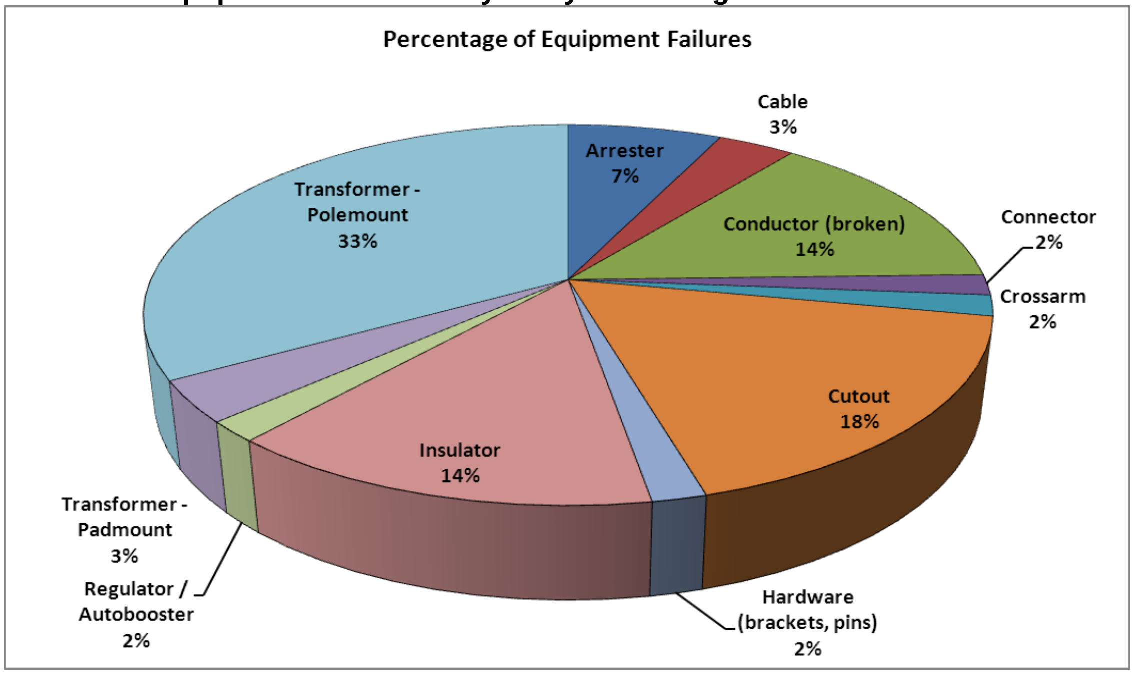
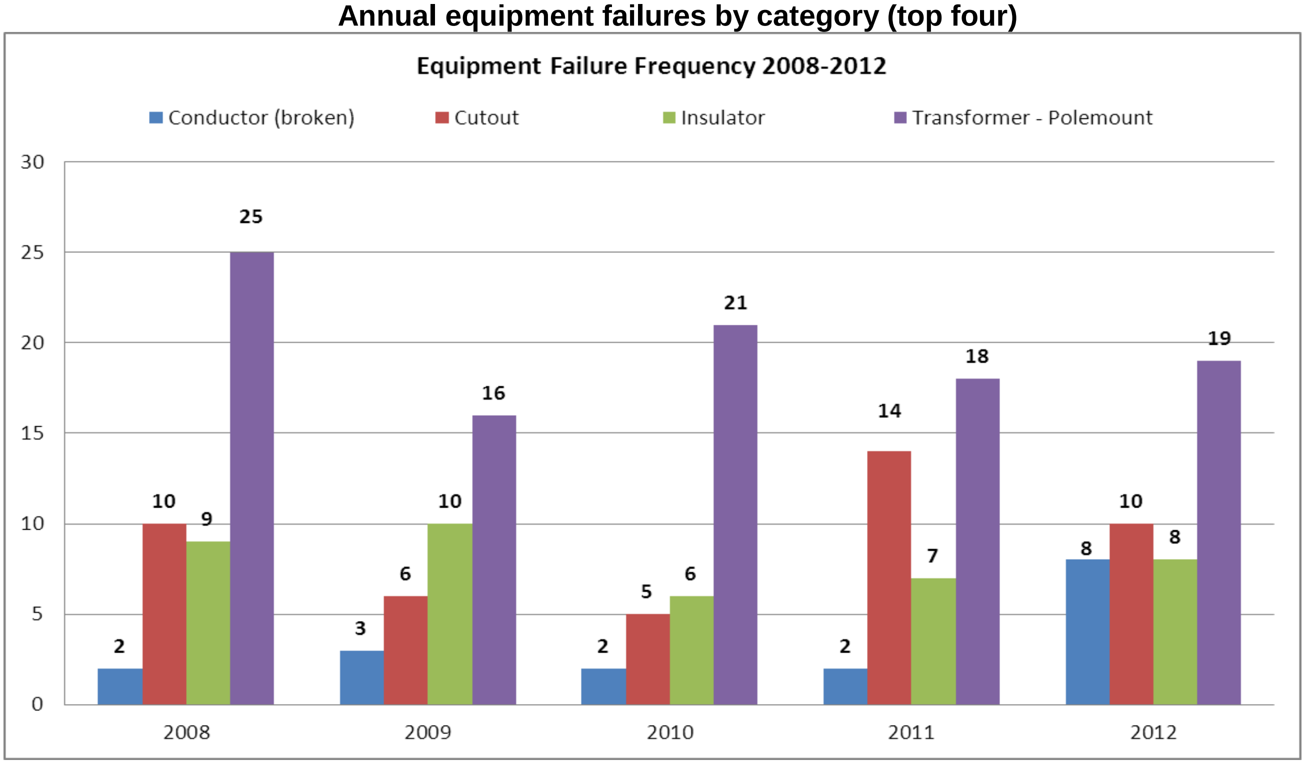


Chart 5
Annual equipment failures by category (top four)



Note: The increase in broken conductors is mostly attributed to broken secondary conductors, failed underground services and URD failures. No one thing is trending as of yet, but this will be reviewed next year to determine if this wasn't an outlier year.

9. Multiple Device Operations in the Past Year (1/1/12-12/31/12)

Table 11 below is a summary of the devices that have operated three or more times in 2012. Refer to section 6.3 for additional work being done in these areas.

Table 11
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
13W2[1]	7	Fuse, Pole 1, West Salisbury Rd	42,779	492
13W2	6	Fuse, Pole 1, Warner Rd	30,991	361
13W2	6	Fuse, Pole 30, Long Street	17,182	132
22W3	4	Fuse, Pole 1, Farrington's Corner Rd	13,878	196
13W3[1]	4	Fuse, Pole 1, Forest Ln	6,726	78
13W3	4	Fuse, Pole 137, Battle St	4,580	55
8X3	3	Fuse, Pole 1, Center Hill Rd	42,640	390
15W1	3	Fuse, Pole 89, Mountain Rd	31,599	309
2H1	3	Fuse, Pole 65, North State St	16,959	198
13W2	3	Fuse, Pole 1, Hensmith Rd	15,654	138
13W2	3	Fuse, Pole 145, Old Turnpike Rd	4,880	60
8X3	3	Fuse, Pole 1, Sanborn Hill Rd North	3,263	28
13W2	3	Fuse, Pole 54, Warner Rd	2,930	30
8X3	3	Fuse, Pole 7, Smith Sanborn Rd	2,717	57
7W3	3	Fuse, Pole 53, Robinson Rd	313	3

10. Other Concerns

This section is intended to identify other reliability concerns that would not necessarily be identified from the analysis above.

10.1. Grey Spacer Cable Insulation

Grey spacer cable and spacers on the Unitil System manufactured prior to1975 have been identified by the manufacturer to have reached the end of its useful life. Samples of failed sections of this cable show significant "ringing" due to the dielectric breakdown of the insulation. This is an industry known problem recognized by the manufacturer due to the UV inhibitor compound in this vintage cable. This problem raises concerns with the insulations' effectiveness, increased probability of conductor burn down, and mechanical strength of the spacers. Locations

[1] In 2012, animal guards were installed on all transformers on this road and added a midline fuse

where this type of cable is installed have been identified and a replacement plan has been developed.

10.2. Recloser Replacement

Through power factor testing it appears that the solid dielectric material used for the poles on a specific type/vintage recloser degrades over time leading to premature failure. The manufacturer has confirmed this concern. Unitil has experienced two (UES-Seacoast and FG&E) failures of type/vintage of recloser in 2011 and removed a third from service due to the appearance of tracking.

10.3. Narrow subtransmission ROW expansion

The UES-Concord subtransmission system has some areas where the right of way (ROW) is narrow, thus, even by cutting the tree line to the edge of the ROW we still leave our system vulnerable to damage by falling trees. Historically, we have experienced noticeably more outages, due to falling trees, on narrow ROW subtransmission line in comparison to larger ROW areas. Thus, we will be actively tracking and attempting expansion of the tree line, given land owner approval, to allow for effective tree mitigation in the problem areas. ROW expansion may be considered in the future.

10.4. 13.8kV Underground Electric System Degradation

The 13.8kV underground electric system has been experiencing connector and conductor failures at an average rate of 2 per year for the last 10 years. (This does not include scheduled replacement of hot terminations identified by inspection) This could be due to the age of the underground system, the amount of non-continuous conductor, and/or the number of tee connectors stringed together in some locations. A study will be done this year to identify the best strategy for dealing with these concerns.

11. Recommended Reliability Improvement Projects

This following section describes recommendations on circuits, sub-transmission lines and substations to improve overall system reliability. The recommendations listed below will be compared to the other proposed reliability projects on a system-wide basis. A cost benefit analysis will determine the priority ranking of projects for the 2013 capital budget. All project costs are shown without general construction overheads

11.1. 33 Line Remote Fault indication and Motor Operators at Iron Works Road

11.1.1. Identified Concerns

Iron Works Substation has 2.8 miles of exposure on a radial subtransmission line. When faults occur on the 33 Line, a crew must arrive and confirm the outage is not near the Substation before restoring these customers via normal switching.

11.1.2. Recommendations

Install three SCADA monitored fault sensing devices on the source side of the 33J6 switch and the load side of the 33J7 switch. Also, install motor operators on the same two switches with SCADA control. This will require communication to the RTU which is included in the price of this project.

This will allow CED to quickly transfer Iron Works Substation to an alternate source for a fault on the Bow Junction Substation side of the 33 Line.

Estimated Project Cost: Material: $20,600 + Labor $24,600
*Estimated Annual Savings – Customer Minutes: 24,607, Customer Interruptions: 0
Customer Exposure: 499(22W1), 42(22W2), 1542(22W3)

*This assumes our Electric System Dispatchers will be able to transfer Iron Works Substation in 10 minutes

11.2. 33 Line Remote Fault Indication at Pleasant Street

11.2.1. Identified Concerns

Circuit 6X3 out of Pleasant Street Substation is a high priority circuit (Feeding Concord Hospital) at the end of a radial subtransmission line. When faults occur on the 33 Line, a crew must arrive and confirm the outage is not near Pleasant Street Substation before restoring these customers via SCADA, which took 40 minutes last year.

11.2.2. Recommendations

Install three SCADA monitored Fault Sensing devices on the source side of the 33J2 and 33J1 switches. This will require communication to the RTU which is included in the price of this project.

This will allow CED to be able to quickly transfer 6X3 to an alternate source for a fault on the West Concord Substation side of the 33 Line.

Estimated Project Cost: Material $9,000 + Labor $4,500
*Estimated Annual Savings – Customer Minutes: 10,775, Customer Interruptions: 0
Customer Exposure: 978

*This assumes our Electric System Dispatchers will be able to transfer Pleasant Street Substation in 10 minutes

11.3. Terrill Park 375J3 Automatic Sectionalizing

11.3.1. Identified Concerns

The 375 line has had an outage, between Garvin's and Terrill Park, during all of the most recent storms. This is due to the width of the ROW and the type of terrain.

11.3.2. Recommendations

Install automatic sectionalizing capability on the 375J3 switch (which already has remote operation capability). This would operate as an automatic restore of Terrill Park Substation and 375X1for a fault on the 375line between Garvin's and Terrill Park, leaving no customers without power. This project is in addition to the effort to expand tree removal zone, see section 10.3 for more details.

Estimated Project Cost: Material: $12,000 + Labor $26,000
Estimated Annual Savings – Customer Minutes: 30,250, Customer Interruptions: 1514
Customer Exposure: 303(16H1), 620(16H3), 567(16X4), 8(16X5),15(16X6), 1(375X1)

11.4. Overbuild a 35kV circuit on 13W2 as an alternative feed to Boscawen Substation

11.4.1. Identified Concerns

The 37 Line from the McCoy Street Tap to Boscawen is a radial subtransmission line with no back up, feeding about 7.7MVA at peak. Some locations on this section of line are becoming increasingly difficult to access and maintain.

11.4.2. Recommendations

Overbuild a 34.5kV express circuit from Boscawen Substation to meet with 4X1. This creates a backup source to Boscawen Substation, without removing the 13.8kV tie between 13W2 and 4W3.

- Overbuild from Boscawen Substation south to pole 2 on North Main St (14,300')
- Install about 1000 feet of 350 MCM CU, 35kV cable in existing underground ducts
- Install Gang Operated Switches at Boscawen Substation and at the tie point with 4X1

*Estimated Project Cost: 2.2 Million
Estimated Annual Savings – Customer Minutes: 48,097, Customer Interruptions: 0
Customer Exposure: 1567(13W3), 468(13W2), 480(13W1), 1(13X4)
*This is a rough estimate

11.5. Circuit 3H3: Recloser replacement at Gulf St Substation

11.5.1. Identified Concerns

Unitil has experienced premature failures of a specific type/vintage of reclosers due to insulation breakdown of the poles.

11.5.2. Recommendations

Replace this 3H3 circuit recloser with a new electronic recloser.

Estimated Project Cost: $19,307
Estimated Annual Savings - Customer Minutes: 5,905, Customer Interruptions: 84
Customer Exposure: 111

11.6. Circuit 8X3: Create Alternate Mainline Along Horse Corner Rd

11.6.1. Identified Concerns

Circuit 8X3 has the largest customer exposure on the capital system at 2,764 customers with an 11.7MVA peak, in 2012. This circuit has no alternative feeds to restore customers during mainline outages.

Building an alternate mainline that can be used to divert some customer exposure permanently and allow an alternate circuit feed during contingency scenarios is the ultimate goal for this area. Three alternatives where looked at one involved crossing over PSNH territory, one involved double circuiting, and the final involved rebuilding Horse Corner Rd. The Horse Corner Rd route was selected because it will create an alternate pole line that in no way will be affected by existing mainline events and does not involve PSNH. Due to the cost of building a new main line, segmenting the process and starting with building up Horse Corner Rd is being considered.

11.6.2. Recommendations

Build an alternate route for a little more than 3 miles of mainline 8X3. This will allow switching to be done for any outages along a portion of main line 8X3 while also providing a path for the eventual splitting of 8X3.

This project will require:

- Rebuilding 18,000ft of Horse Corner Rd from single phase 13.8kV to three phase 34.5kV spacer construction
- Installing three 201A, 19.9kV, regulators on Horse Corner Rd in the vicinity of Dover Rd
- Installing 19 step down transformers, metering would be needed on 1 of these stepdowns
- Installing a grounding bank on Horse Corner Rd to match the existing grounding bank on Dover Rd
- Installing four strategically placed HOG switches (P.160 Horse Corner Rd, P.90 Dover Rd, P.3 Dover Rd)
- Install an electronic recloser at P.1 Horse Corner Rd.

Estimated Project Cost: 1.7 Million
Estimated Annual Savings – Customer Minutes of Interruption: 107,203, Customer Interruptions: 779
Customer Exposure: 2764

12. Conclusion

During 2012, the Capital System has been greatly affected by interruptions involving tree contact. Enhanced tree trimming efforts are beginning to be implemented, which is expected to improve reliability for most of the worst performing circuits identified in this study.

Recommendations developed from this study focused on decreasing restoration time of areas with existing alternative sources, improving reliability of the subtransmission system during storms, and creating alternative sources in areas with poor reliability. In addition, new ideas and solutions to reliability problems are always being explored in an attempt to provide the most reliable service possible.

Attachment 2

UES - Seacoast

Reliability Analysis and Recommendations 2013

Unitil Energy Systems – Seacoast

Reliability Study

2013

Prepared By:

Jake Dusling
Unitil Service Corp.
September 9, 2013

UES – Seacoast 2013 Reliability Study

Reliability Analysis and Recommendations

March 5, 2013

1 Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Seacoast system from January 1, 2012 through December 31, 2012. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The reliability data presented in this report does not include Hurricane Sandy (10/29/12 02:00 to 11/1/12 00:00).

The following projects are proposed from the results of this study and are focused on improving the worst performing circuits as well as the overall UES-Seacoast system reliability. These recommendations are provided for consideration and will be further developed with the intention to be incorporated into the 2014 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
13W1	Install Recloser and Sectionalizer Crystal Hill	$35,000
47X1	Upgrade Circuit Tie with 51X1	$105,000
43X1	Add Recloser and Install Switches	$145,000
22X1	Relocate Main Line Route 111	$825,000
3348 / 3359	Recloser Installation and Distribution Automation Scheme	$300,000
3359	Install Wireless Fault Indicators	$125,000
3348 / 3350	Rebuild Line off the Salt Marsh	$3,000,000
Various	Recloser Replacements	$130,000
Hampton Beach S/S	Add 15 kV Circuit Positions and Remove 4 kV Equipment	$1,250,000

Note: estimates do not include general construction overheads

2 Reliability Goals

The annual corporate system reliability goals for 2013 have been set at 191-156-121 SAIDI minutes. These were developed through benchmarking Unitil system performance with surrounding utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire Seacoast system is used to identify future capital improvement projects and/or operational enhancements which may be required in order to achieve and maintain these goals.

3 Outages by Cause

This section provides a breakdown of all outages by cause code experienced during 2012, excluding Hurricane Sandy. Chart 1 lists the number of interruptions due to each cause. For clarity, only those causes occurring more than 10 times are labeled. Chart 2 details the percent of total customer-minutes of interruption due to each cause. Only those causes contributing greater than 2% of the total are labeled.

Chart 1
Number of Interruptions by Cause

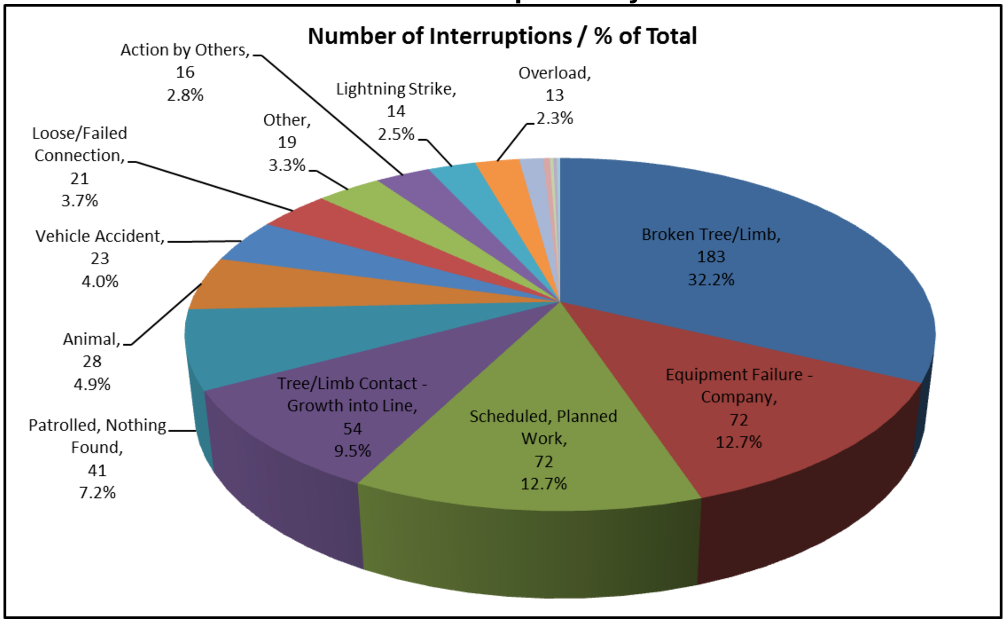
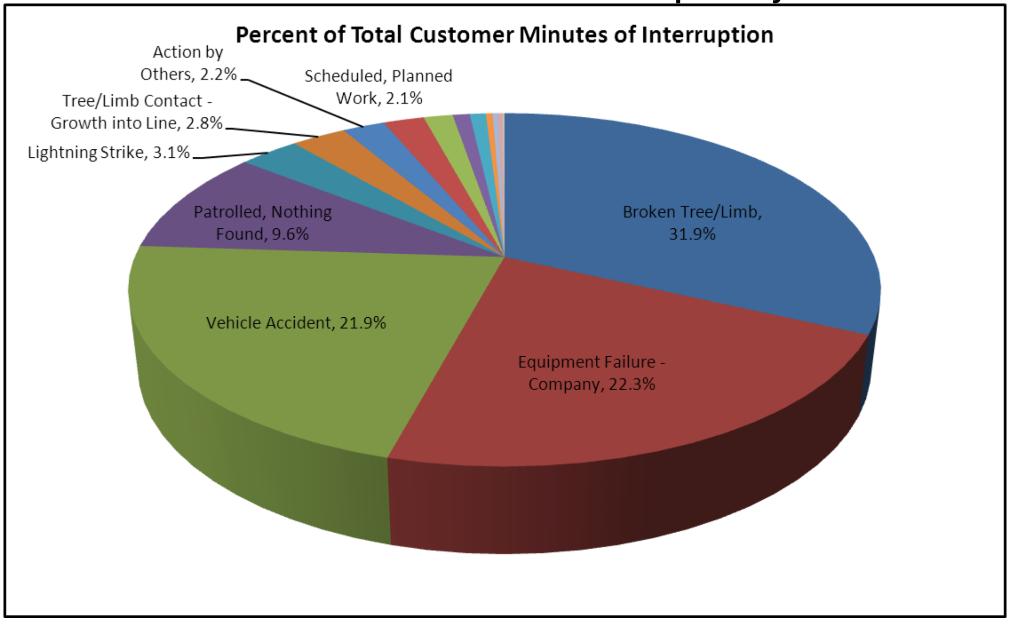


Chart 2
Percent of Customer-Minutes of Interruption by Cause



4 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2012 through December 31, 2012 are summarized in Table 1 below.

Table 1
Worst Ten Distribution Outages

Circuit	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Seacoast SAIDI (min.)	UES Seacoast SAIFI
15X1	11/17/12 Equipment Failure – Company (Conductor)	3,956	486,233	10.69	0.087
2X2	4/24/12 Vehicle Accident	2,480	453,775	9.97	0.055
13W2	5/25/12 Vehicle Accident	1,482	307,636	6.76	0.033
43X1	3/24/12 Vehicle Accident	1,064	221,473	4.87	0.023
58X1	3/13/12 Patrolled, Nothing Found	900	213,300	4.69	0.020
13W2	5/10/12 Vehicle Accident	1,486	193,990	4.26	0.033
54X1	9/7/12 Vehicle Accident	946	184,680	4.06	0.021
58X1	3/13/12 Lightning Strike	590	177,950	3.91	0.013
13W1	4/22/12 Broken Tree/Limb	1,088	156,672	3.44	0.024
21W1	10/25/12 Action by Others	1,252	155,248	3.41	0.028

Note: This table does not include substation, sub-transmission or scheduled planned work outages.

5 Sub-transmission and Substation Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Seacoast system from January 1, 2012 through December 31, 2012.

All substation and subtransmission outages ranked by customer-minutes of interruption during the time period from January 1, 2012 through December 31, 2012 are summarized in Table 2 below.

Table 3 shows the circuits that have been affected by sub-transmission line and substation outages. The table illustrates the contribution of customer minutes of interruption for each circuit affected.

In aggregate, sub-transmission line and substation outages accounted for 39% of the total customer-minutes of interruption for UES-Seacoast, excluding Hurricane Sandy.

