DISTRIBUTION SYSTEM ELECTRIFICATION STUDY

LOS ALAMOS COUNTY

179937

REVISION A

July 8, 2025

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Revision History

Version	Date	Updates
Revision 0	7/8/2025	Initial release of the draft report.

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ADMS	Advanced Distribution Management System
ASRFP	All Source Request for Proposal
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CAP	Climate Action Plan
COP	Coefficient of Performance
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DGA	Dissolved Gas Analysis
EDAM	Extended Day-Ahead Market
EIA	Energy Information Administration
EIR	Energy Infrastructure Reinvestment
EV	Electric Vehicle
FLISR	Fault Location, Isolation, and Service Restoration
GE	General Electric
GRIP	Grid Resiliency and Innovation Partnerships
HMI	Human Machine Interface
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
LACDPU	Los Alamos Department of Public Utilities
LANL	Los Alamos National Laboratory
LAPP	Los Alamos Power Pool
LASS	Los Alamos Switching Station
LIHEAP	Low Income Home Energy Assistance Program
NREL	National Renewable Energy Laboratory
PMO	Project Management Office
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin

PV	Photo-Voltaic
RTU	Remote Terminal Unit
SEL	Schweitzer Engineering Laboratories
SMR	Small Modular Reactor
TOU	Time of Use
ZEV	Zero Emission Vehicle

1.0 Executive Summary

Los Alamos County is expected to experience a significant increase in electricity demand resulting from building and transportation electrification. The County must invest in the electric system to maintain safe and reliable customer service.

1898 & Co. performed a 30-year horizon electrification study for the Los Alamos Department of Public Utilities (LACDPU) to understand the impacts and identify recommendations. An existing system review was performed to document the present status of equipment and the ability of the utility to serve the existing customer loads. Asset health was reviewed using historical records and documentation. Over the next 30 years, a significant asset replacement effort is anticipated for the County. A site walk-down was also performed for the critical substation equipment to identify near-term upgrades. The power flow model review showed that LACDPU is providing satisfactory reliability to customers, and no immediate action was identified. However, substation capacity is limited within the LACDPU system and will be a significant challenge to serving new electrification growth.

An electrification forecast was performed to identify the amount of new electric load that may need to be served by the LACDPU system in the next 15 and 30 years. Customer demographics, federal and state policies, technology advancement and cost, and documents like the Los Alamos County Climate Action Plan were used to develop potential electrification scenarios for different market segments, including transportation, home and commercial buildings, and behind-the-meter solar PV and battery energy storage systems (BESS). Since forecasting the growth of electrification over a long-time period is volatile and affected by numerous factors, three scenarios were created to provide different bookends for the potential adoption of each electrification technology in a market segment.

To help frame the potential peak daily impacts to the LACDPU system under the three scenarios, 1898 & Co. created 24-hour load profiles for each market segment to show the totalized peak demand (kW) impact that could result from new load growth. Mitigations such as time of use rates, managed charging programs, and energy efficiency were considered to estimate the peak demand that the LACDPU electric system must be capable of serving for each scenario.

The peak demand (kW) observed in each electrification scenario varied by magnitude and time of day; however, this study estimates that the future system peak demand will occur during the late evening and early morning hours of a cold winter day. While peak demand from electrification will also grow in the late afternoon and evening during a hot summer day, electrified technologies such as heat pumps and EVs are less efficient in cold temperatures and consume more energy. Therefore, 1898 & Co. estimates that while the time of a summer peak will shift, the magnitude will not exceed the estimated winter peak used in this study.

Forecasted electrification load growth was then added to the power flow model to identify the grid impacts at the peak time based on the existing system configuration. Planning criteria violations were identified in all scenarios. Various system improvements were implemented into the power flow model to maintain service to all customers. A new Eastgate Substation and the upgrade of the White Rock Substation were the most critical projects identified to support electrification load growth. However, the scope of these projects varied between the electrification forecast scenarios studied. Asset replacement is also anticipated to be significant given the 30-year horizon of this study. The LACDPU should develop a comprehensive asset replacement plan that incorporates a more detailed review of asset health and ranking of projects.

A financial analysis was carried out to determine if the estimated incremental revenue generated from electrification would potentially be sufficient to fund the system improvement projects necessary to increase capacity. The rate of electrification and incremental operating margins will need to be timed carefully with system capital investments. Large capital projects such as the Eastgate Substation and the upgrade of the White Rock Substation need to be funded by long-term municipal debt.

The LACDPU staffing levels will fluctuate over the next 30 years in response to electrification. This study focused on the impacts on the Electric Distribution Department. This department operates as a highly effective and tightly integrated unit characterized by a generalist approach where key personnel hold a wide array of responsibilities. To successfully prepare for the future, the Electric Distribution Department must transform into a more specialized organization with greater depth. The core of the new organization is the separation of duties into three primary areas: Engineering and Planning, Project Management Office, and Operations, which are functionally aligned. This structure is common among larger peer utilities. The establishment of this new functional alignment does not necessarily equate to an exclusive reliance on new hires. The LACDPU should look to repurpose skilled personnel across the breadth of the organization to fulfill the new roles envisioned and then look to new hires as necessary.

1.1 Recommendations

This study included many analyses that enabled 1898 & Co. to understand the state of the LACDPU system and the challenges that it faces. 1898 & Co. has identified the following recommendations based on the information reviewed and analyses that were performed as documented in this electrification study:

- Work with MilSoft to improve the power flow model fidelity by maintaining a direct connection between WindMil and the GIS system. This will enable agile power flow studies and investigations into the performance of the LACDPU electrical system.

    - Regularly perform studies to identify system impacts when electrification occurs and recommend the appropriate system improvements.
- Implement Volt-VAR control for new solar PV customers to mitigate potential voltage violations that can result from distributed generation.
- Construct the Eastgate Substation to provide necessary substation capacity for the Town of Los Alamos. The timing and scope of this new substation will depend on the load growth experienced by the LACDPU.
- Upgrade the White Rock Substation to provide necessary substation capacity for the Town of White Rock. The timing and scope of this substation upgrade will depend on the load growth experienced by the LACDPU.
- Investigate demand-side management programs related to water heating, space heating/cooling, and managed EV charging programs. Increased customer service support may be required as the LACDPU implements new programs and works to educate customers on electrification and energy efficiency.

This study also identified several areas where the LACDPU should further investigate and perform additional analysis:

- Develop a holistic asset replacement plan that aligns with the system's needs and the appropriate O&M budgets. This may require a full financial study to determine rate impacts in the near term.
- Analyze all LACDPU departments to identify workforce transition plans and cross-functional roles for a holistic staffing plan that considers electrification.
- Perform a new Integrated Resource Plan (IRP) or consider completing “IRP-lite” modeling between the full IRP analyses to determine the optimal resource selection based on actual market conditions and after resource procurement by the Los Alamos Power Pool.
- Perform an organizational assessment for cross-departmental synergies through a Project Management Office (PMO).

2.0 Inputs and Assumptions

The Los Alamos County Department of Public Utilities (LACDPU) provided many data sources to the 1898 & Co. project team to assess the distribution system. Several workshops and discussions were held to identify system planning criteria, objectives for system improvements, and concerns for the safe and reliable operation of the system as electrification continues. The following sections document many data sources, planning criteria, and key decisions made for this study.

2.1 LACDPU Provided Documents and Data

During the initial stages of this study, LACDPU provided several documents and resources to 1898 & Co. These documents were beneficial for understanding the status of the existing system, the growth of solar PV adoption, asset health, and other insights for the utility. The following list summarizes the documentation reviewed by 1898 & Co.

- **2024 Electrical Condition Assessment** – This document provided an overview of the health of various assets within the LACDPU system. It also discussed historical reliability, operational considerations, and a narrative overview of the system.
- **Electric Resilience Presentation to BPU** – This presentation provided an overview of the LACDPU system and objectives for performing future studies.
- **Los Alamos Integrated Resource Plan** – This document provided an overview of the Los Alamos 2022 IRP, including its preferred portfolio and near-term action plan on resource procurement.
- **Experience and Operations** – This document summarizes the Electric Distribution Department staff, education levels, responsibilities, and job functions.
- **Los Alamos Climate Action Plan (CAP)** – A plan compiled by Los Alamos County to identify carbon emission sources and develop focus areas/strategies for reducing carbon emissions.
- **Reliability Plan 2024** - This document outlines the upcoming projects that LACDPU is constructing to improve the system's reliability and resiliency. It also provides additional discussions on growing PV on the LACDPU system, operational challenges, and aging infrastructure.
- **Townsite Loads** – This Excel file contained the manual meter readings of the distribution feeders at the Townsite Substation, at different times, for the previous year. Amperage per phase was provided along with the reactive power demand.
- **White Rock Sub Loads** - This Excel file contained the manual meter readings of the distribution feeders at the White Rock Substation, at different times, for the previous year. Amperage per phase was provided along with the reactive power demand.
- **Electrification Usage Data** – Total energy usage for all customers in March 2025 and December 2024 was provided, organized by customer meter number.
- **Electrification Customer Data** – Monthly energy and peak demand data were provided for commercial customers for the 12 months from November 2023 to November 2024.
- **EA4 Feeder Monthly Peaks** – Monthly energy and peak demand readings for the EA4 feeder.
- **LA3_S** – Monthly energy and peak demand for the Los Alamos Research Park facility.
- **TC1-TC2 2024 kW Calculated** – Hourly demand data during 2024 for the TC1 and TC2 primary feeders that serve the Los Alamos Townsite Substation.
- **Los Alamos Power Pool Maximum Demand** – Monthly peak demand data for the Los Alamos Power Pool.

- **Consumption Gas Report** – Monthly natural gas consumption data by customer was provided for the 12 months from February 2024 to February 2025.
- **PV Meter List** – LACDPU tracks solar PV applications and installations within the county. This list provided insights into the rate of PV adoption over time.
- **Utility Rules and Regulations** – Municipal codes, policies, and procedures are documented on the county's website[1].
- **DPU Construction Standards** – Standard drawings about the construction of various common components of the electric utility system[2].
- **WindMil Power Flow Model** – This model of the LACDPU system contains pertinent information for conducting power flow analysis, such as power lines, transformers, switches, protective device equipment, and customer loads.
- **Jemez Fire Protection Electric Estimates** – An estimate prepared for a recent large project was shared to provide representative costs for common equipment purchased by LACDPU.
- **White Rock Phasing Maps** – These maps were provided to assist in the WindMil model cleanup effort and validate line phasing for the White Rock system.
- **LACDPU Asset Transfer Project Overview Presentation** – This presentation was shared to understand the assets being transferred from LANL ownership to LACDPU ownership and how the system will be reconfigured with the LASS Substation.

2.2 Substation Transformers

The LACDPU system is served by two substations. Table 2-1 shows the substation transformers used in both the Los Alamos Townsite and White Rock systems. At each substation, multiple transformers maintain service in case of equipment failure.

Table 2-1: Substation Transformer Ratings

Substation	Normal Rating	Comments
Los Alamos Townsite 1	20,000 kVA	Shared with LANL
Los Alamos Townsite 2	20,000 kVA	Shared with LANL
White Rock XFMR 1	5,000 kVA	Backup transformer
White Rock XFMR 2	7,500 kVA	Primary transformer

2.3 Distribution Feeder Peak Load

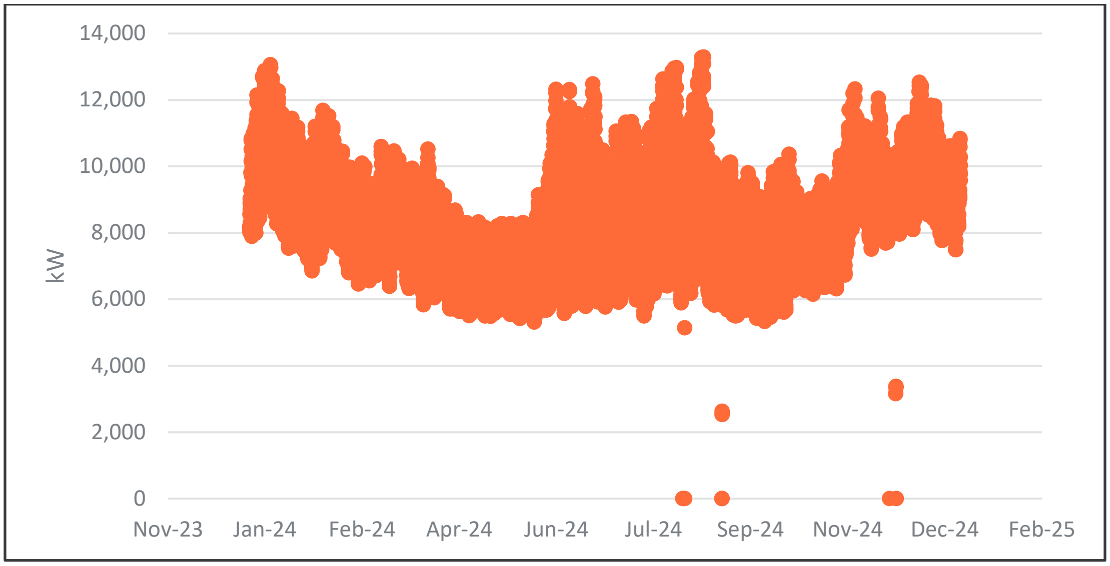
The LACDPU project team identified system load data to allocate the peak planning model. Data availability was a challenge for both the Los Alamos Townsite and White Rock systems, as LACDPU does not have historical distribution feeder SCADA data. Slightly different approaches were taken for the Los Alamos Townsite and White Rock systems.

[1] Los Alamos County Rules and Regulations
https://library.municode.com/nm/los_alamos_county/codes/code_of_ordinances?nodeId=PTIICOOR_CH40UT
[2] DPU Construction Standards
https://losalamosnm.egnyte.com/fl/nViBAuIAID#folder-link/DPU%20Construction%20Standards

2.3.1 Los Alamos Townsite Substation

Two primary Los Alamos National Laboratory (LANL) TA-3 Substation feeders serve the Los Alamos Townsite. Real power readings for these two primary feeders were the foundation for allocating the planning model for the Los Alamos Townsite system. Hourly real power readings for 2024 were reviewed for these two primary feeders. Figure 2-1 shows the yearly profile for the aggregated Los Alamos Townsite Substation. The Los Alamos Townsite Substation appears to peak at a similar magnitude in both the summer and winter seasons.

Figure 2-1: Los Alamos Townsite Substation 2024 Load Readings



1898 & Co. selected the winter peak to model for this study because the complete LACDPU system historically has peaked in the winter, and other data provided by LACDPU centers around this season. Table 2-2 shows the peak primary feeder readings for the community of Los Alamos in the winter season. No reactive power readings were available for these two primary feeders. A 95% power factor was assumed for the Los Alamos Townsite system.

Table 2-2: Los Alamos Townsite Substation Peak Load

Primary Feeder	Distribution Feeders Served	Peak Load	Date
TC 1	13, 14, 15	9,009 kW	1/11/2024 7:00 pm
TC 2	16, 17, 18	4,050 kW	1/11/2024 7:00 pm
Total	-	13,059 kW	1/11/2024 7:00 pm

LACDPU does not have historical SCADA readings for the distribution feeders serving the Los Alamos Townsite system. However, amperage readings are periodically recorded for each feeder. Table 2-3 shows the amperage readings for each feeder recorded during similar date and weather conditions to the peak load shown in Table 2-2. These readings show that each distribution feeder on the system is balanced. They also show 11,401 kVA of total load on the Los Alamos Townsite system. These readings were scaled to estimate the feeder amperage during the recorded peak on 1/11/2024.

Table 2-3: Los Alamos Townsite Feeder Amperage Readings

Feeder	Amps A	Amps B	Amps C	kVA	Date
13	129	130	131	2,972	1/9/2025 4:00 pm
14	95	70	97	1,997	1/9/2025 4:00 pm
15	77	92	111	2,134	1/9/2025 4:00 pm
16	84	114	82	2,134	1/9/2025 4:00 pm
17	65	70	67	1,539	1/9/2025 4:00 pm
18	27	28	27	625	1/9/2025 4:00 pm
Total	**477**	**504**	**515**	**11,401**	**1/9/2025 4:00 pm**

The scaled distribution feeder amperage to match the Los Alamos Townsite Substation peak on 1/11/2024 is shown in Table 2-4. These phase currents were used during the WindMil model load allocation process.

Table 2-4: Los Alamos Townsite Substation Feeder Amperage Scaled to Peak Load

Feeder	Amps A	Amps B	Amps C	kVA
13	156	157	158	3,583
14	115	84	117	2,407
15	93	111	134	2,572
16	101	137	99	2,572
17	78	84	81	1,856
18	33	34	33	753
Total	**576**	**607**	**622**	**13,743**

2.3.2 Additional Loads Considered for the LASS Substation

LACDPU historically has served some loads using distribution feeders from LANL. These loads were not included in the data shown above for the primary feeders TC1 and TC2, but must be considered within the WindMil power flow model. Once the LASS Substation is energized, these loads will be served directly through the LACDPU infrastructure. Table 2-5 shows the peak load used for this study. Some additional assumptions were necessary to estimate peak load on these distribution feeders.

