LOS ALAMOS COUNTY DEPARTMENT OF PUBLIC UTILITIES

2014 ELECTRIC RELIABILITY PLAN

(FOR INFORMATION & DISCUSSION ONLY)

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November 19, 2014

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Executive Summary

This report is the second update to the original Electric Reliability Plan “ERP” dated April 20, 2011 and is a living-document. The purpose for this report is to have a path forward to achieve and maintain a SAIDI of 60 minutes or less for the residents of Los Alamos County.

As the SAIDI illustrates, there has been success in the strategy to address and improve the system reliability. However and because of the single substation source in the Los Alamos town site, we’re always at the mercy of an extreme weather event from perhaps exceeding the targeted SAIDI.

The Los Alamos County Department of Public Utilities “LACU”, electric distribution “ED” spends most of its operational budget on **pro-active and preventive** operations and maintenance “O&M” and constructs capital projects to improve the system reliability. At the end of the report is a cost summary for system reliability improvement projects undertaken from 2011 thru 2014.

The electric department has one 3 person crew assigned primarily to the overhead distribution system to replace rotten poles, weathered cross-arms and aged or obsolete transformers. The challenge with the overhead distribution system is that a large portion of it is at least 50 years of age and operating near or past its useful life. A second 3 person crew is primarily dedicated to pro-actively replacing live-front and obsolete switchgear, transformers, and sections of underground power lines that have failed multiple times. The third 3 person crew primarily works on major capital improvement projects that replaces the aged infrastructure but adds improved reliability features such as new Loops, tie-lines, or 3 phase conversions.

As previously noted, the single most important reliability project the department needs to undertake is the construction of a second substation for the Los Alamos town site. The *Los Alamos Switchgear Substation “LASS”* is tentatively planned to be constructed within 30 months and located at the County Landfill. The new substation is critical to meet the future electrical supply needs of Los Alamos and maintain the system reliability success ED has demonstrated in 2013-2014.

The report provides an overview of the existing transmission and distribution system for the LACU service area; and potential impacts on the overall system reliability. LACU has no transmission line facilities but calls for potential load shedding, gas shortages, etc., would impact LACU’s electric reliability. The transmission lines into Los Alamos are owned by LANL and managed by PNM.

The focus and discussion of the ERP is on the electrical distribution system, the department’s asset management program (AMP), strategies for short-term and long-term action plans, and their impact on system reliability and revenue requirements.

I. System Overview:

Los Alamos Power Pool

The Los Alamos Power Pool (Power Pool) is the product of The Electric Energy and Power Coordination Agreement (ECA) between the Los Alamos County Department of Public Utilities and the Department of Energy (DOE) through the National Nuclear Security Administration (NNSA). The Power Pool purchases, sells, and schedules the power requirements for LACU and Los Alamos National Laboratory (LANL). The Power Pool owns up to 88.5 MW (depending at the time of year) of generation resources and purchases up to 20 MW of power per year.

Los Alamos Transmission System

Public Service Company of New Mexico (PNM) provides 115 KV transmission service into Los Alamos from two substation sources as illustrated in Figure 1. PNM also provides primary and back-up relay protection to the DOE-owned transmission lines and is the "balancing authority" for the Power Pool. The DOE owns the transmission system within Los Alamos to serve LANL and LACU electric facilities. LACU dispatchers operate the transmission system and manage the Power Pool resources 24 hours per day, 365 days per year.

LACU dispatchers manage and control the Los Alamos transmission system via a supervisory and control data acquisition system (SCADA) but have limited control over the LACU distribution system. In Section V, we will look at SCADA expansion alternatives into the LACU distribution system for improved system reliability.

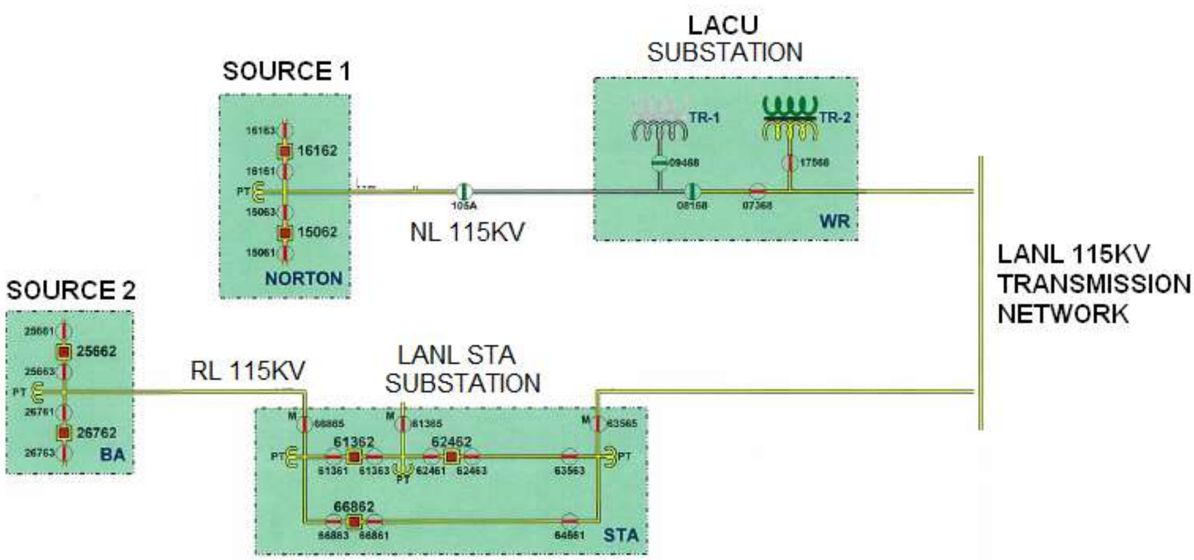

Figure 1. 115KV Transmission lines into Los Alamos

LACU Distribution System

The LACU distribution system consists of two substations, Townsite and White Rock. The Townsite substation illustrated in Figure 2. provides power to the Los Alamos community and is fed by LANL's TA-3 substation via two 15 KV express feeders, TC-1 and TC-2; and normally fed from a 30 MVA transformer, TR-1. There is a back-up tie to a second 30 MVA transformer, TR-2. The Townsite substation bus is configured into two sections, half-bus for TC-1 and half-bus for TC-2. Upon loss of power to TC1 to TC2, LACU can manually transfer the outage bus-section to the energized bus-section.

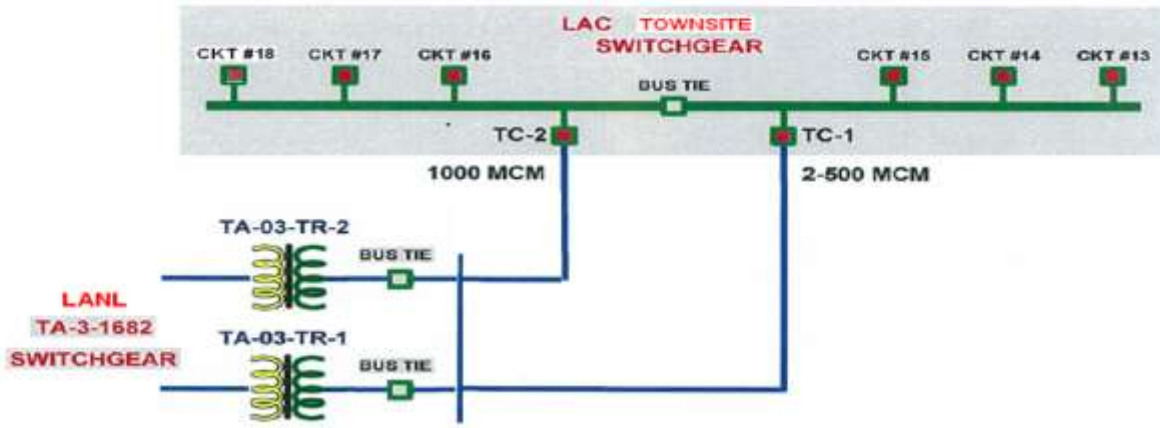

Figure 2. LANL TA3 Substation to LACU TOWNSITE Substation

The transfer feature could be automated by installing a *main and transfer relay* at the Townsite substation bus. However, this feature won't be installed unless LANL can configure the Townsite substation as illustrated in Figure 2A. This configuration powers Townsite with both TR transformers; half bus by TR-1 and half bus by TR-2.

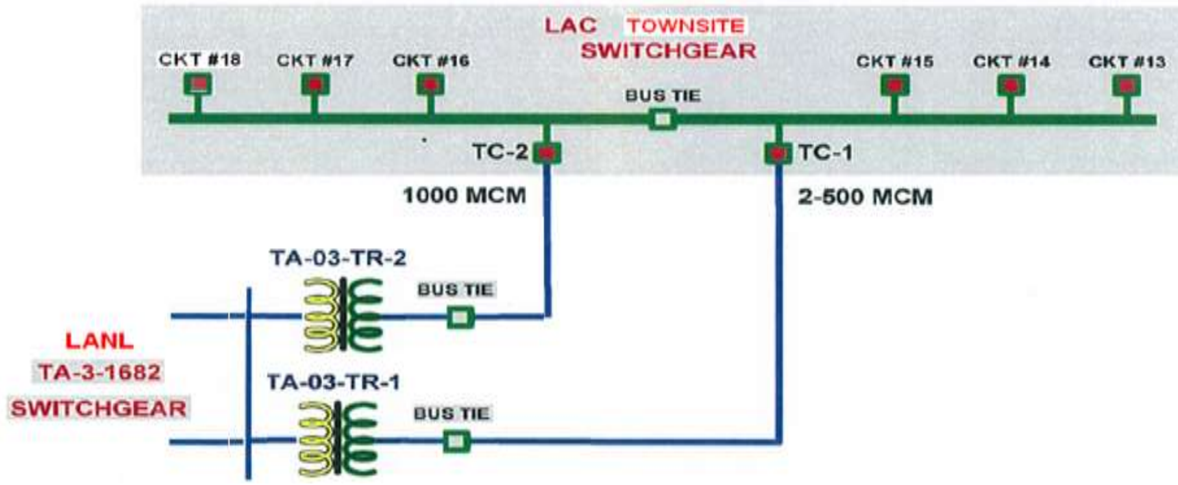

Figure 2A. Preferred LANL TA3 Substation to LACU TOWNSITE Substation

In 2012 LACU and a Japanese government entity known as NEDO (New Energy and Industrial Technology Development Organization) partnered to jointly demonstrate Japanese smart-grid technology on a US distribution grid. NEDO provided 1.8 MW of utility-scale battery storage and 1.0 MW of PV. LACU intends to add a second 1 MW PV at a future date. The integration of the battery and PV sources onto TC-1 and TC-2 is illustrated in Figure 3.