Table 2
Sub-transmission and Substation Outages

Trouble Location	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Seacoast SAIDI (min.)	UES Seacoast SAIFI
3342 Line	12/27/12 Equipment Failure – Company (Shield Wire)	7,616	553,288	12.16	0.167
3348 Line	3/25/12 Equipment Failure-Company (Insulator)	5,273	463,554	10.19	0.116
3359 Line	10/1/12 Patrolled, Nothing Found	3,045	204,015	4.48	0.067
3359 Line	1/18/12 Patrolled, Nothing Found	3,091	159,703	3.51	0.068
Kingston Stepdown	12/13/12 Power Supply Interruption/Disturbance	17,629	123,403	2.71	0.388
Cemetery Lane S/S	5/23/12 Other	294	7,350	0.16	0.006

Table 3
Contribution of Sub-transmission and Substation Outages

Number of events	Trouble Location	Circuit	Customer-Minutes of Interruption	% of Total Circuit Minutes	Circuit SAIDI Contribution
1	Line 3342	2X2	143,697	15.2%	57.12
		3W4	122,608	89.5%	78.91
		17W1	145,962	97.3%	82.51
		17W2	49,491	68.6%	81.13
		46X1	91,530	83.1%	81.35
1	Line 3348	3H1	45,432	97.7%	71.88
		3H2	18,792	95.9%	72.05
		3H3	33,048	98.4%	72.00
		2X3	56,736	64.5%	71.86
		2H1	10,368	87.3%	72.13
		7X2	176,400	31.4%	99.63
		7W1	122,500	50.9%	100.21
2	Line 3359	15X1	101,985	40.6%	106.94
		59X1	120,695	58.7%	119.53
		23X1	141,038	44.6%	130.51
1	Cemetery Lane S/S	15X1	7,350	2.9%	7.71

6 Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures. All circuit reliability data presented in this section includes subtransmission or substation supply outages unless noted otherwise.

6.1 Worst Performing Circuits in Past Year (1/1/12 – 12/31/12)

A summary of the worst performing circuits during the time period between January 1, 2012 and December 31, 2012 is included in the tables below.

Table 4 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The SAIFI and CAIDI for each circuit are also listed in this table.

Table 5 provides detail on the major causes of the outages on each of these circuits. Customer-minutes of interruption are given for the six most prevalent causes.

Circuits having one outage contributing more than 75% of the Customer-Minutes of interruptions were excluded from this analysis.

Table 4
Worst Performing Circuits Ranked by Customer-Minutes

Circuit	Customers Interruptions	Worst Event (% of CI)	Cust-Min of Interruption	Worst Event (% of CMI)	SAIDI	SAIFI	CAIDI
2X2	6,906	37%	948,444	48%	376.99	2.75	137.34
13W2	8,579	17%	826,375	37%	556.17	5.77	96.33
58X1	6,748	13%	732,059	29%	339.87	3.13	108.49
7X2	4,917	36%	562,369	47%	317.63	2.78	114.37
43X1	7,765	24%	545,154	41%	296.43	4.22	70.21
47X1	4,366	28%	436,008	27%	297.13	2.98	99.86
13W1	4,265	26%	416,935	38%	383.59	3.92	97.76
19X3	7,057	44%	408,921	36%	130.23	2.25	57.95
23X1	6,151	18%	316,182	23%	292.58	5.69	51.40
21W1	4,005	31%	266,426	58%	212.80	3.20	66.52

Note: all percentages and indices are calculated on a circuit basis

Table 5
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption					
	Broken Tree Limb	Patrolled, Nothing Found	Lightning Strike	Vehicle Accident	Company Equipment Failure	Tree Growth into Line
2X2	113,583	5,796	0	661,948	157,442	1,890
13W2	164,298	123,478	0	501,353	0	17,356
58X1	113,523	214,871	195,149	168,421	0	12,625
7X2	94,721	16,302	0	504	441,005	0
43X1	246,651	0	0	221,473	41,543	6,749
47X1	395,759	0	6,360	6,868	108	21,877
13W1	182,396	39,144	12,321	0	120,768	53,806
19X3	251,633	48,234	0	4,961	20,008	1,285
23X1	185,578	82,698	306	12,166	11,329	2,992
21W1	77,446	15,332	2,574	0	150	6,912
Total	**1,825,588**	**545,855**	**216,710**	**1,577,694**	**792,353**	**125,492**

6.2 Worst Performing Circuits of the Past Five Years (2008 – 2012)

The annual performance of the ten worst circuits in terms of SAIDI and SAIFI for each of the past five years is shown in the tables below. Table 6 lists the ten worst performing circuits ranked by SAIDI and Table 7 lists the ten worst performing circuits ranked by SAIFI.

The data used in this analysis includes all system outages except those outages that occurred during Hurricane Sandy, the 2011 October Nor'easter, Hurricane Irene, the 2010 Wind Storm, and the 2008 Ice Storm.

Table 6
Circuit SAIDI

Circuit Ranking (1 = worst)	2012		2011		2010		2009		2008	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	56X2	590.69	13W2	698.61	51X1	582.06	15X1	526.90	6W1	1033.5
2	13W2	556.17	54X1	557.90	3H2	575.51	22X1	526.47	21W1	580.27
3	13W1	383.59	17W2	429.40	22X1	518.07	5H2	444.34	5H2	442.97
4	2X2	376.99	22X1	407.92	59X1	509.53	56X2	430.31	51X1	438.66
5	58X1	339.87	17W1	381.20	15X1	387.88	13W2	414.30	20H1	360.47
6	7X2	317.63	46X1	372.37	23X1	378.56	13W1	365.14	21W2	350.88
7	47X1	297.13	13W1	275.45	17W2	361.53	23X1	339.98	7X2	347.68
8	43X1	296.43	21W2	239.71	58X1	308.72	18X1	323.54	56X2	323.79
9	23X1	292.58	11W1	226.92	46X1	306.30	3H1	260.91	58X1	308.38
10	15X1	263.38	7X2	213.44	21W1	291.33	21W2	260.71	23X1	284.28

Table 7
Circuit SAIFI

Circuit Ranking (1 = worst)	2012		2011		2010		2009		2008	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	56X2	7.39	54X1	5.25	51X1	6.65	22X1	6.10	21W1	5.35
2	13W2	5.77	22X1	4.93	3H2	6.01	18X1	5.23	51X1	4.41
3	23X1	5.69	13W2	4.53	22X1	5.21	5H2	5.06	6W1	2.83
4	43X1	4.22	13W1	2.81	15X1	4.38	15X1	4.96	20H1	2.46
5	6W1	4.06	7X2	2.48	23X1	3.77	13W2	4.70	56X2	2.33
6	13W1	3.92	11W1	2.42	59X1	3.43	56X2	4.52	21W2	2.33
7	15X1	3.89	47X1	1.99	11W1	3.29	3H1	4.06	23X1	2.31
8	59X1	3.64	18X1	1.94	13W2	3.21	13W1	3.91	7X2	2.17
9	21W1	3.20	21W2	1.93	28X1	3.07	21W2	3.91	59X1	2.14
10	58X1	3.13	6W1	1.77	20H1	3.01	21W1	3.89	5H2	1.94

Circuit 23X1 is the only circuit that has been on the worst performing SAIDI circuits list for fours of the past five years. Circuit 13W1, 13W2, 21W2, 15X1, 58X1, 7X2 and 22X1 have been on the list for three of the last five years.

Circuit 13W2 has been on the worst performing SAIFI circuits list for four of the last five years and circuits 6W1, 13W2, 21W1, 22X1, 23X1, 56X2 and 59X1 have been on the list for three of the past five years.

6.3 Improvements to Worst Performing Circuit (2011-2013)

Projects completed from 2011 to 2013 that are expected to improve the reliability of the worst performing circuits are included in table 8 below.

Table 8
Improvements to Worst Performing Circuits

Circuit(s)	Year of Completion	Project Description
3342, 3343 and 3348[1]	2013	Installation of Reclosers at Hampton S/S on the 3342, 3353 and 3348 Lines
23X1	2013	Installation of New mainline recloser
	2013	Transfer of load to circuit 27X1
15X1	2013	Cycle Pruning
56X2	2013	Cycle Pruning
13W2	2013	Cycle Pruning
	2012	Installation of reclosers
	2012	Trimmed as part of storm resiliency pilot
58X1	2013	Cycle Pruning
	2012	Trimmed as part of storm resiliency pilot
19X3	2012	Installation of cutout mounted recloser and cutout mounted sectionalizers
	2012	Hazard Tree Mitigation
21W2	2012	Trimmed as part of storm resiliency pilot
21W1	2012	Will benefit from storm resiliency pilot as the mainline is on the same poles as 21W2
2X2	2012	Cycle Pruning
6W1	2011	6W1 was split into two distribution circuit, 6W1 and 6W2

[1] Includes circuits 2H1, 2X2, 2X3, 17W1, 17W2, 46X1, 3H1, 3H2, 3H3, 3W4, 7W1 and 7X2.

7 Tree Related Outages in Past Year (1/1/12 – 12/31/12)

This section summarizes the worst performing circuits by tree related outage during the time period between January 1, 2012 and December 31, 2012.

Table 9 shows these circuits ranked by the total number of customer-minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table. Circuits having two or less tree related outages were excluded from this table.

All streets on the Seacoast system with three or more tree related outage are shown in table 10 below. The table is sorted by number of outages and customer-minutes of interruption.

Table 9
Worst Performing Circuits – Tree Related Outages

Circuit	Customer-Minutes of Interruption	Number of Customers Interrupted	No. of Interruptions
47X1[1]	417,636	4,098	10
43X1[1]	253,400	4,061	14
19X3[2,3]	252,918	4,400	22
13W1[2]	236,202	1,698	8
15X1[4]	182,014	3,481	5
13W2[3,4,5]	181,654	2,509	18
6W1[6]	142,373	1,595	17
58X1[3,4]	126,148	1,070	21
23X1[7]	120,026	2,260	12
22X1[2]	115,919	808	23

[1] A forestry review is recommended to be completed on this circuit in 2014 in the areas where multiple outages have occurred in 2012. Refer to Table 10, "Multiple Tree Related Outages by Street", for these specific locations.
[2] Circuit pruning was completed on this circuit in 2012.
[3] Project(s) was completed in 2012 on this circuit to reduce the impact of tree related outages (refer to Table 8).
[4] Circuit pruning is being performed on this circuit in 2013.
[5] Circuit was trimmed as part of a storm resiliency pilot (ground to sky and hazard tree removal) in 2012.
[6] Planned Mid-Cycle Pruning is being performed on this circuit in 2013
[7] A project was completed in 2013 on this circuit to reduce the impact of tree related outages (refer to Table 8).

Table 10
Tree Related Outages by Street

Circuit	Street	# Outages	Customer-Minutes of Interruption	No. of Customer Interruptions
19X3[1,2,3]	Watson Rd	6	46,566	531
6W2[4]	North Rd	5	34,222	253
22X1[1]	Long Pond Rd	5	19,109	200
47X1[3]	Guinea Rd	4	236,717	2,150
43X1[3,5]	Willow Rd	3	223,399	3,665
47X1[3,6]	Stratham Heights Rd	3	138,062	1,700
22X1[1]	Old Coach Rd	3	64,928	171
13W2[7]	Highland Rd	3	51,796	430
51X1[7]	Portsmouth Ave	3	48,300	625
56X1[1]	Hunt Rd	3	28,764	369
13W2[8]	Thornell Rd	3	20,662	238
19H1[3]	Drinkwater Rd	3	18,870	143
19X3[1]	Beech Hill Rd	3	17,872	141
6W2[4]	Rockrimmon Rd	3	14,905	151
19X3[1]	Linden St	3	14,374	256
43X1[3,5]	Exeter Rd	3	13,421	216
51X1[7]	High St	3	12,286	219
6W1[4]	Hilldale Ave / Peak Rd	3	5,168	83
58X1[4]	Sawyer Ave	3	1,840	38
54X1[1]	Maple Ave	3	1,321	17
54X1[1]	New Boston Rd	3	891	9

[1] Circuit pruning was completed on this circuit in 2012.
[2] Project(s) was completed in 2012 on this circuit to reduce the impact of tree related outages.
[3] A forestry review is recommended to be completed on this circuit during 2014 in this area (refer to section 11.10)
[4] Planned Mid-Cycle Pruning is being performed on this circuit in 2013
[5] Refer to section 11.3 for recommendations in this area.
[6] Refer to section 11.2 for recommendations in this area.
[7] Circuit pruning is being performed on this circuit in 2013.
[8] Circuit was trimmed as part of a storm resiliency pilot (ground to sky and hazard tree removal) in 2012.

8 Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 1, 2012 through December 31, 2012. Chart 2 shows all equipment failures throughout the study period. Chart 3 shows each equipment failure as a percentage of the total failures within this same study period. The number of equipment failures in each of the top three categories of failed equipment for the past five years are shown below in Chart 4.

Chart 2
Equipment Failure Analysis by Cause

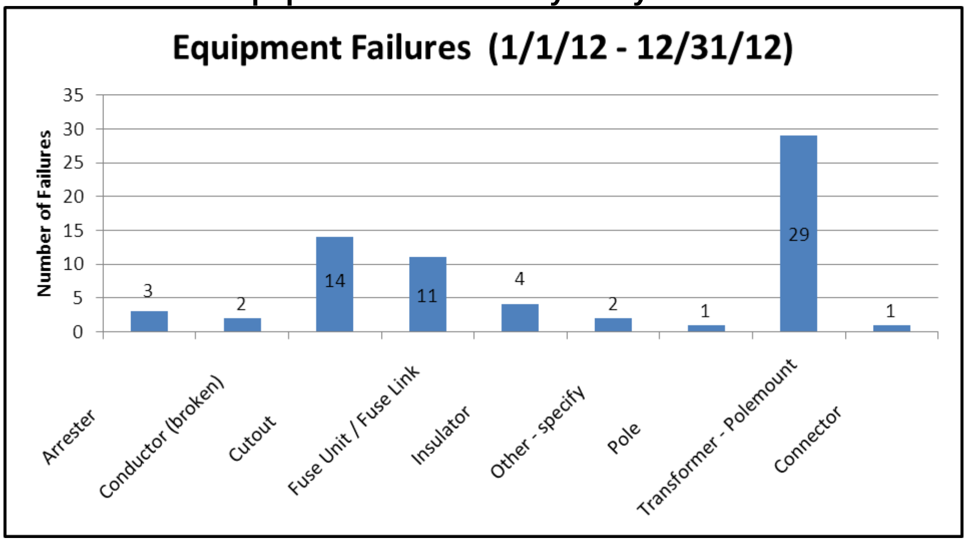


Chart 3
Equipment Failure Analysis by Percentage of Total Failures

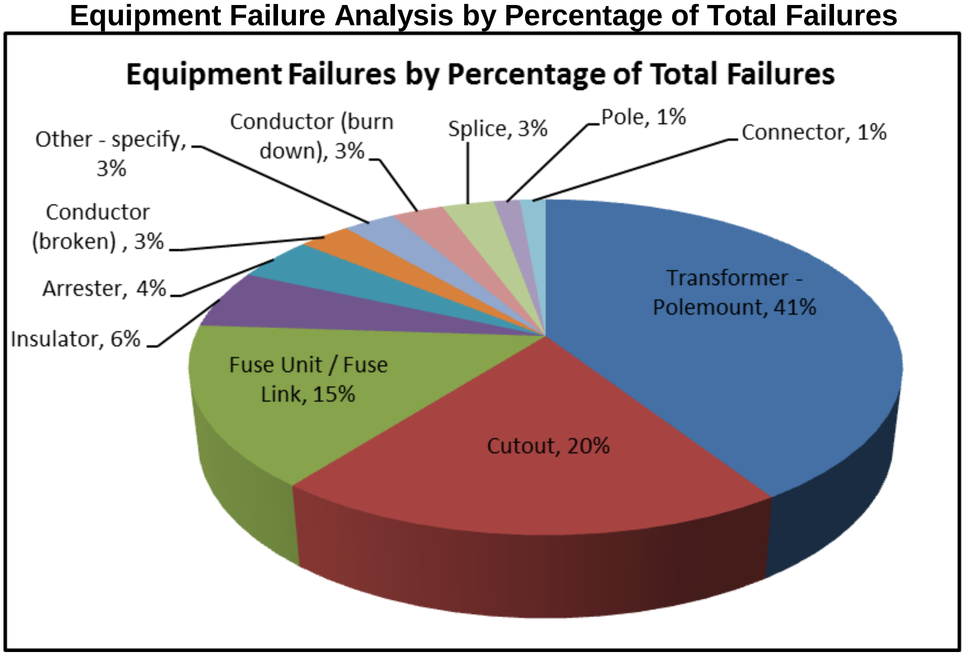
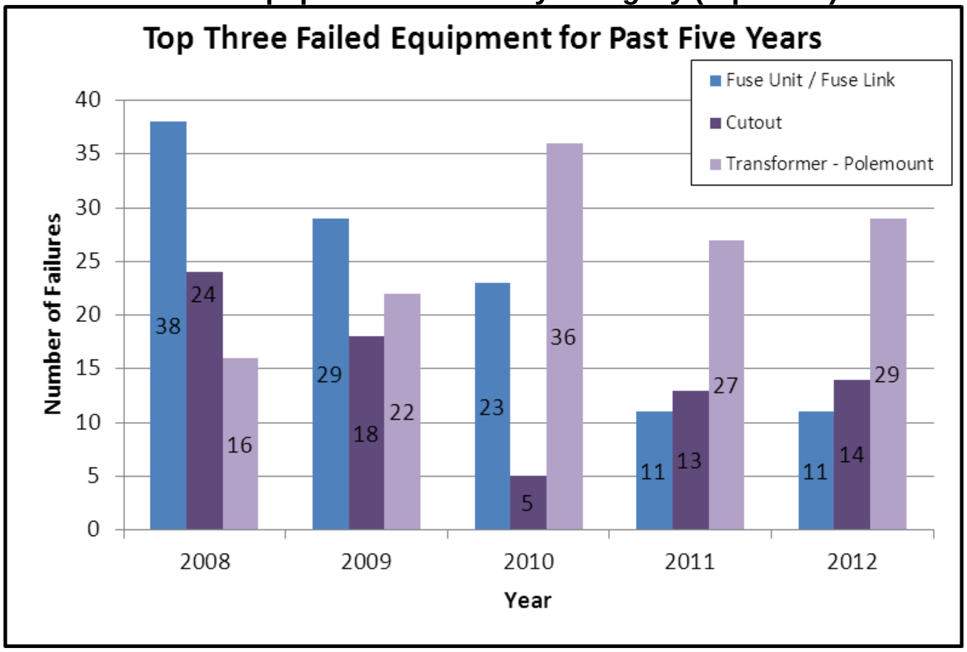


Chart 4
Annual Equipment Failures by Category (top three)



9 Multiple Device Operations in Past Year (1/1/12 – 12/31/12)

A summary of the devices that have operated three or more times from January 1, 2012 to December 31, 2012 is included in table 11 below.

Table 11
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
13W2[1]	4	13W2 Recloser Timberlane S/S	676,311	5,933
23X1[2]	3	Fuse – Pole 111 Amesbury Road, Kensington	12,360	277
58X1[3]	3	Fuse – Pole 1 Sawyer Ave, Atkinson	2,171	20
13W2[1,4]	3	Fuse – Pole 33 Thornell Road, Newton	20,662	238
13W1[5]	3	Fuse – Pole 2 Crystal Hill Circle, Plaistow	56,118	414
51X1[6]	3	Transformer Breaker/Fuse – Pole 162 Portsmouth Ave, Stratham	717	7
19X3[4]	3	Fuse – Pole 69 Epping Road, Exeter	45,556	523

[1] Circuit was trimmed as part of a storm resiliency pilot (ground to sky and hazard tree removal) in 2012
[2] Project(s) was completed in 2013 on this circuit to reduce the impact of tree related outages (refer to Table 8).
[3] Circuit pruning is being performed on this circuit in 2013.
[4] Project(s) was completed in 2012 on this circuit to reduce the impact of tree related outages (refer to Table 8).
[5] Refer to section 11.1 for recommendations in this area.
[6] Animal guards and localized trimming were completed at this location in 2012.

10 Other Concerns

This section is intended to identify other reliability concerns that would not be identified from the analyses above.

10.1 Recloser Replacements

Power factor testing has identified that the solid dielectric material used for the poles on a specific type/vintage recloser degrades over time leading to premature failure. The manufacturer has confirmed this concern. Unitil has experienced two (UES-Seacoast and FG&E) failures of this type/vintage of recloser in 2011 and removed two others from service due to the appearance of tracking.

The two units at Wolf Hill tap are scheduled to be replaced in 2013. This will leave three of this type/vintage reclosers in service in UES-Seacoast, two at the 3347 line tap and one at Stard Road tap.

10.2 Subtransmission Lines Across Salt Marsh

The 3348 line experienced one outage during 2012 caused by a failed insulator and has been damaged several times during major events over the last four years, causing outages to the customers on all the distribution circuits (2H1, 2X3, 3H1, 3H2, 3H3, 7W1 and 7X2) supplied by the 3348, 3350 and 3353 lines distribution . The 3348 line is constructed through salt marsh, making it very difficult to access and repair.

The 3350 line and portions of the 3342 and 3353 lines are also constructed through salt marsh. These lines have the same access concerns, but have been far more reliable than the 3348 line in the past. The 3350 line is radial line that supplies Seabrook substation, if damaged load may need to be left out of service until repairs are made.

Additionally the 3348/3350 tap structure was damaged during Hurricane Sandy in 2012, requiring the 3348 and 3350 lines to remain out of service for several weeks until repairs were made. During this time the load normally supplied by the 3350 line was restored via. distribution ties.

10.3 3347 Line

The 3347 line has been damaged by trees during major events over the past four years, causing outages to customers served by Guinea Road tap, Portsmouth Ave substation and Osram/Sylvania until repairs are made.

The installation of reclosers at Portsmouth Ave Substation and the replacement of the 19X2 relay at Exeter Switching are budgeted in 2013. These upgrades will allow all customers served from Portsmouth Ave substation to be restored via distribution ties for the loss of the 3347 Line. Guinea Road tap and Osram/Sylvania load will remain out of service until repairs are made.

10.4 Hampton Beach Substation

The existing 4 kV equipment, structures and control cabinets at Hampton Beach substation are experiencing rusting and the foundations are deteriorating. In 2009 the 3T2 transformer was removed from service and scrapped due to rusting. Additionally, a majority of the 4 kV insulators are of the brown porcelain variety that are historically prone to failure and the existing switch braids are in need of replacement.

Due to condition concerns, the replacement of the existing 3T1 transformer with a spare unit is budgeted in 2013.

11 Recommendations

This following section describes recommendations on circuits, sub-transmission lines and substations to improve overall system reliability. The recommendations listed below will be compared to the other proposed reliability projects on a system-wide basis. A cost benefit analysis will determine the priority ranking of projects for the 2014 capital budget. All project costs are shown without general construction overheads.

11.1 Circuit 13W1 – Install Recloser and Sectionalizer Crystal Hill

11.1.1 Identified Concerns

The fuse at pole 2 Crystal Hill Circle operated three times during 2012. Additionally, there have been several customer complaints about the reliability in this area.

11.1.2 Recommendation

This project will consist of installing a single-phase electronic recloser in the vicinity of pole 1 Cottonwood Road and replacing the existing 75QA fuse link at pole 2 Crystal Hill Circle with a cutout mounted sectionalizer. This will allow for the installation of a new fuse location along East Road.

The addition of reclosing to this area will benefit approximately 191 customers and the added protective devices will save approximately 55 customers per interruption.

- Estimated annual customer-minutes savings = 9,893
- Estimated annual customer-interruption savings = 103

Estimated Project Cost: $35,000

11.2 Circuit 47X1 – Upgrade Circuit Tie with 51X1

11.2.1 Identified Concerns

Circuit 47X1 was one of the worst performing circuits in 2012 and experienced four main line outages since January 1, 2012.

Additionally, Guinea Road tap is supplied from the 3347 line, which is a radial line that typically experiences damage during major events.

11.2.2 Recommendation

This project will consist of upgrading the existing circuit tie between circuits 47X1 and 51X1 and will include the installation of additional sectionalizing locations along circuit 47X1.