Table 2-5: Additional Loads Considered in Los Alamos

Feeder	Amps A	Amps B	Amps C	kVA	Comments
EA4	72	72	72	1,686	This feeder primarily serves water wells on the east side of the Los Alamos Townsite system. This study utilized the maximum demand recorded for this feeder in January 2024.
NS3	26	26	26	628	This feeder primarily serves the Los Alamos Research Park. Peak month metered demand for these customers was utilized for this study.
NS6	54	54	54	1,294	This feeder primarily serves the Los Alamos Medical Center. To estimate peak demand for this feeder, a combination of peak month billing demand and transformer sizes was used.
S-18	5	10	14	242	Phase current readings were utilized for this feeder.

2.3.3 White Rock Community

No historical SCADA readings are available for the White Rock system. Like Los Alamos Townsite, amperage readings are taken periodically and recorded. These periodical amperage readings were the best data for modeling the White Rock system peak load. The peak readings in Table 2-6 were used to allocate the White Rock system planning model. A 95% power factor was also assumed for the White Rock system.

Table 2-6: White Rock Feeder Amperage Readings

Feeder	Amps A	Amps B	Amps C	kVA	Date
WR1	101	110	79	2,087	1/21/2025 4:10 pm
WR2	81	58	64	1,461	1/21/2025 4:10 pm
WR3	9	4	10	165	1/21/2025 4:10 pm
Total	**191**	**172**	**153**	**3,713**	**1/21/2025 4:10 pm**

2.4 Distribution Feeder Minimum Daylight Load

System load data to allocate the minimum daylight load planning model was necessary to perform the hosting capacity analysis. Periodical feeder amperage readings were used to determine the minimum daylight load for all distribution feeders in the LACDPU system. Table 2-7 shows the readings used for allocating the planning model. Because historical SCADA readings are unavailable, the minimum daylight load for these feeders could be lower. When LACDPU has more frequent meter readings, the minimum daylight load for each distribution feeder can be tracked more accurately.

Table 2-7: Los Alamos System Feeder Minimum Daylight Load Readings

Station	Feeder	Amps A	Amps B	Amps C	kVA	Date
Los Alamos Townsite	13	67	66	70	1,547	4/7/2025 4:18 pm
	14	42	47	48	1,044	4/7/2025 4:18 pm
	15	42	53	60	1,181	4/7/2025 4:18 pm
	16	53	47	53	1,166	4/7/2025 4:18 pm
	17	60	65	62	1,425	4/7/2025 4:18 pm
	18	24	27	25	579	4/7/2025 4:18 pm
	Total	**288**	**305**	**318**	**6,942**	**4/7/2025 4:18 pm**
White Rock	WR1	56	61	43	1,151	4/7/2025 1:34 pm
	WR2	36	18	22	547	4/7/2025 1:34 pm
	WR3	0	0	5	36	4/7/2025 1:34 pm
	Total	**92**	**79**	**70**	**1,734**	**4/7/2025 1:34 pm**

As discussed in the distribution feeder peak load section, some LACDPU loads are served through the LANL infrastructure. Feeder amperage readings during a minimum daylight time were unavailable for these feeders. Some additional data sources were reviewed, and assumptions were made to estimate the minimum daylight load as shown in Table 2-8.

Table 2-8: Minimum Daylight Load for Additional Feeders

Feeder	Amps A	Amps B	Amps C	kVA	Comments
EA4	8	8	8	197	This feeder primarily serves water wells on the east side of the Los Alamos Townsite system. Only monthly peak demand readings are available. In November 2024, a monthly peak of 197 kW was recorded. This reading was utilized for the feeder minimum daylight load, approximately 15% of the peak load.
NS3	8	8	8	190	No minimum daylight feeder readings were available. 30% of the peak load was utilized for this minimum daylight load.
NS6	16	16	16	382	No minimum daylight feeder readings were available. 30% of the peak load was utilized for this minimum daylight load.
S-18	1	3	4	62	No minimum daylight feeder amperage readings were available during this study. 50% of the peak feeder amperage readings represented the minimum daylight load.

2.5 Solar PV

The LACDPU system has many customer-owned solar PV systems in operation. 1898 & Co. reviewed historical records to understand the number of solar PV generators in the system today and the adoption rate over time. Figure 2-2 shows the growth in solar PV capacity over time.

Figure 2-2: Connected Solar PV Capacity

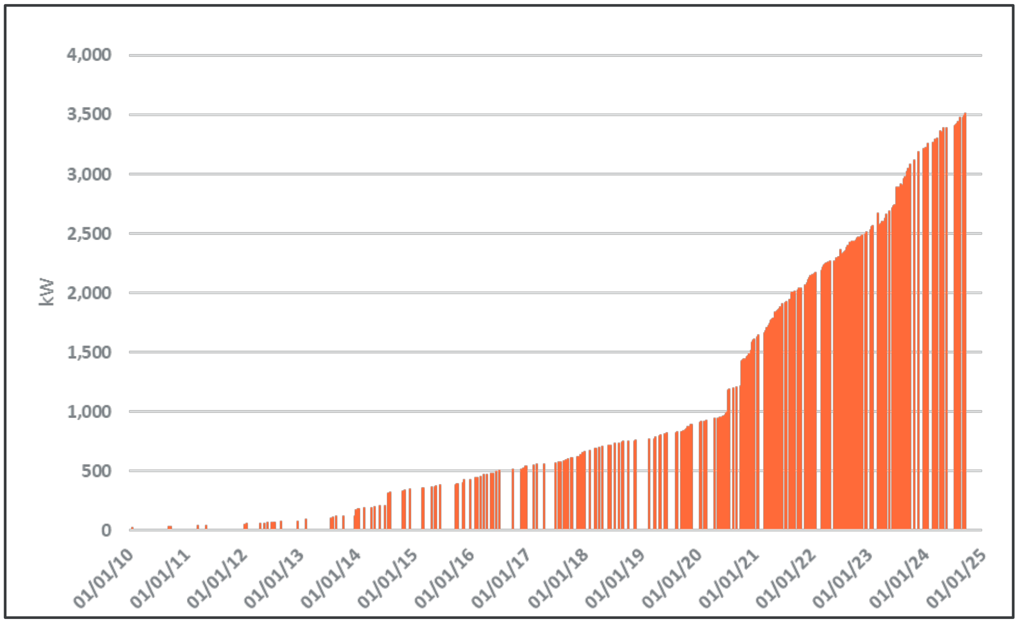
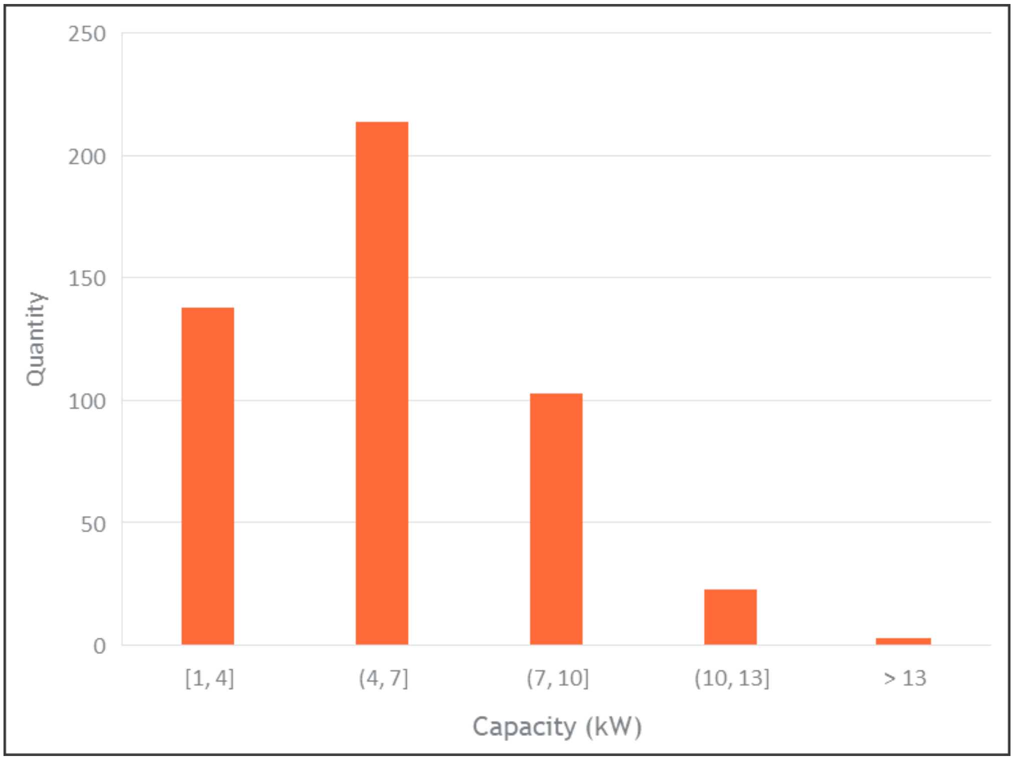


Figure 2-3 shows the nameplate capacity of solar PV installations within the County. Most customer-owned systems are below 10 kW, which is typical of residential-sized generators. However, some systems greater than 10 kW are connected in the County. Depending on the orientation of the PV arrays and weather, solar PV installations will not always operate at their nameplate capacity.

Figure 2-3: Residential Solar PV System Size



2.6 Residential Customers

Residential customers within the LACDPU system are billed monthly based on energy usage. Billing information was incorporated into the WindMil power flow model during the load allocation process, and monthly kWh usage was used to allocate the baseline models.

2.7 Commercial Customers

Commercial customers within the LACDPU system have billing structures that differ from those of residential customers. Peak demand is recorded monthly for commercial customers and incorporated into their monthly bill. This peak demand recorded during the peak month was utilized by 1898 & Co. to validate the peak power flow model and represent the grid impact from commercial customers. Specific considerations were given if a customer's peak demand exceeded 25 kW. These peak demands are specific to each customer and do not necessarily coincide with the LACDPU system peak. There is natural diversity among customers; therefore, it is not likely that all commercial customers will reach their peak demand simultaneously. However, weather and other conditions can influence customers to be near their peak load around the same time. For the minimum daylight power flow model, monthly kWh energy use was considered instead of peak demand for commercial customers when allocating the model.

2.8 Distribution System Equipment

Many utilities typically utilize capacitor banks and voltage regulators to maintain voltage and improve system performance. The LACDPU system is compact compared to other distribution systems. LACDPU uses a 125 V setpoint at the White Rock and Los Alamos substations to maintain voltage on the distribution system.

2.9 Load Allocation Process

The primary objective for load allocation was to more accurately model where energy is consumed at higher rates within the WindMil power flow model by utilizing customer billing data (kWh method) from the LACDPU system. For most of the distribution feeders, this method worked successfully. However, for Los Alamos Townsite Substation Feeder 13, the kWh method would not converge. Nonconvergence can result from connectivity errors in the model, inaccurate load data, or inaccurate equipment data. The transformer kVA method was utilized to allocate the model for this distribution feeder. This alternate method allocates load in the model based on the service transformer size and can simplify the convergence of the power flow simulation. EA4 is a distribution feeder sourced from LANL and serves water pumping facilities east of Los Alamos. This is a long feeder that also has nonconvergence issues. This distribution feeder was allocated using the "length" method, where the load is placed along the line sections of the feeder proportional to their length. This method is the least desirable but was necessary for the convergence of the power flow simulation. Table 2-9 identifies the method that was utilized for each distribution feeder.

Table 2-9: Distribution Feeder Load Allocation Method

Station	Distribution Feeder	Allocation Method
Townsite	13	Transformer kVA Method
	14	kWh Method
	15	kWh Method
	16	kWh Method
	17	kWh Method
	18	kWh Method
LANL	EA4	Length
White Rock	WR1	kWh Method
	WR2	kWh Method
	WR3	kWh Method

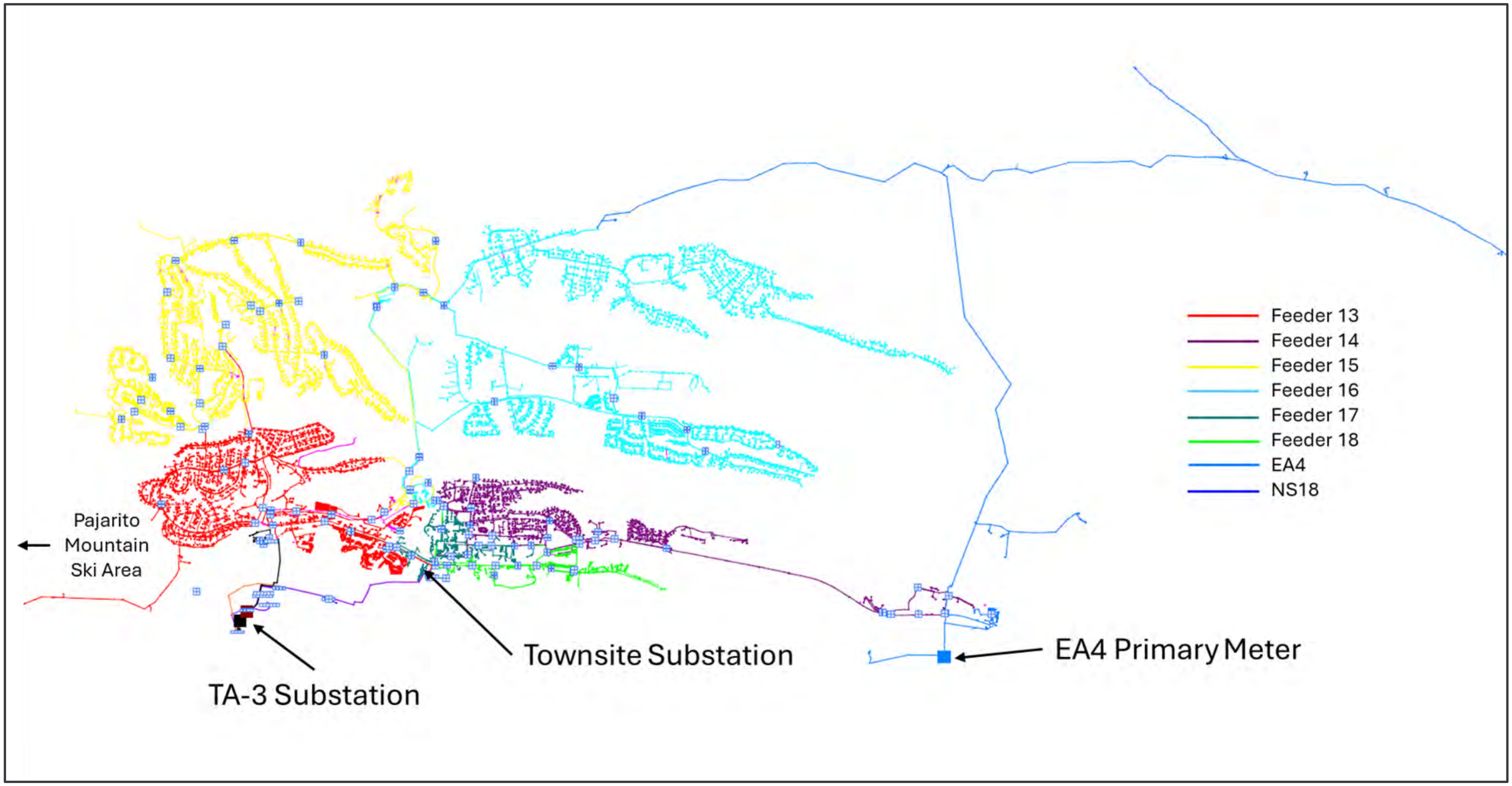
The distribution feeder amperage readings are shown in Table 2-4, Table 2-6, and Table 2-7 and were used to allocate each distribution feeder for the peak load and minimum daylight load models. The following assumptions were used when allocating the model.

- A 95% power factor was assumed for all customers within the LACDPU system.
- For the peak model, rooftop PV generators were set to 0% output due to the Los Alamos Townsite system's peak time in the evening. 35% was used in White Rock, as the recorded peak was at 4 pm.
- For the minimum model, rooftop PV generators were set to 70% output for the Los Alamos Townsite and White Rock systems.
- Commercial customers' load was set to their peak demand during January for the peak load model. Commercial customers were allocated similarly to residential customers for the minimum daylight load model.