S&C Vista padmounted switchgear is utilized to integrate the NEDO and LACU generation sources “Sources” onto TC-1 and TC-2. The Vista’s utilize bi-directional SEL 451 (Sweitzer Engineering Lab) relays to accommodate the reverse power flow conditions from the battery and PV. The fault conditions of the electrical system would change if the Sources are the sole supply source! Therefore, the SEL relays need to be set on either Parallel mode (normal operation) or *Islanding* mode (sole supply source).

The NEDO battery and PV are operated by a Toshiba control system called micro-EMS. The micro- EMS will optimize the battery and PV outputs under varying scenarios wth the primary goal to make the PV dispatchable (and thus reliable). The micro- EMS has the functionality to provide *islanding* means to part of the LACU distribution system but only after a complete feeder shut-down (*before and after* the island). Though this feature has not been tested, LACU does have the capability to provide emergency power to some of its customers upon complete loss of 115KV transmission power to Los Alamos.

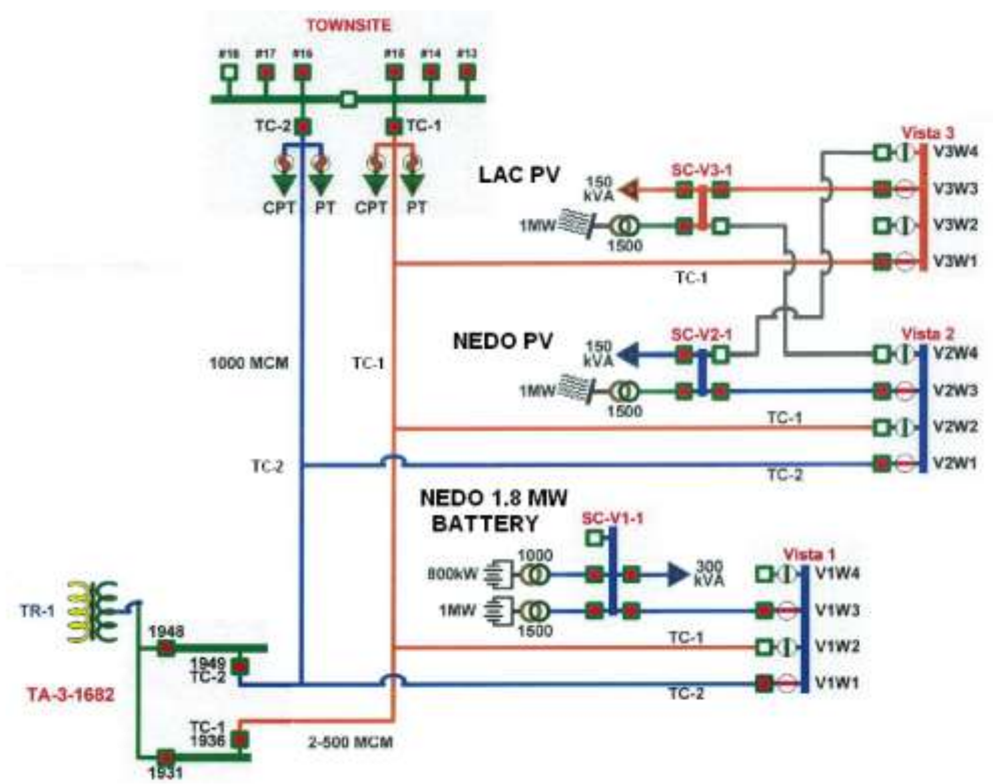

Figure 3. BATTERY & PVs Integration onto TC-1and TC-2

The White Rock substation provides power to the White Rock community and consists of primary and back-up 115KV to 12.47 KV transformers with metal-clad switchgear as illustrated in Figure 4. The primary feed was installed in 2006 and consists of a 10 MVA transformer with metal-clad switchgear. The secondary back-up feed is the original 50 year old 7.5 MVA transformer and metal-clad switchgear. The secondary system is utilized when LANL takes the 115KV transmission section between White Rock and ETA out of service.

Switching between the primary and secondary systems is done manually by paralleling both systems. LAC has a switching procedure in place to ensure the paralleling process is done safely and as quick as possible (less than 30 seconds). Having the back-up substation transformer has great reliability value but utilizing the 50 year back-up switchgear could be a potential risk. A preferred configuration would be to utilize the new switchgear with either transformer. However, this project would require tearing down the old switchgear and establishing a new bus tie between the back-up transformer and newer switchgear. This project may be considered down the road.

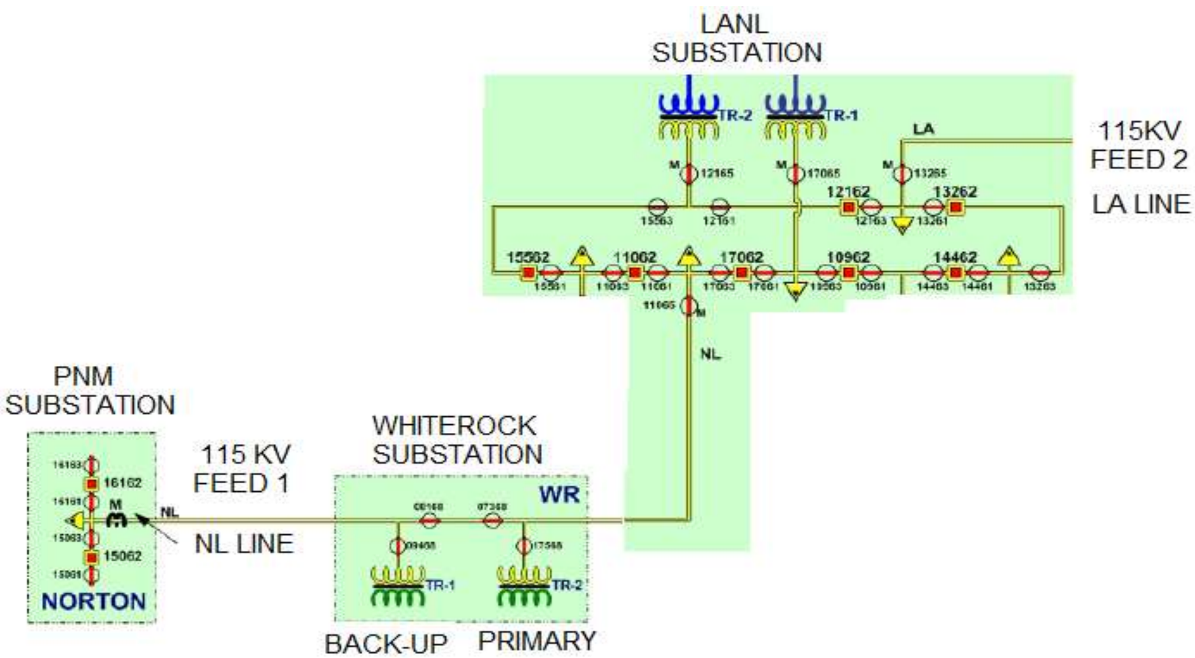

Figure 4. PNM to WHITEROCK Substation to LANL ETA Substation

II. Description of Relevant Systems and Impact on Reliability

<u>The Regional Transmission Grid:</u>

There are two 115 KV transmission lines into Los Alamos as illustrated in Figure 5. One transmission line is owned by LANL and operated by Public Service Company of New Mexico (PNM); the second line is owned and operated by PNM. The Norton line (NL line) originates at the Norton Substation west of Santa Fe and the Reeves line (RL line) originates at the B-A Substation north of Albuquerque. The two transmission lines are primarily "H" wood structures and are approximately 53 and 46 years old respectively. PNM performs an annual line patrol and maintains the transmission lines to provide reliable and continuous service for Los Alamos.

The RL and NL transmission lines have a service capacity of 115 MVA and 130 MVA respectively and are presently loaded at 77% and 68% of capacity; under a single 115KV transmission line operating condition. (Note: Some years ago, an analysis and study was completed to determine the feasibility of constructing a third 115KV transmission line into Los Alamos. Constructing additional transmission facilities into Los Alamos would certainly make sense provided there is additional load requirements; otherwise, the cost of the new transmission line would come at a substantial cost.) From the County's perspective, it is primarily up to LANL to determine the risk associated with a single 115KV transmission line operating condition and justify the need for the third transmission line into Los Alamos.