The cutouts at pole 27 Union Road will be replaced with a new gang-operated switch. New gang-operated switches will also be installed at the intersection of Heights Road and Guinea Road and at the intersection of Heights Road and Bunker Hill Ave. All gang-operated switches will have the capability to be integrated into a distribution automation scheme in the future.

This project will allow circuit 47X1 to be easily sectionalized for faults on the mainline. This is expected to save approximately 75,000 customer-minutes of interruption per event for faults along the mainline of circuit 47X1. For loss of the 3347 line this will save roughly 350,000 customer-minutes of interruption to the customers served from Guinea Road Tap.

- Estimated annual customer-minutes savings = 115,639
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $105,000

11.3 Circuit 43X1 – Add Recloser and Installation Switches

11.3.1 Identified Concerns

Circuit 43X1 was one of the worst performing circuits in 2012 and experienced two main line outages since January 1, 2012.

11.3.2 Recommendation

This project will consist of replacing the 150 QA fuses at pole 55 Exeter Road with an electronically controlled recloser, with the intent of relocating the 150 QA fuses to the vicinity of pole 97 Kingston Road.

Additionally, two new gang-operated switches will be installed along Exeter/Kingston Road to provide additional sectionalizing locations. All gang-operated switches will have the capability to be integrated into a distribution automation scheme in the future.

The new recloser will benefit approximately 1,395 customers. Additionally, this project will allow circuit 43X1 to be easily sectionalized and load restored from circuit 19X3 for faults along Exeter/Kingston Road. This is expected to save approximately 111,000 customer-minutes of interruption per event for faults on the mainline of circuit 43X1.

- Estimated annual customer-minutes savings = 231,324
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $145,000

11.4 Circuit 22X1 – Relocate Main Line to Route 111

11.4.1 Identified Concerns

Circuit 22X1 has been one of UES-Seacoast's worst performing circuits (top 5) three of the last five years.

Additionally, the existing main line along Kingston Road and Pleasant Street typically sustain significant damage during major storms, requiring significant repairs to energize the mainline of 22X1.

11.4.2 Recommendation

This project will consist of building approximately 2.25 miles of new three-phase open wire construction along Route 111 from Mill Road to the Danville Tie. Route 111 is a major state road-way with very little tree exposure.

Additionally, 2,500' of Route 111A will be rebuilt to three-phase construction and a new recloser will be installed along Route 111A to prevent sustained outages for potentially momentary faults.

Once complete, the new main line of 22X1 will run along Route 111 and Route 111A and Kingston/Danville Road will become protected laterals off the new mainline.

This project is expected to save approximately 1,900 customer interruptions per event for faults on Danville Road and Pleasant Street. This will also reduce damage to the mainline of 22X1 during major events.

- Estimated annual customer-minutes savings = 287,266
- Estimated annual customer-interruption savings = 2,992

Estimated Project Cost: $825,000

11.5 3348/3359 Line – Distribution Automation Scheme

11.5.1 Identified Concerns

The 50J59 and 48J50 switches are located on Seabrook Station property requiring crews to pass through a security check-point to performing system switching, which adds significant time to the restoration of Seabrook substation for faults on the 3348.

11.5.2 Recommendation

This project will consist of installing two reclosers at the Seabrook Station Marsh tap, replacing the 50J59 and the 48J50 switches. The new reclosers will communicate with Hampton substation via radio.

With the addition of the new reclosers the normally open point on the 3348/59 line would be moved the 50J59 recloser. An automation scheme would be implemented to automatically restore Seabrook substation for loss of the 3348 line.

The intent is to select a scheme that is expandable to include Cemetery Lane substation, Stard Road tap and Mill Lane tap in the future.

The addition of the new reclosers and the automation scheme will allow for the automatic restoration of Seabrook substation load (approximately 3,000 customers) for the loss of the 3348 line. Additionally, the new reclosers will be set to operate for faults on the 3350 line.

- Estimated annual customer-minutes savings = 175,772
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $300,000

11.6 3359 Line – Wireless Fault Indicators

11.6.1 Identified Concerns

Due to the nature of the 3359 and 3348 lines, the 3359 line must be patrolled prior to performing restoration switching.

The 3359 has experience three outages (not including major events) since the beginning of 2010 totaling 1,0953,330 customer-minutes of interruption and the 3359 typically sustains damage during major storm events.

11.6.2 Recommendation

This project will consist of installing six wireless fault indicators, two each at Cemetery Lane substation, Stard Road tap and Mill Lane tap. The indicators will be integrated into the existing RTU's at these locations to provide status via SCADA.

Prior to installation it will need to be confirmed that SCADA and communications will be able to provide status after the loss of station service.

The addition of the fault indicators will provide immediate indication of the fault location to allow crews to be dispatched to the appropriate locations for patrolling and/or restoration switching. This is expected to save approximately 275,000 customer-minutes of interruption per event for faults on the 3359 line

- Estimated annual customer-minutes savings = 167,391
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $75,000

11.7 3348 and 3350 Line – Rebuild off the Salt Marsh

11.7.1 Identified Concerns

The 3348 line and 3350 line are constructed entirely through the salt marsh in Hampton, Hampton Falls and Seabrook, which makes them difficult to patrol and repair.

The 3350 line is a radial line to Seabrook substation. Load will remain out of service for faults on the 3350 line until the line is repaired.

These lines are concerns during all major wind events. During the 2010 wind storm several structures on the 3348 line were damaged causing the line to be out of service for several months. The line was also damaged in March of 2012 due to a failed insulator which required the line to remain out of service for a few weeks.

During Hurricane Sandy the 3350 tap structure on the 3348 line was damaged, causing the 3350 and 3348 lines to remain out of service for several weeks. Due to the time of year all customers were able to be restored via distribution ties, however during peak load periods approximately 1,200 customers would remain out of service.

11.7.2 Recommendation

This project will consist of building a new 34.5 kV subtransmission line from Hampton substation to Seabrook substation. Once complete the 3348 and 3350 line will be removed from the marsh. There are several possible routes for the new line, including Route 1, the 3359 line right-of-way or along the railroad right-of-way from Hampton to Seabrook.

This project would most likely need to be a multi-year project to allow sufficient time for design and construction.

This project removes approximately 4.5 miles and 3,000 customers of exposure from lines on the salt marsh.

- Estimated annual customer-minutes savings = 112,996
- Estimated annual customer-interruption savings = 1,177

Estimated Project Cost: $3,000,000

11.8 Recloser Replacements

11.8.1 Identified Concerns

Unitil has experienced premature failures of a specific type/vintage of recloser due to insulation breakdown of the poles.

11.8.2 Recommendation

This project will consist of replacing the remaining of these reclosers on the UES-Seacoast system.

- Two (2) at 3347 Line Tap
- One (1) at Stard Road Tap

Below is a summary of the reliability benefit for this project:

Recloser	Customers of Exposure
3347A	5,350
3347B	7,900
59X1	3,050

- Estimated annual customer-minutes savings = 244,560
- Estimated annual customer-interruption savings = 2,548

Estimated Project Cost: $130,000

11.9 Hampton Beach S/S – Add 15 kV Circuit Positions and Remove 4 kV

11.9.1 Identified Concerns

The 4 kV portion of Hampton Beach substation has several condition concerns, including the following:

- Significant wear on the braids of all 4 kV switches
- Brown porcelain insulators that are prone to failure
- Significant rusting of control cabinets and structures
- Degradation of concrete foundations

11.9.2 Recommendation

This project will consist of populating the 3W5 circuit position, upgrading the existing 3W4 circuit position and installing two new 15 kV circuit positions.

Construction will include the re-use of the newly replaced 3T1 transformer and the installation new circuit regulators and reclosers on all circuit positions.

Circuit 3H2 will be converted to 13.8 kV to accommodate this project. Circuits 3H1 and 3H3 will continue to operate at 4 kV.

Once complete this will eliminate condition concerns associated with 4 kV portion of Hampton Beach substation, which serves roughly 1,400 customers.

Estimated Project Cost: $1,250,000

11.10 Miscellaneous Circuit Improvements to Reduce Recurring Outages

11.10.1 Identified Concerns & Recommendations

This following concerns were identified based on a review of Tables 10 and 11 of this report; Multiple Tree Related Outages by Street and Multiple Device Operations respectively.

13W2 Recloser at Timberlane Substation
This device operated four times in 2012 (summarized below). Storm resiliency trimming was completed along the mainline of circuit 13W2 in late 2012. Route 125 should be reviewed to determine if any poles are in locations that could be prone to vehicle accidents.

- 2 Vehicle Accidents along Route 125
- 1 Broken Tree/Limb outage on Route 125
- 1 Patrolled Nothing Found

Customer Exposure = 1,485 Customers

Mid-Cycle Forestry Review
The areas identified below experienced three or more tree related outages in 2012. It is recommended that a forestry review of these areas be performed in 2014 in order to identify and address any mid-cycle growth or hazard tree problems.

- 19X3, Watson Road
- 43X1, Exeter Road
- 43X1, Willow Road
- 47X1, Guinea Road
- 47X1, Stratham Heights Road
- 19H1, Drinkwater Road

12 Conclusion

The UES-Seacoast system has experienced a large number of outages caused by tree contact as well as outages affecting a large number of customers. A more aggressive tree trimming program began in 2011 and should start to reduce the number of tree related outages experienced in the future. In 2012 three circuits on the UES-Seacoast will benefited from a storm resiliency pilot, which consisted of ground to sky trimming and hazard tree removal.

The recommendations made for capital improvement projects within this report are aimed at reducing the duration and customer impact of outages, improving the reliability of the subtransmission system and mitigating damage to distribution mainlines and subtransmission lines during major events.

Attachment 3

Exacter Field Survey

Sample Field Photos and Specific Information Developed for Replacement

<u>Attachment 3</u>
Exacter Field Survey
Sample Field Photos and Specific Information Developed for Replacement

Unitil - Seacoast

Field Engineer - Bill McConaha & Jonathan Kump

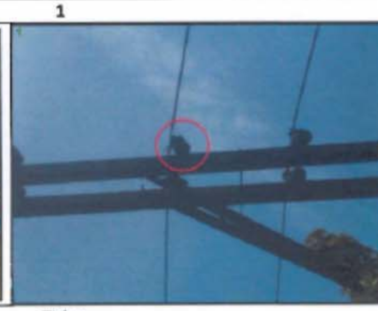
Attributes	
Exacter Group Number	45
Pole ID	053-0102-0-00-00-71
Feeder	E21W1
Latitude	N 42.837675°
Longitude	W 71.151138°
Address	104 Main St
City	Atkinson Twn
State	NH
Finding 1	Pin Insulator
Direction	Center right
Location	Top crossarm
Finding 2	
Direction	
Location	
Finding 3	
Direction	
Location	
Comments	

45

Title:

Attributes	
Exacter Group Number	1
Pole ID	056-0002-0-PB-00-71
Feeder	E21W1
Latitude	N 42.837290°
Longitude	W 71.151073°
Address	4 Meditation Ln
City	Atkinson Twn
State	NH
Finding 1	Pin Insulator
Direction	Center
Location	Top crossarm
Finding 2	
Direction	
Location	
Finding 3	
Direction	
Location	
Comments	

1



Title:

Attachment 4

REP Project Listing

2013 Actual Expenditures

Unitil Energy Systems **Attachment 4**
REP Project Spending 2013
All projects closed to Plant In Service

Budget Number	Auth #	Description	Budget	Installation Costs	Cost of Removal	Salvage	Total Project Spending
System Hardening Reliability							
DPBC01	C-13211	Distribution Pole Replacement	$ 348,428	$ 509,372	$ 52,828	$ 69	$ 562,130
DPBE01	E-13130	Distribution Pole Replacement	501,631	585,286	21,776	632	606,430
		Subtotal	$850,059	$1,094,658	$74,603	$701	$1,168,561
Asset Replacement							
DRBC05	C-13267	4W4 Recloser on Lakeview	10,600	13,154	1,443	0	14,597
DREB07	E-13166	Portsmouth Ave S/S - Install Reclosers	303,200	204,077	0	0	204,077
DRBE02	E-13170	Hampton S/S - Install Breakers 3342, 3353 and 3348 Lines	612,160	322,154	0	0	322,154
DREB07	E-13154	Fuse Changes to Address Mainline Unfused Laterals & Sensitivity Concerns	0	25,184	2,792	0	27,976
		Subtotal	$925,960	$564,569	$4,235	$0	$568,804
		Totals	**$1,776,019**	**$1,659,227**	**$78,839**	**$701**	**$1,737,365**

Carryover to 2014

None

Schedule 1

Unitil Energy Systems
Non-REP Plant Calculation

(Thousand of Dollars)

Actuals At 12/31/2013				
Plant Account	**Account Description**	**Total Plant**	**Accumulated Reserve**	**Net Book Value**
105-00	Plant Held for Future Use	763	-	763
301-00	Organization-E	0	-	0
303-00	Intangible Software-5 Yea-E	2,003	1,085	917
303-01	Intangible Software-3 Yea-E	92	88	4
303-02	Intangible Software-10 Yea-E	2,307	261	2,047
343-00	PRIME MOVERS-E	56	10	46
360-01	ROW - Distribution-E	227	-	227
360-02	ROW - Distribution-E	1,675	-	1,675
361-00	Distribution Structures-E	168	135	33
362-00	Distribution Station Equi-E	22,587	6,349	16,238
364-00	Distribution Poles, Tower-E	49,264	19,944	29,320
365-00	Distribution Overhead Con-E	64,822	19,518	45,304
366-00	Distribution Underground -E	1,671	544	1,127
367-00	Distribution Underground -E	16,357	6,319	10,038
368-00	Distribution Line Transfo-E	23,750	8,103	15,647
368-01	Transformer Installations-E	16,077	3,254	12,823
369-00	Distribution Services-E	18,661	11,313	7,348
370-00	Distribution Meters-E	9,544	1,416	8,128
370-01	Meter Installation-E	3,701	(2,094)	5,794
371-00	Installations on Customer-E	1,665	307	1,358
373-00	Street Lights & Signal Sy-E	3,078	1,514	1,564
373-01	Street Lights & Signal Sy-E	-	-	-
389-00	General & Misc. Land-E	19	-	19
390-00	Structures-E	3,803	1,875	1,928
390-01	General & Misc. Structures	144	0	144
391-01	Office Furniture & Fixtur-E	935	117	818
391-03	Computer Equipment-E	8	9	(1)
392-00	Transportation Equipment-E	1,261	1,214	47
393-00	Stores Equipment-E	81	54	27
394-00	Tools, Shop and garage Eq-E	1,392	572	820
395-00	Laboratory Equipment-E	585	256	328
397-00	Communication Equipment-E	3,660	2,585	1,075
398-00	Miscellaneous Equipment-E	108	72	36
399-00	Other Intangible Plant-E	1,667	1,667	0
				-
	Total	**$252,132**	**$86,486**	**$165,645**

Unitil Energy Systems
Non-REP Plant Calculation

(Thousand of Dollars)

Actuals At 12/31/2012				
Plant Account	**Account Description**	**Total Plant**	**Accumulated Reserve**	**Net Book Value**
105-00	Plant Held for Future Use	763	-	763
301-00	Organization-E	0	-	0
303-00	Intangible Software-5 Yea-E	1,504	846	658
303-01	Intangible Software-3 Yea-E	92	84	8
303-02	Intangible Software-10 Yea-E	2,226	37	2,189
343-00	PRIME MOVERS-E	56	6	50
360-01	ROW - Distribution-E	227	-	227
360-02	ROW - Distribution-E	1,675	-	1,675
361-00	Distribution Structures-E	168	131	37
362-00	Distribution Station Equi-E	20,209	5,824	14,386
364-00	Distribution Poles, Tower-E	46,401	19,016	27,385
365-00	Distribution Overhead Con-E	60,878	18,530	42,348
366-00	Distribution Underground -E	1,591	512	1,078
367-00	Distribution Underground -E	15,714	6,004	9,709
368-00	Distribution Line Transfo-E	23,416	7,783	15,633
368-01	Transformer Installations-E	14,664	2,960	11,705
369-00	Distribution Services-E	18,002	10,454	7,548
370-00	Distribution Meters-E	9,428	1,182	8,246
370-01	Meter Installation-E	3,501	(2,259)	5,760
371-00	Installations on Customer-E	1,517	296	1,221
373-00	Street Lights & Signal Sy-E	3,007	1,360	1,646
373-01	Street Lights & Signal Sy-E	-	-	-
389-00	General & Misc. Land-E	19	-	19
390-00	Structures-E	3,774	1,799	1,974
390-01	General & Misc. Structures			
391-01	Office Furniture & Fixtur-E	1,073	205	868
391-03	Computer Equipment-E	8	9	(1)
392-00	Transportation Equipment-E	1,745	1,643	103
393-00	Stores Equipment-E	91	61	30
394-00	Tools, Shop and garage Eq-E	1,436	574	863
395-00	Laboratory Equipment-E	579	256	323
397-00	Communication Equipment-E	3,641	2,348	1,293
398-00	Miscellaneous Equipment-E	113	72	41
399-00	Other Intangible Plant-E	1,667	1,667	0
				-
	Total	**$239,186**	**$81,401**	**$157,785**

Unitil Energy Systems
Non-REP Plant Calculation

(Thousand of Dollars)

Change Between Periods						
Plant Account	**Account Description**	**Total Plant**	**Accumulated Reserve**	**Net Book Value**	**Less: REP Projects**	**Adjusted Net Book Value**
105-00	Plant Held for Future Use	0	-	0		0
301-00	Organization-E	-	-	-		-
303-00	Intangible Software-5 Yea-E	499	240	259		259
303-01	Intangible Software-3 Yea-E	-	4	(4)		(4)
303-02	Intangible Software-10 Yea-E	81	223	(143)		(143)
343-00	PRIME MOVERS-E	-	4	(4)		(4)
360-01	ROW - Distribution-E	-	-	-		-
360-02	ROW - Distribution-E	-	-	-		-
361-00	Distribution Structures-E	-	4	(4)		(4)
362-00	Distribution Station Equi-E	2,377	525	1,852	525	1,327
364-00	Distribution Poles, Tower-E	2,863	928	1,935	929	1,005
365-00	Distribution Overhead Con-E	3,944	988	2,956	255	2,701
366-00	Distribution Underground -E	81	32	49	4	45
367-00	Distribution Underground -E	644	314	329	2	327
368-00	Distribution Line Transfo-E	333	320	14		14
368-01	Transformer Installations-E	1,413	295	1,118		1,118
369-00	Distribution Services-E	659	859	(199)	14	(214)
370-00	Distribution Meters-E	116	234	(118)		(118)
370-01	Meter Installation-E	199	165	34		34
371-00	Installations on Customer-E	147	11	137		137
373-00	Street Lights & Signal Sy-E	71	153	(82)	1	(83)
373-01	Street Lights & Signal Sy-E	-	-	-		-
389-00	General & Misc. Land-E	-	-	-		-
390-00	Structures-E	29	75	(46)		(46)
390-01	General & Misc. Structures	144	0	144		144
391-01	Office Furniture & Fixtur-E	(138)	(88)	(50)		(50)
391-03	Computer Equipment-E	-	-	-		-
392-00	Transportation Equipment-E	(484)	(428)	(56)		(56)
393-00	Stores Equipment-E	(10)	(7)	(3)		(3)
394-00	Tools, Shop and garage Eq-E	(44)	(2)	(42)		(42)
395-00	Laboratory Equipment-E	6	(0)	6		6
397-00	Communication Equipment-E	19	237	(217)		(217)
398-00	Miscellaneous Equipment-E	(5)	0	(5)		(5)
399-00	Other Intangible Plant-E	-	0	(0)		(0)
		-	-	-		-
	Total	**$12,945**	**$5,085**	**$7,860**	**$1,731**	**$6,129**

Project Name	Distribution Pole Replacement C-13211	4W4 Recloser on Lakeview C-13267	Distribution Pole Replacement E-13130	Fuse Changes to Address Mainline Unfused Laterals & Sensitivity Concerns E-13154	Portsmouth Ave S/S - Install Reclosers E-13166	Hampton S/S - Install Breakers 3342, 3353 and 3348 Lines E-13170	REP Projects Total Additions
Plant Account							
362-00					$ 204,077	$ 322,154	$ 526,231
364-00	425,948	6,137	437,781	2,826			872,692
365-00	83,424	7,017	127,251	22,358			240,050
366-00			3,690				3,690
367-00			1,988				1,988
369-00			13,558				13,558
371-00							-
373-00			1,018				1,018
Totals	**$ 509,372**	**$ 13,154**	**$ 585,286**	**$ 25,184**	**$ 204,077**	**$ 322,154**	**$ 1,659,227**

Depreciation calculation on REP projects

Close Date		Nov-13	Nov-13	Dec-13	Dec-13	Dec-13	Dec-13	Total Depreciation
Depreciation Months		2	2	1	1	1	1	
Utility Account								
362-00	2.66%	$ -	$ -	$ -	$ -	$ 452	$ 714	$ 1,166
364-00	3.80%	2,698	39	1,386	9	-	-	4,132
365-00	3.74%	520	44	397	70	-	-	1,030
366-00	2.09%	-	-	6	-	-	-	6
367-00	2.61%	-	-	4	-	-	-	4
369-00	5.83%	-	-	66	-	-	-	66
371-00	7.79%	-	-	-	-	-	-	-
373-00	8.04%	-	-	7	-	-	-	7
Total Depreciation		**$ 3,218**	**$ 83**	**$ 1,866**	**$ 79**	**$ 452**	**$ 714**	**$ 6,412**
Cost of removal		$ 52,828	$ 1,443	$ 21,776	$ 2,792	$ -	$ -	$ 78,839
Salvage		(69)	-	(632)	-	-	-	(701)
Total COR & Salvage		**$ 52,759**	**$ 1,443**	**$ 21,144**	**$ 2,792**	**$ -**	**$ -**	**$ 78,138**
Net Project Cost		**$ 558,913**	**$ 14,514**	**$ 604,564**	**$ 27,897**	**$ 203,625**	**$ 321,440**	**$ 1,730,953**

Net Book: REP Projects

362-00	$ 525,065
364-00	$ 929,495
365-00	$ 255,278
366-00	$ 3,756
367-00	$ 2,033
369-00	$ 14,238
371-00	$ -
373-00	$ 1,088
	$ 1,730,953

Schedule 2

Schedule 2

Unitil Energy Systems, Inc.
May 1, 2014 Step Adjustment Revenue Requirement

Starting Step Date	5/1/2014
Non-REP Plant Additions Step Adjustment	2013
Beginning Non-REP Net Plant in Service (January 1)	$ 154,355,411
Non-REP Plant Additions	$ 11,285,905
Less: Non-REP Depreciation	$ 5,157,066
Ending Non-REP Net Plant in Service (December 31)	$ 160,484,250
Change in Non-REP Plant in Service	$ 6,128,839
75% of Change in Non-REP Net Plant in Service	$ 4,596,629
75% of Change in Non-REP Net Plant in Service	$ 4,596,629
Rate of Return	8.39%
Operating Income Requirement	$ 385,657
Tax Gross Up	1.6814
Return	$ 648,436
Depreciation on 75% of Non-REP Plant Additions (3.66%)	$ 309,798
Property Taxes on 75% Change in Non-REP Net Plant in Service (1.74%)	$ 79,981
Total Non-REP Step Adjustment Revenue Requirement	$ 1,038,215
REP Plant Additions Step Adjustment	
Beginning REP Net Plant in Service (January 1)	$ 3,429,982
REP Plant Additions	$ 1,659,227
Less: REP Depreciation	$ (71,726)
Ending REP Net Plant in Service (December 31)	$ 5,160,935
Change in REP Net Plant in Service	$ 1,730,953
Rate of Return	8.39%
Operating Income Requirement	$ 145,227
Tax Gross Up	1.6814
Return	$ 244,182
Depreciation on REP Plant Additions (3.66%)	$ 60,728
Property Taxes on Change in REP Net Plant in Service (1.74%)	$ 30,119
Total REP Step Adjustment Revenue Requirement	$ 335,028
Other Step Adjustments	
VMP Reconciliation(1)	$ 163,962
Grand Total Step Adjustment Revenue Requirement	**$ 1,537,205**