2.10 New Los Alamos Switching Station

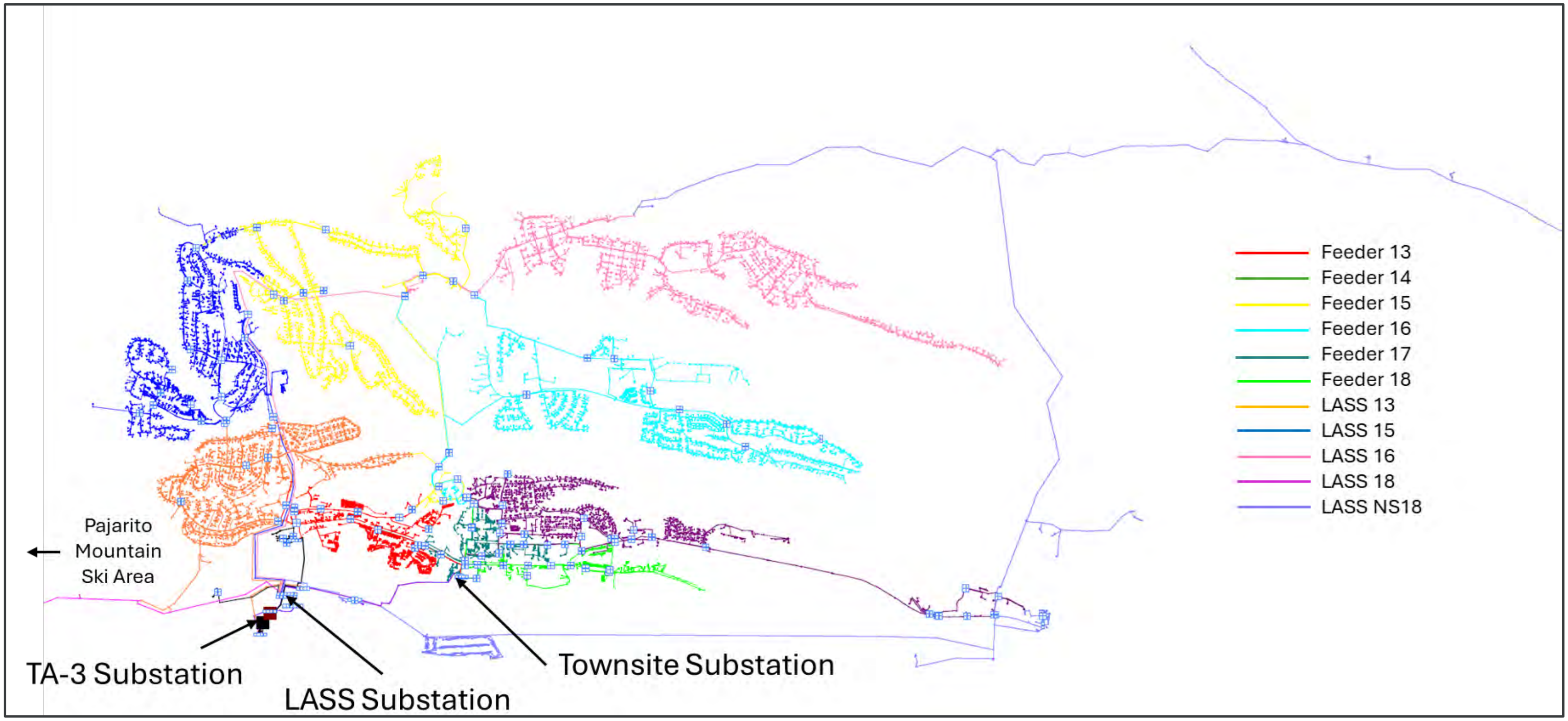
LACDPU recently energized the new LASS Substation to provide an additional source and new distribution feeders to the Los Alamos Townsite System. This new station will improve reliability by reducing customer counts per feeder and exposure per feeder while enhancing the system's operational flexibility. Figure 2-4 shows the previous configuration of the Los Alamos Townsite system, which utilized six county-owned distribution feeders and several feeders sourced from LANL.

Figure 2-4: Previous Configuration of the Los Alamos Townsite System



The previous configuration of the Los Alamos system was used to allocate the power flow model based on historical data. Next, the model was reconfigured to represent the Los Alamos system's current configuration with the energized LASS Substation. Figure 2-5 shows an updated model with the new LASS Substation, which adds redundancy and additional distribution feeders to the area. This current configuration, with the LASS Substation energized, was the foundation for the power flow analysis used in this study.

Figure 2-5: Current Configuration of the Los Alamos Townsite System with LASS Substation Energized



2.11 Distribution Planning Criteria

The following criteria were used to evaluate the distribution system's performance, both for the existing system assessment and for analyzing the future system. Distribution planning criteria are based on normal operating equipment ratings and standard system criteria to maintain safe and reliable customer service.

- No conductor or equipment should exceed 100% of the normal rating.
- The primary voltage should be between 118 V and 126 V, following ANSI C84.1 range A and assuming a 4 V drop through the service transformer.
- LACDPU system feeder relays and reclosers are not configured to detect reverse power flow. Reverse power flow through these devices was not permitted for hosting capacity analysis.

2.12 Eastgate Substation Representative Cost

LACDPU has previously proposed constructing a new substation on the east border of the Los Alamos Townsite system. This would be a traditional substation with two power transformers connected to the area's 115 kV transmission system. This study confirmed that the Eastgate Substation was required to successfully serve customers in the Los Alamos Townsite system for all electrification scenarios. Table 2-10 shows the assumed capacity and equipment for the Eastgate Substation in each electrification forecast scenario. These rough order-of-magnitude estimates for each scenario were incorporated into the financial analysis. The costs presented are in 2025 dollars.

Table 2-10: Eastgate Substation Representative Cost

Scenario	Capacity and Equipment	Cost
Scenario 1	Two 33.7 MVA transformers, each with a four-feeder switchgear and a tie breaker between the two switchgears. One mile of 115 kV transmission line extension.	$17,700,000
Scenario 2	Two 22.4 MVA transformers, each with a four-feeder switchgear and tie breaker between the two switchgears. One mile of 115 kV transmission line extension.	$17,000,000
Scenario 3	Two 14 MVA transformers, each with a four-feeder switchgear and tie breaker between the two switchgears. One mile of 115 kV transmission line extension.	$16,800,000

2.13 White Rock Substation Upgrade Representative Cost

Upgrades at the White Rock Substation are anticipated to be necessary to support forecasted electrification load growth on the White Rock system. Table 2-11 shows the assumed upgraded capacity and equipment for the White Rock Substation in each electrification forecast scenario. These rough order-of-magnitude estimates for each scenario were incorporated into the financial analysis. The costs presented are in 2025 dollars.

Table 2-11: White Rock Substation Upgrade Representative Cost

Scenario	Capacity and Equipment	Cost
Scenario 1	Upgrade the complete White Rock Substation to two 22.4 MVA transformers, with four-feeder switchgears and a tiebreaker between the two switchgears.	$12,700,000
Scenario 2	Upgrade the complete White Rock Substation to two 14 MVA transformers, four-feeder switchgears and a tiebreaker between the two switchgears.	$12,700,000
2055 Scenario 3	Replace the existing transformers with two 10 MVA transformers and keep much of the equipment the same.	$5,200,000
2040 Scenario 3	Only replace Transformer 1 with a 10 MVA transformer and keep much of the equipment within the substation the same.	$2,600,000

2.14 Representative Distribution System Equipment Costs

LACDPU provided copies of recent job estimates that were reviewed, in addition to other construction estimate documentation in the State of New Mexico, to inform the following rough-order-of-magnitude estimates for typical equipment identified in this study. Table 2-12 shows the common equipment utilized in the distribution system. This is not an exhaustive list of equipment utilized by the LACDPU. This range of magnitude costs was used to estimate the high-level financial impact of each electrification scenario evaluated. An underground cable is significantly more expensive to construct than an overhead conductor. Cable terminations, insulation, trenching, conduit, and construction considerations all impact the cost of underground cable installation. It is anticipated that with electrification, single-phase residential service transformers will be replaced with higher ratings, and/or multiple transformers will replace a single existing service transformer. A higher equipment cost of $10,000 was used for this study, which is approximately 1.25 times the average historical residential service transformer cost ($8,000). Secondary service lines can vary significantly for customers throughout the LACDPU system. This estimated average service line upgrade cost was applied in this study. The costs presented are in 2025 dollars.

Table 2-12: Common Equipment Representative Costs

Equipment/Project	Unit Cost
1 Mile of Installed 500 MCM CU Cable	$2,300,000
1 Mile of Installed 4/0 CU Cable	$1,800,000
1 Mile of Installed 477 ACSR Conductor	$525,000
1 Mile of Installed 4/0 ACSR Conductor	$500,000
PME Switch (Various Types)	$75,000
Overhead Switch	$25,000
1,800 kVAR Capacitor Bank	$115,000
500 kVA Voltage Regulator	$90,000
Residential Single-Phase Service Transformer (Various Sizes)	$10,000
Commercial Three-Phase Service Transformer (Various Sizes)	$90,000
Typical Secondary Service Line Upgrade (~500 ft.)	$6,000

3.0 Existing System Review

The 1898 & Co. team reviewed several data sources provided by LACDPU to understand the condition of the existing infrastructure. System models were also evaluated, and power flow analysis was performed to observe their performance.

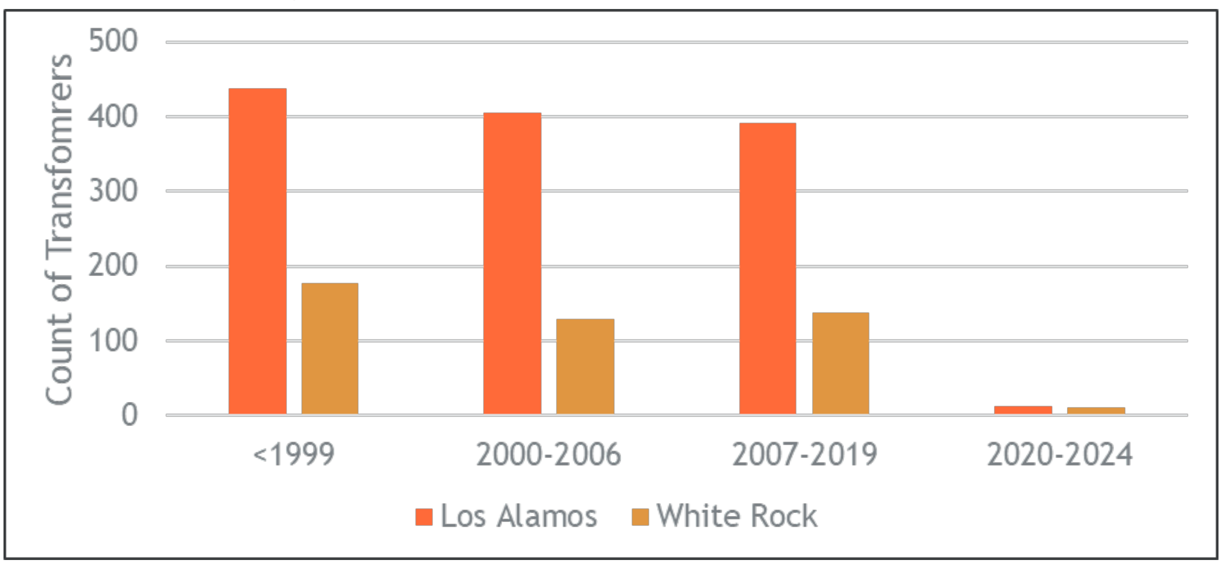
3.1 Distribution Asset Health and Reliability Review

Operating an electrical distribution system requires the procurement and maintenance of many different assets. Some major assets in the Los Alamos system are service transformers, main line switches, underground cable, and overhead conductor. These assets are vital to delivering power from the county-owned substations to customers. LACDPU performed a condition assessment of these assets that 1898 & Co. reviewed for this study. This assessment and the 1898 & Co. review are summarized below.

3.1.1 Service Transformers

Service transformers convert the primary system medium voltage to the appropriate utilization voltage for customers. These transformers can be mounted on pole tops or pad-mounted. For the LACDPU system, service transformers have an expected service life of 25-40 years. Figure 3-1 shows the ages of all service transformers within the LACDPU system. Approximately 600 service transformers were installed before 1999 and are nearing the end of their expected service life. LACDPU typically does not replace service transformers until failure, visible equipment damage, or customer service increases require an upgrade of the service transformer. This service transformer replacement practice is typical for the electric utility industry. LACDPU is replacing aged assets as operational budgets allow. When service transformers are replaced, LACDPU increases the size to provide additional capacity for future electrification. It is assumed in this study that the secondary service conductors are of the same age and condition as the associated service transformers. Secondary service conductors must also be replaced at rates similar to service transformers. Given this study's 30-year horizon, it is anticipated that most existing service transformers and associated secondary service conductors will need to be replaced by 2055.

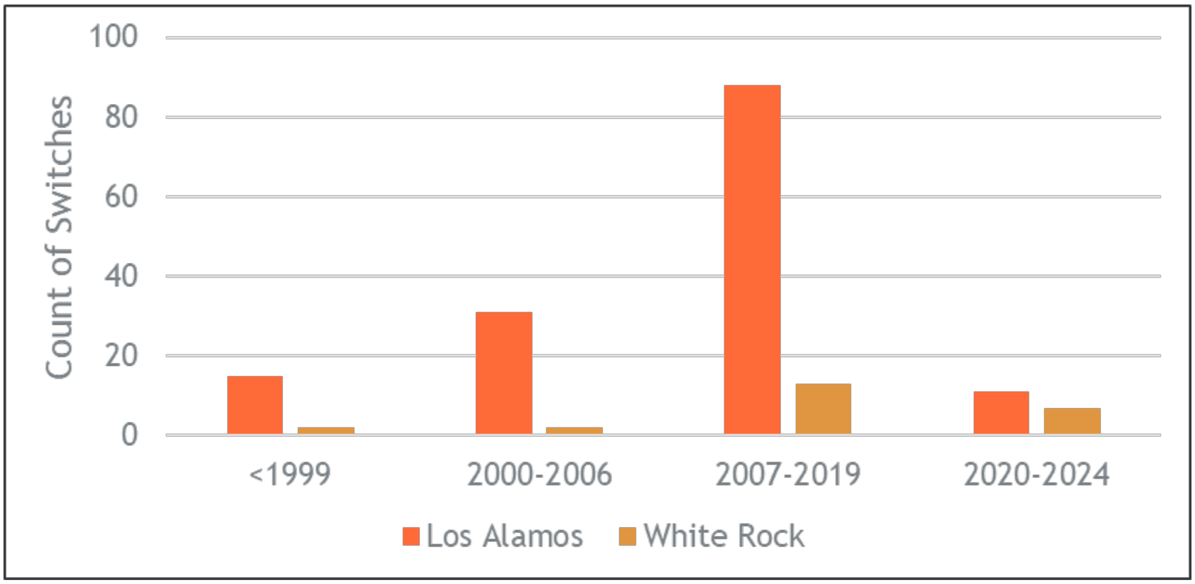
Figure 3-1: LACDPU System Service Transformer Installations



3.1.2 Mainline Switches

Mainline switches are used to sectionalize and isolate portions of the distribution feeder and provide termination points for conductor and cable. Mainline switches are primarily in the underground portion of the LACDPU system and are pad-mounted. Mainline switches have an expected life of 20 years in the LACDPU system. Figure 3-2 shows the ages of all mainline switches within the LACDPU system. Since 2006, LACDPU has made a significant effort to replace failing switches. Most switches within the LACDPU system operate within the expected asset life. LACDPU inspects switches for damage and deterioration and replaces switches preemptively when issues are identified. However, some switches exceed their life expectancy and must be replaced to avoid equipment failure and customer outages. Over the 30-year timeline of this study, it is anticipated that all existing mainline switches will need to be replaced by 2055.