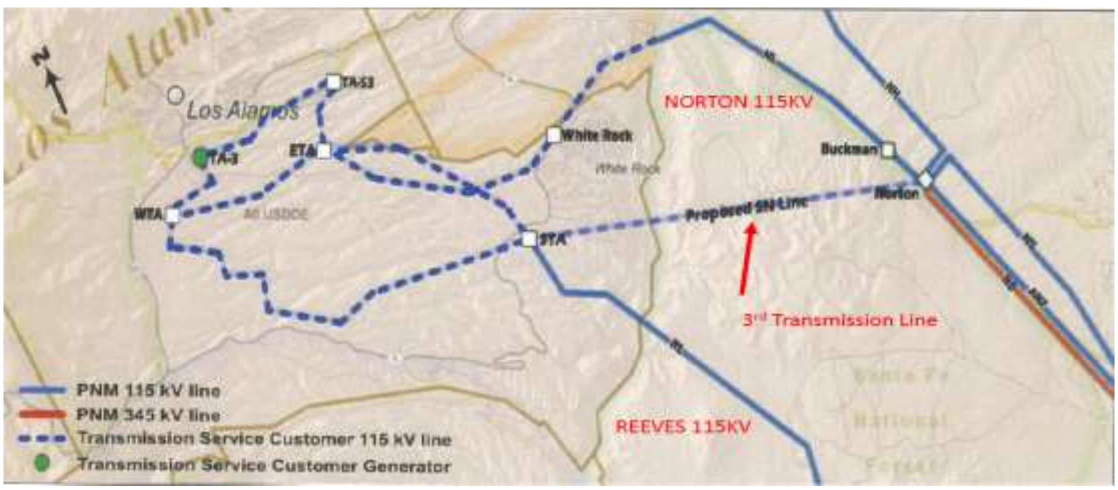

Figure 5. Regional 115KV transmission to Los Alamos

The NL and RL transmission lines are normally operated in a looped configuration. However, there are times when a section of the transmission line is taken out of service due to emergency maintenance or annually to comply with the National Energy Regulatory Commission (NERC) service reliability standards. NERC requires that relays and breakers be removed from service and tested periodically to ensure the protective equipment is functional when called upon. However, operating the NL or RL transmission lines in single radial mode exposes Los Alamos to full loss of power should there be a transmission line contact during these NERC testing events. LANL should continue and ensure that NERC testing is completed when good weather avails. LANL provides LACU with advanced notice for scheduled line maintenance, equipment outages, configuration changes, etc. LAC pre-plans and places its engineering and line operations staff on stand-by notice until LANL can place the system back to normal.

However, there may be instances when transmission line power must be curtailed for reasons beyond PNM or LANL's control. During such events, the Western Electric Coordinating Council (WECC) rules may require the DOE and LACU to curtail their electrical load. LACU has adopted Policy and Procedure No. DPUICLA-PRC-008-8 per WECC standards, as its Frequency Load Shedding Plan and is illustrated in Table 1. LACU has programmed into its substation relays, load-shedding functions through the under/over frequency settings.

Transmission instability may occur due to large variations between the generation and load normally caused by transmission line faults or generator unit failures. Transmission line faults may *dump* generation or load; and may cause other transmission lines to overload resulting in a *domino effect* of mismatched generation with load. These events may lead to grid *instability* until the generation and load is matched again. The LACU substation relays will shed load at different frequency levels to help keep the transmission grid stable. Should the Frequency Load Shedding Plan go in effect, the Feeders at the top of the list will rotate to the bottom of the list below (after the most recent event).

Table 1. WECC Under-Frequency Load Shedding

Load Shedding Block	% Of Required Customer Load Dropped	Circuit	% Of Actual Load Dropped	Pickup (Hz)	Tripping Time*
1	5.3	16	14	59.1	14 cycles
2	5.9		X	58.9	14 cycles
3	6.5	WR2	7	58.7	14 cycles
4	6.7	15	15	58.5	14 cycles
5	6.7		X	58.3	14 cycles
Additional automatic load shedding to correct under frequency stalling					
	2.3	X	X	59.3	15 sec
	1.7	X	X	59.5	30 sec
	2.0	X	X	59.5	60 sec
Load automatically restored from 59.1 Hz block to correct frequency overshoot					
	1.1	WR2	7	60.5	30 sec
	1.7	WR2	X	60.7	5 sec
	2.3	WR2	X	60.9	15 cycles

- *Tripping time includes relay and circuit breaker times.
- X = conditions already met by previous action.

During February 2011, severe cold fronts caused natural gas shortages and outages affecting the northern part of the State. These natural gas events may affect the transmission grid as more gas turbines are placed into service. Therefore, LACU at some point may be called to curtail gas consumption by shedding electrical feeder load as illustrated in Table 2.

Table 2. Gas hourly usage per feeder (estimated)

Feeder	Number of Customers	Ccf per hour (High)	Ccf per hour (Mid)	Ccf per hour (Low)	% Cust Dropped
13	1675	838	1256	1675	18.9%
14	537	430	580	644	6.0%
15	1871	936	1403	1871	21.1%
16	1839	920	1379	1839	20.7%
17	193	193	338	591	2.1%
18	212	212	371	649	2.4%
WR1	1590	795	1193	1590	17.9%
WR2	963	482	722	963	10.9%
TOTALS	8880	4806	7242	9822	100%

<u>The Local Transmission Grid:</u>

LANL owns seven (7) 115KV transmission lines within the DOE laboratory area and operates them in a looped configuration to link its five (5) substations; STA, ETA, WTA, TA53, and TA3 as illustrated in Figure 6. The 23.5 miles of transmission lines are patrolled and maintained annually. All transmission right-of-way is within DOE property, readily accessible and could be repaired fairly quickly in the event of a major problem. Therefore, the regional transmission system within LANL is expected to be very reliable.

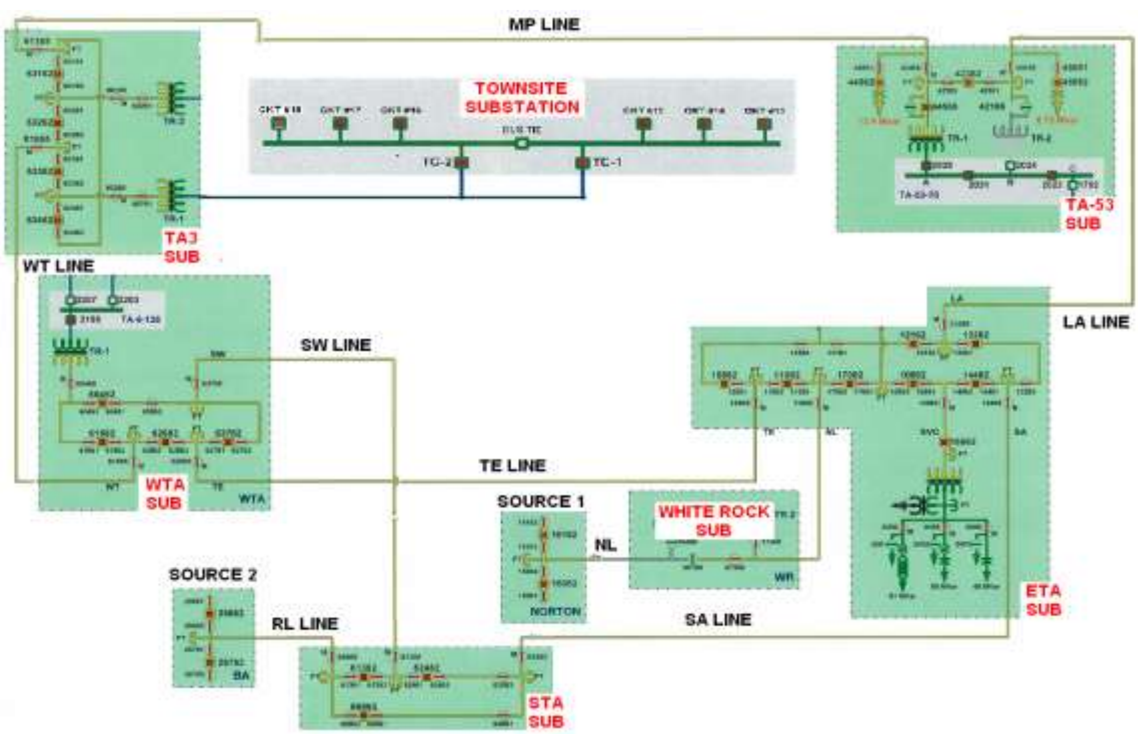

Figure 6. DOE 115KV Transmission Lines

The White Rock substation is fed from PNM's Norton substation (NL line) and via LANL's ETA substation (NL' line). The substation is fed directly from the looped 115 KV transmission system, has redundant transformers and therefore, can be considered as having very reliable transmission service.

The Townsite substation if fed from LANL's TA3 substation which is served by LANL's WTA substation (WT line) and TA53 substation (MP line). However, the Townsite substation is fed at *distribution voltages* (13.2 KV) and would be considered as having less reliable transmission service simply because it isn't tied to the 115 KV transmission system directly.

LANL's TA-3 substation is 50-60 years old including its two 30 MVA transformers, TR-1 and TR-2, and are operating near the end of their useful life. The substation's 13.2KV distribution bus #1682 is also over 50 years old and in need of replacement. In terms of the TA-3's continual reliability, the substation could be susceptible to mechanical failures because of its age. In 2010, LANL and LACU commissioned the "TA-3 and TA-53 Substation Replacement Feasibility Study" which looks at replacement options for TA-3. LANL has secured congressional funding for the TA-3 substation replacement project for 2016; 2 years beyond earlier estimates. (Note: In the absence of LANL not starting on its TA-3 substation replacement project as presently planned, LACU is prepared to add a second substation, Los Alamos Switchgear Substation, "LASS" on its own. The LASS substation is tentatively designed to be installed next to the LACU's battery site.)

The Local Distribution Grid:

At the distribution level, the vulnerability is the lack of redundant substation sources in Los Alamos and White Rock. For comparison purposes, Los Alamos is served by 9 water wells and White Rock is served by 3 water wells yet each location has a single substation electrical source! The water well comparison is illustrated because water distribution networks function very similar to electric distribution networks. Water wells are centrally located and deliver their utility source outwards at some given pressure. Electrical substations should also be centrally located to distribute their utility power outwards at a given voltage. In water distribution systems, the major network systems tend to be *looped* so that if a particular water well fails, the water can continue to flow from an alternate well(s). On the electrical side of things, there is no back-up electrical substation sources to re-route power to in the event of a catastrophic failure at either Townsite or White Rock. This means that a failure at either substation location would have to be repaired and in order to restore full electrical service.