(1) Reversal of prior year reconciliation

Schedule 3

Unitil Energy Systems, Inc.
Rate Design Calculations

	(1)	(2)	(3)	(4)	(5)
	Billing Units	Step 3 Adjustment Rates May 1, 2013	Step 4 Adjustment Rates May 1, 2014	Step 4 Adjustment Revenue May 1, 2014	Percent Change
Residential - D					
Test Year Consumers	763,694	$10.27	$10.27	$7,843,138	
First 250 kWh	172,809,013	$0.03239	$0.03427	$5,922,363	
Excess kWh	307,829,586	$0.03739	$0.03927	$12,088,821	
Total Design Revenue				$25,854,322	3.63%
Small General Service - G2 kWh					
Test Year Consumers	6,691	$13.52	$13.88	$92,871	
Annual kWh	774,710	$0.03114	$0.03196	$24,763	
Total Design Revenue				$117,635	2.66%
Small General Service - G2 QR WH / SH					
Test Year Consumers	3,831	$6.06	$6.22	$23,829	
Annual kWh	6,204,726	$0.02980	$0.03060	$189,847	
Total Design Revenue				$213,677	2.66%
Small General Service - G2 Demand					
Test Year Consumers	118,727	$17.85	$18.32	$2,175,073	
Demand kW	1,301,458	$10.00	$10.26	$13,354,128	
Annual kWh	333,296,033	$0.00000	$0.00000	$0	
Total Design Revenue				$15,529,201	2.65%
G2 Demand - kW Transformer Ownership Discount					
Test Year kW	50,700	($0.39)	($0.39)	-$19,773	
Total Design Revenue				-$19,773	0.00%
Subtotal G2 Demand inc. Transformer Ownership Discount					
Total Design Revenue				$15,509,428	2.66%
Large General Service - G1					
Test Year Consumers Secondary	1,382	$94.22	$96.72	$133,667	
Test Year Consumers Primary	432	$55.84	$57.32	$24,762	
Demand kVA	989,158	$6.75	$6.92	$6,848,298	
Annual kWh	347,650,754	$0.00000	$0.00000	$0	
Total Design Revenue				$7,006,727	2.60%
G1 - kVA Transformer Ownership Discount					
Test Year kVA	412,729	($0.39)	($0.39)	-$160,964	
Total Design Revenue				-$160,964	0.00%
Subtotal G1 inc. Transformer Ownership Discount					
Total Design Revenue				$6,845,763	2.66%

Unitil Energy Systems, Inc.
Rate Design Calculations

	(1)	(2)	(3)	(4)	(5)
	Billing Units	Step 3 Adjustment Rates May 1, 2013	Step 4 Adjustment Rates May 1, 2014	Step 4 Adjustment Revenue May 1, 2014	Percent Change
Outdoor Lighting - OL					
Delivery charge - Annual kWh	8,988,739	$0.00000	$0.00000	$0	
Fixture revenue					
100W Mercury Vapor Street	21,269	$10.94	$11.23	$238,816	
175W Mercury Vapor Street	1,155	$13.24	$13.59	$15,701	
250W Mercury Vapor Street	1,415	$15.20	$15.60	$22,080	
400W Mercury Vapor Street	3,578	$18.37	$18.86	$67,475	
1000W Mercury Vapor Street	60	$37.88	$38.88	$2,333	
250W Mercury Vapor Flood	1,085	$16.28	$16.71	$18,136	
400W Mercury Vapor Flood	2,344	$19.77	$20.29	$47,562	
1000W Mercury Vapor Flood	783	$33.69	$34.58	$27,080	
100W Mercury Vapor Power Bracket	6,406	$11.06	$11.35	$72,711	
175W Mercury Vapor Power Bracket	1,072	$12.42	$12.75	$13,668	
50W Sodium Vapor Street	37,978	$11.16	$11.46	$435,288	
100W Sodium Vapor Street	1,067	$12.74	$13.08	$13,960	
150W Sodium Vapor Street	4,510	$12.80	$13.14	$59,255	
250W Sodium Vapor Street	11,866	$16.40	$16.84	$199,787	
400W Sodium Vapor Street	3,084	$21.04	$21.60	$66,619	
1000W Sodium Vapor Street	1,685	$37.39	$38.38	$64,675	
150W Sodium Vapor Flood	2,834	$14.97	$15.37	$43,561	
250W Sodium Vapor Flood	3,397	$17.92	$18.39	$62,477	
400W Sodium Vapor Flood	4,910	$20.54	$21.09	$103,555	
1000W Sodium Vapor Flood	3,519	$37.72	$38.73	$136,281	
50W Sodium Vapor Power Bracket	1,153	$10.22	$10.50	$12,101	
100W Sodium Vapor Power Bracket	649	$11.65	$11.96	$7,763	
175W Metal Halide Street	0	$17.12	$17.57	$0	
250W Metal Halide Street	0	$18.74	$19.24	$0	
400W Metal Halide Street	0	$19.48	$20.00	$0	
175W Metal Halide Flood	0	$19.99	$20.52	$0	
250W Metal Halide Flood	0	$21.70	$22.28	$0	
400W Metal Halide Flood	0	$21.75	$22.32	$0	
175W Metal Halide Power Bracket	0	$15.93	$16.35	$0	
250W Metal Halide Power Bracket	0	$17.02	$17.47	$0	
400W Metal Halide Power Bracket	0	$18.29	$18.78	$0	
Total Design Revenue				$1,730,883	2.66%
Total Design Revenue				$50,271,707	
Total Billed kWh	1,177,553,561				
Total Billed kW/kVA	2,290,616				
Step Adjustments				$1,537,205	
Overall Percentage Change				3.15%	
Residential Step Adjustment Percentage Increase over prior year (115% of overall)				3.63%	
Non-residential Step Adjustment Percentage Increase				2.66%	

Schedule 4

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on D Rate Customers

Average kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
125	$29.49	$29.73	$0.23	0.8%
250	$48.72	$49.19	$0.47	1.0%
500	$88.42	$89.36	$0.94	1.1%
600	$104.29	$105.42	$1.13	1.1%
750	$128.11	$129.52	$1.41	1.1%
1,000	$167.81	$169.69	$1.88	1.1%
1,250	$207.51	$209.86	$2.35	1.1%
1,500	$247.21	$250.03	$2.82	1.1%
2,000	$326.60	$330.36	$3.76	1.2%
3,500	$564.79	$571.37	$6.58	1.2%
5,000	$802.97	$812.37	$9.40	1.2%

		Rates - Effective 12/1/2013	Rates - Proposed 5/1/2014	Difference
Customer Charge		**$10.27**	**$10.27**	**$0.00**
		kWh	**kWh**	**kWh**
Distribution Charge:	First 250 kWh	$0.03239	$0.03427	$0.00188
	Excess 250 kWh	$0.03739	$0.03927	$0.00188
External Delivery Charge		$0.02006	$0.02006	$0.00000
Stranded Cost Charge		$0.00027	$0.00027	$0.00000
Storm Recovery Adjustment Factor		$0.00221	$0.00221	$0.00000
System Benefits Charge		$0.00330	$0.00330	$0.00000
Default Service Charge		$0.09556	$0.09556	$0.00000
TOTAL	First 250 kWh	**$0.15379**	**$0.15567**	**$0.00188**
	Excess 250 kWh	**$0.15879**	**$0.16067**	**$0.00188**

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 Rate Customers

Load Factor	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
20%	5	730	$152.68	$154.45	$1.77	1.2%
20%	10	1,460	$287.50	$290.57	$3.07	1.1%
20%	15	2,190	$422.33	$426.70	$4.37	1.0%
20%	25	3,650	$691.98	$698.95	$6.97	1.0%
20%	50	7,300	$1,366.12	$1,379.59	$13.47	1.0%
20%	75	10,950	$2,040.25	$2,060.22	$19.97	1.0%
20%	100	14,600	$2,714.38	$2,740.85	$26.47	1.0%
20%	150	21,900	$4,062.65	$4,102.12	$39.47	1.0%
36%	5	1,314	$220.30	$222.07	$1.77	0.8%
36%	10	2,628	$422.75	$425.82	$3.07	0.7%
36%	15	3,942	$625.19	$629.56	$4.37	0.7%
36%	25	6,570	$1,030.09	$1,037.06	$6.97	0.7%
36%	50	13,140	$2,042.33	$2,055.80	$13.47	0.7%
36%	75	19,710	$3,054.57	$3,074.54	$19.97	0.7%
36%	100	26,280	$4,066.81	$4,093.28	$26.47	0.7%
36%	150	39,420	$6,091.29	$6,130.76	$39.47	0.6%
50%	5	1,825	$279.47	$281.24	$1.77	0.6%
50%	10	3,650	$541.08	$544.15	$3.07	0.6%
50%	15	5,475	$802.70	$807.07	$4.37	0.5%
50%	25	9,125	$1,325.93	$1,332.90	$6.97	0.5%
50%	50	18,250	$2,634.02	$2,647.49	$13.47	0.5%
50%	75	27,375	$3,942.10	$3,962.07	$19.97	0.5%
50%	100	36,500	$5,250.19	$5,276.66	$26.47	0.5%
50%	150	54,750	$7,866.35	$7,905.82	$39.47	0.5%

	Rates - Effective 12/1/2013	Rates - Proposed 5/1/2014	Difference
Customer Charge	**$17.85**	**$18.32**	**$0.47**
	All kW	**All kW**	**All kW**
Distribution Charge	$10.00	$10.26	$0.26
Stranded Cost Charge	$0.06	$0.06	$0.00
TOTAL	**$10.06**	**$10.32**	**$0.26**
	kWh	**kWh**	**kWh**
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.02006	$0.02006	$0.00000
Stranded Cost Charge	$0.00006	$0.00006	$0.00000
Storm Recovery Adj. Factor	$0.00221	$0.00221	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09016	$0.09016	$0.00000
TOTAL	**$0.11579**	**$0.11579**	**$0.00000**

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 kWh Meter Rate Customers

Average Monthly kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
15	$15.73	$16.10	$0.37	2.4%
75	$24.56	$24.98	$0.42	1.7%
150	$35.59	$36.07	$0.48	1.4%
250	$50.31	$50.87	$0.57	1.1%
350	$65.02	$65.67	$0.65	1.0%
450	$79.73	$80.46	$0.73	0.9%
550	$94.45	$95.26	$0.81	0.9%
650	$109.16	$110.05	$0.89	0.8%
750	$123.88	$124.85	$0.98	0.8%
900	$145.95	$147.04	$1.10	0.8%

	Rates - Effective 12/1/2013	Rates - Proposed 5/1/2014	Difference
kWh Meter Customer Charge	**$13.52**	**$13.88**	**$0.36**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.03114	$0.03196	$0.00082
External Delivery Charge	$0.02006	$0.02006	$0.00000
Stranded Cost Charge	$0.00027	$0.00027	$0.00000
Storm Recovery Adjustment Factor	$0.00221	$0.00221	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09016	$0.09016	$0.00000
TOTAL	**$0.14714**	**$0.14796**	**$0.00082**

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 QRWH and SH Rate Customers

Average kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
100	$20.64	$20.88	$0.24	1.2%
200	$35.22	$35.54	$0.32	0.9%
300	$49.80	$50.20	$0.40	0.8%
400	$64.38	$64.86	$0.48	0.7%
500	$78.96	$79.52	$0.56	0.7%
750	$115.41	$116.17	$0.76	0.7%
1,000	$151.86	$152.82	$0.96	0.6%
1,500	$224.76	$226.12	$1.36	0.6%
2,000	$297.66	$299.42	$1.76	0.6%
2,500	$370.56	$372.72	$2.16	0.6%

	Rates - Effective 12/1/2013	Rates - Proposed 5/1/2014	Difference
Customer Charge	**$6.06**	**$6.22**	**$0.16**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.02980	$0.03060	$0.00080
External Delivery Charge	$0.02006	$0.02006	$0.00000
Stranded Cost Charge	$0.00027	$0.00027	$0.00000
Storm Recovery Adjustment Factor	$0.00221	$0.00221	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09016	$0.09016	$0.00000
TOTAL	**$0.14580**	**$0.14660**	**$0.00080**

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on G1 Rate Customers

Load Factor	Average Monthly kVa	Average Monthly kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
25.0%	200	36,500	$6,720.43	$6,756.93	$36.50	0.5%
25.0%	400	73,000	$13,346.63	$13,417.13	$70.50	0.5%
25.0%	600	109,500	$19,972.84	$20,077.34	$104.50	0.5%
25.0%	800	146,000	$26,599.04	$26,737.54	$138.50	0.5%
25.0%	1,000	182,500	$33,225.25	$33,397.75	$172.50	0.5%
25.0%	1,500	273,750	$49,790.76	$50,048.26	$257.50	0.5%
25.0%	2,000	365,000	$66,356.27	$66,698.77	$342.50	0.5%
25.0%	2,500	456,250	$82,921.78	$83,349.28	$427.50	0.5%
25.0%	3,000	547,500	$99,487.30	$99,999.80	$512.50	0.5%
40.0%	200	58,400	$9,877.75	$9,914.25	$36.50	0.4%
40.0%	400	116,800	$19,661.28	$19,731.78	$70.50	0.4%
40.0%	600	175,200	$29,444.80	$29,549.30	$104.50	0.4%
40.0%	800	233,600	$39,228.33	$39,366.83	$138.50	0.4%
40.0%	1,000	292,000	$49,011.86	$49,184.36	$172.50	0.4%
40.0%	1,500	438,000	$73,470.68	$73,728.18	$257.50	0.4%
40.0%	2,000	584,000	$97,929.50	$98,272.00	$342.50	0.3%
40.0%	2,500	730,000	$122,388.32	$122,815.82	$427.50	0.3%
40.0%	3,000	876,000	$146,847.14	$147,359.64	$512.50	0.3%
57.0%	200	83,220	$13,456.05	$13,492.55	$36.50	0.3%
57.0%	400	166,440	$26,817.87	$26,888.37	$70.50	0.3%
57.0%	600	249,660	$40,179.70	$40,284.20	$104.50	0.3%
57.0%	800	332,880	$53,541.53	$53,680.03	$138.50	0.3%
57.0%	1,000	416,100	$66,903.36	$67,075.86	$172.50	0.3%
57.0%	1,500	624,150	$100,307.93	$100,565.43	$257.50	0.3%
57.0%	2,000	832,200	$133,712.49	$134,054.99	$342.50	0.3%
57.0%	2,500	1,040,250	$167,117.06	$167,544.56	$427.50	0.3%
57.0%	3,000	1,248,300	$200,521.63	$201,034.13	$512.50	0.3%
71.0%	200	103,660	$16,402.88	$16,439.38	$36.50	0.2%
71.0%	400	207,320	$32,711.54	$32,782.04	$70.50	0.2%
71.0%	600	310,980	$49,020.21	$49,124.71	$104.50	0.2%
71.0%	800	414,640	$65,328.87	$65,467.37	$138.50	0.2%
71.0%	1,000	518,300	$81,637.53	$81,810.03	$172.50	0.2%
71.0%	1,500	777,450	$122,409.19	$122,666.69	$257.50	0.2%
71.0%	2,000	1,036,600	$163,180.84	$163,523.34	$342.50	0.2%
71.0%	2,500	1,295,750	$203,952.50	$204,380.00	$427.50	0.2%
71.0%	3,000	1,554,900	$244,724.15	$245,236.65	$512.50	0.2%

	Rates - Effective 12/1/2013	Rates - Proposed 5/1/2014	Difference
Customer Charge - Secondary	**$94.22**	**$96.72**	**$2.50**
	All kVA	**All kVA**	**All kVA**
Distribution Charge	$6.75	$6.92	$0.17
Stranded Cost Charge	$0.07	$0.07	$0.00
TOTAL	**$6.82**	**$6.99**	**$0.17**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.02006	$0.02006	$0.00000
Stranded Cost Charge	$0.00007	$0.00007	$0.00000
Storm Recovery Adjustment Factor	$0.00221	$0.00221	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge*	$0.11853	$0.11853	$0.00000
TOTAL	**$0.14417**	**$0.14417**	**$0.00000**

* Default Service Charges shown are based on the average of the DSC for December 2013 - February 2014.

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates for May 1, 2014 Step Adjustment
Impacts do NOT include the Electricity Consumption Tax
Impact on OL Rate Customers*

	Nominal Watts	Lumens	Type	Average Monthly kWh	Total Bill Using Rates Effective 12/1/2013	Total Bill Using Rates Proposed 5/1/2014	Total Difference	% Total Difference
	Mercury Vapor:							
1	100	3,500	ST	40	$15.58	$15.87	$0.29	1.9%
2	175	7,000	ST	67	$21.01	$21.36	$0.35	1.7%
3	250	11,000	ST	95	$26.22	$26.62	$0.40	1.5%
4	400	20,000	ST	154	$36.23	$36.72	$0.49	1.4%
5	1,000	60,000	ST	388	$82.89	$83.89	$1.00	1.2%
6	250	11,000	FL	95	$27.30	$27.73	$0.43	1.6%
7	400	20,000	FL	154	$37.63	$38.15	$0.52	1.4%
8	1,000	60,000	FL	388	$78.70	$79.59	$0.89	1.1%
9	100	3,500	PB	40	$15.70	$15.99	$0.29	1.8%
10	175	7,000	PB	67	$20.19	$20.52	$0.33	1.6%
	High Pressure Sodium:							
11	50	4,000	ST	21	$13.60	$13.90	$0.30	2.2%
12	100	9,500	ST	43	$17.73	$18.07	$0.34	1.9%
13	150	16,000	ST	60	$19.76	$20.10	$0.34	1.7%
14	250	30,000	ST	101	$28.12	$28.56	$0.44	1.6%
15	400	50,000	ST	161	$39.72	$40.28	$0.56	1.4%
16	1,000	140,000	ST	398	$83.56	$84.55	$0.99	1.2%
17	150	16,000	FL	60	$21.93	$22.33	$0.40	1.8%
18	250	30,000	FL	101	$29.64	$30.11	$0.47	1.6%
19	400	50,000	FL	161	$39.22	$39.77	$0.55	1.4%
20	1,000	140,000	FL	398	$83.89	$84.90	$1.01	1.2%
21	50	4,000	PB	21	$12.66	$12.94	$0.28	2.2%
22	100	95,000	PB	43	$16.64	$16.95	$0.31	1.9%
	Metal Halide:							
23	175	8,800	ST	66	$24.78	$25.23	$0.45	1.8%
24	250	13,500	ST	92	$29.41	$29.91	$0.50	1.7%
25	400	23,500	ST	148	$36.65	$37.17	$0.52	1.4%
26	175	8,800	FL	66	$27.65	$28.18	$0.53	1.9%
27	250	13,500	FL	92	$32.37	$32.95	$0.58	1.8%
28	400	23,500	FL	148	$38.92	$39.49	$0.57	1.5%
29	175	8,800	PB	66	$23.59	$24.01	$0.42	1.8%
30	250	13,500	PB	92	$27.69	$28.14	$0.45	1.6%
31	400	23,500	PB	148	$35.46	$35.95	$0.49	1.4%

Luminaire Charges For Year Round Service:

Rates - Effective 12/1/2013		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.	
Customer Charge	**$0.00**	1	$10.94	11	$11.16	23	$17.12
		2	$13.24	12	$12.74	24	$18.74
	All kWh	3	$15.20	13	$12.80	25	$19.48
Distribution Charge	$0.00000	4	$18.37	14	$16.40	26	$19.99
External Delivery Charge	$0.02006	5	$37.88	15	$21.04	27	$21.70
Stranded Cost Charge	$0.00027	6	$16.28	16	$37.39	28	$21.75
Storm Recovery Adj. Factor	$0.00221	7	$19.77	17	$14.97	29	$15.93
System Benefits Charge	$0.00330	8	$33.69	18	$17.92	30	$17.02
Default Service Charge	$0.09016	9	$11.06	19	$20.54	31	$18.29
		10	$12.42	20	$37.72		
TOTAL	**$0.11600**			21	$10.22		
				22	$11.65		

Rates - Proposed 5/1/2014		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.	
Customer Charge	**$0.00**	1	$11.23	11	$11.46	23	$17.57
		2	$13.59	12	$13.08	24	$19.24
	All kWh	3	$15.60	13	$13.14	25	$20.00
Distribution Charge	$0.00000	4	$18.86	14	$16.84	26	$20.52
External Delivery Charge	$0.02006	5	$38.88	15	$21.60	27	$22.28
Stranded Cost Charge	$0.00027	6	$16.71	16	$38.38	28	$22.32
Storm Recovery Adj. Factor	$0.00221	7	$20.29	17	$15.37	29	$16.35
System Benefits Charge	$0.00330	8	$34.58	18	$18.39	30	$17.47
Default Service Charge	$0.09016	9	$11.35	19	$21.09	31	$18.78
		10	$12.75	20	$38.73		
TOTAL	**$0.11600**			21	$10.50		
				22	$11.96		

	Difference	Mercury Vapor-Difference		Sodium Vapor-Difference		Metal Halide-Difference	
Customer Charge	**$0.00**	1	$0.29	11	$0.30	23	$0.45
		2	$0.35	12	$0.34	24	$0.50
	All kWh	3	$0.40	13	$0.34	25	$0.52
Distribution Charge	$0.00000	4	$0.49	14	$0.44	26	$0.53
External Delivery Charge	$0.00000	5	$1.00	15	$0.56	27	$0.58
Stranded Cost Charge	$0.00000	6	$0.43	16	$0.99	28	$0.57
Storm Recovery Adj. Factor	$0.00000	7	$0.52	17	$0.40	29	$0.42
System Benefits Charge	$0.00000	8	$0.89	18	$0.47	30	$0.45
Default Service Charge	$0.00000	9	$0.29	19	$0.55	31	$0.49
		10	$0.33	20	$1.01		
TOTAL	**$0.00000**			21	$0.28		
				22	$0.31		

* Luminaire charges based on All-Night Service option.

Schedule 5

Unitil Energy Systems, Inc.
PUC 308.11 - F-1 Rate of Return
12 Months Ending December 31, 2013

Schedule 1: Calculation of Per Books Rate of Return

Cost of Service		Rolling 12 Months
Electric Service Revenues	$	133,735,436
Other Operating Revenue		2,805,731
Total Operating Revenues		**136,541,167**
Operating Expenses:		
Purchased Power		57,925,798
Transmission		23,869,042
Distribution		9,481,446
Cust. Accounting & Service		3,767,945
Admin. & General		8,526,780
Depreciation		8,874,050
Amortization		3,202,432
Taxes-Other Than Income		4,891,960
State & Federal Income Taxes		3,888,998
Int on Customer Deposits		36,193
Total Operating Expenses		**124,464,644**
Net Operating Income	**$**	**12,076,523**
Less: EE Revenue, Tax Affected		(425,687)
Less: Other FT Oper Inc (Not Tax Affected)		1,360,565
Net Operating Income - Adjusted	**$**	**11,141,645**

Rate Base		5 Qtr Avg
Utility Plant in Service	$	242,561,491
Less: Reserve for Depreciation & Amortization		83,481,956
Net Utility Plant		**159,079,535**
Plus:		
M&S Inventories		1,329,196
Cash Working Capital		2,572,006
Prepayments		9,376,490
Other Special Deposits - ISO		4,576,238
Less:		
Deferred Income Taxes		26,406,494
Customer Advances		460,946
Customer Deposits		1,146,701
Total Rate Base	**$**	**148,919,324**
Utility Operating Income - 8.39% Cost of Capital	$	12,497,898
Utility Operating Income - Actual	$	11,141,645
Operating Income Deficiency (Surplus)	**$**	**1,356,253**
Income Tax Gross-Up	$	889,571
Revenue Deficiency (Surplus)	**$**	**2,245,823**
Return on Rate Base - Actual		**7.48%**
Return on Rate Base - Authorized DE 10-055		**8.39%**
ROE - Actual		**7.67%**
ROE - Authorized DE 10-055		**9.67%**

Schedule 2: Cost of Capital - Authorized DE 10-055

	Percent Total	Cost Rate	Weighted Cost Rate
Common Equity	45.45%	9.67%	4.40%
Preferred Stock Equity	0.16%	6.00%	0.01%
Long Term Debt	51.53%	7.60%	3.92%
Short Term Debt	2.86%	2.50%	0.07%
Total	**100.00%**		**8.39%**

2013 Storm Resiliency Pilot Program Results

Addendum to the:

Storm Resiliency Pilot Program 2012

Cost Benefit Analysis

Prepared By:

Sara Sankowich & Raymond Letourneau
Unitil Service Corp.
April 10, 2013
Addendum date: March 4, 2014 Pages 17 - 21

1. Storm Pilot Overview

In 2012, Unitil embarked on a pilot study to test the effectiveness of performing targeted vegetation management to reduce effects of storm events on the electric system. This pilot was initiated after the Unitil Service territory in New Hampshire was met with 2 large events in 2011, Hurricane Irene and the October Snowstorm and had sustained other frequent major storm events over the past 4 years.