Figure 3-2: LACDPU System Switch Installations

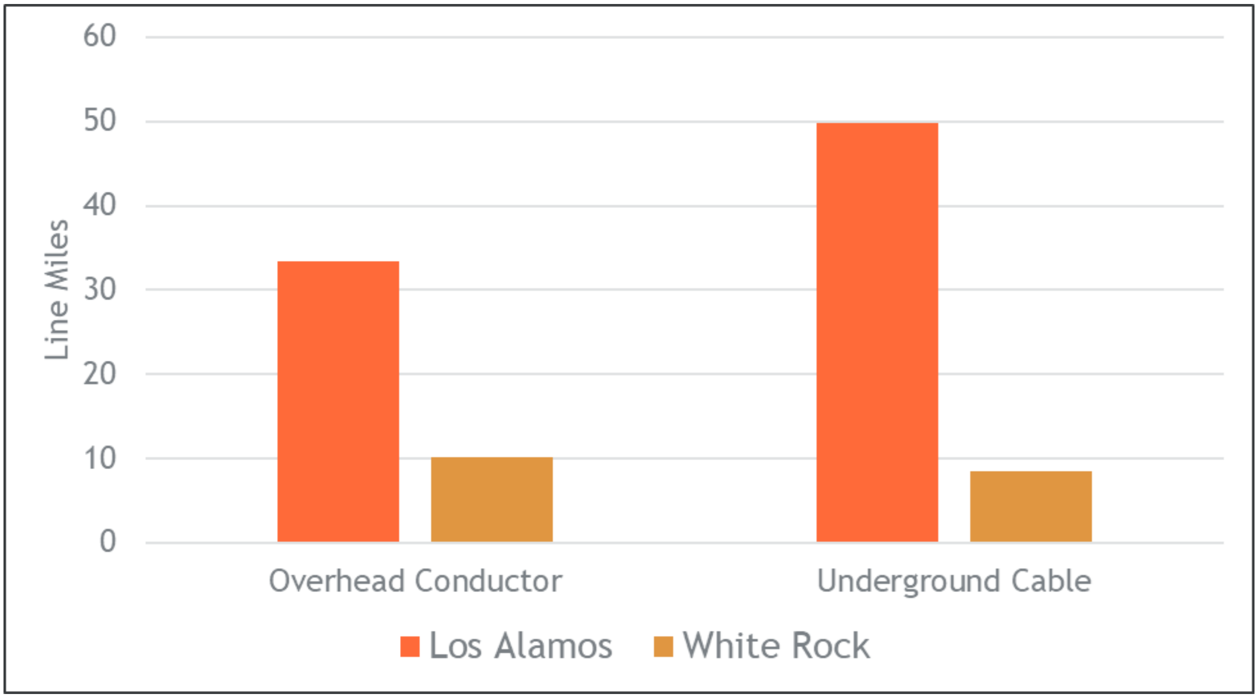


3.1.3 Overhead Conductor and Underground Cable

Overhead conductors are a cost-effective way to deliver power to customers. However, they are more susceptible to faults and are typically less reliable than underground cables. Additionally, overhead conductors also have a greater aesthetic impact. The life expectancy of overhead conductors in the LACDPU system is 40 years. The WindMil power flow model shows that approximately 43 line-miles of primary overhead conductor exist within the LACDPU system.

Underground cable distributes power to customers with minimal aesthetic impact and is typically more reliable than overhead conductors. The life expectancy of underground cables in the LACDPU system is 30 years. However, if cable is installed in conduit, it can have a lifespan that is greater than direct buried cable. The WindMil power flow model shows that approximately 58 line-miles of primary underground cable exist within the LACDPU system. Figure 3-3 shows the approximate number of primary overhead conductors and underground cables within the LACDPU system. Given this study's 30-year timeline, most existing overhead conductors and underground cables are anticipated to be replaced by 2055.

Figure 3-3: LACDPU System Primary Overhead Conductor and Primary Underground Cable Line Miles



3.2 Substation Assessment

1898 & Co. performed a walk-down of LACDPU-owned substation yards to visually inspect the condition of equipment and to assess the overall condition and functionality of key components. This included a general review of transformers, circuit breakers, switchgear, busbars, grounding systems, and protective relays to identify signs of wear and/or malfunction. Additionally, the review evaluated the condition of site access, security, and the substation layout, alongside a review of Supervisory Control and Data Acquisition (SCADA) systems. Environmental factors were considered, including a review of oil spill containment to ensure compliance with local and national regulations.

Below are recommendations regarding repairs, upgrades, and operational improvements to the LACDPU substations. This also includes a list of action items to address areas requiring attention to ensure long-term reliability.

3.2.1 2.2.1 White Rock Substation

White Rock substation has two power transformers and is known as a two-unit (2) substation. Transformer 1 (115kV/12.47kV at 5/5.6/7 MVA) was installed in the 1950s. In 2019, transformer arresters & bushings were replaced, and a new circuit switcher and switchgear enclosure were installed. Dead-End Disconnect Switch blades were replaced in 2020.

Findings and recommendations for Unit 1 of White Rock Substation are as follows:

- The existing Transformer is equipped with an automatic tap changer; however, it is not functioning correctly, requiring maintenance crews to adjust tap settings in the field manually. We recommend replacing this with an automatic on-load tap changer to maintain proper voltage regulation.

Transformer 2 (115kV/12.47kV at 7.5/11.5/15.5 MVA), first installed around the 1950s, underwent a complete rebuild in 2006, which included a new circuit switcher, transformer and switchgear enclosure.

Findings and recommendations for Unit 2 of Whiterock Substation are as follows:

- The existing Transformer has multiple leaks; we recommend addressing these repairs as soon as possible to prevent further issues and maintain its integrity. We also recommend performing annual Dissolved Gas Analysis (DGA) testing on the transformer, as it supports early fault detection, enables condition-based maintenance, and contributes to extending the transformer's operational life.

The following recommendations apply to both Unit 1 & Unit 2 of White Rock Station:

- The existing General Electric (GE) relays are outdated, obsolete, no longer supported by GE as of January 2020, and have limited capabilities, such as no advanced protection schemes, no programmable logic, basic metering, run on legacy software, basic communication protocols, and don't support web-based HMI. We recommend replacing them with Schweitzer Engineering Laboratories (SEL) relays offering enhanced protection and communication capabilities. SEL relays provide advanced features such as arc flash detection, event recording, and diagnostic capabilities, support the latest communication protocols, and have built-in programmable logic. They are also better equipped against cybersecurity threats.
- The existing GE meters provide basic energy and power calculations, but lack advanced power quality monitoring, support legacy communication protocols, run on legacy software, lack encryption, and have fixed input and outputs (I/O's) and legacy support from GE. We recommend replacing them with SEL-735 meters to improve accuracy and resolution. SEL meters offer advanced power monitoring, built-in programmable logic for custom alarms, extensive event logs, modular I/O's, and support a wide range of modern communication protocols.
- We recommend replacing the remote terminal unit (RTU) with a SEL-RTAC with Human Machine Interface (HMI) capability. The SEL-RTAC offers data acquisition and visualization, system integration, local/remote monitoring, control, integrated alarms, and annunciation.
- This station currently uses a radio and modem setup for communication purposes. We recommend upgrading to fiber optic communications to improve data speed, reliability, and security.

2.2.2 Los Alamos Townsite Switching Station

This station is a single switchgear enclosure in Los Alamos without security fencing.

The findings and recommendations for Townsite are as follows:

- Install a durable, weather-resistant security fence around the switchgear to safeguard personnel, prevent unauthorized access, reduce liability, and improve the site's safety.
- Breakers at this station currently lack remote control capability. We recommend upgrading the equipment to enable remote operation for improved safety, control, and response time.
- The existing GE relays are outdated, obsolete, no longer supported by GE as of January 2020, and have limited capabilities, such as no advanced protection schemes, no programmable logic, basic metering, run on legacy software, basic communication protocols, and don't support web-based HMI. We recommend replacing them with SEL relays, which offer enhanced protection and communication capabilities. SEL relays provide advanced features such as arc flash detection, event recording, and

diagnostic capabilities, support the latest communication protocols, and have built-in programmable logic. They are also better equipped against cybersecurity threats.

- The existing Bitronics meters are suitable for basic metering and monitoring but lack advanced power quality monitoring, support legacy communication protocols, lack encryption, and have fixed I/O's. We recommend replacing them with SEL-735 meters to improve accuracy and resolution. SEL meters offer advanced power monitoring, built-in programmable logic for custom alarms, extensive event logs, modular I/O's, and support a wide range of modern communication protocols.
- We recommend replacing the RTU with the SEL-RTAC w/HMI capability, which offers data acquisition and visualization, system integration, local/remote monitoring, control, integrated alarms, and annunciation.
- This station currently uses a radio and modem setup for communication purposes. We recommend upgrading to fiber to improve data speed, reliability, and security.

3.3 Current and Future Supply Markets Assessment

LACDPU and LANL make up the Los Alamos Power Pool (LAPP) and are currently in the implementation phase of their 2022 Integrated Resource Plan (IRP), completed in June of 2022, which determined what new resources to procure in the future to cover the growing power supply needs. The 2022 IRP[3] outlined a preferred portfolio that included storage, solar, wind, and a small-modular nuclear reactor (SMR) by the end of the study period. However, the SMR project, for which LACDPU was going to have a Power-Purchase Agreement (PPA) in 2030, was cancelled by the developer in November of 2023[4]. Resource procurement must, at minimum, cover the loss of this SMR PPA. 1898 & Co. recommends that LAPP complete an updated IRP that expands on the three cases evaluated in the 2022 IRP to account for all potential scenarios and determine the optimal resource solution. 1898 & Co. also recommends that after the 2022 IRP is updated, LAPP look at completing "IRP-lite" modeling in between the full IRP analysis to see what the optimal resource selection is based on actual market conditions and after resource procurement by LAPP.

For LAPP to determine what resources are currently available for procurement, they should consider releasing All-Source Request for Proposals (ASRFPs) for generating resources tied to what resources were considered as part of the 2022 IRP preferred portfolio. As some of the capacities for different resources LAPP seeks to acquire are under 100 MW in certain years, LAPP could consider working with Public Service Company of New Mexico (PNM) or another New Mexico entity to acquire larger assets, whether through ownership or PPAs.

[3] FTI Consulting (2022, June) Los Alamos County 2022 Integrated Resource Plan https://www.losalamosnm.us/files/sharedassets/public/v/1/departments/utilities/documents/integrated-resource-plan-irp-2022-final-report.pdf

[4] (2023, November 8). Utah Associated Municipal Power Systems (UAMPS) and NuScale Power agree to terminate the Carbon Free Power Project. https://www.nuscalepower.com/press-releases/2023/utah-associated-municipal-power-systems-and-nuscale-power-agree-to-terminate-the-carbon-free-power-project

As PNM has expressed its interest in joining the California Independent System Operator (CAISO) Extended Day-Ahead Market (EDAM), there is potential for more competitive bids from resources that LAPP can procure if they also follow PNM into participating in the CAISO EDAM. However, 1898 & Co. cannot comment with any certainty on the impacts of CAISO EDAM participation, as EDAM is not expected to become operational until May of 2026. PNM has expressed interest in participating but has not given an explicit timeline for when they would join. Assuming PNM joins EDAM and LAPP follows PNM, LAPP would then be able to procure energy from members who are participants in the EDAM; however, the LAPP will have to verify how the power gets delivered while being aware of potential transmission congestion and wheeling costs when procuring resources outside the LAPP footprint. These potential bottlenecks could cause congestion that reduces the expected economic flow into the footprint or “pancaked” transmission/wheeling costs required to move the power. Most major utilities in Arizona have announced their intentions to join SPP Markets +, a competitor to the CAISO EDAM, and the power must wheel through Arizona to get into New Mexico due to the current topology of the transmission system.

As the CAISO EDAM Market participation rules have not been finalized, potential issues could arise if LAPP were to join EDAM. Currently, load-serving entities who are members of CAISO must have a 15% Planning Reserve Margin (PRM) on top of their peak load to meet any potential shortfalls on their own. The 2022 preferred portfolio for LAPP did not feature a continuous 15% PRM across all years and would require the procurement of additional resources to reach the 15% PRM, assuming this is still a requirement if the LAPP joins the EDAM. LAPP should monitor these market participation rules and update its IRP modeling and resource procurement accordingly to understand the impacts of joining CAISO EDAM.

3.4 Existing Distribution System Model and Power Flow Assessment – Peak Load

Electric utilities typically use power flow software to study the distribution system. WindMil, a software developed by MilSoft, is utilized by LACDPU. It is a standard software used among electric cooperatives and municipal utilities throughout the United States. The WindMil power flow model aggregates GIS data, equipment attributes, customer demand, and operational measurements to perform various analyses.

3.4.1 WindMil Power Flow Model Fidelity

After reviewing the GIS system for recent changes, the LACDPU staff developed the existing WindMil power flow model used for this study. LACDPU does not have a direct connection between the GIS system and its WindMil power flow model. As a result, manual efforts were necessary to clean up the power flow model in preparation for this study. New meters and equipment have been added for new customer loads connected in recent years. Solar PV customers are maintained in the GIS system, but these generators were not initially modeled in the WindMil power flow model. 1898 & Co. worked with LACDPU staff to incorporate solar PV generators into the power flow model. Another effort mapped billing information to modeled customers to perform a more accurate load allocation. This mapping was achieved but must be manually maintained until a direct connection can be made between the GIS, billing information systems, and the WindMil power flow model.

1898 & Co. recommends that LACDPU further investigate the following opportunities to improve power flow modeling efforts.

- Work with MilSoft to maintain the ability to extract a current model from the GIS system. This will reduce the manual efforts of maintaining a separate GIS system and a WindMil model. Below is a summary of manual efforts required to clean the model in preparation for power flow analysis.

- Meter numbers were not maintained in the WindMil power flow model. A scripting effort was required to identify the appropriate meter number for each customer in the power flow model.
- Solar PV customers were not contained in the WindMil power flow model. A scripting effort was required to add PV generators to the WindMil power flow model.
- Phasing within the power flow model was not accurate. LACDPU phasing maps were reviewed manually to correct phasing in the model. Assumptions for customer phasing were made if phasing maps were not available.
- Single-phase transformers within the overhead portions of the system were not modeled correctly. Single-phase transformers were distributed among the two-phase laterals. Manual corrections were performed.
- In several locations, conductor types were upgraded to reflect recent capital projects where three-phase lines were extended to new pad mount switchgear.
- Secondary conductors in many locations were not modeled correctly. A strenuous effort was necessary to correct parallel secondary conductors and unintended loops. This model cleanup can potentially influence the results of the power flow analysis. Field verification and improved GIS mapping would be the ideal approach to correct this in the future.

- Maintain a historical record of SCADA data for feeders and substations. Recording historical interval data for the distribution feeders and substation transformers will help future modeling efforts allocate loads to different system demands.
- Develop a process for incorporating customer billing information into the WindMil power flow model. This will streamline future load allocations and specific scenario analysis. Not all customers within the WindMil power flow model successfully incorporated billing information, which influenced the accuracy of the load allocation and required 1898 & Co. to utilize different load allocation methods in this study.

3.4.2 Normal Configuration Review

1898 & Co. evaluated the current Los Alamos Townsite system's power flow with the energized LASS Substation. Figure 3-4 shows an overview of the Los Alamos Townsite system. Red represents the feeders that originate from the LASS Substation. Blue represents the distribution feeders that originate from the Townsite Substation. Green represents the primary feeders that originate from the TA3 Substation.

Figure 3-4: Los Alamos Townsite System Colored By Substation

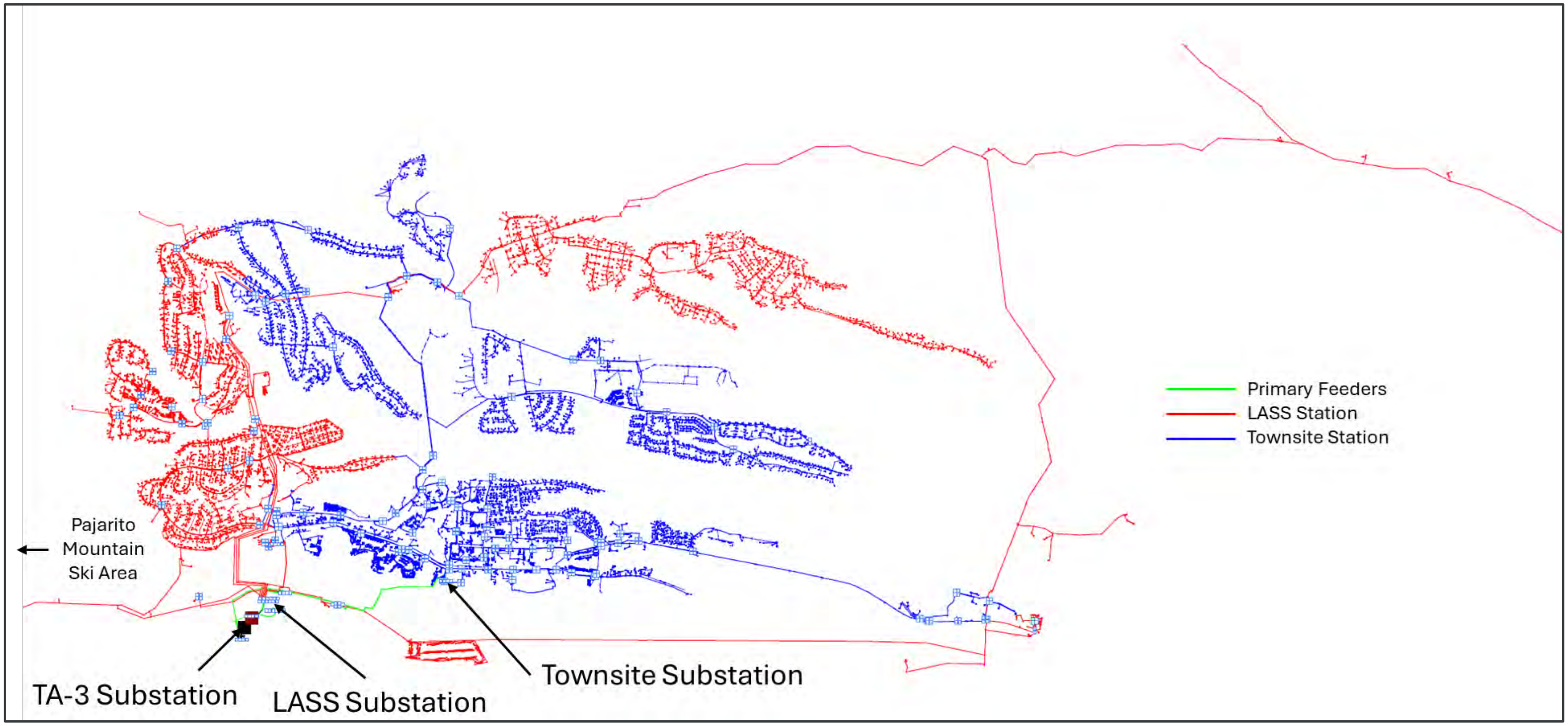


Table 3-1 shows the power flow results for each distribution feeder within the Los Alamos Townsite system. No voltage or equipment loading violations were observed. The LASS Substation provides many more distribution feeders within the Los Alamos Townsite system, which helps reduce the customer load per feeder. Reducing the load per distribution feeder helps to limit the number of customers impacted by potential outages. However, the LASS Substation does not increase the load serving capacity of the Los Alamos Townsite System. The substation transformers at the TA-3 Substation limit the load serving capacity.