Also, the Townsite substation serves almost 6500 customers with primarily 6 feeders; and, a feeder outage may affect between 800 to 3600 customers. Section VI illustrates how having two additional substation sources will configure the Los Alamos distribution grid such that the 6500 customers that can be served by 12 feeders; thereby substantially reducing the customers per feeder. i.e. potential feeder power outages would affect less customers into the future!

The Townsite switchgear substation (Townsite) has six (6) feeders, #13, #14, #15, #16, #17, and #18. In addition, LANL provides *primary metering* points to LACU to serve other LAC customers via LANL distribution lines including Royal Crest mobile home park, NM Consortium Building, Los Alamos Medical Center (LAMC), Ski Hill, Pueblo & Rendija Canyons, and Totave in San Idelfonso Pueblo. Overall, eight (8) distribution feeders serve the Los Alamos community as illustrated in Figure 7.

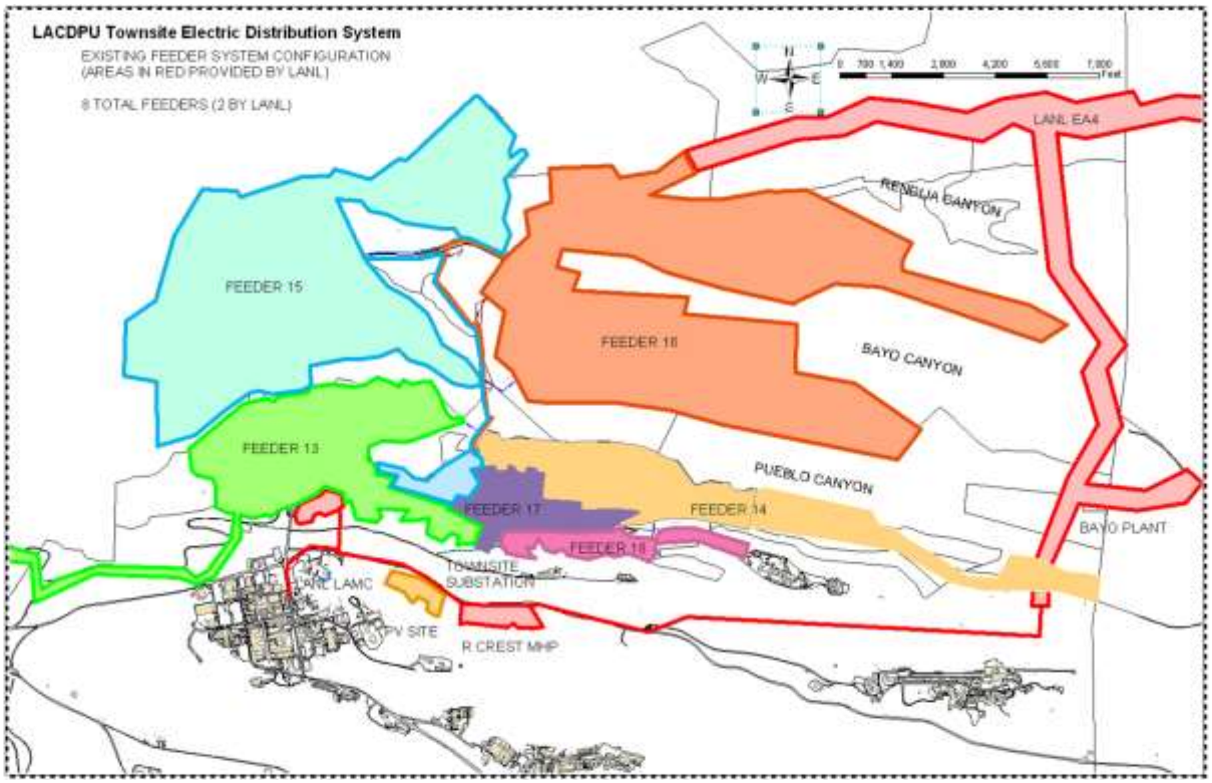

Figure 7. Existing Los Alamos distribution area

The White Rock community is served by the White Rock substation as illustrated in Figure 8. The substation was upgraded during 2006 with the installation of a new 10 MVA transformer and the addition of a new 15KV metal-clad distribution switchgear bus. The substation transformer is presently operating at 60% capacity during the winter peaks. The new switchgear substation contains four circuit breakers for Feeders WR1, WR2 and two spares (future A19 tract). The substation includes an older 7.5 MVA transformer and the original 15KV switchgear substation bus. The 7.5 MVA transformer and switchgear is utilized when LANL requires a NL or NL', 115KV transmission outage. From a transformer reliability perspective, having two transformers is certainly a plus. From a switchgear bus reliability perspective, having the spare 7.5 MVA transformer tied to the new switchgear would be the best alternative but would require a substation but upgrade; a project which may be pursued down the road.

On the distribution side, the WR1 and WR2 feeders can be paralleled within a quarter mile but it has limited use because each feeder remains mostly radial. An ideal looped configuration is when the feeders can be paralleled at each end. For example, the WR2 feeder was looped during 2013 with the construction of the mile-long WR2 UG Feeder tie. The project consisted of a new UG power line along SR 4 with new loops to La Senda areas A and B, and Pajarito Acres 1 and 2.

An alternative source tie (not ideal but an option) could come from LANL but would require a voltage transformation. LANL has a 13.2 / 7.62 KV distribution feeder in close proximity to both WR1 and WR2 but our operating voltage is 12.47 / 7.2 KV.

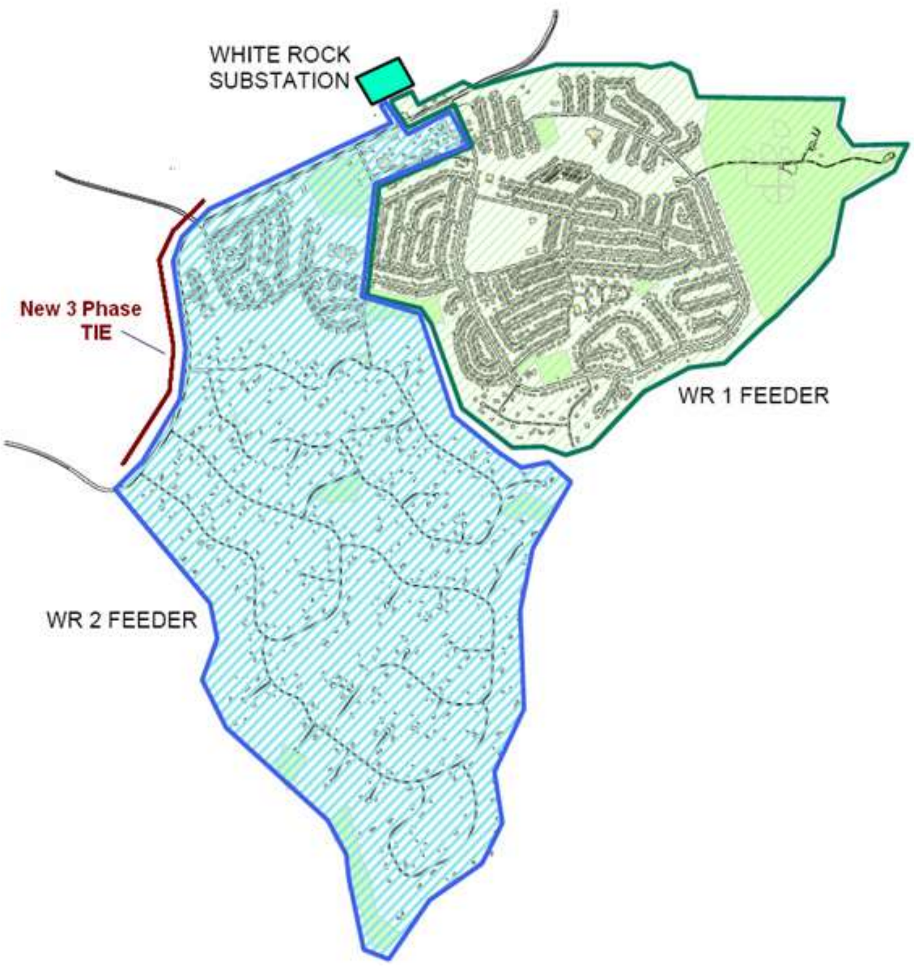

Figure 8. White Rock distribution area

The projected load in the White Rock service area does not require the need for a second substation now or in the foreseeable future. From a distribution source perspective, the reliability for the White Rock service area is influenced greatly by its ability to maintain its substation energized.

III. Discussion of Prior Years' Performance

Analysis of Performance Measures

LACU measures its system reliability with four (4) performance factors as defined by IEEE Standard 1366-2003.

SAIDI = System Average Interruption Duration Index. This is the total duration of interruption for the average customer during a predefined period of time; or

$$\text{SAIDI} = \frac{\text{Sum of all customer outage durations}}{\text{Total number of Customers Served}}$$

SAIFI = System Average Interruption Frequency Index. This is how often the average customer experiences an outage over a predefined period of time; or

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of Customers Served}}$$

CAIDI = Customer Average Interruption Duration Index. This is the average time required to restore service; or

$$\text{CAIDI} = \frac{\text{Sum of all customer outage durations}}{\text{Total number of customer interruptions}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

ASAI = Average System Availability Index. This is the fraction of time that a customer has received power during the defined reporting period; or

$$\text{ASAI} = \frac{\text{Service hours available} - \text{SAIDI}}{\text{Customer demand hours}} = \frac{8760 - \text{SAIDI}}{8760}$$

Table 3. Reliability Performance Measurement Factors

12 Month History Ending	Oct 14		APPA AVG 2013 (recent)
Total # of Accounts	8850		
Total # of Interruptions	33		
Sum Customer Interruption Durations	5909:15:	Hrs: Min	
# Customers interrupted	5976		
SAIFI	1.08	Int / Cust	1.11
SAIDI	**0:40**	Min	0:58:49
CAIDI	0:59	Min / Int	1:13:86
ASAI	99.999	% Available	99.86

Table 3 provides the four (4) nationally recognized performance measurement reliability factors through September, 2014. All factors calculated are based on a twelve month running average. Figure 8 illustrates the SAIDI for the last 5+ years and Table 4 provides the SAIDI on a per Feeder basis.