The 2011 October Snowstorm caused widespread damage and prolonged outages and was ranked as the 3rd largest event in the state's history.[1] The NH PUC Regulated Utilities' Preparation and Response Report indicated customers expressed frustration with costs incurred with the outages.

> *"Customers also expressed frustration with the personal costs incurred as a result of multi-day outages. For residential customers, those costs are driven in part by the purchase of fuel for generators; lodging and meals for those who cannot remain in their homes; lost wages for those who work from home; and spoiled food with the loss of refrigeration. Business customers experienced revenue losses, as well. Without electricity, many customers in New Hampshire lack water, as well as heat."*[2]

In after storm meetings with towns and annual emergency preparedness meetings, Unitil also saw that customers expressed a desire for something to be done. Customer's increased reliance on technology coupled with the economic cost of service interruption and safety aspect contributes to the changing expectation of uninterrupted service. Certain towns even expressed support for more tree work to be done.

Unitil began to explore the options available to "harden" or make the system more resilient to storms. After the review of different options available, such as undergrounding electric lines, and reviewing their rough cost estimates, Unitil recognized that there was an opportunity to consider the effects of implementing a vegetation centered storm hardening program.

In order to study the effects of the program and whether the program provided valuable benefits to customers, Unitil proposed to study the cost to implement, the reliability effects, and the public acceptance, against the cost of storm preparation, the cost of storm restoration and response, and the cost of storm to customers - both residential and business.

This report outlines the storm pilot program development, implementation, results and future recommendations.

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[1] NH PUC "The October Snowstorm – New Hampshire's Regulated Utilities' Preparation and Response" November 20,2012, Appendix E p55

[2] NH PUC "The October Snowstorm – New Hampshire's Regulated Utilities' Preparation and Response" November 20,2012, Section VI p38

2. 2012 Storm Pilot Development

To develop the storm pilot program, Unitil targeted specific circuits (shown in Table 1) in communities in the Seacoast area that expressed desire for storm hardening and additional tree work. Each circuit was chosen for its recent historic reliability performance, number of customers served, field conditions, and location.

The design was for critical 3-phase sections of the circuit, from the substation out to the first protection device, to have tree exposure reduced by removing all overhanging vegetation or pruning “ground to sky”. Intensive hazard tree review and removal was to be conducted on these critical sections. In cases where the customer count was over 500 customers at the first protection device, overhang and hazard tree removal was to be continued to the second protection device. From that point, hazard tree inspection and removal was to be conducted out to the third protection device or along remaining three phase lines.

Table 1

Circuit	Scheduled Miles
E13W2	4.65
E58X1	5.42
E21W2	4.66
Total	**14.73**

Unitil also met with towns and communities in the development stage to gain insight into their critical infrastructure needs for the town. The locations of police and fire departments, schools, emergency shelters and other critical business centers were taken into account along with the critical electric infrastructure.

Cost estimates for this pilot program were calculated using a weighted cost per mile estimate for pruning and tree removal including customer outreach and education materials, work planning, notification, and monitoring, plus an addition of traffic control costs.

3. 2012 Storm Pilot Implementation

Implementation began with an outreach program, where towns were notified of the intent, scope of work, and tentative schedule. An informational brochure was developed for customers and plans were put up on the company web site.

Unitil hired a consultant certified arborist work planner trained in risk tree assessment and hazard identification. The consultant was trained in the project scope and risk tree assessment level desired and work planning began on the three identified circuits. The work planner also conducted extensive customer outreach and education related to the program and sought tree owner consent for pruning and removal.

After all work-planning was completed, the pilot program was to put out to bid to Unitil’s qualified line-clearance vendors. An extensive request for proposal document and pre-bid meeting was prepared to ensure full understanding and lowest market price for specified work. A number of bid questions was also included and evaluated to ensure selected vendor exhibited Unitil's shared values and desired a partnership to invest in the communities where this tree work was being conducted.

Tree pruning and removal work began by the selected vendor in the beginning of October and continued through the end of December. The use of specialized equipment such as cranes, log loaders, staged wood removal sites and mowers was implemented to reduce the surrounding vegetation impact and overall appearance to the community.

4. Storm Pilot Results and Analysis

a. Work Delivery

When work was completed, 14.7 miles of critical three phase line had all overhanging vegetation removed (pruned "ground-to-sky") and 1,685 hazard trees were removed along this critical line portion as well as 9.9 additional miles of three phase. (see Table 2)

Table 2

2012 Storm Pilot Work Details			
Circuit	**Scheduled Miles**	**Completed Miles**	**# of Removals**
E13W2	4.65	4.65	614
E58X1	5.42	5.42	408
E21W2	4.66	4.66	663
Total	**14.73**	**14.73**	**1685**

b. Customer Response

Overall, there was excellent support from the towns and customers involved. There was limited opposition before work began and very little complaints or concerns as work progressed and completed.

In fact, Unitil received lots of praise for the program, especially after Hurricane Sandy and other minor storms in the end of 2012 and beginning of 2013. (See **Section C**, below for more on studying the impact during Hurricane Sandy) Some of the customer responses from Twitter include:

@tgnh: Thanks @Unitil for the intense tree removal in my town recently. I'm sure it's why we did not lose power!

@hiltonizer: @Unitil No outage for me here in Newton today, Asplundh has been here everyday for a month+ and doing a good job. Tell your arborist thanks!

@scateo: Hats off to @Unitil, their extensive tree maintenance campaign paid off in little if any disruption of serve this year in my area.

@scateo: Fantastic job of limbing past summer is paying off in lack of outages! Your actions really paid off.

@mackgraddiesdad: So far so good! The trimming really does help! Keep cutting those trees back off the lines ... love staying connected in storm!

@richguarino: Congratulations, taking down those trees in Newton paid off. Not one outage yesterday…

Some of the web submittals and emails received include:

Submitted on Monday, February 18, 2013
Address of service request: *54 Walker Road*
City: *Atkinson*
State of residence: *New Hampshire*
Subject: *Great Work!*
Message: *There doesn't seem to be a way to contact you to give you compliments! I just want to say your electrical support/maintenance has improved incredibly. The winds through the blizzard and this past weekend's storm would have knocked out our power for sure 4-5 years ago. Your preventive work has paid off and we are in such better shape as a result. Thank you so much!! We all notice and are buzzing about it. I was just worried you never hear the good stuff!*

Submitted on Thursday, November 29, 2012
Address of service request: *19 Forest St.*
City: *Plaistow*
State of residence: *New Hampshire*
Subject: *Recent Storm*
Message: *My husband and I very often travel from Plaistow to Exeter to our doctors and hospital. There seemed to be a lot of tree work bring done.*
Just to let you know we feel all the tree work has paid off as Unitil came through the storm practically unscathed. Congratulations.

Submitted on Tuesday, October 23, 2012
Address of service request: *4 Crystal Hill Circle*
City*: Atkinson*
State of residence: *New Hampshire*
Subject: *Tree/Vegetation management*
Message: *If you are the ones who are responsible for the tree crews in Atkinson, clearing trees from the power lines - THANK YOU!, thank you for the increased vegetation management. Hopefully they are able to take care of some of the trees near intersection of East Road and Crystal Hill Road as well as anything they see on Crystal Hill Circle, sure would like them to take some of the*

tall pines near the lines down... but seeing some vegetation work getting done after being here 18 years is great.

c. Pilot Response Testing in Hurricane Sandy

During the course of the pilot pruning and removal work, Unitil was faced with a unique situation to test the work's response to a storm event. On October 29, 2012 Hurricane or "Super Storm" Sandy came up the east coast and affected Unitil's New Hampshire service territory. At this time, one of the two storm pilot circuits, E58X1, was in the final stages of completion. Only a few customer tree removal negotiations and pruning spots remained. The E21W2 circuit pruning and removal was just beginning, however, and work had not started on the E13W2. This left the unique opportunity to study the effects on the worked and unworked circuits during one event. As rain and wind from Hurricane Sandy pelted the Seacoast area, the E58X1 circuit held up remarkably well. The main line of the circuit experienced no events and many of the customers fed off this circuit did not experience a single interruption. A customer communication to the company after the storm event, shown below, is representative of many emails, phone calls and Twitter "tweets" Unitil received and the customer experience during this storm event:

> *Just wanted to let you know how wonderful it was not to lose power during the hurricane. I believe it was directly attributable to all the tree cutting and trimming Unitil did especially in the Pollard Road and Westville Road area. My husband and I had our home built here thirty seven years ago....this is the **<u>first</u>** big storm that I can remember that power remained on!! I know there is no assurance this will be the norm but I think you all are striving hard to make it that way. Thanks so much!! -Plaistow NH*

There was one tree related event in the storm pilot area along the E58X1 where a desired tree removal, still in discussion with an unsure homeowner, failed and contacted the phases. The tree was removed and those customers affected were restored quickly. Following the event, the property owner gave consent for additional tree removal.

The other two Storm Pilot circuits faced more tree related incidents and the main line of both of these circuits experience tree related troubles which led to substation lock-outs. A field review by the System Arborist directly after the storm event showed multiple tree failures along the Storm Pilot designated area. Two sideline tree failures on the E13W2 on East Rd, Plaistow and East Rd, Atkinson had been marked and approved for removal prior to the storm.

In other analysis, studying the number of tree related events on the portions of the E58X1 which had not been included in the storm pilot, compared to the number of tree related events on the main line, where the storm pilot was conducted also demonstrate convincing results. There was one event on the main line versus 18 events on the remaining portions of the circuit. For a visual map of the incidents, see Attachment 1: *Hurricane Sandy Tree Related Outages E58X1* of the Company's February 28, 2013 Step Adjustment Filing.

d. Pilot Benefits

The Unitil Seacoast service territory was also hit with other wind and snow events over the November 2012 to January 2013 time frame. Again, in each event, the Storm Pilot circuits performed well with no major events.

From this pilot, it is apparent that the Storm Hardening Pilot work has the ability to prevent tree related failures and subsequent electric incidents. This reduction in incidents reduces damage to the electric infrastructure and the need for crews to respond, in turn reducing overall storm costs.

There are also a number of other benefits associated with a tree exposure reducing Storm Hardening program, including:

- Preserving municipal critical infrastructure
- Minimizing the dependence on mutual aid and off system resources
- Minimizing the total number of resources required to restore service
- Shortening the duration of major events
- Minimizing the overall cost of restoration
- Reducing economic loss to municipals, businesses, and customers
- Most cost effective solution vs. other alternatives
- Minimal bill impact on a per-customer basis

The next section briefly describes each of these benefits.

Because of the design of the Storm hardening program, much of a municipality's critical infrastructure is included in the targeted circuitry. These areas are also most often the business centers for the municipality, and therefore include gas stations, restaurants and hotels. Preserving power during multiple day events to both municipal infrastructure and business districts ensures functioning emergency services, and a place where residents can seek temporary warmth and shelter.

As many states and regulatory jurisdictions have established standards for restoring power during major events, the competition for securing outside line resources has increased significantly, and as a result, resources have become both scarce and very expensive. Often, in order to secure an adequate amount of resources for a particular event, Unitil has been required to reach outside of the New England area, adding travel time and additional cost. Unfortunately, there does not appear to be a ready solution for this problem. One way, however, to manage these escalating costs is to prevent the damage from occurring in the first place. Less damage translates into a reduced need for outside crews, which in turn lowers overall costs and shortens the duration of an event.

As electric utilities review various options to improve overall storm performance, the undergrounding of utility infrastructure is often mentioned, but quickly dismissed due to significant cost and impracticality. The results of the pilot suggest that the implementation of a Storm Hardening program may achieve similar performance to that of undergrounding at a fraction of the cost.

Municipalities and businesses have described the significant economic impact of losing power for multiple days. These natural disasters are very disruptive, result in a loss of business income and tax revenue, personal income loss, and increased costs to municipalities due to the requirements of providing emergency services, debris removal, and requiring overtime work for multiple departments. Any actions that help to minimize this disruption will provide some measure of economic relief.

Finally, customers have expressed concern with losing power for multiple days. Although it is impossible to prevent storm damage across the entire system, preserving power and minimizing damage for each municipality along its main business corridor as well as protecting its emergency critical infrastructure appears to offer significant promise as a means to assure safety and provide some measure of security during and after these extreme weather events.

e. Pilot Costs

All pilot program work was completed within 7% of the estimated budget, with final expenditures (excluding spring tree replanting costs) totaling $572,652. Table 3 shows the cost break down.

Table 3

2012 Storm Pilot Cost Details	
Component	**Cost**
Brochures & Work Materials	$ 4,568
Work Planning & Oversight	$ 36,958
Pruning, Removals, & Police	$531,126
Total	**$572,652**

f. Estimated Customer Costs as a Result of Interruption of Electric Service

The Company provided extensive testimony in NHPUC Docket No. DE 10-055 regarding the costs associated with the loss of electric service for customers. The following summarizes the significant points of this testimony.

The Company believes that reliable electric service is essential to the economic well-being of the businesses and industries we serve, and to the welfare of those who live and work in our communities. Furthermore, interruptions to electric service are both expensive to repair, and expensive to the businesses and individuals who rely on electricity for commercial and household purposes. To cite one example, a 2004 study conducted by Lawrence Berkeley National Laboratory (Berkeley Lab) for the U.S. Department of Energy's Office of Electric Transmission and Distribution estimated that electric power outages and blackouts cost the nation about $80 billion annually. Of this, $57 billion (73 percent) was attributed to losses in the commercial sector and $20 billion (25 percent) in the industrial sector.[3] A subsequent study performed by Berkeley Lab in 2009 provided extensive data on the cost of customer interruptions, including estimates of the average cost of electric interruptions (in 2008 dollars) broken down by customer type, outage duration, time of day, day of week, and other variables.[4]

Utilizing the Company's customer count by class (i.e. Large CI, Small CI, and Residential), and the cost data developed in the 2009 Berkeley Lab study, as well as the Company's 10-year average SAIFI and CAIDI reliability metrics, it is possible to calculate annual costs due to electric service interruptions. For this analysis, all outages were included, including those outages that would normally be excluded from reported reliability under the PUC major storm criteria, since customers do not differentiate between interruptions that are "inclusionary" or "exclusionary" for reliability reporting purposes. The result of this calculation shows that the cost for our customers is approximately $67 million per year.

It is important to note that this is by no means an exact or highly accurate estimate. A more accurate estimate would require detailed consideration of where outages occur in relation to specific types of customers, when outages occur (time of day, day of week), the actual duration of individual outages, and other variables. However, as an order of magnitude estimate, it is instructive when considering the cost of reliability enhancement programs, such as the Storm Resiliency Program, in relation to the value provided to customers. Based on the data from the Berkeley Lab study, any reasonable set of assumptions based on Unitil Energy's historic level of reliability will result in a cost to customers of tens of millions of dollars annually due to interruptions in electric service.

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[3] Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Kristina Hamachi LaCommare and Joseph H. Eto, September 2004.
[4] Estimated Value of Service Reliability for Electric Utility Customers in the United States, Michael J. Sullivan, Ph.D., et al, June 2009.

g. Avoided Company Costs

As described in the Company's February 28, 2013 Step Adjustment Filing, Unitil proposed to implement a 10-year Storm Resiliency Program aimed at reducing tree related outages along approximately 33 miles per year of critical circuitry. It is anticipated that this program will reduce tree related outages for both minor and major weather events. This in turn will reduce the economic impact of interruptions for our customers as described in the previous section, and also reduce overall Company costs of storm preparation, crew costs, and logistics. In addition, this program will ultimately reduce restoration duration.

In order to develop the avoided costs to the Company, we reviewed the data from the Company's two most recent significant storm events; "Snowtober" in October of 2011, and Super Storm Sandy in October of 2012. Selected statistics are shown in Table 4 below.

Table 4

Event Name	Number of Troubles	Total Cost of Event	Average Cost per Trouble
"Snowtober"	362	$2,073,586	$5,728
Super Storm Sandy	428	$2,269,530	$5,303
Totals	**790**	**$4,343,116**	**Avg. $5,498**

Immediately following Super Storm Sandy, the Unitil's System Arborist performed an assessment of the circuit miles involved in the Storm Resiliency Pilot. The results of this field survey showed that the critical main-line circuit miles that had been trimmed per the Storm Resiliency specifications showed no tree related damage, while the critical main-line circuit miles that had not yet been trimmed experienced two tree related troubles. The non-trimmed circuit encompassed 4.6 pole miles of circuitry. Presumably, if this non-trimmed circuitry was completed prior to Super Storm Sandy, the company would have avoided the repair cost of the two trouble locations.

In order to develop a high level avoided cost estimate for the Storm Resiliency Program, it requires an extrapolation of the filed survey data above over the 33 miles of Storm Resiliency program. Performing this calculation results in avoiding approximately 14 tree related outages per storm event (33 miles divided by 4.6 miles; multiply this result by 2 tree troubles) along the circuit miles where the program was implemented. Using the average cost per trouble developed in Table 1, we arrive at an avoided cost of approximately $76,972 per storm event of avoided company costs ($5,498 times 14 avoided tree troubles). This figure would accumulate every year as we complete an additional 33 miles of Storm Resiliency trimming.

As with the estimate for the Customer Costs, this estimate is by no means exact, and can vary significantly based on the assumptions and other factors. A more accurate estimate would require significantly more data points, additional field surveys, and an analysis of costs over a greater number of storm events. However it does provide a measure of magnitude in relation to the cost of the Storm Resiliency program.

As was stated earlier, The Storm Resiliency Program will also provide cost benefits for day-in and day-out troubles. In order to develop a high level avoided cost estimate for these troubles, it requires an extrapolation of avoided tree related troubles per mile across the mitigated circuits. By looking at the annual tree related interruptions for New Hampshire with exclusions taken, and the total number of overhead line miles in New Hampshire, a tree related interruption per mile figure can be calculated. In 2012, Unitil sustained 446 interruptions directly attributable to trees. With 1,169 miles of overhead line, the tree related interruptions per mile is 0.38. (446 interruptions divided by 1,169 miles) This tree related interruption per mile figure multiplied by the 33 miles of line being mitigated annually provides the annual avoided tree related interruptions. This calculation (0.38 interruptions per mile multiplied by 33 miles) results in 13 avoided interruptions, assuming the Storm Resiliency Program eliminates all tree related outages. Assuming the average cost per trouble is 50% of the cost of trouble in a major event ($5,498 divided by 2 equals $2,749) we arrive at an avoided cost of $35,737 per year of avoided company costs ($2,749 times 13 avoided tree interruptions). This figure would accumulate every year as we complete an additional 33 miles of Storm Resiliency trimming.

h. Comparison of Costs to Avoided Costs

When comparing the costs of performing the Storm Resiliency work annually against the high level avoided costs, the comparison shows a reduction in the annual program costs of $112,709, bringing the net annual cost of the program to $1,310,291. Comparing this to the annual cost of $67,000,000 incurred to customers as a result of interruptions of electric service shows that although the costs of implementing the program outweigh the direct company avoided costs, the overall investment would result in a reduction to significantly high customer costs annually. See Table 5 below.

Table 5

Comparison of Costs to Avoided Costs			
Annual Component	**Cost**	**Avoided Cost**	**Cost to Customers** (without the additional work)
Storm Resiliency Program	$1,423,000		
Major Storm Events*		- $ 76,972	
Normal Operation Events		- $ 35,737	
Public Direct Costs of Interruption Events			$67,000,000
Totals	**$1,423,000**	**- $ 112,709**	**$67,000,000**

* Assumes 1 major event annually

While the direct avoided costs are moderate and the avoided costs to customers are high, the indirect or avoided costs to customer have the potential to be even greater. In fact, a moderate 2% savings in the Company's SAIFI and CAIDI annual reliability metrics would translate into customer savings of $1.34 million (2% of the $67 million shown in Table 5); an almost breakeven proposition for our customers.

Certain other benefits to our municipals would also accrue, such as hardening societally critical portions of circuits that serve areas of the community that provide necessary basic services (see conclusion), including municipal critical loads such as police and fire stations, emergency shelters, gas stations, and restaurants and hotels. Other benefits such as overall customer satisfaction or the value of customer gratification in providing a pro-active response to their concerns are difficult to measure, but provide as much or even greater value to the program.

5. Storm Resiliency Program Recommendation

After reviewing the results of the Storm Hardening Pilot program, Unitil found that the reliability effects, the avoided interruptions and costs, the positive public acceptance, and the benefits to customers more than offsets the cost to implement. Unitil is cautious to seek additional funding as we value our relationship with customers and recognize the current economic conditions, however we feel this program brings extreme value and is the best method to reduce storm costs and damages vs. alternatives. As demonstrated in the previous section, we feel this program brings savings to customers through future avoided storm costs.

For this reason, Unitil is proposing to add a Vegetation Management Storm Resiliency program component as part of the overall Vegetation Management Program. This program will build on the pilot program to expand the scope across our Seacoast and Capital regions by mitigating a manageable storm resiliency work plan annually until the system has been completed. The following section explains the development of the proposed program in detail.

6. Development of the Storm Resiliency Program and 2013 Plan

a. Application to System and Circuit Selection

When designing the Storm Resiliency Program, the full list of circuits was reviewed for applicability to the storm resiliency program. Criteria for the program included exclusion based on 1) tree related field condition, 2) customer count and 3) circuit total miles of 3-phase. Any circuits that were located primarily in low tree density areas were removed from the list. Any circuits with less than 500 customers served were reviewed for need as well as any circuit with 3-phase miles less than 2 miles.

Of the 110 circuits containing overhead lines in New Hampshire, 54 were chosen to be included in the storm resiliency program, including the three already mitigated in 2012. The sum of the 3-phase overhead line, which will be mitigated under this program, along the remaining 51 circuits is 331 miles.

The scope of the storm resiliency work will mirror the pilot program's specifications where critical sections of the circuit, from the substation out to the first protection device, will have tree exposure reduced by removing all overhanging vegetation or pruning "ground to sky." Intensive hazard tree review and removal will also be conducted on these critical sections. In cases where the customer count is either over 500 customers or over 1/3 the total customers served at the first protection device (if less than 500), overhang and hazard tree removal will continue to the second protection device. From that point, hazard tree inspection and removal will be conducted out to the third protection device or along remaining three phase lines.

b. Annual Mitigation Goal

In order to determine the annual goal mileage for mitigation, a number of important factors were taken into consideration. First, the number of miles worked needs to be manageable from the Unitil Forestry perspective. There needs to be adequate time to perform work planning, allow for competitive bidding, complete the work and review in the field within the year time frame.

Second, the number of miles needs to be manageable from a line-clearance tree vendor perspective. The line-clearance tree vendor needs adequate equipment and resources to deliver the large quantity of work, both pruning and removals, in the year time frame. This balance of quantity of work and time frame greatly influences the bid price to do work and must be managed appropriately.

For this reason, Unitil felt that working and managing approximately double the work quantity from 2012, approximately 15 miles, would be appropriate. The annual mitigation goal could be set from 25 to 35 miles annually and be feasible.

c. Time Frame Extrapolation

Using the annual goal mileage range, a total program time frame was extrapolated. With 331 miles remaining to be mitigated, and an annual workplan of approximately 33.1 miles, the entire system could be completed in a 10 year time frame.

d. Estimated Costs

Future costs of the storm resiliency program were estimated using the actual 2012 cost per mile of $39,222 plus estimated cost increases for future work based lessons learned from the pilot.