Table 3-1: Los Alamos Townsite System Normal Configuration Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	1,123	-92	1,141	61	122.9
	14	2,304	761	2,427	110	122.5
	15	1,148	342	1,198	61	122.8
	16	1,244	352	1,294	69	121.8
	17	1,836	605	1,933	83	124.0
	18	710	236	749	33	123.6
	Substation	**8,409**	**2,221**	**8,698**	**-**	**-**
LASS	13T	1,605	770	1,781	82	123.6
	NS6	1,270	247	1,294	54	124.8
	15T	1,246	372	1,300	77	123.1
	NSM6*	-	-	-	-	-
	16T	1,280	397	1,340	69	122.2
	NS3	621	89	628	99	124.8
	NS18	1,864	636	1,970	87	120.0
	18T	502	240	557	24	123.6
	Substation	**8,468**	**2,918**	**8,958**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

Figure 3-5 shows an overview of the White Rock system. Only one substation serves the White Rock system, and each distribution feeder is colored individually. Feeders WR1 and WR2 serve most of the White Rock load.

Figure 3-5: White Rock System Colored by Distribution Feeder

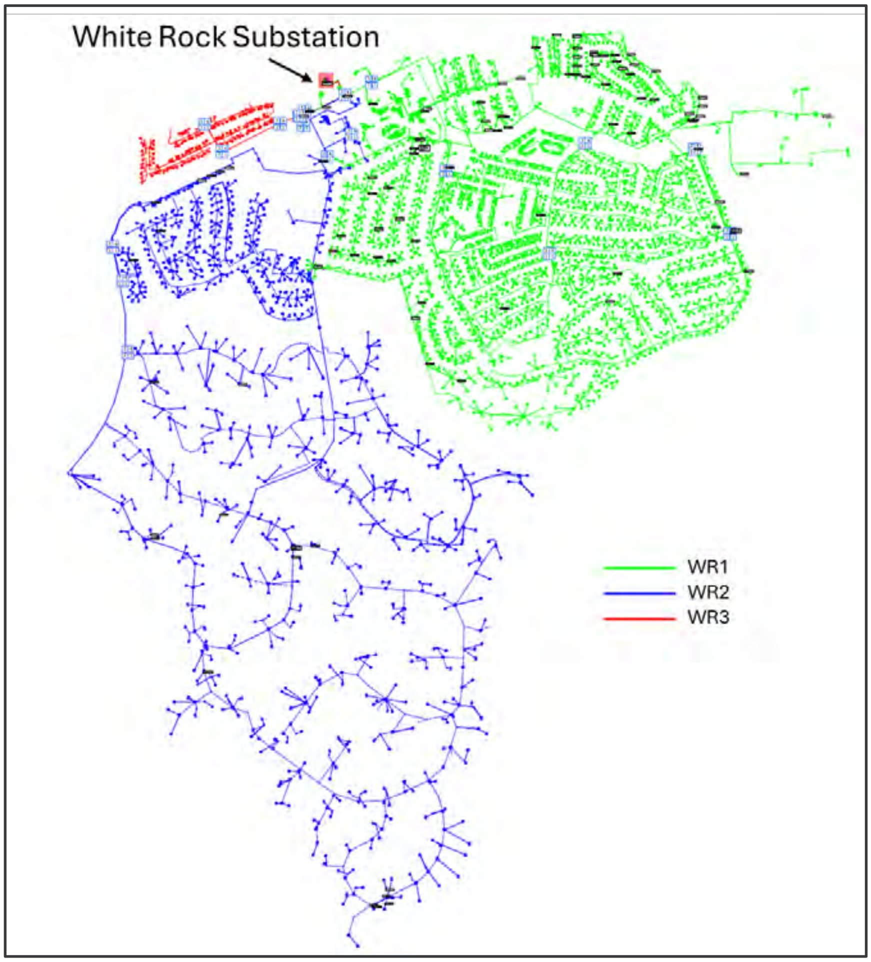


Table 3-2 shows the power flow results for each distribution feeder within the White Rock system. No voltage or equipment loading violations were observed. Transformer 1, which has a normal rating of 7,500 kVA, usually serves the White Rock system. This review shows some remaining load-serving capacity in the normal configuration.

Table 3-2: White Rock System Normal Configuration Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	2,075	710	2,193	112	120.6
	WR2	1,455	505	1,540	82	121.2
	WR3	163	54	171	10	124.3
	Substation	3,693	1,270	3,905	-	-

3.4.3 Contingency Configuration Review

After reviewing the normal configuration power flow results, various substation outage contingency configurations were evaluated to determine whether the LACDPU system has sufficient capacity. The most impactful outages to prepare for are the loss of a substation transformer and the loss of a single primary feeder. Using the power flow model, contingency restoration efforts were reviewed for each primary feeder and substation transformer in the Los Alamos Townsite system. Table 3-3 shows a summary of results for the Los Alamos Townsite system. The LASS Substation, which was modeled before the forecasted electrification load growth was applied, can restore all customers.

Table 3-3: Los Alamos Townsite System Contingency Configuration Summary

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 1	9,038	17,811	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. Transformer 2 is the most limiting element in this contingency.
Loss of XFMR 2	8,443	17,811	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. Transformer 1 is the most limiting element in this contingency.
Loss of TC1	4,719	8,682	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	3,963	8,682	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	4,483	8,831	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	4,348	8,831	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.

The loss of the main power transformer was reviewed in the White Rock system in Table 3-4. The backup transformer at the White Rock Substation can successfully restore all customers. However, its 5 MVA rating does not leave much capacity for additional load growth. Substation transformer upgrades for the White Rock system will be necessary, with anticipated electrification load increases.

Table 3-4: White Rock System Contingency Configuration Summary

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 1	3,905	3,905	5,000	No	No	Transformer 2, which has a higher rating compared to Transformer 1, normally serves the load. Transformer 1 has sufficient capacity to restore all the White Rock load. Feeders 16 and 17 restore all customers through distribution feeder ties. Transformer 1 is the most limiting element in this contingency.

3.4.4 System Reliability Observations

The contingency review showed that the LACDPU system is configured to restore all customers for major outage events impacting the substations and primary feeders. However, extended outages can occur due to faults and equipment failure impacting radial portions of the distribution feeders in the LACDPU system. The White Rock system is constructed with many loops that can be used to restore power to customers while repairs are made on the system. The Los Alamos Townsite system has longer radial distribution feeders extending onto the mesas. These radially fed mesas can present challenges in maintaining customer power due to an outage. Opportunities to loop these radial areas will help to improve future restoration efforts and potential outages necessary for construction efforts.

3.5 Hosting Capacity Assessment – Minimum Daylight Load

Hosting capacity analysis is a study method that estimates how much Distributed Energy Resources (DERs) can be added to the electric distribution system without requiring system improvements. Typically, hosting capacity analysis is performed during the minimum daylight load time, where customer load is low and DER output can be high, resulting in greater potential for reverse power flow. WindMil can perform many steady-state analyses, but hosting capacity analysis is a method that WindMil does not support. 1898 & Co. utilized the export function from WindMil to convert the power flow model to another software called Cyme, which Eaton develops. Cyme can perform hosting capacity analysis, which was used to generate the results discussed in this section.

3.5.1 Planning Criteria – Hosting Capacity Limitations

Increasing DER penetration on the distribution system provides more renewable energy to the local grid and can offset the use of fossil fuels. However, increasing DER penetration can cause challenges in operating and maintaining the distribution system. DERs can cause equipment loading violations if enough renewable energy is produced above equipment ratings. High voltage violations can occur if generation exceeds local load and the system voltage rises. The protection system can also be negatively impacted as increasing reverse power flows can desensitize protection schemes and cause nuisance tripping of relays due to phase loading imbalance. To properly evaluate the hosting capacity of the LACDPU distribution feeders, 1898 & Co. and the LACDPU project team discussed the desired planning criteria to maintain safe and reliable operation of the system without requiring system improvements.

- **Equipment Loading** – no conductor or equipment should exceed 100% of the normal rating.
- **Voltage** – primary system voltage must remain between 118 V and 126 V.
- **Reverse Power Flow (Protection)** – No reverse power flow is permitted through reclosers or the feeder relay.

3.5.2 Minimum Daylight Load Models

DERs stress the distribution system during the minimum daylight load, where generation output is most likely to exceed customer load in the distribution system. LACDPU gathered phase amperage readings for each feeder during a light load day in the spring. These amperage readings are contained in Section 2.4. The WindMil model was allocated using these minimum daylight readings. Then, the Los Alamos Townsite system model was reconfigured to represent the new configuration with the energized LASS Substation. Table 3-5 shows the minimum daylight load estimated for each distribution feeder in the new configuration.

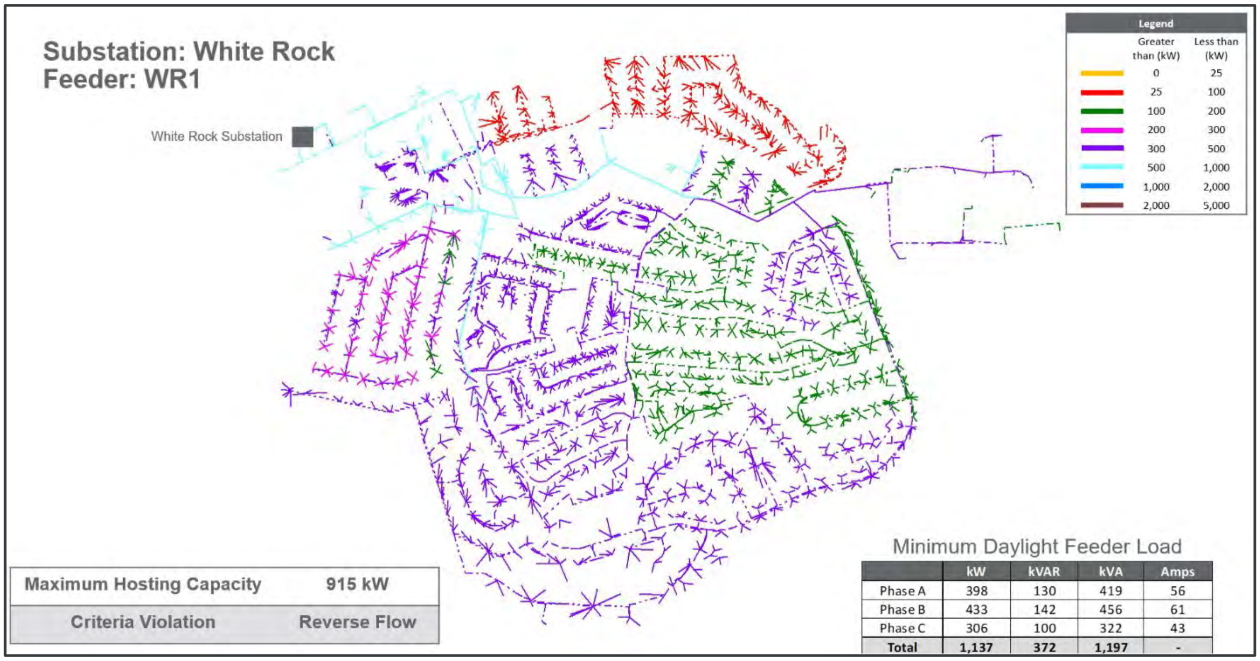
Table 3-5: Feeder Minimum Daylight Load

Substation	Feeder	kW	kVAR	kVA
Townsite	13	499	-264	575
Townsite	14	981	286	1,022
Townsite	15	526	151	548
Townsite	16	560	128	575
Townsite	17	1,360	397	1,418
Townsite	18	557	168	582
LASS	13T	679	512	852
LASS	S6	375	74	382
LASS	15T	594	159	616
LASS	16T	560	238	609
LASS	NS3	180	48	186
LASS	NS18	243	69	253
LASS	18T	303	172	349
White Rock	WR1	1,113	324	1,160
White Rock	WR2	531	168	556
White Rock	WR3	35	11	38

3.5.3 Hosting Capacity Visuals

Figure 3-6 shows an example of the hosting capacity heat maps that were prepared while performing this analysis. The legend color shows the remaining capacity in each line section to host additional DER. Typically, the greatest hosting capacity is observed near the substation where the conductor and equipment have the highest ratings. Proximity to the substation also reduces the potential for reverse power flow through protective devices and high voltage from excess generation. The maximum hosting capacity value identified for each feeder is often found near the substation. It represents the largest amount of generation that could be placed on the feeder at an optimal location. Minimum daylight feeder load power flow results are also shown in each visual as customer load impacts the hosting capacity. The hosting capacity generally decreases further from the substation where conductor sizes are smaller, and voltage rise is more likely to occur. See Appendix A for visuals of each feeder analyzed.

Figure 3-6: Hosting Capacity Analysis Feeder Visual Example



3.5.4 Summary of Results

Hosting capacity analysis was performed individually for each distribution feeder within the LACDPU system. The summary of results are shown in Table 3-6. Reverse power flow through the feeder relay was the most limiting criterion from this analysis. LACDPU will need to evaluate system improvements for the feeder relays and other protective devices to host additional DER beyond the hosting capacity presented in this analysis. System improvements are related to correctly sensing the direction of current flow to avoid desensitization and nuisance tripping. It is important to note that this analysis was based on feeder amperage readings provided by LACDPU during the spring of 2025. The hosting capacity represented in this study is intended to reflect only the current modeled primary system. If the minimum daylight load decreases, the hosting capacity is also expected to decrease. As new customer DER is added to the LACDPU system, the hosting capacity of the system will be reduced, and these hosting capacity results will become outdated. Secondary conductors, service transformers, and panel upgrades may still be required for customer-owned new PV interconnections even if some hosting capacity is represented on the primary system.

Table 3-6: Summary of Hosting Capacity Analysis Results

Substation	Feeder	Existing DER Capacity kW	Maximum Remaining Hosting Capacity kW	Criteria Violation
Townsite	13	137	461	Reverse Flow
Townsite	14	178	929	Reverse Flow
Townsite	15	140	435	Reverse Flow
Townsite	16	287	425	Reverse Flow
Townsite	17	0	1,309	Reverse Flow
Townsite	18	14	534	Reverse Flow
LASS Station	13T	117	625	Reverse Flow
LASS Station	S6	0	375	Reverse Flow
LASS Station	15T	123	408	Reverse Flow
LASS Station	16T	208	334	Reverse Flow
LASS Station	NS3	0	180	Reverse Flow
LASS Station	NS18	0	205	Reverse Flow
LASS Station	18T	0	285	Reverse Flow
White Rock	WR1	276	915	Reverse Flow
White Rock	WR2	328	383	Reverse Flow
White Rock	WR3	66	35	Reverse Flow

3.6 Grid Modernization Strategies

Modernizing the electric distribution system will require investment in new technologies and operational methods. Typically, the term Advanced Distribution Management System (ADMS) describes the operation of the holistic distribution system through generation control, load management, protective equipment, data systems, and billing information. Table 3-7 shows each technology/strategy and the anticipated value to LACDPU based on the unique characteristics of their system. The next steps indicate recommended actions for the LACDPU project team to explore and implement these technologies and methods further. Appendix B contains the takeaways from each workshop discussion and further details.