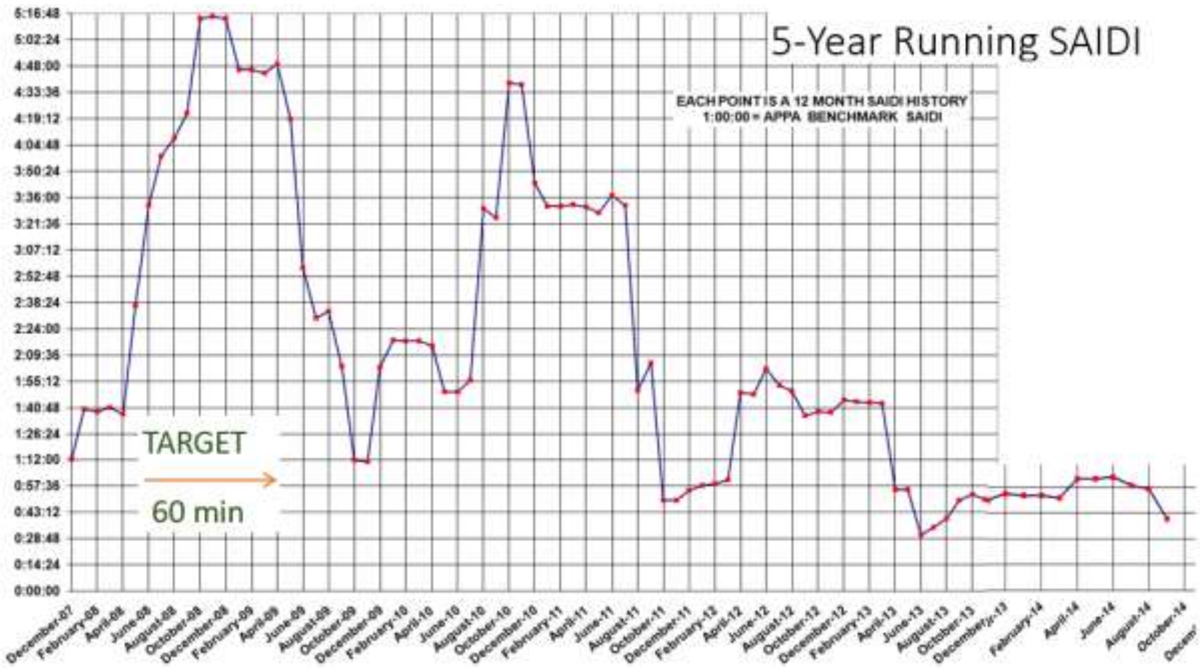

Figure 8. Graph of LAC SAIDI with 60 minute TARGET

Table 4 illustrates that approximately 19 minutes of the 40 minute SAIDI was due to Weather or on LANL served feeders. The high SAIDI for the EA4 feeder was due to a broken pole caused by a local citizen (didn't get hurt) but beyond LAC control. The WR2 SAIDI has been largely due to faults in single phase primary UG sections with secondary or residual caused problems as described in page 28.

Table 4. Reliability Performance on a per Feeder Basis

Most Recent SAIDI, 1 Year Running (September 2014 - October 2013)											
Number of Customers per Feeder											
1480	723	2131	1650	120	37	174	1875	660	8850	Weather	LANL
Circuit 13	Circuit 14	Circuit 15	Circuit 15	Circuit 17	Circuit 18	EA4	WR1	WR2	TOTAL	SAIDI	SAIDI
0:69	0:0	0:04	0:34	0:19	0:52	4:56	0:11	2:41	0:40	0:15	0:04

SAIDI Comparison with Nearby Utilities

The SAIDI for the nearby utilities is illustrated in Table 5. LACU's service area is similar to that of Kit Carson Electric Coop (KCEC) and Jemez Mountains Electric Coop (JMEC); whereas PNM's service area is more urban. KCEC, JMEC, and LACU service area includes mountainous terrain with heavy winter snow fall. The five (5) year SAIDI average for LACU is around 1 hours and 49 minutes and is typical for utilities serving mountainous terrain but County's goal is 60 minutes or less.

Table 5. LAC SAIDI comparison with nearby utilities

	SAIDI 5 YEAR TOTAL (MINUTES)					
UTILITY	2013	2012	2011	2010	2009	AVG
Kit Carson Electric Coop	90	53	90	114	90	87
Jemez Mountains Electric Coop	230	338	448	885	337	448
PNM (Santa Fe Area)	84	94	109	124	93	101
LOS ALAMOS COUNTY	54	102	58	210	120	109

Overview of past year's SAIDI & Disturbances

The LACU met its goal for achieving a SAIDI less than 60 minutes in 14 of the past 18 months. The LACU would have met its goal for the entire 18 months but due to pro-active underground replacement projects, it was necessary to de-energize sections of lines while major underground equipment were replaced (Trinity & Oppenheimer new Loop additions). Over the long haul, these replacement projects (that affected the SAIDI temporarily) will help improve the reliability in Los Alamos.

We continue to have sporadic and random underground line section failures throughout the system; and this can be expected into the future. During the Fault identification, isolation, and re-routing of power (around failed line section), we've had some residual (secondary) failures. The issue is having to close-in into a faulted line with a standard 200 amp elbow. Some underground subdivisions may have 10 transformers daisy-chained and the only recourse is close-in into the fault section one or two times. However, LAC does have a new strategy to minimize or prevent these residual failures.

With the overhead system, we've had a few tree issues blowing into the open-secondary (un-insulated) in customer back-yards and wrapping up the wires. However, we've dodged major pole and transformer failures largely because of our pole replacement and transformer replacement program.

Strategy in dealing with the SAIDI

The historical improvement of the SAIDI for the last 5 years illustrates that LAC's strategy for reliability improvement is working and so we're continuing on as follows:

(1) Continue to perform a root-cause analysis for every power outage;
(2) Continue with the Asset Management Program, “AMP”, features for line inspections, operations & maintenance, “O&M”, etc.
(3) Continue to monitor line sections which have failed during the past; prioritize, and place into the AMP features;
(4) Continue to dedicate one crew for overhead power line O&M;
(5) Continue to dedicate one crew for underground power line replacement;

IV. Description of Distribution System and impacts on Reliability

<u>Distribution System</u>

LACU owns and operates the Electric Distribution System (EDS) in Los Alamos and White Rock areas. The EDS is comprised of approximately 66% underground (UG) distribution and 34% overhead (OH) distribution serving approximately 8,500 customers. There are approximately 6,100 customers in the Los Alamos area and 2,400 customers in White Rock.

For OH distribution, the major components are power poles (PPs), overhead conductor (OH wire), and pole mounted transformers (XFMRs). The transformers are either two (2) bushing conventional or single (1) bushing CSP (completely self-protected). The two-bushing transformers are often referred to as *delta* transformers by the line crews because they require two energized phases to produce full customer service power of 120/240 volts. The CSP transformers require only one energized phase to produce full power.

For UG distribution, the major components are switchgear (SG), primary junction boxes (PJBOX), primary cable (PUG), padmounted transformers (PADs), secondary cable (SUG), and secondary junction boxes (SJBOX). Single phase pads provide power to residential areas and three-phase pads provide power to commercial businesses.

There are two operating distribution voltages in the LACU’s system, 13.2 KV line-to-line (7.62KV line-to-neutral) in Los Alamos Townsite; and 12.47 KV line-to-line (7.2KV line-to-neutral) in White Rock. LAC can utilize the same distribution system components such as poles, fuses, wire, insulators, rubber goods, switchgear, etc. in both areas because the components are rated at 15KV line-to-line. However, LACU must keep different transformer inventories for Townsite and While Rock because of the different operation voltages. (Note: For emergency purposes, the transformers for either area can be tapped to +/- 10% to match the correct voltage for either Townsite of White Rock; but is not a standard practice).

<u>Age and replacement challenges</u>

The large majority of the OH system exceeds 50 years and is operating at or near the end of its useful life. Similarly, the large majority of the UG system was installed

during the 1970s with cable technology that was good for 30-40 years. Therefore, LACU must plan to proactively replace those sections of the distribution network that experience and show signs of failure; having a 10 year replacing strategy is a good start.
The OH and UG systems have repair and replacement challenges which may impact the SAIDI as replacement projects are underway. Figure 8A illustrates a map area of inaccessible areas due to right-of-way encroachment or customer blockage. Having inadequate work access or having to work around landscaped areas, etc., make it difficult for LACU to replace rotten poles and overloaded transformers. For the UG system, having to dig in and around areas congested with buried utilities makes it difficult to dig for routine repairs; more so when having to install replacement lines.

For the overhead system, most of the replacement work needs to be performed while the existing power line is energized or while *hot*. *Hot* work safety procedures require the feeder over-current protection be disabled (from normal reclosing) while the work is being performed. This means that an inadvertent line contact may kick-out an entire feeder (or line section) while the *hot work* is underway. Similarly and with underground systems, replacing of live-front (uninsulated) equipment will generally require an outage *before and after* the work; again, for safety purposes. Therefore, replacing portions of the existing system will generally require the disabling of the overcurrent protection, small power outages or switch-overs, additional safety precautions, slower work process, etc. Replacement projects may impact the SAIDI temporarily and will increase the cost of replacement.