Upon looking at the range in submitted bid prices for the 2012 pilot project, it was apparent that the successful vendor bid prices reflected the fact that they operated out of a location within one of the towns where the storm pilot was being performed. In the absence of this advantage and the addition of travel costs and fuel related to working in other locations across Unitil territory, it was estimated that the cost per mile would be increased to approximately $43,000 a mile.

For 33.1 miles to be mitigated annually at $43,000 a mile, the total annual costs come to approximately $1,423,000 a year.

e. Annual Circuit Selection Process

Of the 51 circuits proposed to undergo storm resiliency program mitigation, an annual selection process has been developed to prioritize those circuits with the greatest need. From increasing importance, the following criteria are proposed to be used: field condition and tree density, past tree-related reliability performance as shown by Unitil's tree model, regional location, and time since last prune or hazard tree mitigation.

Field condition and past tree-related reliability were given the most weight as this drives the actual expected future tree failures based on actual standing hazard trees and actual past failure occurrences.

To look at past tree-related reliability, Unitil's tree model produces a reliability based ranking of every circuit experiencing tree-related outages over a historic 3 year time frame. By circuit, the model sums a customer served ranking, a tree-related events per mile rank, and a customers interrupted per event rank to produce an overall tree-related reliability ranking. The events per mile rank is designed to look at the density of events, indicating a more systemic issue may be present in the field such as pest infestation, residual damage from past storms, or other geographic based field condition. The customers interrupted per event rank is designed to look at where the tree failure condition was located along the circuit and the overall impact of the interruption to the circuit integrity. This is designed to highlight those circuits having failures along portions of circuits that serve the most customers. These individual reliability rankings are combined together to give an overall picture of the circuit reliability and impact if mitigated.

Circuit selection by regional location also plays an important role. In order to be able to deliver the annual work, make it attractive and cost effective to partner line-clearance tree vendors, and manageable from a supervisory perspective, we limited any one year's plan to either the Seacoast or Capital regions.

f. 2013 Plan

For 2013, resiliency work on 33.1 miles of line in the Capital service area is proposed over 4 circuits in the Capital Region at a total cost of the annual proposed spending of $1,423,000 (an increase of $888,000 from the $535,000 approved for last year's pilot program). These circuits, shown in Table 6, affect the areas of Bow, Penacook, and Canterbury.

Table 6

2013 Storm Pilot Planned Work Details		
Circuit	**Overhead Miles**	**Scheduled Miles**
C13W1	33.5	6.2
C18W2	33.6	5.0
C4X1	34.3	7.7
C7W3	23.2	14.2
Total		**33.1**

7. Conclusion

Unitil embarked on a Storm Pilot Program in 2012 in response to the increasing trend of costly and devastating storm events and the public outcry for something to be done to increase response time and shorten event duration. Upon completion of the successful pilot program, Unitil was able to perform a thorough analysis of the results, let in part due to the timing of major storm event Hurricane Sandy in October of 2012. This unique situation led to the conservative high level analysis of potential cost savings of future storm resiliency program implementation. That coupled with the anticipated future savings and economic benefits to customers led to a recommendation for the continuance of storm pilot work as an annual Storm Resiliency Program.

In a recent prominent industry trade magazine from February of 2013, it was suggested that there are evolving concepts as utilities and regulators consider how best to harden the system, manage the effects of storms, all while holding costs at reasonable levels. Their first concept fits exactly in line with what Unitil proposed and piloted in 2012 and was summarized in the article as follows:

> *"The first concept involves circuits that would be designated for special hardening attention. Often, the aftermath of a storm with a widespread impact is particularly hard on the surrounding community because basic required services are not available for days after a storm. For example, gasoline stations have no power to pump gas, people cannot buy ice to throw into refrigerators and pharmacies cannot open. This was a complaint in Florida following the catastrophic 2005 hurricane season. Recently, this was a major concern through New Jersey and New York City in the wake of Hurricane Sandy.*
>
> *Here substantial consideration is given to hardening societally critical circuits, those serving important areas of a community that provide necessary basic services. The cost of making special preparation on these circuits would be permitted to be apportioned over the entire customer base. After a particularly violent storm, homeowners as well as some offices and business might be without power, but the community as a whole would have access to needed basic goods and services."*[5]

As supported by this document, Unitil feels that it is on the cusp of a growing industry need and has developed a comprehensive and balanced approach to providing increased resiliency in storm events.

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[5] Hardening the System, Nicholas Abi-Samara, Lee Willis, and Marvin Moon, Transmission and Distribution World, February 2013, P33

8. 2013 Storm Resiliency Pilot Implementation and Results

a. 2013 Implementation

As with the 2012 pilot, implementation of the 2013 storm resiliency pilot program work, located in Unitil's Capital service territory, began with an outreach program where towns were notified of the work intent, scope of work, and the tentative schedule. The original informational brochure for customer notification and education about the resiliency program was updated, and the new 2013 locations and plans were put up on the company's web site.

Unitil employed three consultant certified arborist work planners trained in risk tree assessment and hazard identification for this project. The consultants were trained in the project scope and risk tree assessment level desired, and work planning began on the four identified circuits. The work planners also conducted extensive customer outreach and education related to the program and sought tree owner consent for pruning and removal. Overall, customers were very understanding about the need for tree work, and the majority of customers consented to pruning and tree removal. There were only 119 trees that were identified as removal candidates where property owners did not want the tree removed. In each case, the owner consented to enhanced pruning instead.

After all work-planning was completed, the 2013 pilot program work was to put out to bid to Unitil's qualified line-clearance vendors. An extensive request for proposal document and pre-bid meeting was prepared to ensure full understanding of the scope and help deliver the lowest market price for specified work. A number of bid questions were also included and vendor response was evaluated to ensure the selected vendors exhibit Unitil's shared values and desire a partnership to invest in the communities where this tree work was being conducted.

Two vendors were chosen to complete the work. Tree pruning and removal work began by the selected vendors immediately after bid award in September and continued through the end of December. The use of specialized equipment such as cranes, a 100 foot bucket, log loaders, staged wood removal sites and mowers was implemented to reduce the surrounding vegetation impact and overall appearance to the community.

b. Work Delivery

When work was completed, 32.3 miles of line were mitigated over the 4 identified circuits. 15.6 miles of critical three phase line had all overhanging vegetation removed (pruned "ground-to-sky") and 2,271 hazard trees were removed along this critical line portion as well as 16.7 additional miles of three phase. (See Table 7)

Table 7

2013 Storm Pilot Work Details			
Circuit	**Scheduled Miles**	**Completed Miles**	**# of Removals**
C13W1	6.2	6.2	657
C18W2	5.0	5.0	823
C4X1	6.9[6]	6.9	253
C7W3	14.2	14.2	538
Total	**32.3**	**32.3**	**2,271**

c. Pilot Response Testing in October Wind Event

During the course of the 2013 pilot pruning and removal work, Unitil was faced with a situation to test the work's response to a minor storm event. On November 24-25, 2013 the company's Capital region experienced a wind event that was forecasted as an EII 4 event with wind gusts of 40-50mph. At this time, two of the Company's 2013 storm resiliency pilot program circuits, C13W1 and C4X1, were complete. During this event, tree related outages were sustained on three of the four pilot circuits, with the most outages being in the Canterbury, NH area on the C13W1 circuit. There were 4 tree related events on this circuit's laterals, but no tree related events on the portions that underwent storm resiliency work.

As designed, the critical portions of this circuit did not experience an interruption and many customers served off this circuit did not experience an electrical outage. It is impossible to know precisely whether an event on the critical portion was avoided as a result of the just completed trimming. However, by looking at the tree related events on the surrounding lines, an estimate of events that would have been expected on the critical portions can be determined.

By looking at the number of events on the unworked portion, an event per mile calculation can be determined. Assuming that the portion of circuit that was worked would have had the same tree failure rate, this event per mile calculation can be used to determine the avoided events on the storm resiliency circuit miles. (See Table 8) There were 4 events along the 27.3 miles not under the storm resiliency program; 0.146 events per mile. Apply this to the storm resiliency area worked and assume this work avoided 0.146 events per mile over the entire 6.2 miles of area worked; then ~1 event on the critical portions of line was avoided during this wind event.

[6] C4X1 scheduled mileage adjusted from 7.7 miles to 6.9 miles before work planning, due to circuit configuration and isolating device changes.

Tree Related Outages on November 24-25, 2013							
Circuit	# Outage Events	# Customers Interrupted	Total Circuit Miles	SRP Mileage Worked	Mileage Non-SRP	Events / Mile on Non-SRP	Avoided Events on SRP portions
C13W1	4	141	33.5	6.2	27.3	0.146	0.908

d. 2013 Pilot Costs

All pilot program work was completed within 5% of the estimated budget, with final expenditures (excluding spring tree replanting costs) totaling $1,351,976. Table 8 shows the cost break down.

Table 8

2013 Storm Pilot Cost Details	
Component	**Cost**
Brochures & Work Materials	$ 2,845
Work Planning & Oversight	$ 55,919
Pruning, Removals, & Police	$1,293,212
Total	**$1,351,976**

e. Additional Benefits

In addition to the significant benefits described in detail in sections 4 d. and 4 g. of the original report (preserving critical electric and municipal infrastructure, reduction of economic loss to municipals, businesses, and customers, minimize dependence on mutual aid, and shortening the duration of major events, etc.) additional benefits to the communities where work occurs were identified.

Tree removal and pruning is the foundation of storm resiliency program, and a major effort is made so that the byproduct, woody biomass, from this work is put back into the communities, thereby reducing the need for heating oil or other non-renewable energy sources of electricity. The vendor working on the C13W1 and C4X1, Mayer Tree, actually measured the amount of woody biomass removed on these two circuits allowing for an estimate of this benefit to be calculated. 344 tons of wood logs were removed and taken to Concord Steam to be processed for cogeneration and 663 tons of wood chips were removed and taken to the new cogeneration plant in Berlin, NH. In total, 1007 tons of woody biomass was removed on these two circuits alone. One cord of wood is approximately 2 tons, so there were about 504 total cords of wood removed.

If estimated that when burned the wood produces about 25 million BTU's per cord[7], the 504 cords of wood are equal to 12.6 billion BTU's. 1 billion BTU's can generate all the electricity that approximately 300 average homes use in one month[8]. Using the 12.6 billion BTU's that can be generated from the 504 cords of wood removed, 3,780 average homes could be powered by this wood for a month, or about 315 average homes for a year. This does not include wood left on-site for property owners, which adds additional woody biomass removed under the project and also reduces home heating bills or eliminates firewood purchase cost for these customers.

Another fringe benefit of the project is the tree vendor worker employment in the area, corresponding police and flagger traffic control employment, and the economic impact to the state and communities from their employment. Between the two vendors it is estimated that 20 to 30 tree workers were employed over the 3 months, with an additional 10 to 15 roadway safety personnel employed per day.

f. Additional Research & Support

Utility storm resiliency and associated programs are an emerging trend. In an effort to remain updated on the potential practices and solutions available, the Company frequently reviews articles and research documents on this topic. Additional supporting documents relating to storm resiliency and vegetation management were recently found.

The following document cites recent major storm events and offers vegetation management as an important consideration to improve storm resiliency.

Houseman, Doug, "The #1 Way to Improve Storm Resilience (it's not about outage management)", SmartGridNews.com, January 2014.

The following document cites municipal storm resiliency as an emerging issue and offers critical infrastructure hardening as a key factor in an initiative for energy resilience.

Massachusetts Department of Energy Resources, "Energy Resiliency for Climate Adaptation Initiative", January 2014.

The following document, while not specifically focused on vegetation management centered resiliency programs, discusses the economic impact of power outages and cites studies that estimate the total cost of power outages caused by weather in the United States.

President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages", August 2013.

[7] http://forestry.usu.edu/htm/forest-products/wood-heating

[8] U.S. Energy Information Administration (EIA). 2006. Apples, oranges, and Btu https://edis.ifas.ufl.edu/fr284

9. Conclusion

Unitil embarked on a Storm Pilot Program in 2012 in response to the increasing trend of costly and devastating storm events and the public outcry for something to be done to increase response time and shorten event duration. After overwhelmingly positive results from this program, Unitil proposed to complete a second, slightly larger Storm Pilot Program in 2013. Again, this program was met with huge success as over 2,000 trees were removed over 32 miles of critical electric and municipal infrastructure. As demonstrated by the supporting documentation presented here, and most specifically the results seen in Hurricane Sandy and the minor wind event in November of 2013, Unitil believes this program has significant benefit to customers and municipalities.

As supported by this document, Unitil feels that it is on the cusp of a growing industry need and has developed a comprehensive and balanced approach to providing increased resiliency in storm events.

Energy Resiliency for Climate Adaptation Initiative

DOER's "Energy Resiliency for Climate Adaptation Initiative" is part of the Patrick Administration's comprehensive climate change preparedness effort. The grant program is focused on municipal resilience: protecting communities from interruptions in energy services due to severe climate events enhanced by the effects of climate change.

The initiative is funded by $40 million in Alternative Compliance Payments (ACP), which are paid by electric retail suppliers if they have insufficient Renewable or Alternative Energy Certificates to meet their compliance obligations under the Renewable and Alternative Portfolio Standard programs. Funding is to be allocated appropriately and competitively across the Commonwealth.

DOER will engage with other state agencies, regional planning agencies, and the utilities to prepare for this initiative.

Grants will be available for communities to harden critical energy services using clean energy technology for critical facilities.

- Critical facilities include:
  - Life safety resources – police, fire, hospitals, wastewater treatment, and shelters
  - Lifeline resources – food supply, communications and transportation
  - Community resources – city/town halls and senior centers, schools or multi-family housing developments capable of sheltering
- Clean energy technologies include:
  - Distributed renewable energy generation (electric and heating/cooling systems) and energy efficiency
  - CHP/district energy systems
  - Energy storage (flywheels, batteries, electric vehicles, hot/cold water storage)
  - High efficiency fuel cells
  - Energy management and demand response systems
  - Advanced controls, switches, inverters and other grid stability technologies
  - Microgrids

Preliminary Timeframe

Establish program design: November 2013 - February 2014

Solicit proposals from cities and towns: March - June 2014

Proposal evaluation, awards, and implementation are expected to span the remainder of 2014 and into 2015.

For more information, contact Amy McGuire, amy.mcguire@state.ma.us, 617-626-7380

ECONOMIC BENEFITS OF INCREASING ELECTRIC GRID RESILIENCE TO WEATHER OUTAGES

Executive Office of the President

August 2013

This report was prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology

Executive Summary

Severe weather is the leading cause of power outages in the United States. Between 2003 and 2012, an estimated 679 widespread power outages occurred due to severe weather. Power outages close schools, shut down businesses and impede emergency services, costing the economy billions of dollars and disrupting the lives of millions of Americans. The resilience of the U.S. electric grid is a key part of the nation's defense against severe weather and remains an important focus of President Obama's administration.

In June 2011, President Obama released *A Policy Framework for the 21st Century Grid* which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21st century smart grid technologies focused at increasing the grid's efficiency, reliability, and resilience, and making it less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage occurs.

Grid resilience is increasingly important as climate change increases the frequency and intensity of severe weather. Greenhouse gas emissions are elevating air and water temperatures around the world. Scientific research predicts more severe hurricanes, winter storms, heat waves, floods and other extreme weather events being among the changes in climate induced by anthropogenic emissions of greenhouse gasses.

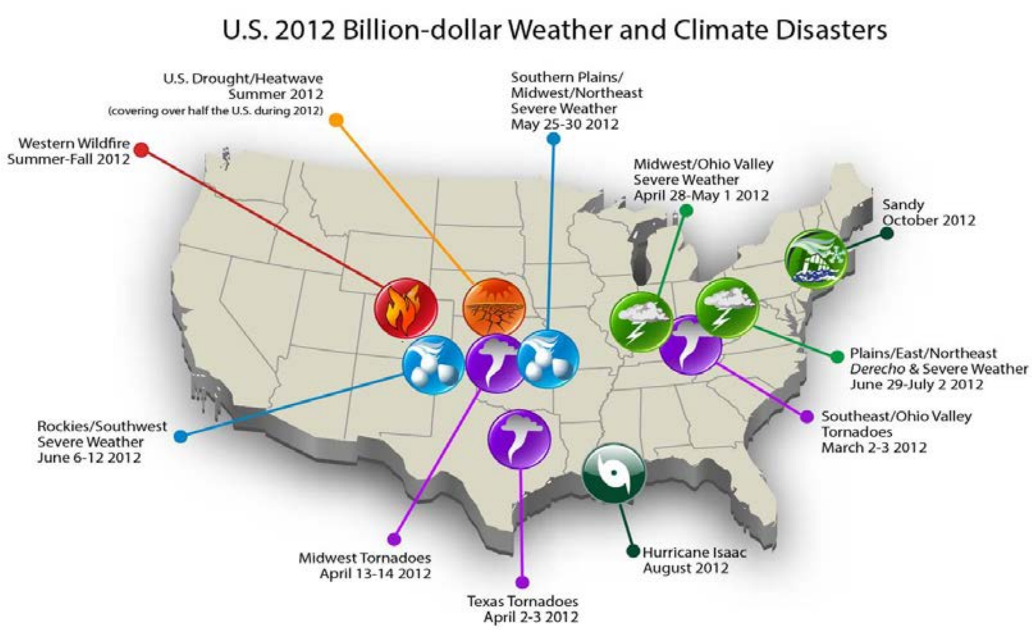
This report estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience. Over this period, weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion. Annual costs fluctuate significantly and are greatest in the years of major storms such as Hurricane Ike in 2008, a year in which cost estimates range from $40 billion to $75 billion, and Superstorm Sandy in 2012, a year in which cost estimates range from $27 billion to $52 billion. A recent Congressional Research Service study estimates the inflation-adjusted cost of weather-related outages at $25 to $70 billion annually (Campbell 2012). The variation in estimates reflects different assumptions and data used in the estimation process. The costs of outages take various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid. Continued investment in grid modernization and resilience will mitigate these costs over time – saving the economy billions of dollars and reducing the hardship experienced by millions of Americans when extreme weather strikes.

I. Introduction

The U.S. electric grid ("the grid") constitutes a vital component of the nation's critical infrastructure and serves as an essential foundation for the American way of life. The grid generates, transmits, and distributes electric power to millions of Americans in homes, schools, offices, and factories across the United States. Investment in a 21st century modernized electric grid has been an important focus of President Obama's administration. A modern electric grid will be more reliable, efficient, secure, and resilient to the external and internal cause of power outages – improving service for the millions of Americans who rely on the grid for reliable power.

Severe weather is the number one cause of power outages in the United States and costs the economy billions of dollars a year in lost output and wages, spoiled inventory, delayed production, inconvenience and damage to grid infrastructure. Moreover, the aging nature of the grid – much of which was constructed over a period of more than one hundred years – has made Americans more susceptible to outages caused by severe weather. Between 2003 and 2012, roughly 679 power outages, each affecting at least 50,000 customers, occurred due to weather events (U.S. Department of Energy).

The number of outages caused by severe weather is expected to rise as climate change increases the frequency and intensity of hurricanes, blizzards, floods and other extreme weather events. In 2012, the United States suffered eleven billion-dollar weather disasters – the second-most for any year on record, behind only 2011. The U.S. energy sector in general, and the grid in particular, is vulnerable to the increasingly severe weather expected as the climate changes (DOE 2013).



Source: National Oceanic and Atmospheric Administration

The American Recovery and Reinvestment Act of 2009 ("Recovery Act") allocated $4.5 billion to the U.S. Department of Energy (DOE) for investments in modern grid technology which have begun to increase the resilience and reliability of the grid in the face of severe weather (Executive Office of the President 2013). A more resilient grid is one that is better able to sustain and recover from adverse events like severe weather – a more reliable grid is one with fewer and shorter power interruptions. Methods for improving the resilience and reliability of the grid include both high and low-tech solutions.

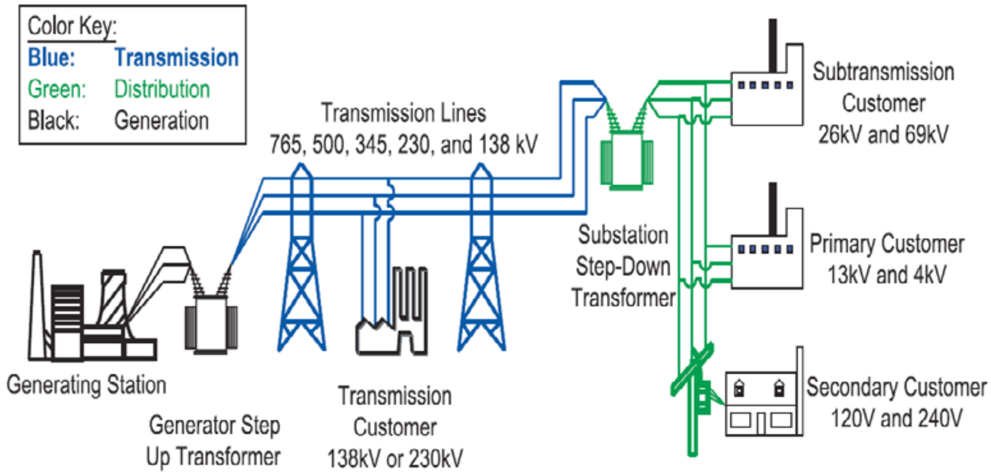
This report begins by describing the current state of the U.S. electric grid, the impact of widespread power outages caused by severe weather, and the increasing intensity and frequency of severe weather due to climate change. The report then documents numerous strategies for increasing the grid resilience and reliability. Lastly, an economic model is presented and used to estimate the annual cost of power outages caused by severe weather in the United States. The benefits of increased grid resilience include the avoided cost of these outages.

II. Status and Outlook of the Electric Grid

The grid delivers electricity to more than 144 million end-use customers in the United States (U.S. Energy Information Administration 2013). The grid consists of high-voltage transmission lines, local distribution systems, and power management and control systems.[1] Electricity is produced at generation facilities and transported to population centers by high-voltage transmission lines. After arriving at population centers, electricity enters local distribution systems where it travels through a series of low-voltage lines in a process called "stepping down" before reaching homes, offices and other locations for consumption. The grid connects Americans with 5,800 major power plants and includes over 450,000 miles of high voltage transmission lines (American Society of Civil Engineers 2012).

[1] Although the grid also includes generation facilities, this report focuses on the status and outlook of the grid's transmission, distribution and management/control systems.