Table 3-7: Grid Modernization Strategies Summary

Technology/Strategy	Value to LACDPU	Next Steps
Transmission Scale BESS	Low	There is no near-term action; this is an area where there may be value in the long term. It is dependent on cooperation with Pueblo and other parties.
Distribution Scale BESS	High	Near-term, LACDPU should consider a further detailed feasibility study.
Residential BESS	Low	No action, not an area to pursue for LACDPU.
Mobile BESS	High	In the near term, LACDPU should consider adding a mobile BESS to its portfolio. Several use cases are under consideration for this resource.
FLISR	Medium	LACDPU should look for opportunities to implement reclosers and smart switches into the system. System reliability is good today, but it must be monitored as the system grows with electrification.
Distribution Microgrid	Medium	No near-term action. Consider microgrid compatibility when deploying new equipment on the system. As technology matures, there may be more opportunities in the long term.
Modular Substations	Low	This study has shown how traditional substation capacity can serve the forecasted electrification load. Modular substations are not necessary for LACDPU in the near term.
Volt-Var Optimization	Low	There is no near-term action. Voltage is well-regulated in the system today. Increasing DER penetration may require LACDPU to focus more on Volt-VAR optimization in the long term.
Demand Response Programs	High	Thermostat, water heater, or managed EV charging programs are areas to investigate further

4.0 Adoption Modeling and Forecasting

In 2024, Los Alamos County adopted an ambitious Climate Action Plan (CAP) to protect the community's health and environment.[5] The CAP outlines a roadmap to achieve carbon neutrality by 2050, requiring the elimination of natural gas from buildings and the full adoption of electric vehicles. While reaching these goals demands significant Community efforts, the necessary technologies, such as electric vehicles, heat pumps, and induction stoves, are commercially available today. The primary challenge lies in deploying these technologies and establishing supportive public policies.

Meeting the CAP objectives necessitates grid expansion as the transportation and building sectors electrify. Concurrently, Los Alamos County customers may invest in solar panels and distributed energy resources (DERs). However, severe weather and aging infrastructure could increase service interruptions, increasing customer sensitivity to outages as they depend on the grid for heating, cooling, and transportation.

To address these challenges, Los Alamos County needs a 30-year master plan that integrates these climate goals and identifies necessary infrastructure enhancements to support anticipated electrification loads. Quantifying the current market and forecasting future grid demand are essential to creating this master plan.

1898 & Co. analyzed four major market segments: transportation electrification, home electrification, commercial electrification, and distributed solar PV and batteries. We developed three scenarios to create different bookends for the potential adoption of each electrification technology in a market segment. These scenarios informed different projections for grid demand over the next 30 years.

4.1 Electrification Scenarios

1898 & Co. developed three scenarios projecting grid demand growth over the next 30 years. Each scenario is outlined below.

Scenario 1 aligns with Los Alamos County's Climate Action Plan (CAP), targeting carbon neutrality by 2050. This requires 100% electric vehicle (EV) adoption for passenger cars and eliminating natural gas in all buildings. The CAP also calls for new building standards that improve energy efficiency. A 2022 NREL report indicates a correlation between EV ownership and increased homeowner adoption of rooftop solar and battery energy storage systems (BESS); consequently, 1898 & Co. assumes that these two technologies will have a very high adoption rate under this scenario.[6] However, 1898 & Co. also understands that not every home has a rooftop ideal for installation of solar PV due to sharding or the direction the home faces. Therefore, Scenario 1 projects the following by 2055:

- 100% EV adoption for all vehicles.
- 100% electrification of all homes and commercial properties, eliminating natural gas use.

[5] *Los Alamos Climate Action Plan*. (2024). Los Alamos County. https://www.losalamosnm.us/files/sharedassets/public/v/2/departments/county-manager/documents/losalamoscap_20241104-reduced.pdf

[6] Sharda, S., Garikapati, V. M., Goulias, K., Reyna, J. L., Sun, B., Spurlock, C. A., & Needell, Z. (2022, November 13). *Is the Adoption of Electric Vehicles (EVs) and Solar Photovoltaics (PVs) Interdependent or Independent?* Behavior, Energy, and Climate Change Conference, Washington DC. https://docs.nrel.gov/docs/fy23osti/84543.pdf

- 20% improvement in energy efficiency for homes and commercial properties.
- 35% adoption of rooftop solar for homes and commercial properties.
- 20% adoption of BESS for homes and commercial properties.

Scenario 2 reflects New Mexico's current public policy landscape, including federal, state, and local grants, incentives, and tax credits. Where available, it also follows historical trends in Los Alamos County. Intended as a moderate projection based on January 2025 conditions, Scenario 2 assumes the following by 2055:

- Continuation of Los Alamos County's historical EV adoption rate.
- 50% electrification of homes and commercial properties.
- 10% improvement in energy efficiency for homes and commercial properties.
- 25% adoption of rooftop solar for homes and commercial properties.
- 10% adoption of BESS for homes and commercial properties.

Scenario 3 assumes minimal influence from the CAP or government regulations on technology adoption, resulting in significantly lower electrification rates. By 2055, Scenario 3 projects:

- EV adoption rates match the statewide average in Los Alamos County.
- 25% electrification of homes and commercial properties.
- No improvement in energy efficiency for homes and commercial properties.
- 12% adoption of rooftop solar for homes and commercial properties.
- 5% adoption of BESS for homes and commercial properties.

4.2 Forecasting Methodology

This analysis addresses the key question: What is the different potential for Los Alamos County's residents adopting new technologies? To help frame this potential, 1898 & Co. used the Bass Diffusion Model to show adoption trends over the 30-year forecast. The Bass Diffusion Model is shown below:

$$\frac{dN(t)}{dt} = \left[p + q * \frac{N(t)}{m}\right] * [m - N(t)]$$

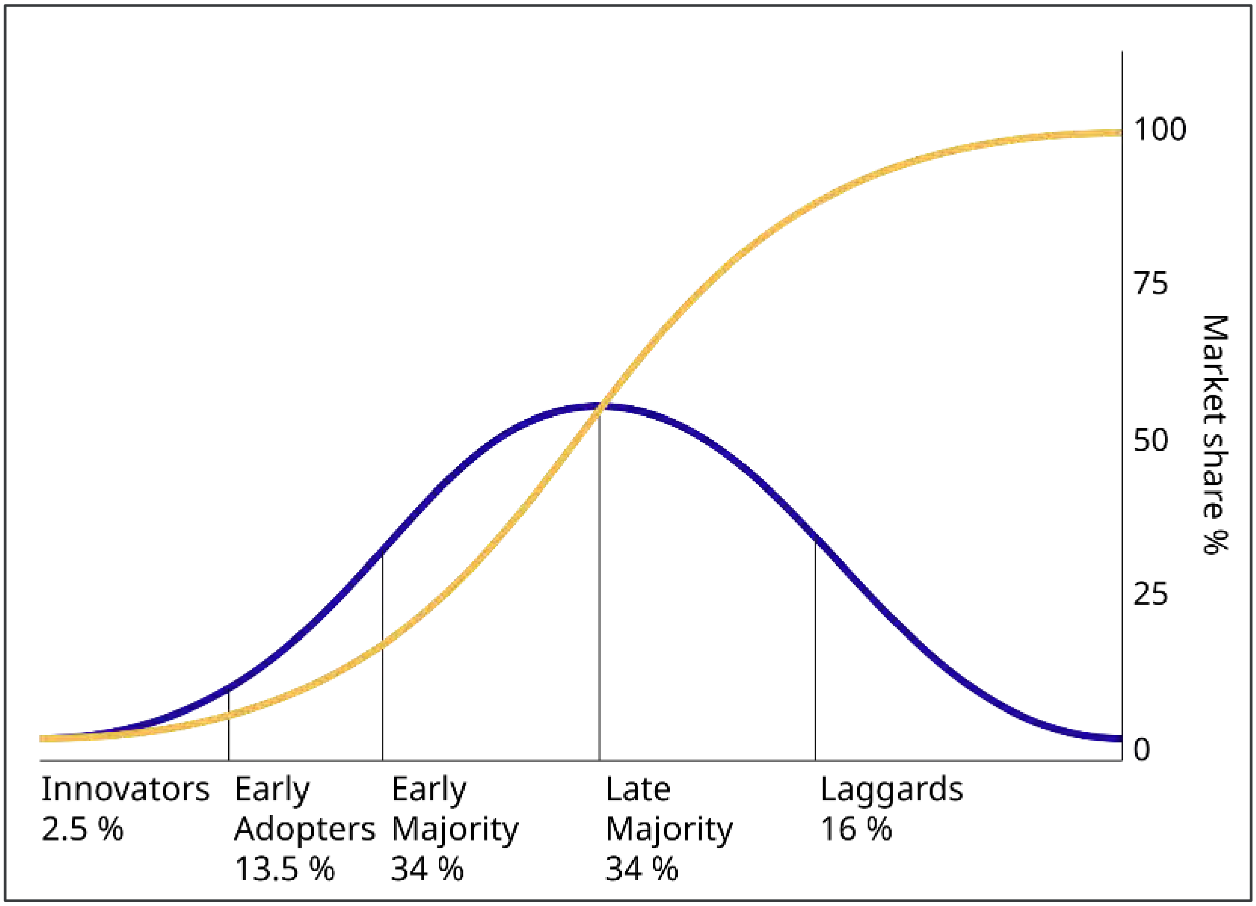
Where:

- **N(t):** Cumulative adopters at time t.
- **m:** Total potential market size (Los Alamos County population).
- **p:** Coefficient of innovation (external influence, e.g., advertising).
- **q:** Coefficient of imitation (internal influence, e.g., word-of-mouth).
- **dN(t)/dt:** Adoption rate at time t.

The Bass model is suitable for forecasting technology adoption as the key variables are well-defined. The market size (*m*) is relatively stable, based on the county's consistent population. While the adoption rate (*dN(t)/dt*) could be unrealistic (e.g., 25% of households replacing water heaters annually), 1898 & Co. adjusted this to reflect realistic technology lifecycles (i.e., only 1/15 of the population of water heaters are purchased each year, because water heaters have a 15-year lifespan). While *p* and *q* are less directly observable, they were calibrated to match the projected outcomes of each scenario. For example, in Scenario 1 (100% electric water heater adoption by 2055), *p* and *q* were adjusted to reach 100% market share by 2055; similarly, Scenarios 2 and 3 had adjusted *p* and *q* values reflecting 50% and 25% market share by the same date, respectively.

The Bass Diffusion model generates a characteristic S-curve, illustrating the adoption phases: the innovator experimenting with the new technology, followed by early adopters, a rapid increase among the early majority, and a slower uptake by the late majority and laggards. The curve's shape remains consistent across scenarios; however, adjusting *p* and *q* alters how slow or fast the rate of adoption occurs. For example, repealing a tax credit (reducing *p*) would stretch the curve, while introducing a grant program (increasing *p*) would compress it.

Figure 4-1: Diffusion of Innovation



P and *q* are sensitive to many factors, such as government policies and incentives, the cost of a product and its lifespan, and the community's attitude towards the product. Los Alamos County residents fit the profile of consumers most likely to buy or lease an electric vehicle: they are highly educated, have high-income, and have multiple vehicles in the household.[7] 30% of New Mexico's population has a bachelor's degree or higher, but 68% of Los Alamos County residents have a college degree. The average New Mexican with a bachelor's degree earns $54,832 annually, but the same person, on average, earns $87,014 in Los Alamos County.[8] 65% of households in the Los Alamos townsite and 83% of White Rock residents own two or more vehicles.[9] Given these demographic characteristics, 1898 & Co. expects the community to view EVs positively and adopt the technology more quickly than the rest of the state. Other zero-emission technologies, such as heat pumps, induction stoves, and solar panels, are also expected to be adopted at a higher rate than in the surrounding region.

The Bass Diffusion Model provides yearly estimates of technology adoption within the community. This process is repeated for each scenario, resulting in three distinct market share projections for each technology over the next 30 years. Subsequently, 1898 & Co. characterized each device's grid impact, considering its energy consumption profile, operational duration, and the likelihood of simultaneous operation across multiple households. The grid impact of each device is multiplied by the number of devices in the community for each scenario.

4.3 Transportation Electrification

Transportation and related land use account for 38% of Los Alamos County's greenhouse gas emissions, as identified in the county's climate action plan. While the plan advocates for increased public transit and bicycle use, most air quality agencies around the country prioritize zero-emission vehicles (ZEVs) as a mitigation strategy. ZEVs offer a direct replacement for existing vehicles, enabling straightforward tracking of vehicle registrations and quantifiable emission reductions. However, widespread ZEV adoption requires upgrades to electric utility infrastructure to meet the increased power demand.

[7] (PDF) An Analysis of Attributes of Electric Vehicle Owners' Travel and Purchasing Behavior: The Case of Maryland. (n.d.). *ResearchGate*. Retrieved June 16, 2025, from https://www.researchgate.net/publication/335455046_An_Analysis_of_Attributes_of_Electric_Vehicle_Owners'_Travel_and_Purchasing_Behavior_The_Case_of_Maryland

[8] U.S. Census Bureau, U.S. Department of Commerce. (n.d.). Educational Attainment. *American Community Survey, ACS 5-Year Estimates Subject Tables, Table S1501*. Retrieved June 16, 2025, from https://data.census.gov/table/ACSST5Y2023.S1501?t=Education&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false.

[9] U.S. Census Bureau, U.S. Department of Commerce. "Selected Housing Characteristics." American Community Survey, ACS 5-Year Estimates Data Profiles, Table DP04, 2023, https://data.census.gov/table/ACSDP5Y2023.DP04?g=dp04&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false.

4.3.1 Vehicle Population Estimate

In 2020, Los Alamos County had a population of 19,419, with 13,179 residing in the Los Alamos census-designated place (CDP, hereafter called Los Alamos Townsite) and 5,852 in White Rock CDP.[10] The county comprises 8,754 households: 7,304 single-family homes, 1,291 multi-family dwellings, and 159 manufactured homes. 8,667 households are DPU customers.[11] Occupancy rates are approximately 95%, slightly higher in Los Alamos Townsite and lower in White Rock.[12]

There is no detailed survey of the county's vehicle population, but statewide and national estimates provide a basis for calculation. The 2021 VIUS survey reported 1,310,700 vehicles in New Mexico, with 95.2% light-duty passenger cars and pickup trucks, 3% medium-duty, and 1.9% heavy-duty vehicles.[13] Census Bureau data (Table 4-1) provides vehicle ownership estimates per household for Los Alamos County, Los Alamos Townsite, and White Rock.

Table 4-1: Vehicle Count Per Household

Vehicle Count	LACDPU	Los Alamos Townsite	White Rock
Zero Vehicles	1.60%	2.30%	0.00%
One Vehicle	29.50%	32.40%	16.90%
Two Vehicles	39.10%	39.70%	38.70%
Three+ Vehicles	29.80%	25.60%	44.40%

Based on Experian's North American Automotive Database, supplemented by data from VIUS, ACS, and household counts, 1898 & Co. estimates a total of 18,156 vehicles in Los Alamos County: 12,750 in Los Alamos townsite and 5,406 in White Rock. A detailed breakdown by vehicle weight class for the county, Los Alamos Townsite, and White Rock is provided in Table 4-2. These populations will be further broken down by their respective fleets in the following sections of this chapter.

[10] *U.S. Census Bureau QuickFacts: White Rock CDP, New Mexico; Los Alamos CDP, New Mexico; Los Alamos County, New Mexico; New Mexico*. (n.d.). Retrieved June 2, 2025, from https://www.census.gov/quickfacts/fact/table/whiterockcdpnewmexico,losalamoscdpnewmexico,losalamoscountynewmexico,NM/EDU635223

[11] *Annual Report 2024*. (n.d.). Los Alamos Department of Public Utilities. Retrieved June 2, 2025, from https://indd.adobe.com/view/00a3a765-088f-41a2-96cc-cda75220b416

[12] *DP04: Selected Housing Characteristics—Census Bureau Table*. (n.d.). Retrieved June 2, 2025, from https://data.census.gov/table/ACSDP5Y2023.DP04?q=dp04&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false

[13] *VIUS213A: All Vehicles by ... - Census Bureau Table*. (n.d.). Retrieved June 2, 2025, from https://data.census.gov/table/VIUSA2021.VIUS213A?q=vius21&g=040XX00US35

Table 4-2: Vehicles by Weight Class & Location

Vehicle Class	LACDPU	Los Alamos Townsite	White Rock
Light Duty (Class 1 & 2)	17,927	12,548	5,379
Medium Duty (Class 3, 4, 5, & 6)	147	126	21
Heavy Duty (Class 7 & 8)	82	76	6
Total	**18,156**	**12,750**	**5,406**

As of January 2025, Experian's North American Automotive Database estimated approximately 497 EVs registered in the county (out of 11,471 statewide), virtually all of them light-duty passenger cars owned by residents.

The VIUS survey estimates approximately 57,300 new vehicle registrations annually in New Mexico, encompassing new and used car sales and in-migration.[14] For Los Alamos County, this equates to approximately 824 vehicles per year. In the Forecasting Methodology section, this figure serves as the upper limit for annual EV adoption, representing 100% electric vehicle adoption among new registrations.