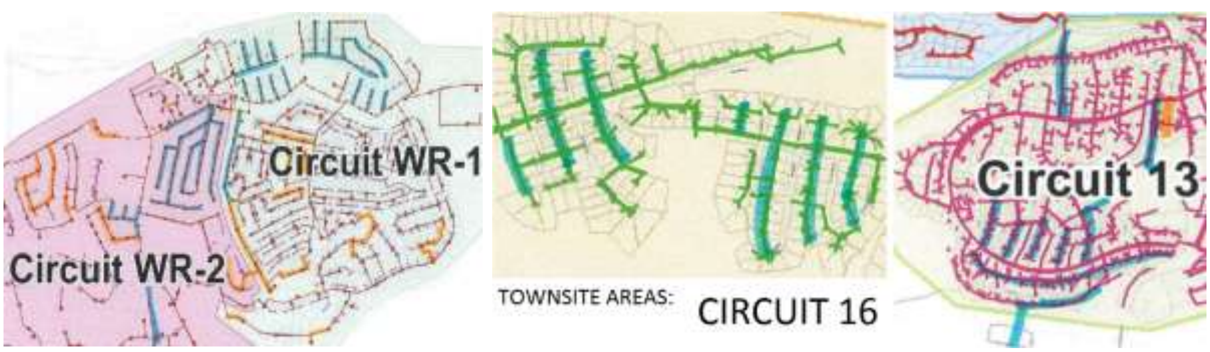

Figure 8A. Areas not readily accessible

<u>Maintain, repair or replace</u>

Through the AMP process, the lingering question is whether to maintain, repair or replace. Based in the AMP process success, LAC will continue to operate under the following guidance:

1. LACU must adequately maintain its electric distribution system moving forward so that equipment can reach and exceed its useful life. For OH, this means pole treating every 5-10 years; 10 years for new poles and 5 years for

older poles. For UG, this means continuing with the AMP features with respect to quarterly inspections & routine O&M.

2. LACU must continue to track repairs to its distribution system; after several failures, UG sections must be planned for replacement.
3. LACU must continue to prioritize replacement efforts to critical feeder sections which impact the most customers and have the biggest impact on the SAIDI.

Sections V and VI provide short-term and long-term action plans, “Plans” that must be constructed in parallel largely because of the age of the distribution system. The Plans do impact the revenue requirements for the utility but LAC is conscientious about implementing the Plans over several years. The LAC strategy is to continue to improve the system reliability yet maintain electrical rates below rates of neighboring utilities. Also, LAC will continue to ask for customer feedback (every other year) with regards to electric reliability, value, and the increased level of rates to support those two efforts. LAC’s goal is to strive to provide the highest level of reliable, utility service its customers expect to receive.

V. Discussion of Short Term Action Plans

Asset Management Program for OH

Under the department’s AMP, each of 10 crew members is responsible for his Feeder. Six lineman are assigned the six overhead distribution feeders: 13, 15, 16, EA4, WR1 & WR2. Each year, the AMP program requires that each lineman perform quarterly line patrols, a detailed feeder assessment, and provide input with regards to feeder areas that require immediate and long term action plans. For example, tree trimming, leaning pole, loose guy wire, etc. would be considered an immediate action. Feeder conversions, tie-lines, reconductoring, etc. would be considered long term actions.

Overhead Pole Replacement Program

In 2005, all distribution poles were inspected and treated at the ground line. Almost 250 poles or roughly 13% of the system poles were rejected but temporarily braced. In 2012 and as part of the Redinet project, LAC and Redinet cost-shared for the replacement of approximately 45 poles to accommodate the new Redinet fiber network in parts of Los Alamos and White Rock (government & school facilities).

During 2013, all system poles were re-inspected and treated again; approximately 50 poles were rejected. In the same year, LACU started an overhead maintenance crew to primarily focus on overhead pole & cross-arm replacement and tree trimming. To date, LACU’s in-house crews have replaced over 50 utility poles.
In order to replace rejected and braced poles at inaccessible locations as illustrated in Figure 8A, the department has budgeted for the procurement of a back-yard pole setting unit and purchased a truck load of steel poles. Steel poles weigh

approximately 50% of what a wood pole type douglas fir weighs; but cost twice as much. Figure 8B illustrates a typical braced pole and a new steel pole.

Also, to back-track and replace over 220 braced poles, the department will seek an on-call contractor to help replace all braced poles within the next 2-3 years; and subject to funds available. Otherwise, the department will forge ahead with its in-house crew. In the next few years, the department will start focusing on replacing sections of the overhead conductor wire which have been in service over 50 years; particularly those areas which contain obsolete CWC (copper-weld-copper) wire.

Figure 8B. Typical braced pole & backbone broken pole; & new Steel Pole

Infrared OH line inspection

During the winter, the department will continue to *infra-red* critical sections of the underground and overhead systems to look for hot-spots as illustrated in Figure 9. Hot spots are areas that have loose connections leading to high-resistant points; these points will eventually burn up, fail, and cause a power outage.

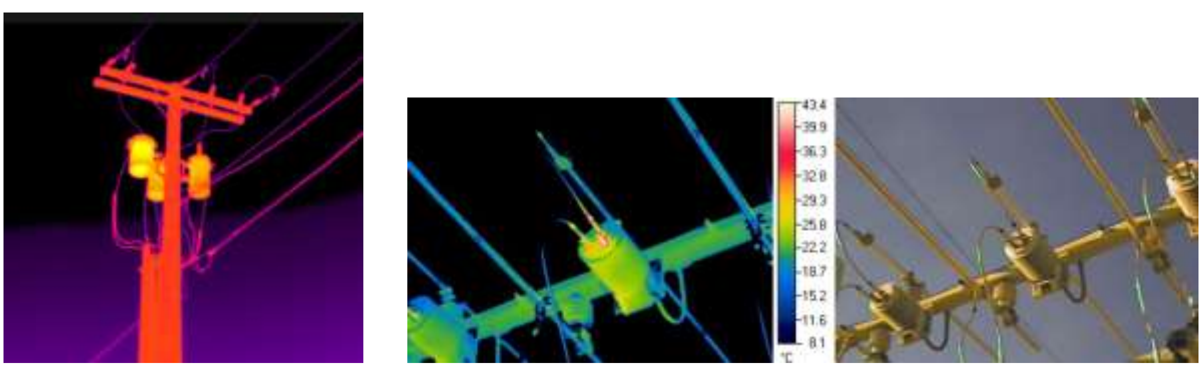

Figure 9. Infra-red picture for transformer pole & air break switch

Asset Management Program for UG

Four lineman are assigned the four underground distribution feeders: 14, 17, 18, & LAMC/Landfill. Similarly, each year the linemen perform quarterly line patrols, a detailed feeder assessment, and provide input with regards to feeder areas that require immediate and long term action plans. For example, unleveled equipment, equipment oil leakage, rodent intrusion, equipment tagging, etc. would be considered an immediate action. Switch replacement, live-front transformer replacement, rust or oxidation painting, etc., would be considered a long term action plan.

UG Primary Replacement Program

As previously stated, much of the existing primary underground distribution system consists of typical 1970s cable standards with 30-40 year cable life expectancy including: non-jacketed, direct buried, 175 mil insulation, XLP (cross link poly), non-strand filled cable. Today's primary underground cable has a 40-50 year cable life expectancy including: exterior jacket, 220 mil (more insulation), TRXLPE (tree retardant cross link poly) or EPR (ethylene propylene rubber), strand-filled and installed in conduit.

LACU continues to experience primary cable failures in most subdivision areas, but mainly during the wet seasons. Moist ground tends to accelerate the *treeing effect* in the cable insulation leading to primary cable failures. The *tree effect* provides the shorting path, or *fault*, between the energized conductor and grounded neutral. When primary cable sections experience two or more *faults*, the line section is ranked with a low or high priority. When high priority primary line sections are designed for replacement, other engineering and reliability upgrade features are added. For example, radial lines may be converted to loops, single phase lines may be converted to three phase, ridding of live-front equipment, adding sectionalizing points, re-routing for accessibility, etc. The idea is to ensure that even if the newly installed line fails, power can be restored even faster than before while impacting the least amount of customers. For example, the Canyon URD Project, Sioux Village, WR2 Loop Addition, Trinity Apartment Replacement Project, and LAMC replacement project are recent pro-active projects which included loops, tie-points, and other reliability improvement designs as part of the original replacement project.

VI. Discussion of Long Term Action Plans

New LASS Substation Addition

The top reliability project for LACU is the construction of the new LASS Substation addition near the County landfill as illustrated in Figure 10. The LASS Substation is needed in order to maintain the SAIDI target into the future. LASS is also critical to the supply of steady and reliable electric power to the residents of the Los Alamos Townsite; more so if the Townsite area is expected to grow electrically.

Figure 10. Preferred area for new LASS substation addition

The LASS substation will relieve load from the existing Townsite Substation. Under existing conditions and for a TC1 feeder outage, the Townsite peak demand exceeds the TC2 feeder ampacity rating as illustrated in Table 6 below. The loading condition may worsen as Los Alamos County succeeds in bringing in electrical growth addition at the former 901 Trinity Site and DP Road.

Table 6. Potential TC2 Feeder Loading for a TC1 Feeder Outage

Feeder	Size	Rating	Max Carrying Load	Townsite Peak Load 2011	2012	2013
TC1 TC2	(2) 500 mcm CU 1000 mcm Cu	720 amp 615 amp	16 MW 14.1 MW	15.9 MW	14.8 MW	14.1 MW

The LASS Substation will add feeder sources to maintain and improve the SAIDI and the system reliability in the Townsite area as illustrated in Figure 11 and as follows:

1. Reduce the number of customers on Townsite substation feeders 13, 15, & 16 (by moving half the customers on those feeders to LASS);
2. Provide new feeders 13T, 15T, 16T, etc.
3. Provide connection to the 1.8 MW batteries and PV systems;
4. Provide power to LACU customers with LACU power lines and not from LANL power lines; i.e. Transfer Station, LAMC, Royal Crest MH Park;

5. Add 50% additional system redundancy during scheduled or unscheduled outages to Townsite Substation Feeders. Feeders 13T, 15T, & 16T on LASS can backfeed feeders on Townsite 13, 15, 16, Ski Hill, LAMC, etc.