Basic Structure of the U.S. Electric Grid



Source: U.S. Canada Power System Outage Task Force

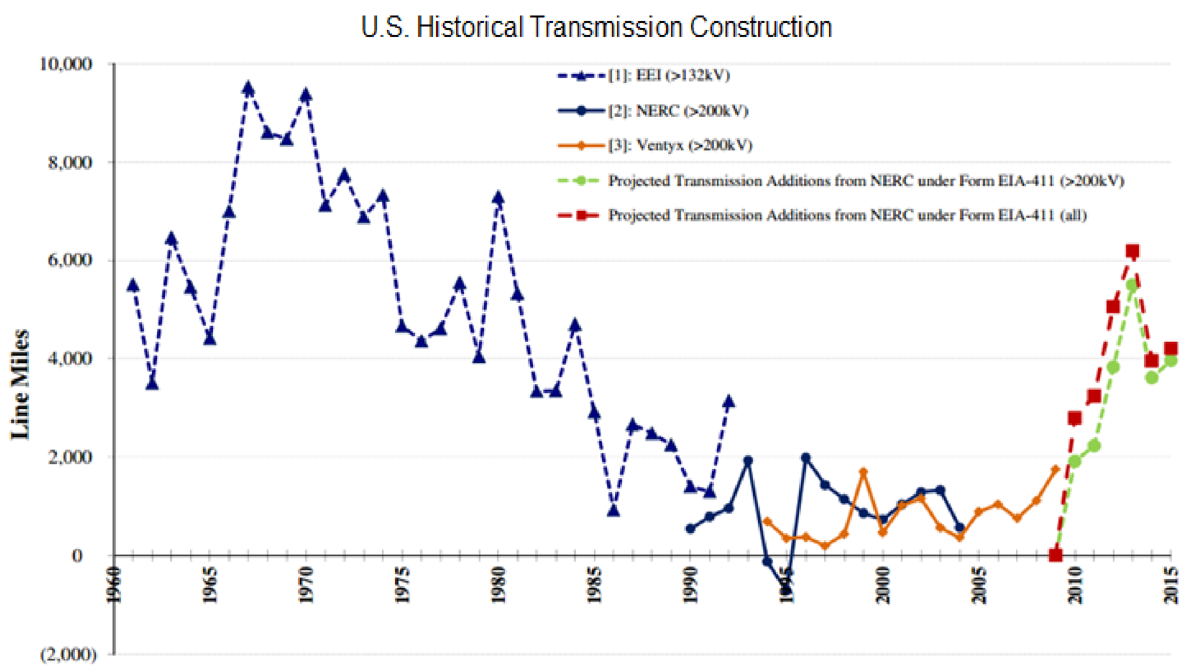
The transmission grid consists of eight regions and is overseen by the North American Electric Reliability Corporation (NERC), a non-profit entity responsible for the reliability of the bulk power system in North America (including the United States and Canada), subject to the oversight of the Federal Energy Regulatory Commission (FERC). The U.S. electric system is primarily comprised of three interconnections (Eastern, Western and Texas interconnection). The three interconnections are linked by direct current (DC) transmission lines which limit and control the amount of electricity transferred between them. Within each interconnection, electricity travels through a network of alternating current (AC) transmission lines.

North American Reliability Corporation, Grid Regions

Source: North American Reliability Corporation

Most of the grid is privately owned by for-profit utility companies. Since public utilities are natural monopolies, government agencies regulate electric rates and operating practices. State agencies regulate the rates charged by local utilities while both federal and state governments oversee the operation of generating facilities and transmission systems (ASCE 2012). Electric utilities are defined as any entity generating, transmitting or distributing electricity. Utilities can be either publicly-owned, investor-owned or cooperatives. As of 2010, roughly 62 percent of utilities were publicly-owned; however, investor-owned utilities serve the majority of customers (68 percent) (American Public Power Association 2012).

Construction of the grid began in the late 1880s and continues today – albeit at a significantly slower pace. In the mid-2000s, transmission lines across all eight NERC regions were built at a rate of roughly 1,000 circuit miles per year. This rate more than doubled to 2,300 circuit miles in the five years leading up to a NERC reliability assessment published in 2012. Despite the increase, projected construction of transmission lines remains well below the rates experienced between 1960 and 1990 (Pfeifenberger 2012). Seventy percent of the grid's transmission lines and power transformers are now over 25 years old and the average age of power plants is over 30 years (Campbell 2012).



Source: The Brattle Group, 2012

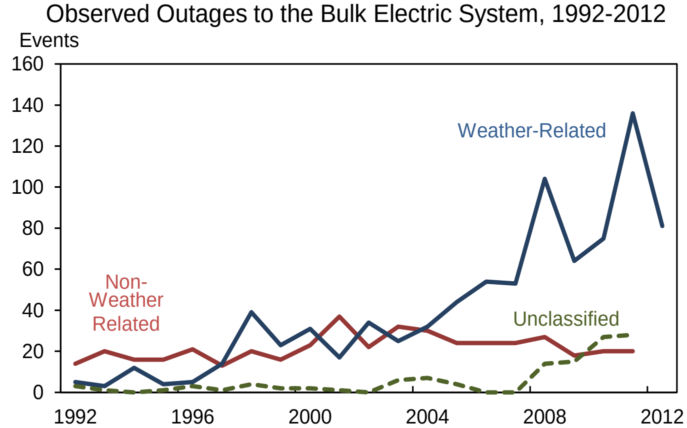
The age of the grid's components has contributed to an increased incidence of weather-related power outages. For example, the response time of grid operators to mechanical failures is constrained by a lack of automated sensors. Older transmission lines dissipate more energy than new ones, constraining supply during periods of high energy demand (ABB Inc. 2007). And, grid deterioration increases the system's vulnerability to severe weather given that the majority of the grid exists above ground.

In response to the growing need for grid modernization, the federal government has allocated billions of dollars to replace, expand and refine grid infrastructure. The American Recovery and Reinvestment Act of 2009 (“Recovery Act”) allocated $4.5 billion for investments in modern grid technology (EOP 2013). Smart grid technology utilizes remote control and automation to better monitor and operate the grid. Between June 2011 and February 2013, Recovery Act funds have been used to deploy 343 advanced grid sensors, upgrade 3,000 distribution circuits with digital technology, install 6.2 million smart meters and invest in 16 energy storage projects (EOP 2013). These investments have contributed to significant increases in grid resilience, efficiency and reliability.

III. Impact of Severe Weather on the U.S. Electric Grid

Severe weather is the single leading cause of power outages in the United States. Outages caused by severe weather such as thunderstorms, hurricanes and blizzards account for 58 percent of outages observed since 2002 and 87 percent of outages affecting 50,000 or more customers (U.S. DOE, Form OE-417). In all, 679 widespread outages occurred between 2003 and 2012 due to severe weather. [2] Furthermore, the incidence of both major power outages and severe weather is increasing. Data from the U.S. Energy Information Administration show that weather-related outages have increased significantly since 1992.

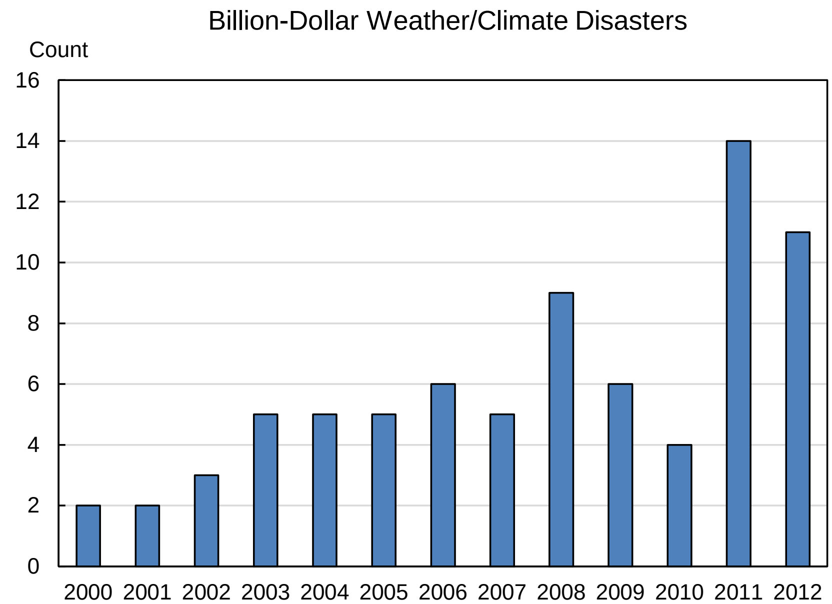
Observed Outages to the Bulk Electric System, 1992-2012



Source: Energy Information Administration

[2] Other causes of power outages include: operational failures, equipment malfunctions, circuit overloads, vehicle accidents, fuel supply deficiencies and load shedding – which occurs when the grid is intentionally shut down to contain the spread of an ongoing power outage (U.S. DOE, Form OE-417).

Since 1980, the United States has sustained 144 weather disasters whose damage cost reached or exceeded $1 billion. The total cost of these 144 events exceeds $1 trillion (U.S. Department of Commerce 2013). Moreover, seven of the ten costliest storms in U.S. history occurred between 2004 and 2012 (U.S. DOC 2012). These "billion dollar storms" have rendered a devastating toll on the U.S. economy and the lives of millions of Americans.



Source: National Oceanic and Atmospheric Administration (NOAA)

According to the National Climate Assessment, the incidence and severity of extreme weather will continue to increase due to climate change. The 2009 assessment of the U.S. Global Change Research Program (USGCRP) on behalf of the National Science and Technology Council found that anthropogenic emissions of greenhouse gases are causing various forms of climate change including higher national and global temperatures, warmer oceans, increased sea levels, and more extreme weather events (USGCRP 2009). The increased incidence of severe weather represents one of the most significant threats posed by climate change (USGCRP 2013).

Climate change is expected to alter patterns of precipitation. Northern areas of the United States are projected to become wetter, especially in the winter and spring, while southern areas are projected to become drier. In addition, heavy precipitation events will become more frequent. Depending on location, severe downpours currently occurring once every 20 years are projected to occur every 4 to 15 years by 2100 (USGCRP 2009).

In addition to higher temperatures and changing patterns of precipitation, scientists expect warmer ocean temperatures to increase hurricane intensity. Hurricanes draw energy from the temperature difference between ocean surfaces and the mid-level atmosphere. Over the past three decades, the North Atlantic has already experienced the trend of increasing hurricane intensity (Kossin et al. 2007). Moreover, several studies project a substantial increase in hurricane-related costs due to climate change (Mendelsohn et al. 2012; Nordhaus 2010; Narita et al. 2009). Similarly, winter storms will also become stronger, more frequent, and costly (USGCRP 2009). Investment in modern infrastructure will be required to maintain grid reliability as these weather changes occur.

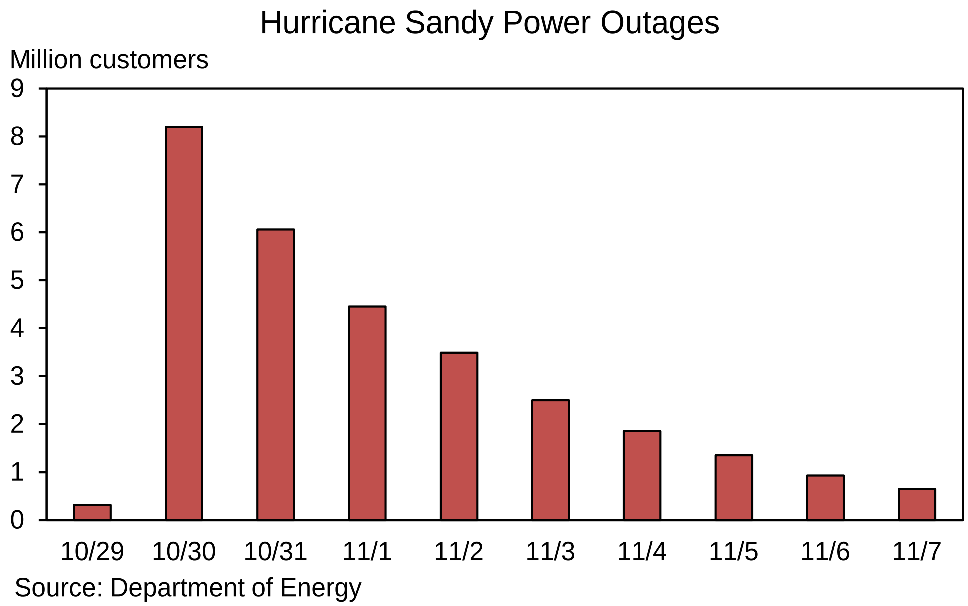
Case Study: Superstorm Sandy

Superstorm Sandy made landfall near Atlantic City, New Jersey as a post-tropical cyclone on October 29, 2012 and then continued northwest over New Jersey, Delaware and Pennsylvania. The heaviest damage was due to record floods in New York and New Jersey. A storm surge of 12.65 feet hit New York City causing flooding of 4 to 11 feet in Lower Manhattan. New Jersey experienced a storm surge of 8.57 feet which caused flooding of 2 to 9 feet in ten counties across the state. In all, the storm damaged 650,000 homes and knocked out power for 8.5 million customers.

Sandy directly caused the deaths of 72 people in the United States and an estimated $65 billion in damages – the second-costliest cyclone to hit the U.S. since 1900. Sandy indirectly caused the death of another 87 people, 50 of which were attributed to power outages. Numerous senior citizens without heat died from hypothermia while other victims died of carbon monoxide poisoning due to improperly vented generators (U.S. DOC 2013; Blake 2013).

Smart grid investments made by the U.S. Department of Energy's Smart Grid Investment Grant (SGIG) in some of the states hit by Sandy lessened the impact for thousands of electric customers. For example, In Philadelphia, roughly 186,000 smart meters were up and running by the time Sandy hit. The Philadelphia Electric Company (PECO) estimated that about 50,000 customers experienced shorter outages due to its new smart grid systems, which also included upgrades to its Outage Management System (OMS). PECO observed more than 4,000 instances where smart meters were able to remotely determine when power was restored, saving PECO and its customers time and money.

In the Washington D.C. metropolitan area, the Potomac Electric Power Company (PEPCO) said it was able to restore power to 130,000 homes in just two days after Sandy thanks to advanced meter infrastructure (AMI) deployed under its SGIG projects. With smart meters and AMI connecting roughly 425,000 homes, PEPCO received "no power" signals that allowed them to quickly pinpoint outage locations. The signals arrived at PEPCO's central monitoring center, allowing the company to respond to customers quickly and effectively. After power was restored, PEPCO continually "pinged" the meters to verify service restoration, thus avoiding the need to send repair crews.



Case Study: Hurricane Irene

Hurricane Irene made landfall near Cape Lookout, North Carolina on August 27, 2011 as a category one hurricane and then continued north-eastward making a second landfall near Atlantic City, New Jersey. Irene's most significant impact was on the mid-Atlantic states through New England with the heaviest damage occurring in New Jersey, Massachusetts and Vermont due to inland flooding (Avila and Cangialosi 2011). In all, 2.3 million people were mandatorily evacuated in advance of Irene's devastation (U.S. DOC, 2011).

More than 6.5 million people in the United States lost power during Hurricane Irene, which includes over 30 percent of the people living in Rhode Island, Connecticut and Maryland (U.S. DOE 2011). Irene caused the death of 41 people in the United States and resulted in $15.8 billion in total damages (Avila and Cangialosi 2011) - the seventh costliest hurricane in U.S. history (U.S. DOC 2012a).

Smart grid investments made before Irene's landing lessened the storm's impact for thousands of electric customers. Investments in advanced metering infrastructure (AMI) improved outage notification and response time, greatly reducing the duration of outages. In Pennsylvania, the Pennsylvania Power & Light's (PPL) smart grid investments in distribution automation technologies made a difference for 388,000 customers who lost power.

IV. Strategies for Achieving Grid Resilience

Grid resilience, a core requirement for climate adaptation, includes hardening, advanced capabilities, and recovery/reconstitution. Although most attention is placed on best practices for hardening, resilience strategies must also consider options to improve grid flexibility and control. Resilience includes reconstitution and general readiness such as pole maintenance, vegetation management, use of mobile transformers and substations, and participation in mutual assistance groups. This section summarizes several key ways to improve grid resilience. Additional details are provided in the U.S. Department of Energy report (DOE 2010a).

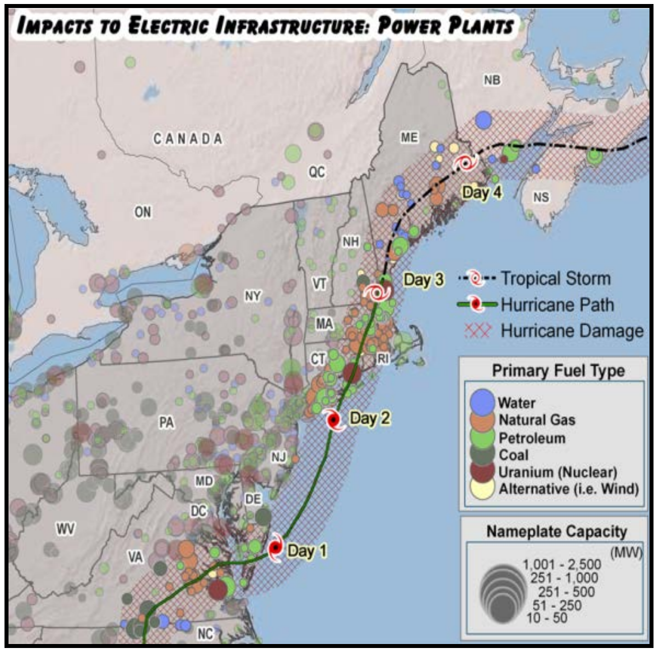
Grid resilience strategies require a partnership across all levels of government and the private sector to promote a regional and cross-jurisdictional approach. Because the electric grid cannot be 100 percent secure, the strategy must identify the greatest risks to the system and determine the cost and impact to mitigation/hardening strategies to advance the capability of the grid. Furthermore, the 2003 Northeast Blackout and the 2011 Southwest Blackout raised several reliability issues and technology limitations that add complexity to grid resilience. Although this report focuses on the economic benefit of avoiding outages related to severe weather, grid resilience encompasses an all-hazard approach.

Priority 1: Manage Risk

Risk management is a process that examines and evaluates policies, plans, and actions for reducing the impact of a hazard or hazards on people, property and the environment. Managing expectations is an important aspect of risk management because risk to the grid cannot be completely eliminated even with the most appropriate and successful strategies. (The National Academies Press 2012).

An important part of assessing risk is the ability to conduct exercises to identify and mitigate the potential impacts of identified hazards. In 2011, the Department of Energy conducted four major regional exercises across the country. One of the scenarios for the Northeast Exercise simulated a hurricane. The simulated hurricane closely resembled Hurricane Irene and produced an estimate of 6.4 million customers without power.

Individual utilities also engage in storm preparation, response planning, and readiness exercises. These activities are important, as is communication and coordination among utilities and participation in mutual aid programs.



Priority 2: Consider Cost-Effective Strengthening

Electricity is a critical element of the highly interdependent energy supply and distribution system. A refinery or pipeline pumping station, even if undamaged by a hurricane, will not be able to operate without access to electricity. Most utilities have active plans in place to harden their infrastructure against wind and flood damage. In fact, since 2005, multiple state public utility commissions have issued rulemakings and/or regulatory activities related to electricity infrastructure hardening.

Hurricane-force winds are the primary cause of damage to electric utility transmission and distribution (T&D) infrastructure. Upgrading poles and structures with stronger materials constitutes a primary hardening strategy. For distribution systems, this usually involves upgrading wooden poles to concrete, steel, or a composite material, and installing support wires and other structural supports. For transmission systems, this usually involves upgrading aluminum structures to galvanized steel lattice or concrete. In addition, adequate vegetation management programs can help prevent damage to T&D infrastructure. Although transmission system outages do occur, roughly 90 percent of all outages occur along distribution systems (Edison Electric Institute).

Placing utility lines underground eliminates the distribution system's susceptibility to wind damage, lightning, and vegetation contact. However, underground utility lines present significant challenges, including additional repair time and much higher installation and repair costs. Burying overhead wires costs between $500,000 and $2 million per mile, plus expenses for coolants and pumping stations. Perhaps the most important issue for coastal regions is that underground wires are more vulnerable to damage from storm surge flooding than overhead wires.

Common hardening activities to protect against flood damage include elevating substations and relocating facilities to areas less prone to flooding. Unlike petroleum facilities, distributed utility T&D assets are not usually protected by berms or levees. Replacing a T&D facility is far less expensive than building and maintaining flood protection. Other common hardening activities include strengthening existing buildings that contain vulnerable equipment, and moving equipment to upper floors where it will not be damaged in the event of a flood.

Case Study: Florida Power & Light Company
Florida Power & Light Company (FPL) expects to invest approximately half a billion dollars between 2013 and 2015 to improve electric system resilience for its customers. The plan builds on the company's storm hardening initiative by incorporating additional lessons learned from Superstorm Sandy, such as those related to flooding, as well as from Florida storm activity in 2012. These recent experiences show that strengthened electric infrastructure reduces storm-related outages and reduces restoration times when outages occur. Specifically, FPL's 2013-2015 investment plans include: 1) hardening for critical facilities and other essential community needs, 2) accelerated deployment of wind-resilient transmission structures and equipment, and 3) strengthened equipment in areas most vulnerable to storm surges. (Florida Power & Light Company 2013, DOE 2012a)

Priority 3: Increase System Flexibility and Robustness

Additional transmission lines increase power flow capacity and provide greater control over energy flows. This can increase system flexibility by providing greater ability to bypass damaged lines and reduce the risk of cascading failures. Power electronic-based controllers can provide the flexibility and speed in controlling the flow of power over transmission and distribution lines.

Energy storage can also help level loads and improve system stability. Electricity storage devices can reduce the amount of generating capacity required to supply customers at times of high energy demand – known as peak load periods. Another application of energy storage is the ability to balance microgrids to achieve a good match between generation and load. Storage devices can provide frequency regulation to maintain the balance between the network's load and power generated. Power electronics and energy storage technologies also support the utilization of renewable energy, whose power output cannot be controlled by grid operators.

A key feature of a microgrid is its ability during a utility grid disturbance to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid. Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid in an equally seamless fashion. Technologies include advanced communication and controls, building controls, and distributed generation, including combined heat and power which demonstrated its potential by keeping on light and heat at several institutions following Superstorm Sandy.[3]

Priority 4: Increase Visualization and Situational Awareness

Until recently, most utilities became aware that customers had lost power when the customers called to report the outage. Thus utilities have had incomplete information about outage locations, resulting in delayed and inefficient responses. Smart meters have outage notification capabilities which make it possible for utilities to know when customers lose power and to pinpoint outage locations more precisely. Smart meters also indicate when power has been restored. When the outage notification capability enabled by smart meters is coupled with automated feeder switching, the result is a significant improvement in field restoration efforts since field crews can be deployed more efficiently, saving time and money. The Recovery Act investment has added greater visibility and intelligence across the electric system through advanced outage management systems, distribution management tools as well as transmission visibility.

Another example, synchrophasor technology, derived from phasor measurement units (PMUs), is used within the transmission system to provide high-fidelity, time-synchronized visibility of the grid. PMUs enable operators to identify reliability concerns, mitigate disturbances, enhance the efficiency/capacity of transmission system, and help manage islanding during emergency situations.

[3] Stony Brook University, "In the Aftermath of Superstom Sandy: A Message from President Stanley," http://www.stonybrook.edu/sb/sandy/index.shtml; ICF International, "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities," 03/2013, http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

Case Study: Entergy Corporation
During Hurricane Gustav in 2008, Entergy, an energy company responsible for delivering power to customers in Arkansas, Louisiana, Mississippi and Texas, had 14 transmissions trip-out-of-service in the Baton Rouge to New Orleans area which created a Baton Rouge-New Orleans electrical island for 33 hours, meaning interconnection to the grid was lost. During this period, Entergy was able to control the island's frequency, balance three large generating units, and maintain electric service to customers because of the 21 PMUs the company had installed across a four-state area. PMUs identified and warned of islanding conditions during emergencies and provided Entergy with insight into how to manage islands and where else in the territory additional PMUs were needed. Entergy's success with PMUs during Gustav demonstrated that these devices had moved from being optional equipment to vital components of a modern electric grid (Galvan et al. 2008).

Priority 5: Deploy Advanced Control Capabilities

Many of the recipients of Recovery Act funds are deploying automated feeder switches that open or close in response to a fault condition identified locally or to a control signal sent from another location. When a fault occurs, automated feeder switching immediately reroutes power among distribution circuits isolating only the portion of a circuit where the fault has occurred. The result is a significant reduction in the number of customers affected by an outage and the avoidance of costs typically borne by customers when outages occur.

One recent example involves EPB of Chattanooga who estimated that power outages resulted in an annual cost of $100 million to the community and installed automated fault isolation and service restoration technology. During a July 2012 wind storm, automated switching in the distribution system instantly reduced the number of sustained outages by 50 percent to 40,000 customers. When coupled with information on customer outage provided by meters, the utility was able to avoid 500 truck rolls and reduce total restoration time by 1.5 days, representing almost $1.5 million in operational savings and significant avoidance of costs to customers.

The reports for both the 2011 Arizona-Southern California and 2003 Northeast blackouts illustrate that real-time monitoring tools were inadequate to alert operators to rapidly changing system conditions and contingencies (FERC/NERC 2012). Providing operators with new tools that enhance visibility and control of transmission and generation facilities could help them manage the range of uncertainty caused by variable clean electricity generation and smart load, thus enhancing the understanding of grid operations.