4.3.2 Charging Behavior and Infrastructure

Forecasting the grid impact of transportation electrification requires understanding how people will interact with their EVs. The preexisting grid can handle a handful of EVs in a neighborhood, but the grid impact of EVs will be significantly magnified if all 18,156 vehicles are plugged in simultaneously.

Fortunately, such an event is less likely to occur as people have different work and leisure schedules, drive varying miles, have various driving behaviors, and have varying access to home EV charging. The coincident load, which is the load of all EVs charging at the same time, for residential charging is calculated in this study as follows:

$$Coincident\ Load = N * kW * HC * DF$$

Where:

- N is the number of EVs in the community
- kW is the average power rating of the charger (in kW)
- HC is the percentage of EV drivers who charge at home
- DF is the diversity factor, representing the percentage of EV drivers charging at any given time. The diversity factor can also be viewed as the probability of all vehicles charging simultaneously.

[14] *2021 VIUS Table 2b*. (n.d.). Tableau Software. Retrieved June 2, 2025, from https://explore.dot.gov/views/2021VIUSTable2b/Dashboard1?%3Aembed=y&%3AshowVizHome=n&%3AapiID=host0#navType=0&na

The Bass Diffusion Model estimates how many EVs will be in Los Alamos County for each scenario for a given year. However, the charging behaviors of this population of EVs can be further split up. Generally, 30% of drivers will plug in immediately upon coming home, most likely around 6 pm. 40% of drivers will schedule their car to charge at a preset time using either an app on their phone or a smart charging station. For example, the driver plugs in their car at 6:00 pm but then instructs the app to start and finish charging the vehicle at a pre-set time such as 4:00 am. The app will trigger the charging to begin at the appropriate time, such as 12:00 am, to ensure the charging session is finished at the pre-set time which is 4:00am in this example. Lastly, 30% of drivers may not use a Level 2 charger and opt for a Level 1 charger by plugging it into a household 120V outlet. This "slow charging" means drivers who plug in at 6 pm will likely still be charging by 5 am the next day and will probably only unplug once it's time to leave the house.[15]

To track these different charging behaviors, 1898 & Co. split the residential EV population into three groups with varying charging behaviors. The Immediate and Scheduled charging groups use a level 2 charger with an assumed output of 7.7 kW while the Level 1 charging group uses a typical household 120V wall outlet with a maximum output of 1.44 kW.

Another factor that can reduce the grid impact of residential home charging is the assumption that some vehicles cannot access a home charger. On average, 80% of EV drivers charge at home.[16] The other 20% may not have access to a charger and must rely on public charging stations, or they may have charged up elsewhere earlier in the day and don't need to charge at home.

In addition, most EVs may only need to charge every two or three days, depending on the miles driven. The average daily vehicle miles traveled in New Mexico is 38 miles, while most EVs have a range of 250 miles or more. For this analysis, 1898 & Co. chose a 30% diversity factor to represent the coincident probability of drivers charging at the same time. The diversity factor can also be viewed as drivers charging every two to three days.[17] Non-residential vehicles are expected to charge every day.

1898 & Co. repeated these calculations with minor adjustments for the following distinct groups within transportation electrification:

- Los Alamos County Fleet
- Atomic City Transit
- Los Alamos Public School District
- Commercial fleets
- Residential EVs – Immediate charging
- Residential EVs – Scheduled charging
- Residential EVs – Level 1 charging

[15] Smart, J. G., & Salisbury, S. D. (2015). *Plugged In: How Americans Charge Their Electric Vehicles* (No. INL/EXT-15-35584). Idaho National Laboratory. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf

[16] Blonsky, M., Munankarmi, P., & Balamurugan, S. P. (2021). Incorporating Residential Smart Electric Vehicle Charging in Home Energy Management Systems. *2021 IEEE Green Technologies Conference (GreenTech)*, 187–194. https://doi.org/10.1109/GreenTech48523.2021.00039

[17] Bollerslev, J., Andersen, P. B., Jensen, T. V., Marinelli, M., Thingvad, A., Calearo, L., & Weckesser, T. (2022). Coincidence Factors for Domestic EV Charging From Driving and Plug-In Behavior. *IEEE Transactions on Transportation Electrification*, *8*(1), 808–819. https://doi.org/10.1109/TTE.2021.3088275

4.3.3 Zero Emission Vehicle Public Policy

Governments can play a significant role in EV adoption, primarily by leveraging economic policy tools. Some policymakers advocate for new incentive programs or regulations, while others attempt to dismantle existing ones. Just as important, many policymakers do not advocate one way or the other, and their neutral stance allows the status quo to persist.

As of January 2025, the federal government had pulled two major levers. First, the Inflation Reduction Act reengineered the long-standing EV tax credit to allow taxpayers to claim up to $7,500 if the EV was made in America and used a battery with a high percentage of minerals sourced from America and allied countries.[18] Second, the EPA adopted tighter emission standards for light and medium-duty vehicles beginning in 2027, which would significantly reduce the air pollution that new cars can legally emit.[19] The simplest option for automakers would be to sell considerably more zero-emission vehicles to balance out the emissions of all the other cars they sell. Since January 2025, the new administration has signaled that it will change both policies, but it is unclear how much or what potential impact it could have on the EV market.

In 2022, the New Mexico state legislature adopted the New Motor Vehicle Emission Standards.[20] These rules require automakers to sell cars and trucks that produce fewer emissions compared to the federal emission standards and partially align with several air quality rules from California: Advanced Clean Cars II, Advanced Clean Trucks, and the Heavy-Duty Omnibus. Unlike the EPA emission standards for model year 2027 mentioned previously, the New Mexico rule requires at least 43% of all new cars sold in 2027 to be zero-emission, and that requirement will ramp up to 82% by 2032. Since January 2025, the new federal administration has signaled that it wants to challenge the three California air quality rules that New Mexico's New Motor Vehicle Emission Standards align with, and it is unclear whether the White House will also challenge this rule.

New Mexico also offers the EV Charging Station Make-Ready Building Renovation tax credit. This tax credit provides homeowners with $500 for purchasing and installing equipment that makes the house EV-ready, with additional plus-ups for qualified income-eligible residents or commercial properties.[21]

Lastly, no local county or LACDPU-specific public policy related to EVs exists. New Mexico anti-donation laws preclude LACDPU from offering rebates that PNM and other utilities in the state offer.

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[18] *Credits for new clean vehicles purchased in 2023 or after | Internal Revenue Service*. (n.d.). Retrieved June 2, 2025, from https://www.irs.gov/credits-deductions/credits-for-new-clean-vehicles-purchased-in-2023-or-after

[19] *Multi-Pollutant Emissions Standards for Model Years 2027 and Later LightDuty and Medium-Duty Vehicles: Final Rule* (No. EPA-420-F-24-016). (2024). United States Environmental Protection Agency. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1019VP5.pdf

[20] *New Motor Vehicle Emissions Standards (Advanced Clean Cars II/Advanced Clean Trucks)*. (n.d.). Retrieved June 2, 2025, from https://www.env.nm.gov/climate-change-bureau/transportation/

[21] Energy Conserving Products. (n.d.). *Energy Conservation and Management*. Retrieved June 2, 2025, from https://www.emnrd.nm.gov/ecmd/tax-incentives/energy-conserving-products/

4.3.4 Los Alamos County Fleet

The Los Alamos County government maintains a fleet to carry out the county's day-to-day operations. This fleet comprises 128 light-duty cars and trucks, 78 medium-duty vehicles, and 29 heavy-duty vehicles.[22]

Vehicles in municipalities and county government fleets typically drive 10,000 miles or less annually, and 1898 & Co. has assumed that Los Alamos falls within this range. For this reason, 1898 & Co. assumes that light-duty vehicles will charge once every 3 days on a level 2 charger with a 7.7 kW output, medium-duty vehicles will charge daily with a 22.5 kW charger, and heavy-duty vehicles will charge daily with a 50 kW charger. 1898 & Co. expects that most vehicles will begin charging at 6 pm and finish at 2 am, with a small percentage continuing to charge into the morning hours depending on day-to-day variations in energy needs.

Most county vehicles will dwell overnight at the Los Alamos County Warehouse, alongside buses from Atomic City Transit and the Los Alamos Public School District. Given the concentration of high-power charging for medium- and heavy-duty vehicles, the site is an excellent candidate for a charge management system (CMS). This software system can assess the battery status for all vehicles plugged in and optimize charging based on vehicle schedules. For example, the CMS prioritize the transit buses to receive a full charge before beginning their service at 5:30 am, while delaying school buses until after their morning service. Electrifying vehicles at this county-owned facility presents unique challenges, but opportunities exist to optimize and flatten the grid impacts of charging these vehicles.

1898 & Co. forecast the following outcomes for the three scenarios:

Table 4-3: Los Alamos County Fleet, 2040

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	64 Light Duty Vehicles 39 Medium Duty Vehicles 15 Heavy Duty Vehicles	32 Light Duty Vehicles 20 Medium Duty Vehicles 7 Heavy Duty Vehicles	16 Light Duty Vehicles 10 Medium Duty Vehicles 4 Heavy Duty Vehicles
Daily kWh	5,032	2,516	1,258
Peak kW	529	265	132

Table 4-4: Los Alamos County Fleet, 2055

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	128 Light Duty Vehicles 78 Medium Duty Vehicles 29 Heavy Duty Vehicles	64 Light Duty Vehicles 39 Medium Duty Vehicles 15 Heavy Duty Vehicles	32 Light Duty Vehicles 20 Medium Duty Vehicles 7 Heavy Duty Vehicles
Daily kWh	10,065	5,032	2,516
Peak kW	1,059	529	265

[22] FTI Consulting. (2022). *Los Alamos County 2022 Integrated Resource Plan*. https://www.losalamosnm.us/files/sharedassets/public/v/1/departments/utilities/documents/integrated-resource-plan-irp-2022-final-report.pdf

4.3.5 Atomic City Transit

Atomic City Transit offers Los Alamos townsite and White Rock public transportation services. 1898 & Co. does not have detailed information on the 14 transit buses' duty cycles. The transit agency has already selected the Gillig 35' Battery Electric Low Floor Plus bus as its choice for zero-emission buses in the future. Transit service begins at 5:50 am and end at 7:37 pm. 1898 & Co. assumes that the transit buses will have at least 10 hours to charge at night, meaning that a 50 kW charger would be sufficient for most buses.

However, an on-route charging station may be required if Atomic City Transit were to operate a more challenging or energy intensive route. An on-route pantograph charging station is a high-power overhead system that interfaces with battery electric buses at transit stops to rapidly recharge their batteries without disrupting service. The Gillig bus is capable of charging via this method at 350 kW. Most transit agencies only let their buses top off for ten minutes before returning to service, which translates to an hourly load of 58 kW because the opportunity charger would only be active during the day and would not coincide with the heavy charging demands that are expected to occur in the evening.

As mentioned previously, a CMS is an ideal solution for flattening the charging demands on the county's fleet.

1898 & Co. has forecast the following outcomes for the three scenarios:

Table 4-5: Atomic City Transit, 2040

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	7	4	2
Daily kWh	4,258	2,000	1,000
Peak kW	350	200	100

Table 4-6: Atomic City Transit, 2055

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	14	7	4
Daily kWh	7,758	4,258	1,750
Peak kW	700	350	175

4.3.6 Los Alamos Public Schools

The Los Alamos Public Schools has a fleet of 20 school buses. Like most school districts, the school buses operate on a morning and early afternoon shift, transporting students to and from school. The midday downtime of school buses offers a unique opportunity to shift the charging time of the buses to daytime hours, when demand on the grid is near its daily minimum load due to solar PV generation. The school district can minimize its grid impact by shifting most charging between 9 am and 2 pm and performing supplemental charging at night as needed. In this study, we have assumed that a 50 kW charger per bus will provide the required energy for operations.

As mentioned previously, a charging management system is an ideal solution for flattening the charging demands on the county's fleet.

1898 & Co. forecast the following outcomes for the three scenarios:

Table 4-7: Los Alamos Public Schools, 2040

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	10	5	3
Daily kWh	2,400	1,200	720
Peak kW	325	163	98

Table 4-8: Los Alamos Public Schools, 2055

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	20	10	5
Daily kWh	4,800	2,400	1,200
Peak kW	650	325	163

4.3.7 Commercial Fleets

After eliminating the county, transit, and school district fleets, 17,887 vehicles are owned by LAC residents or commercial fleets. 1898 & Co. assumes that all remaining medium-duty and heavy-duty vehicles belong to commercial fleets and that the duty cycle of light-duty commercial vehicles is like that of residential light-duty vehicles in terms of charging behavior.

1898 & Co. assumes that local businesses own 69 medium-duty and 19 heavy-duty vehicles. 1898 & Co. does not know the specific duty cycle of these fleet vehicles, but data from the VIUS survey indicates that most of these vehicles drive 100 to 178 miles daily. For this reason, 1898 & Co. assumes that these vehicles will charge during the night.

1898 & Co. also assumes that medium-duty vehicles will charge daily with a 22.5 kW charger and heavy-duty vehicles will charge daily with a 50 kW charger. 1898 & Co. expects that most vehicles will begin charging at 6 pm and finish by 4 am, with some vehicles charging in the middle of the day when employees take their lunch breaks.

1898 & Co. forecast the following outcomes for the three scenarios:

Table 4-9: Commercial Fleets, 2040

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	43 Medium Duty Vehicles 12 Heavy Duty Vehicles	28 Medium Duty Vehicles 8 Heavy Duty Vehicles	19 Medium Duty Vehicles 5 Heavy Duty Vehicles
Daily kWh	3,758	2,455	1,692
Peak kW	395	258	178

Table 4-10: Commercial Fleets, 2055

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	69 Medium Duty Vehicles 19 Heavy Duty Vehicles	66 Medium Duty Vehicles 18 Heavy Duty Vehicles	47 Medium Duty Vehicles 13 Heavy Duty Vehicles
Daily kWh	6,066	5,791	4,118
Peak kW	638	609	433

4.3.8 Residential Vehicles

This section outlines the three types of charging assumed for residential light-duty vehicles. We have assumed that on any given day, some vehicles will immediately charge, others will schedule a charge, and the last set of vehicles will only use Level 1 charging.

4.3.8.1 Immediate Charging

The remaining 17,799 light-duty vehicles are assumed to be owned by Los Alamos County residents. As outlined previously, approximately 80% of EV drivers charge at home, and 30% charge on any day. The EV population can be further split into three groups based on charging behavior and the time of day.

The first group is EV drivers who plug their cars in immediately upon returning home, approximately 30% of the population or up to 5,340 vehicles daily. These cars charge on a 7.7 kW level 2 charger and will likely take up to 4 to 6 hours to fully charge. The peak demand for this group will likely occur around 6:00 pm on a typical workday and be completed by 11 pm.

4.3.8.2 Scheduled Charging

The second group is EV drivers who plug in their cars upon returning home but preset their EVs to charge at a specific time. This group will be the most responsive to a potential time-of-use rate with EV drivers programming their chargers or vehicles to take advantage of lower rates. 1898 & Co. expects 40% of Los Alamos County’s EV drivers to follow this behavior, with up to 7,120 vehicles daily. These cars will charge on a 7.7 kW charger and take about 4 to 6 hours to fully charge.

The timing of this group can vary depending on how a time-of-use rate is structured. 1898 & Co. assumed that this population would end charging by 4:00 am. This means that a few cars could start charging by midnight, with more vehicles starting to charge as time progresses until 100% of this population is charging at 3:00 am. The percentage will drop sharply each hour after 4:00 am as people start their day.

4.3.8.3 Level 1 Charging

The last group is EV drivers who plug their cars in immediately upon returning home to a level 1 charger powered by a standard 120 V wall outlet. The assumed power output of the level 1 charger is 1.4 kW; over 11 hours from 6:00 pm to 5:00 am, the car will gain approximately 15.4 kWh. The advantage of this approach is that the driver does not need to purchase and install additional hardware, as most EVs come with a level 1 charger standard, nor hire an electrician to install a 240V outlet. For residents who do not make frequent trips to Santa Fe or Albuquerque, Level 1 charging is sufficient for traveling within the county.

1898 & Co. expects 30% of the population, or up to 5,339 vehicles per day, will charge using this method. Most EV drivers will charge immediately upon returning home around 6:00 pm until they leave the house the next day.

4.3.8.4 Residential Charging Summary

1898 & Co. forecast the following outcomes for the three scenarios for all three behaviors:

Table 4-11: Residential EVs, 2040

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	Immediate: 2,105 Scheduled: 3,469 Level 1: 2,602	Immediate: 1,148 Scheduled: 2,193 Level 1: 1,645	Immediate: 278 Scheduled: 1,033 Level 1: 775
Daily kWh	102,987	62,366	25,412
Peak kW	8,469 at 1 am	5,240 at 1 am	2,302 at 1 am

Table 4-12: Residential EVs, 2055

	Scenario 1	Scenario 2	Scenario 3
Vehicle Quantity	Immediate: 4,690 Scheduled: 6,916 Level 1: 5,187	Immediate: 3,718 Scheduled: 5,619 Level 1: 4,215	Immediate: 1,124 Scheduled: 2,161 Level 1: 1,621
Daily kWh	212,754	171,472	61,335
Peak kW	17,196 at 1 am	13,914 at 1 am	5,158 at 1 am

4.3.9 Public charging

The last significant load from transportation electrification comes from public charging stations. 1898 & Co. examined the impact of residents who may not have access to a home charger or need to charge while driving around town.