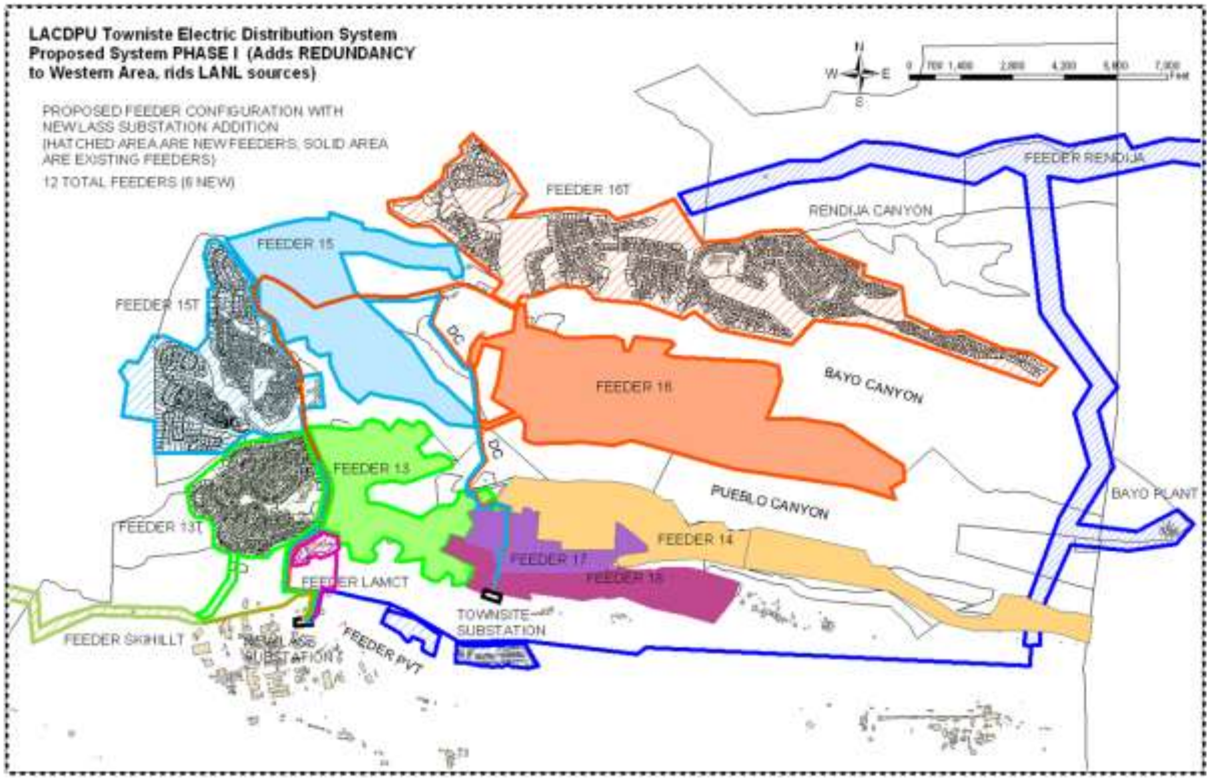

Figure 11. Los Alamos distribution area with LASS substation addition (when compared with Figure 7.)

<u>Distribution system SCADA expansion</u>

The LACU power production group (LACP) has SCADA capabilities at the Townsite and White Rock substations. LACP monitors the individual feeder relay for breaker status and real-time power flows. The SCADA system can be expanded to OPEN and CLOSE each feeder remotely. Often times and during a power outage, the LACU lineman has to patrol the power line to find and isolate the problem; then, return back to the substation to restore power. With SCADA control of the feeder breaker, the lineman can request the LACP operator to simply CLOSE the breaker remotely and thereby aiding in the restoration process quickly.

Feeders 13 and 16 have four feeder line electronic reclosers (EOCRs) that can be integrated into the LACP SCADA system. The EOCRs can be retrofitted with a SCADA card, a micro-wave radio, and integrated into LACP's microwave radio communication system. These *node additions* can be mapped into the LACP SCADA system for automated control. With SCADA control, an EOCR lock-out can be detected by LACP and immediately be aware of the power outage area. LACP can then dispatch the linemen directly to the problem area and not have to rely on customer outage calls. When the linemen isolates and repairs the overhead power line problem, LACP can remotely CLOSE the EOCR and restore power quickly.

Similarly and after the new LASS substation is constructed, all *backfeeding* tie-points can be fitted with S&C SCADA mate switches. During power outages, the switches can be remotely controlled by the operator to help the linemen re-route and restore power more efficiently. Figure 11 illustrates the S&C SCADA mate switch which is predominately the industry standard. In summary, expanding the existing LACP SCADA system into the distribution feeder network will help LACU identify outages quickly; allow lineman to be dispatched directly to the problem areas, and potentially allow LACP the ability to re-route power and restore power quickly and efficiently.

S&C Scada-Mate Switching System **S&C Omni-Rupter Automated Switching System**

Figure 11. S&C SCADA OH Switches

<u>Three Phase Primary OH Backbone Rebuild</u>

Table 7 illustrates the feeder length of the main three-phase OH back bone system with pole quantities. The long-term plan is to replace all three phase back bone poles to ensure the long term reliability; a single major back-bone pole failure could potentially impact thousands of customers. On April 1, 2012 a single WR2 pole failure had a 40 minute impact on the SAIDI for 1 year. Single-phase pole laterals which serve less than 50 customers will be replaced on a lower priority basis. As previously stated, the LACU OH maintenance crew and on-call contractor will work on the pole replacement project. After the major back-bone poles are replaced, LACU will focus on replacing the backbone overhead conductor.

Table 7. Three Phase Main Feeder OH Backbone Lengths

FEEDER #	# OF POLES	MILES OF LINE
13	81	3.44
Ski Hill	70	3.5
15	111	3.15
16	137	4.53
WR1	65	1.83
WR2	73	3.41
EA4	150	9
TOTALS	687	28.86

Primary UG Improvement Projects:

Three major underground replacement projects or additions were constructed in the last several years: 0.8 mile, WR2 Loop Addition, 1.2 mile, Canyon Road Rebuild Project, and 1.0 mile, Tsikumu Village Primary Replacement Project. The three projects had become burdensome to LACU customers and affected the SAIDI year after year. The projects not only replaced the failed underground sections but also added three phase power line sections and new single phase primary loops. Each project cost in the neighborhood of $500K and it will be difficult to sustain those type of projects in the future without impacting utility rates. Though no major underground capital replacement project has been identified in the immediate future by the asset management team, LACU is prepared to deal with major SAIDI impact projects as they may arise in the future.

Other long term UG projects which will provide long-term reliability improvement is the addition of new UG or OH Loops. LACU has many radial lines which power anywhere from 30 to 100 customers; a failure on the radial line leaves few alternatives to restore power in a timely fashion. By identifying these long radial power lines, LACU can install new Loops within reasonable costs. Figure 12 illustrates priority areas for Loop additions in White Rock.

Figure 12. Single Phase Loop Addition Targets in White Rock

VFI Transformer additions in large subdivisions

The LACU has many underground subdivisions with single phase primary laterals with 10+ transformers configured in a daisy-chain. When LACU experiences a faulted line section, it must identify the fault, isolate it, then backfeed the outage area from a new power source. Backfeeding is done by manually transferring electrical load with a 200 amp elbow; at least two times during the restoration process. With continual line section failures, the manually backfeeding process is resulting in secondary and residual failures; i.e. elbows or other weakened points.

Therefore, LACU must look at other engineering solutions in identifying and isolating failed line sections so that no secondary or residual failures occur. Figure 13 illustrates a reasonable engineering solution ($8K per VFI transformer) where faults can be detected, identified to smaller line segments, and allows LACU linemen to safely re-route power without utilizing elbows or fuses. The VFI solution will simply trip the interrupter in a safe manner and no secondary failures.

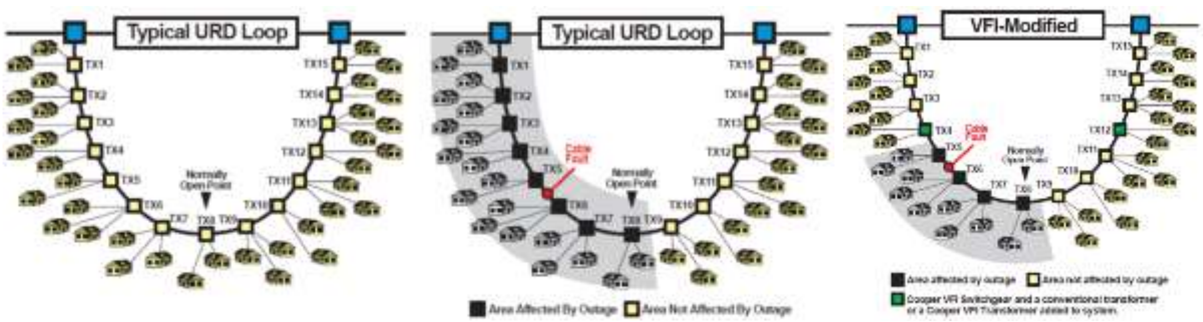

Figure 13. VFI Transformer Fault Isolation & Restoration Solution

New East gate Substation Addition

The proposed East gate substation is similar in need to the LASS substation except that it provides a power source and feeder redundancy to the east side of Los Alamos. The substation need will be in proportion to the electrical needs for development along DP Road and the Camino Entrada area. The LAC-LANL jointly owned EA4 feeder is 9 miles in length and spans across rough mesa terrain from Pueblo to Rendija Canyons. The EA4 feeder provides power to the waste water treatment Plant, water wells and pumps along Rendija Canyon, and to San Idelfonso’s Totavi area. The age and condition of the EA4 feeder, construction ability, and inaccessibility may prove to be an unreliable feeder source into the future without major capital investment. Also, power outages to the EA4 feeder may shut-down critical LAC water and waste water treatment facilities unpredictably.

Figure 14 illustrates the added redundancy to the east side of Los Alamos with the addition of the new East gate substation. The substation adds new feeders for the DP road area (18T), Pajarito Cliffs Site, Bayo Plant, San Idelfonso, and a new feeder

14T to add redundancy to the Townsite substation's Feeder 14. This project would be in the 5-7 year outlook.