Priority 6: Availability of Critical Components and Software Systems

Installing equipment health sensors can reveal possibilities for premature failures. Typically, these devices are applied on substations and other equipment whose failure would result in significant consequences for utilities and customers. When coupled with data analysis tools, equipment health sensors can provide grid operators and maintenance crews with alerts and actionable information. Actions may include taking equipment offline, transferring load to alleviate stress on critical components, or repairing equipment. Understanding equipment condition allows utilities to undertake predictive and targeted maintenance. As a result, utilities can employ asset management strategies that lead to greater availability of critical components.

Large power transformers are custom-designed equipment that entail significant capital expenditures and long lead times due to an intricate procurement and manufacturing process. These transformers can cost millions of dollars and weigh between approximately 100 and 400 tons. The domestic production capacity for large power transformers in the United States is improving. In addition to EFACEC's first U.S. transformer plant that began operation in Rincon, Georgia in April 2010, at least three new or expanded facilities will produce extra high voltage large power transformers (U.S. DOE 2012b).

V. The Economic Benefit of Modernization and Increased Grid Resilience

The significant impact of severe weather on the U.S. electric grid showcases the importance of investment in grid modernization. A modern electric grid will be more resilient to severe weather, meaning outages will affect fewer customers for shorter periods of time. This report estimates the annual cost of outages caused by severe weather.

The Cost of Power Outages

Several studies have estimated the total cost of power outages in the United States, including those caused by weather and those caused by non-weather related events. These studies are based on estimates of utility customers' value of service reliability, which is in turn estimated either by surveys of willingness to pay for avoided outages or by survey estimates of the direct costs of outages (Sullivan et al. 2009).

Previous Estimates of Annual Cost of Power Outages

Source	Estimate (2012 dollars)	Year published
All outages		
Swaminathan and Sen	$59 billion	1998
PRIMEN	$132 to $209 billion	2001
LaCommare & Eto	$28 to $169 billion	2005
Weather-related outages		
Campbell (CRS)	$25 to $70 billion	2012

An early estimate of the total cost of power outages was developed by Swaminathan and Sen in 1998. The estimate uses data from a 1992 Duke Power survey on the cost of outages to the U.S. industrial sector. The study focuses solely on industrial customers and excludes the commercial and residential sectors. The study extrapolates survey data from industrial firms in the southeastern region of the United States to estimate the cost of outages to industrial firms across the country. Evidence suggests, however, that the cost of outages to industrial customers varies significantly by geographic region (Lawton et al. 2003).

In 2001, Primen Inc., a consulting firm now a part of the Electric Power Research Institute, estimated the total cost of power outages using survey data from 985 industrial and digital economy (DE) firms. Unlike Swaminathan and Sen, Primen's survey was representative of firms in all geographic regions of the United States. Industrial and DE firms were chosen due to their sensitivity to power outages and important contribution to U.S. GDP. Each firm was asked to estimate the cost of hypothetical outages varying in duration, time of day and whether or not the outage was expected.[4] The results of the surveys were extrapolated across all business sectors to determine the total annual cost of outages. Like Swaminathan and Sen, Primen's inflation-adjusted cost estimate of $132 billion to $209 billion does not account for the cost of outages to residential customers.

In 2005, LaCommare and Eto estimated the total cost of power outages using national statistics reported by utility firms on outage frequency and duration. The cost of each outage was determined using a cost function calculated in Lawton et al. 2003. Lawton based the function on survey data gathered from various customer groups on the cost of outages. Using Lawton's cost function, LaCommare and Eto found that two-thirds of the annual cost of outages was caused by those lasting less than five minutes ("momentary outages"). According to LaCommare and Eto, this is due to the high frequency of momentary outages relative to sustained outages.

It appears that the only prior estimate of the cost of outages caused specifically by weather was published by the Congressional Research Service in 2012 (Campbell 2012). Campbell estimated the inflation-adjusted annual cost of weather-related outages in the United States to be between $25 billion and $70 billion. Campbell's calculations draw on prior estimates of the total cost of outages, outage duration and the fraction of outages due to weather.[5,6]

[4] This valuation method is known as direct cost estimation (or "direct costing") and is widely used by utilities to assess the value of power reliability (PRIMEN 2001).

[5] Campbell's estimate of the cost of outages caused by weather-events was derived in two steps. First, Campbell calculated the cost of outages lasting longer than five minutes ("sustained outages"). The cost of sustained outages was calculated by multiplying Primen's 2001 estimate of the total cost of outages ($132 to $209 billion) by the

New Estimate of the Cost of Weather-Related Outages

This report provides new estimates of the annual cost of power outages caused by weather. The estimates are based on value-of-service (VOS) data compiled by Sullivan et al. (2009), originally collected by major electric companies using customer surveys. A range of costs is calculated for each year between 2003 and 2012. These annual estimates are then used to calculate a range of the inflation-adjusted average annual cost.

The estimate in this report uses data from the U.S. Department of Energy on power outages occurring between 2003 and 2012 and composite VOS estimates by customer type (residential, commercial and industrial).

Value-of service data. Customer value-of-service was calculated as a function of outage duration using a model from Sullivan et al. (2009). Sullivan et al. provides original VOS estimates for various customer groups using data from 28 consumer surveys conducted by 10 major electric companies between 1989 and 2005. These surveys assessed the cost of power outages to residential customers and commercial/industrial customers of varying size. Commercial and industrial customers were surveyed using the direct cost method. Each firm was asked to estimate the cost of hypothetical power interruptions varying in duration, time of day and whether or not the outage was expected. Residential customers were asked to report their willingness to pay to avoid similar outages. The willingness to pay (WTP) method is a form of contingent valuation – a method used in economics to value goods and services not bought or sold in a marketplace. The willingness to pay method was used to estimate the cost to residential customers because – unlike firms – a substantial fraction of foregone consumer welfare (i.e. being without heat) does not translate into direct costs borne by residents.[7]

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percentage of outages lasting longer than five minutes (43 percent). Campbell excluded momentary outages since they are rarely caused by weather events. Second, Campbell calculated the cost of outages caused by weather by multiplying the cost of sustained outages by the percentage of outages due to weather-events. Campbell used two different estimates for the percentage of outages due to weather – one from the University of Vermont (44 percent) and one from the Lawrence Berkeley Laboratory (78 percent) (Hines 2008; Mills 2012). The two estimates were used to calculate a range of the inflation-adjusted cost of outages caused by weather: $25 billion to $70 billion.

[7] The contingent valuation method (CV) – which includes willingness to pay measures – has been the subject of academic debate. In 1993, the National Oceanic and Atmospheric Administration (NOAA) convened a panel chaired by two Nobel Laureate economists to assess the validity of CV measures. The panel concluded that, if correctly implemented, the CV method provides reliable value estimates. The panel then established a set of universal guidelines for effective CV surveys. Subsequent literature has further advanced the understanding and

The utility surveys compiled by Sullivan et al. (2009) are not necessarily random samples of all utility customers. Two different weighting schemes were therefore used to adjust the estimates to reflect the current distribution of residential, commercial, and industrial customers as reported by the U.S. Bureau of Economic Analysis. These two different weighting schemes yield two different estimates of the average VOS for an outage of a given duration.

Outage distribution data. The U.S. Department of Energy tracks the cause, duration and number of customers affected for each power outage reported in a given year.[8] Outages are reported to DOE by electric utilities under a mandatory reporting requirement. This mandatory reporting dataset is henceforth referred to as the DOE MRDS. For major storms like Superstorm Sandy and Hurricane Irene, DOE also tracks the power restoration process. The number of customers without power in major storms is published in Emergency Situation Reports twice a day during the storm and with decreasing frequency in the days that follow.[9]

The next figure shows the distributions of customer power outages for fifteen major storms occurring between 2004 and 2012[10]. In the plot, the peak number of customers affected is normalized to one for comparability. The distribution shows the fraction of customers without power, as a percentage of the peak number of customers without power, at any given time during the outage event.

All of the fourteen storm-outage-profiles resemble one another, even though they range in duration from 3 to 20 days. The number of customers affected rises sharply in the first few hours of the event and peaks 15 to 25 percent into the total duration. Power is restored to a majority of customers relatively quickly, however a substantial number of customers remain without power long after the event begins. The fourteen storm profiles were used to construct a representative profile shown in black on the chart below. This representative profile was then applied to all power outages caused by weather reported in the DOE MRDS.[11]

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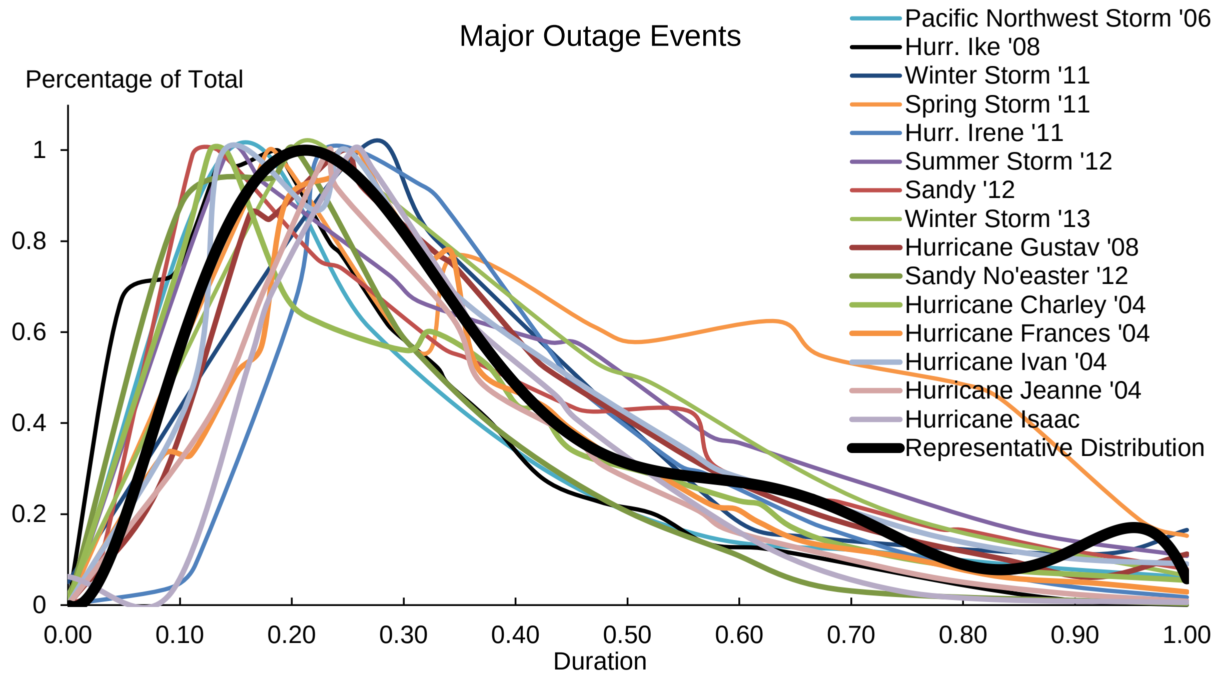
validity of the method – see Carson et al. 1996; Carson 1997; Foreit and Foreit 2002; and Johnston and Joglekar 2005.

[8] The data are compiled in Electric Emergency Incident and Disturbance Reports available at http://www.oe.netl.doe.gov/oe417.aspx.

[9] See http://www.oe.netl.doe.gov/emergency_sit_rpt.aspx.

[10] The chosen storms are all non-overlapping storm events reported in the Emergency Situation Reports with at least seven published outage reports, thereby providing enough distinct outage and time observations to compute a useful empirical customer outage profile.

[11] In instances in which a storm has Emergency Situation Reports and can be identified in the DOE MRDS, data from the reports are used in place of the mandatory reporting data.



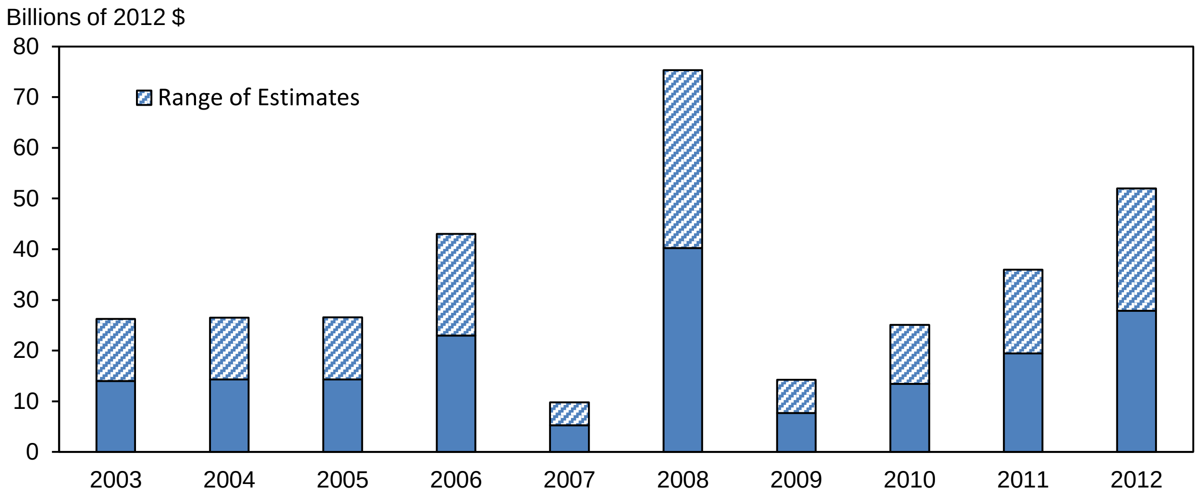
Source: Department of Energy, Office of Electrcity Delivery and Energy Reliability

Estimate of the cost of weather-related outages. Outage cost was calculated using the two sets of VOS estimates derived using Sullivan et al. (2009). The cost of an outage was calculated twice since each set of VOS estimates results in a different outage cost estimate. Using each set of VOS estimates, a weighted cost was calculated for outages of different durations. The weighted cost function was derived by assigning weights to Sullivan et al.'s customer groups based on each group's share of the total pool of electricity customers.

After calculating a weighted cost for each outage duration, an average cost function was determined for U.S. electric customers. The total cost of each outage in the DOE MRDS was estimated using the average per-customer cost function aggregated by the number of customers affected and the outage duration distribution. Finally, outage costs were aggregated by year and adjusted for inflation. Because the calculations were performed using each set of VOS estimates, two estimates of the annual cost of outages are provided for each year. Across all ten years, the average annual cost of outages caused by weather ranges from $18 to $33 billion.

The estimated costs by year are provided in the following figure and table. There is considerable variation in costs by year, ranging from $5 to $10 billion in 2007 to $40 to $75 billion in 2008. Large storms dominate these cost estimates. Outage costs due to Hurricane Ike in 2008 are estimated to be $24 to $45 billion while outage costs due to Superstorm Sandy in 2012 are estimated to be $14 to $26 billion.

Estimated Costs of Weather-Related Power Outages



Source: CEA estimates using data from Census Bureau, Department of Energy , Energy I nformation Administration, Sullivan et al 2009.

Year	Estimated Cost of Weather Related Outages (Billions 2012 $)
2012	$27 – $52
2011	$19 – $36
2010	$13 – $25
2009	$8 – $14
2008	$40 – $75
2007	$5 – $10
2006	$23 – $43
2005	$14 – $27
2004	$14 – $27
2003	$14 – $26

These estimates account for numerous costs associated with power outages including: lost output and wages, spoiled inventory, inconvenience and the cost of restarting industrial operations. The value of lost output can be calculated separately using the DOE MRDS and additional aggregate wage and output data. When calculated, the calculations show that between 20 and 25 percent of the annual cost of weather-related power outages are due to lost output.

Discussion

The methodology here is subject to a number of caveats. The (scaled) distribution of outages was estimated based on data from large storms and then applied to smaller storms. Although the analysis here suggests that the shape of the distribution does not depend on storm size, the shape could be different for small and large storms. Additionally, to the extent that businesses are prioritized for power restoration, the estimate in this report may overstate the actual cost of outages. On the other hand, because these estimates only account for storms with widespread outages, and because the majority of costs may come from the more-frequent momentary outages lasting less than 5 minutes (LaCommare and Eto 2005), the small storms neglected here could substantially add to the cost estimates.

Like the estimates discussed in the literature, the estimates in this report are based on private costs borne by customers who lose power. In addition to private costs, outages also produce externalities – both pecuniary and nonpecuniary. For example, outages that limit air transport produce negative network externalities throughout the country. Generally speaking, the costs of major outages are borne not only by those without power, but also by the millions of people inconvenienced in other ways.

The estimate in this report also differs from the effect of weather-related outages on GDP. Some of the lost GDP arising from storms is made up later by overtime hours, additional hiring, and additional consumption. For example, when the electrical grid goes down, the money spent on line crews to repair and replace grid components enters into GDP. Similarly, GDP is increased when a homeowner replace spoiled food. These additional expenditures counteract the negative effect of the storm on GDP, but they do not increase welfare. Essentially, GDP is higher after a homeowner restocks the refrigerator – but the homeowner is worse off for having to do so.

Additional Benefits of Resilience

A more resilient electric grid brings a host of benefits beyond reduced vulnerability to severe weather. Investments in smart grid technology designed to increase resilience can improve the overall effectiveness of grid operations leading to greater efficiencies in energy use with accompanying reductions in carbon emissions, as well as providing greater assurances to businesses upon which our economy depends (U.S. DOE 2010b; 2011b). These technologies can also enhance national security by bolstering the nation's defense against cyber-attacks given that 99 percent of all U.S. Department of Defense installations located within the United States rely on the commercial electric grid for power (Samaras and Willis 2013).

Increased grid resilience may also reduce expenditures not directly captured in this paper's cost estimates: expenditures by firms and individuals on back-up generators, second utility feeds, power conditioning equipment and other items purchased to mitigate the effects of power outages.

Many of these additional benefits of grid resilience constitute positive externalities – societal benefits beyond the direct costs avoided by electric customers. For example, power outages can hinder public safety since police, firefighters and emergency medical personnel struggle to provide assistance during outages (Sullivan et al. 2009). Manufacturing businesses far removed from an outage may face economic costs if their supply chains are disturbed. Online businesses engaged in long-distance transactions may also be negatively affected by reduced internet traffic. These externalities are arguably large in dollar terms, but quantifying them goes beyond the scope of this report.

VI. Conclusion

The U.S. electric grid is highly vulnerable to severe weather. This report estimates the average annual cost of power outages caused by severe weather to be between $18 billion and $33 billion per year. In a year with record-breaking storms, the cost can be much higher. For example, weather-related outages cost the economy between $40 billion and $75 billion in 2008, the year of Hurricane Ike. These costs are expected to rise as climate change increases the frequency and intensity of hurricanes, tornadoes, blizzards and other extreme weather events.

Preparing for the challenges posed by climate change requires investment in 21st century technology that will increase the resilience and reliability of the grid. The Recovery Act allocated $4.5 billion for investments in smart grid technologies.

A multi-dimensional strategy will prepare the United States for climate change and the increasing incidence of severe weather. Developing a smarter, more resilient electric grid is one step that can be taken now to ensure the welfare of the millions of current and future Americans who depend on the grid for reliable power.

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Blogging the Grid

The #1 way to improve storm resilience (it's not about outage management)

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Quick Take: *If you read Smart Grid News, then you clearly have a strong interest in smart grid technology. But sometimes our interests can cloud our vision. Take Doug Houseman's comments by way of example. He points out that a leading cause of winter outages is not a lack of technology, but rather lack of plain old vegetation management.*

Although he focuses on the recent ice storm, his observations also apply to areas subject to hurricanes, tornadoes and high winds. I hope you will take a moment to read his suggestions at the bottom. Although it's great to push for technology improvements, we still need to work for best practices in other areas too. ***- Jesse Berst***

By Doug Houseman

Over the weekend prior to Christmas, more than 500,000 homes and businesses here in Michigan lost power in an ice storm. Hundreds of out-of-state workers took their Christmas holiday week and drove their trucks to Michigan to work in cold, snowy weather to return the power to these customers. I want to first thank every one of the linemen, troublemen, and vegetation specialists for their work at restoring the power. All of the people in Michigan thank you.

No, the power system and smart grid equipment didn't fail

Many people think that the power system and the smart grid equipment failed, which in many ways can't be further from the truth. DTE and Consumer's Energy got better pictures of the outages where smart meters and other communicating grid equipment was deployed then they ever had before. Initial dispatch was timely and effective, even if most people would not believe it.

The initial response was probably (my guess) 20 to 30% faster and better dispatched then it would have been without the communications from the field. With more and more people assuming that the power company knows, and also not being able to call in when the power goes out, the communicating equipment in the field is critical to good dispatch.

Over the weekend, I did some traveling in the state and looked at some of the sites where the power was out, they were easy to find: piles of firewood were stacked under the power line, from what had been trees. Based on the outage statistics that we have collected in the last year from many utilities, the number 1 cause of outage are – trees! Even in the underground world, trees have an impact on outage. When the trees tip and bring their root ball with them, this can be just as destructive to underground lines as overhead, but the underground problems can take much longer to solve and in frozen ground, they can be a real mess to fix.

Vegetation management is critical

I would rather be in a bucket than down with a pickax trying to open up frozen ground. But enough of overhead vs. underground. The more important issue here is the decline in the ability for utilities to trim trees. In Michigan up until 2012, the allowed budget for tree trimming meant that the utilities could (on average) only visit each mile of line for tree trimming every 12 to 14 years. I know from my own yard that a tree that is 5 feet tall can be 40 feet tall in 14 years. While trees coated in ice can be beautiful, they can also be deadly, snapping and falling with much more weight than they would have had without the ice.

Vegetation management is a critical part of reliability that has been underfunded for years in much of the world, not just in Michigan.

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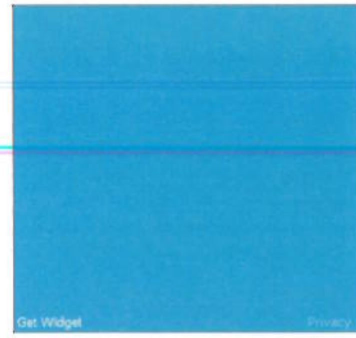

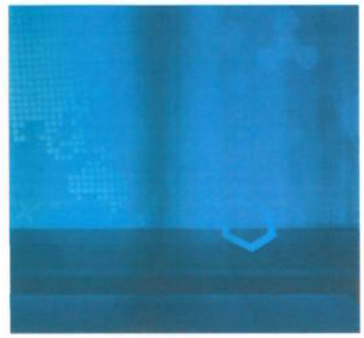

Not only is underfunding a problem, but home owners refusing to let people trim their trees and cities that have gotten to the point where you are not allowed to trim more than the minimum amount of a tree to remove direct contact to the wires. Then, add the Ash Borer, the Birch Borer, and the Gypsy Moth in Michigan and you have literally millions of dead trees in the state waiting to fall or burn. Some cities created special millages to remove street trees that were dead, others did not. But the problem exists, I can drive 10 miles and see 20 or 30 trees that are dead or dying alongside the road, no matter where I go. I even have a dead tree in my back yard that I have to take down in the spring.

How to mitigate the damage

If we want to reduce the number of people who lose power in a winter or even a summer storm we have to take the following steps:

1) Restore the budgets for vegetation management.
2) Return to sensible trimming rules, no more "Y" cuts to allow trees to grow up both sides of a line – if the tree is straddling the line it has to come down.
3) Rules about right of way clearance that make it impossible for a home owner to refuse to have trees trimmed.
4) Offering people dwarf varieties of trees to plant near lines, most dwarf trees never exceed 25 feet in height, and they typically offer better privacy and good shade. They are also great for leaving the shade off the roof of homes with photovoltaic systems installed on them.
5) State commission sponsored education on vegetation in the rights of way.

Much of this will be unpopular, but less so than being out of power on a week when the high temperature is 35 degrees.

If we really do want to fix reliability, it has to start with vegetation management.

Doug Houseman is Vice President of Innovation and Technology for EnerNex.

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