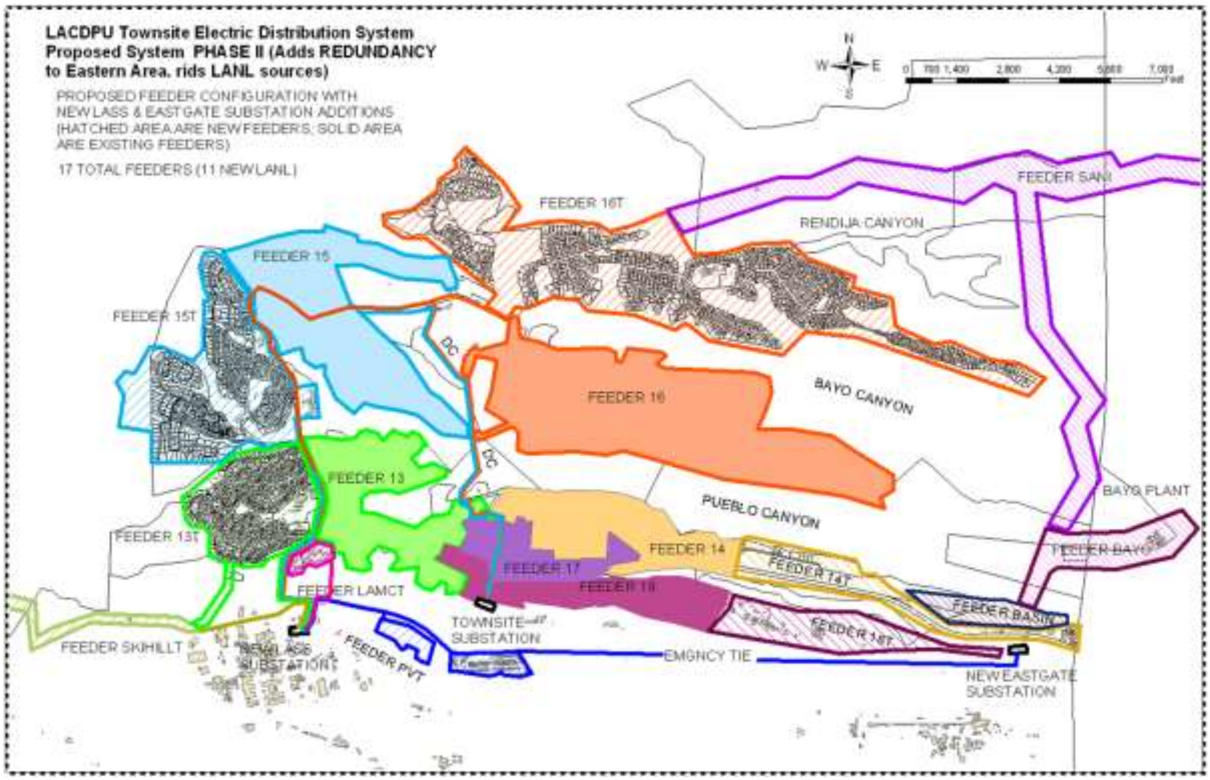

Figure 14. Los Alamos distribution area with East gate substation addition (when compared with Figures 11 & 7)

VII. System Reliability Improvement Projects Completed

LACU developed projects that were not high-revenue but impacted the SAIDI significantly. For example, performing a new over-current protection study and implementing the suggested changes, assigning each of 10 lineman his feeder of responsibility, performing quarterly line inspections, performing a root-cause after every power outage, increased O&M which required mostly labor such as tree-trimming, insulating every pole-top transformer for animal contacts, etc.

Tables 8 & 9 below summarize the system reliability improvement projects (SRIP) completed by LACU since 2011 and Figure 8 in page 18 illustrates the SAIDI over the same period. As illustrated, LACU can't overlook the positive impacts of the SRIP with the SAIDI. Also, the SRIP helped mitigate and correct system deficiencies which would otherwise have impacted the deficient SAIDI even more.

Table 8 System Reliability Improvement Projects 2013-2014 (est. & rounded)

	Reliability Improvement Projects	Area	Year	Cost
1	Tsikumu 1 phase replacement	2800 ft.	2014	$ 150,000
	(3 phase addition)	2800 ft.		$ 350,000
2	WR2 3 phase feeder Tie	4200 ft.	2013	$ 400,000
	(3 phase UG loop with 1 ph loops)			
3	Canyon Ph 1 & 2 (1 ph replacement)	5000 ft.	2013-2014	$ 500,000
	(3 phase addition)	900 ft.		
4	LAMC Source-Transfer Replacement		2013	$ 200,000
5	Feeder 13 Diamond Tie	1300 ft.	2014	$ 75,000
6	PME Switchgear Replacements			
	901 Trinity Site	2	2013	$ 50,000
	Trinity Village	2	2014	$ 60,000
	LAMC	1	2014	$ 40,000
	Oppenheimer/Trinity	1	2014	$ 40,000
7	Padmount Transformer Replacement (live front to dead-front conversion)			
	300 KVA	35 Rover	2014	$ 12,000
	Miscellaneous 1 phase	White Rock	2013-2014	$ 30,000
	Miscellaneous 1 phase	Townsite	2013-2014	$ 30,000
8	Primary Replacement Projects			
	Range Road to Cemetary 1 phase	750 ft.	2014	$ 40,000
	Trinity Village 3 phase, 1 phase	200 ft.	2014	$ 50,000
	Knecht to DP Road	1200 ft.	2013	$ 200,000
9	In house Tree Trimming		2013-2014	$ 40,000
10	60 Utility Pole Change outs	White Rock	2013-2014	$ 60,000
		Townsite	2013-2014	$ 60,000
				$ 2,387,000

NOTE:

The Tsikumi, WR2, LAMC, Canyon, and Trinity Village projects replaced the failed primary UG sections but also added new engineering design features including: new Loops and tie-points; and replaced live-front equipment with new dead-front (insulated) transformers and switchgear.

Table 9   System Reliability Improvement Projects 2011-2012 (est. & rounded)

	Reliability Improvement Projects	Area	Year	Cost
1	Feeder 15-16 OH Rebuild	2.7 miles Feeders 15-16	2011	$1100K
2	Feeder 15-16 UG Rebuild	2 miles	2011-2012	$600,000
3	Feeder 14 UG Rebuild	Downtown	2011-2012	$200,000
4	Feeder 17 Expansion	Downtown	2011-2012	$200,000
5	New Feeder 18 & Expansion	Downtown	2011-2012	$200,000
6	10 PME Switchgear Replacements	Townsite	2011-2012	$300,000
7	Padmount Transformer Replacement (live front to dead-front conversion)			
	300 KVA	Golf Course	2012	$12,000
	500 KVA	Smiths	2012	$18,000
	150 KVA	Conoco	2012	$8,000
	300 KVA	Ashley Inn	2011	$12,000
	Four (4) 225KVA	Bomber Field	2011	$50,000
	300 KVA	VFW	2012	$12,000
	300 KVA	Long View	2012	$12,000
				$124,000
8	Overhead to Underground Conversion			
	Sycamore Tank		2012	$10,000
	Golf Course Well		2012	$10,000
	Bomber Field	retire 1200 ft	2011	$25,000
9	Primary Replacement Projects			
	IRIS	1100 ft. 3PH	2012	$50,000
	Loma Vista (replace & add loop)	500 ft 1 ph	2011	$75,000
	712 IRIS primary replacement	300 ft 1 ph	2011	$15,000
10	Contract Tree Trimming	Underway	2012	$100,000
11	30 Utility Pole Change outs	Service wide	end 2012	$150,000

$ 2,183,000

NOTE:

The Feeder 15-16 rebuild included new engineering design features such as larger conductor for emergency operations, dampeners to avoid conductor galloping across the canyons, and was raptor protection friendly. A new UG feeder 18 was introduced to the distribution grid to power most of the Los Alamos downtown area. The downtown area is now served by two commercial-only Feeders #17 and #18.

VIII. Summary

In 2009, the LACU was struggling with the system reliability and the SAIDI was over 5 hours per consumer. At that time, there were many problems in the distribution system and LACU needed to develop short-term and long-term action plans to address the different infrastructure issues. In 2010, the department developed an Electric Reliability Plan, “ERP”; the ERP identified the issues and problems into three different work areas: engineering, overhead, and underground. The 2010 ERP described the strategy for the short-term and long-term action plans in the three work areas. During 2010, increased revenue funds were authorized to address the different action plans and the SAIDI steadily decreased. The work load was tough and LACU crews all too often functioned in a reactive mode; i.e. problem occurs, fix it, move on to another problem.

Also in 2011, the ERP was updated and the action plans were updated as well. Increased revenue funds were authorized to continue with the action plans and the SAIDI continued to decrease. By 2012, the ED department had started to catch up with the increased work load and the department reorganized its FTES (full time employees). Two operations staff retired but were replaced with two new linemen; this allowed the department to develop a third line operations crew.

By 2013 and 2014, the ED department was able to catch up enough that 2 crews were primarily assigned to pro-active O&M and replacement projects. For the first time in recent memory, LACU is able to properly plan and replace sections of the electrical distribution grid which have failed in the past. By the same time, LACU had met its SAIDI target. However, the SAIDI target would not have been possible without the increased revenue and operational funds authorized.

Though LACU has met the SAIDI target of 1 hour or less, there are still challenges ahead as identified in this, the 2014 ERP update. The drive to meet the SAIDI target begins with the customers who expect a steady and reliable electrical supply but ends with them as well; because the customers must sustain the electrical rates which provide the revenue stream to meet and sustain the SAIDI target. However, LACU recognizes the balance between electric reliability WITH the retail cost for electricity within the neighboring utilities AND how much LACU customers are willing to support. Therefore, LACU will continue to engage its customers through a customer survey on this issue.