NREL offers a straightforward approach for estimating the number of public charging stations for a given population.[23] Following their method and using the forecasted EV population in 2040 and 2055, 1898 & Co. projects the following outcomes for the three scenarios:

Table 4-13: Public Chargers, 2040

	Scenario 1	Scenario 2	Scenario 3
Charger Quantity	Level 2: 217 DCFC: 18	Level 2: 137 DCFC: 12	Level 2: 65 DCFC: 6
Daily kWh	15,215	9,767	4,812
Peak kW	1,312	847	425

Table 4-14: Public Chargers, 2055

	Scenario 1	Scenario 2	Scenario 3
Charger Quantity	Level 2: 432 DCFC: 36	Level 2: 351 DCFC: 28	Level 2: 135 DCFC: 12
Daily kWh	29,940	24,003	9,630
Peak kW	2,569	2,049	836

[23] Wood, E., Borlaug, B., Moniot, M., Lee, D.-Y., Ge, Y., Yang, F., & Liu, Z. (n.d.). *The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure*.

4.4 Home Electrification

Per the 2020 census, Los Alamos County comprises 8,754 households, of which 7,581 utilize natural gas, averaging 743 therms annually per household.[24] These households primarily use natural gas for four appliances: space heating (furnaces or boilers), water heating, clothes drying, and cooking (ranges). While all-electric alternatives have long existed, recent advancements in heat pump technology and innovative features offer significantly improved efficiency compared to older electric and gas appliances.

Leveraging the U.S. Energy Information Administration (EIA)'s national household energy consumption surveys and applying their New Mexico-specific data to estimate current market share, 1898 & Co. developed various forecasts to meet each of the three scenarios. According to the 2020 EIA survey, New Mexico's natural gas end-use distribution is: 63% space heating, 30% water heating, 3% clothes drying, and 3.5% cooking.[25]

4.4.1 Space heating

The EIA estimates that 67% of homes in New Mexico utilize a natural gas furnace for central heating, with an additional 7% relying on steam or hot water boilers. 1898 & Co. assumes that up to 7,200 households in Los Alamos County uses natural gas for space heating.

There are several options available for electrifying central heating systems. The simplest of these technologies is the resistive heater. It converts electrical energy into thermal energy by passing an electric current through a resistive material like a metal coil. However, resistive heaters are inefficient; for each kilowatt (kW) of energy consumed, they provide only a kW-equivalent heat. The HVAC industry uses the coefficient of performance (COP) to measure the efficiency of heating or cooling systems, which is defined as the ratio of useful heating or cooling output to energy input. A resistive heater typically has a COP of 1.0. However, a significant advantage is their cost: with small units available from big box stores for as low as $10, with many different shapes and sizes available at moderately higher prices. These are best used to heat individual bedrooms rather than the whole house and the total potential market size could be one per bedroom, plus an additional unit for a family room.

A more efficient alternative is the heat pump, an air conditioner that can reverse its operation. Using a reversible valve, the refrigerant within the unit can transfer heat from the outside to the inside of a house. Depending on outdoor temperatures, heat pumps can achieve a COP ranging from 2.0 to 4.0, making them significantly more efficient than resistive heaters.

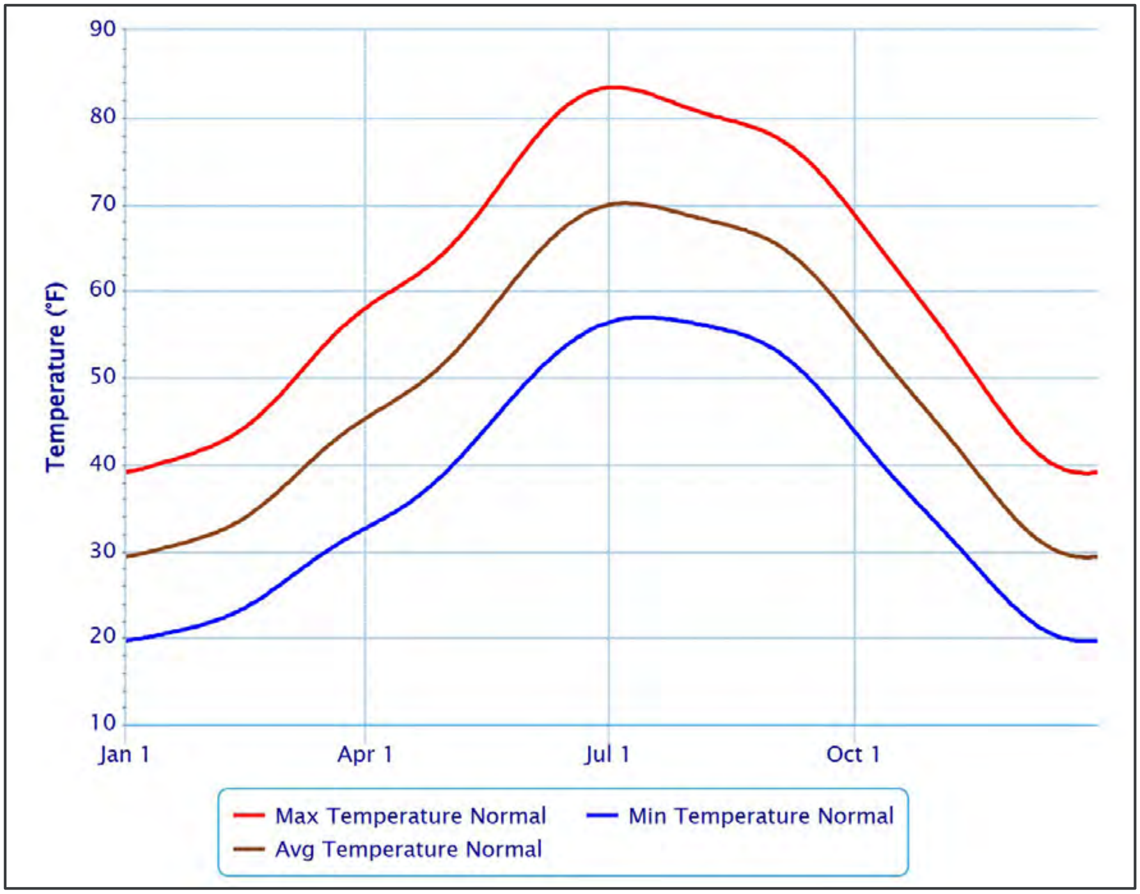
One drawback of heat pumps is their reduced effectiveness in extremely cold conditions. At temperatures around 5°F, the COP of many heat pumps may drop to 1.0. However, recent advancements in refrigerants have allowed some models to generate heat even at -20°F. Additionally, the industry has introduced a "cold climate" label for products, achieving a COP of 1.75 at 5°F.

[24] *FY2023 Annual Report*. (2024, February 22). Los Alamos Department of Public Utilities. https://indd.adobe.com/view/7a4f583d-abf0-437d-bf0d-bb170d516fce

[25] *Highlights for space heating in U.S. homes by state, 2020*. (2023, March). U.S. Energy Information Administration, Office of Energy Demand and Integrated Statistics. https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Space%20Heating.pdf

While Los Alamos County might consider cold-climate heat pumps, they are likely unnecessary for most residents. Historical weather data collected from the NOAA Online Weather Data (NOWData) from the Los Alamos airport over the past 25 years shows the coldest extended period was 20 hours below 10℉ in January 2013. Typically, the minimum temperature is in the low 20s, making standard heat pumps sufficient for the area. Moreover, an off-the-shelf heat pump is significantly more efficient than a gas furnace, which generally has a COP of 0.80.

Figure 4-2: Daily Climate Normal (1991 - 2020) - Los Alamos, NM[26]



Some residents may be concerned about those 20 hours below 10℉ and may also be worried that an intense winter storm could considerably lower temperatures for up to a week. Many heat pump manufacturers now offer optional resistant heaters for the heat pump itself, which would keep the unit warm enough to work more efficiently.

As of January 2025, New Mexicans can benefit from various incentive programs. The federal government offers a tax credit of up to $2,000 for purchasing and installing a heat pump, alongside an additional $8,000 rebate from the Home Electric and Appliance Rebate Program. Additionally, New Mexico provides a $1,000 Sustainable Building Tax Credit. However, LACDPU does not offer incentives due to an anti-donation law.

[26] US Department of Commerce, N. (n.d.). *Daily Climate Normals (1991-2020)—LOS ALAMOS, NM*. NOAA's National Weather Service. Retrieved June 16, 2025, from https://www.weather.gov/wrh/Climate?wfo=abq

Heat pumps are available in two styles: centralized and mini-split systems. A centralized heat pump resembles a central air conditioner and costs between $2,000 and $5,500, plus installation. A mini-split system, ideal for single rooms, uses a smaller outdoor unit and an air handler, costing around $1,500 plus installation. Both types have a lifespan of 10 to 20 years. A centralized heat pump is ideal for homes with existing ductwork and air conditioning, while mini-splits are suitable for supplemental heating in persistently cold rooms. Mini-splits are generally more efficient than centralized heat pumps.

1898 & Co. modeled the grid impact of 7,200 households transitioning to heat pumps, divided into two populations: 40% central heat pumps and 60% mini-splits. This partition was adjusted based on home size: homes under 500 sq ft. used only mini-splits, while those over 3,000 sq ft. used only central heat pumps.

Regardless of the technology chosen, space heating will significantly impact the LACDPU grid with forecasted peak load at 5:00 am, typically the coldest time in January. Unlike electric vehicles, 80% of homes will likely run space heating devices simultaneously, with additional devices like resistance heaters activated to provide supplemental heating.

1898 & Co. projects the following outcomes for the three scenarios:

Table 4-15: Space Heating, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Central Heat Pump: 3,159 Mini-split: 2,327 Resistant Heater: 1,601 Backup for heat pumps: 948	Central Heat Pump: 411 Mini-split: 338 Resistant Heater: 968 Backup for heat pumps: 123	Central Heat Pump: 238 Mini-split: 198 Resistant Heater: 597 Backup for heat pumps: 71
Daily kWh	114,215	19,330	12,579
Peak kW	9,642	1,869	1,227

Table 4-16: Space Heating, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Central Heat Pump: 6,261 Mini-split: 5,198 Resistant Heater: 11,843 Backup for heat pumps: 1,878	Central Heat Pump: 3,142 Mini-split: 2,581 Resistant Heater: 5,957 Backup for heat pumps: 943	Central Heat Pump: 1,571 Mini-split: 1,307 Resistant Heater: 2,893 Backup for heat pumps: 471
Daily kWh	253,864	143,168	79,379
Peak kW	23,826	13,445	7,425

4.4.1.1 Building Energy Efficiency

The climate action plan highlights several reasons for enhancing building energy efficiency, but from a grid perspective, the most compelling reason is the ability to capture energy from previously generated heat. In cold conditions, heat escapes from a house through small gaps in windows and doorways, as well as through inadequate insulation in exterior walls and roofs. To maintain a stable interior temperature, the home's heating system must compensate for this net heat loss. By sealing air leaks and improving insulation, these losses can be significantly reduced, allowing the home to retain more heat from the heating system.

1898 & Co. incorporated a multiplier into space heating calculations to simulate the potential impacts of new building standards and incentive programs aimed at upgrading existing homes. The improvements modeled for each scenario are as follows:

- **Scenario 1:** 20% improvement
- **Scenario 2:** 10% improvement
- **Scenario 3:** 0% improvement

These multipliers are incorporated into the forecast presented in Table 4-15 and Table 4-16.

4.4.2 Water heating

EIA estimates that 70% of homes in New Mexico use natural gas water heaters, while 10% utilize propane. In Los Alamos County, this equates to approximately 6,128 out of 8,754 households relying on fossil fuels as their primary water heating source.

Two primary technologies are available for those considering all-electric water heating options. The first is the conventional electric storage water tank, which employs resistive heating to warm water within a large tank. This system typically requires 4.5 kW to heat the water, taking approximately one hour.

The second option is a heat pump water heater. While resembling a conventional electric storage tank, it is generally taller to accommodate the heat pump component. This system usually consumes 3 kW to heat water but may take an additional 20 minutes to complete the process. Transferring heat from the ambient air into the tank can also dehumidify the surrounding air, necessitating a drainage pipe for condensate removal. If the heat pump water heater is in a heated space (such as a laundry room), it may cool the room by 1- or 2-degrees Fahrenheit, but it depends on the configuration of the unit and the home. Both 120 V and 240 V models are commercially available.

A third alternative is an all-electric tankless water heater. This device uses resistive heaters to heat water, often drawing around 25 kW, instantly. Widespread adoption of this technology could significantly increase power demand, adding strain to the distribution system.

Incentives for water heaters often mirror those for heat pumps. Homeowners can receive a tax credit covering 30% (up to $2,000) of the purchase and installation costs of a heat pump water heater, with a total tax credit cap of $3,200 per year for all appliances receiving a tax credit. To maximize this benefit, homeowners might consider purchasing a heat pump one year and a qualified water heater the next, leveraging the $2,000 tax credit each year. The Home Electric and Appliance Rebate Program also offers a $1,750 tax credit for qualified water heaters. New Mexico also provides a $1,000 Sustainable Building Tax Credit. However, due to an anti-donation law, Los Alamos County does not offer incentives.

Unlike space heating, water heating demands can occur at almost any time of day. 1898 & Co. anticipates that most households will experience peak usage during the morning and early evening hours, coinciding with residents starting or ending their day. 1898 & Co. projects the following outcomes for the three scenarios:

Table 4-17: Water Heating, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 2,268 Heat Pump: 1,683	Conventional: 528 Heat Pump: 284	Conventional: 51 Heat Pump: 166
Daily kWh	35,022	8,542	1,811
Peak kW	2,606	636	135

Table 4-18: Water Heating, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 2,606 Heat Pump: 4,359	Conventional: 1,046 Heat Pump: 2,167	Conventional: 102 Heat Pump: 1,097
Daily kWh	52,752	26,240	8,559
Peak kW	3,926	1,953	637

4.4.3 Clothes drying

EIA estimates that 80% of New Mexico homes already use an electric clothes dryer, 18% use natural gas, and 1% use propane. In Los Alamos County, this translates to approximately 1,721 homes using fossil fuels as their primary fuel for drying clothes.

Several alternative all-electric clothes drying technologies exist, but a heat pump clothes dryer is a more energy efficient option. Like the heat pump water heater, this device is more energy efficient than traditional electric clothes dryers but can take an extra 30 minutes to dry a typical load of laundry.

The Home Electrification and Appliance Rebates program allows homeowners to receive up to $840 per household. No state incentive programs exist, and LACDPU does not offer incentives due to an anti-donation law.

Like water heaters, 1898 & Co. assumes that most homes will have heavy usage in the morning and early evening hours when residents start or end their day.

1898 & Co. projects the following outcomes for the three scenarios:

Table 4-19: Clothes Dryers, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 656 Heat Pump: 337	Conventional: 270 Heat Pump: 57	Conventional: 39 Heat Pump: 33
Daily kWh	4,538	1,642	304
Peak kW	712	258	48

Table 4-20: Clothes Dryers, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 806 Heat Pump: 872	Conventional: 458 Heat Pump: 433	Conventional: 76 Heat Pump: 219
Daily kWh	6,839	3,718	1,021
Peak kW	1,073	583	160

4.4.4 Cooking

The EIA estimates that 55% of homes in New Mexico use an electric range, cooktop, or oven, while 50% use a natural gas range, cooktop, or oven. This overlap is due to hybrid equipment that utilizes electricity and natural gas. In Los Alamos County, this translates to approximately 4,377 households relying on fossil fuels as their primary cooking fuel.

Traditional electric cooktops operate similarly to resistive heaters: electricity flows through a resistive material, converting into thermal energy to heat anything in contact. Recently, induction cooktops have gained popularity for their efficiency and safety features. Induction technology uses magnetic fields to heat the pan directly, and the cooktop automatically turns off if the pan is removed. The “burner” does not conduct heat – only the pan is heated by the magnetic force. For a typical meal, a resistive coil cooktop consumes 3 kW, whereas an induction cooktop uses only 2.1 kW. The oven component remains the same in both types of devices.

The Home Electrification and Appliance Rebates program offers homeowners up to $840 per household. There are no state-level incentive programs, and Los Alamos County does not provide incentives due to an anti-donation law.

Like water heaters and clothes dryers, 1898 & Co. anticipates that most households will experience peak usage of cooking appliances during morning and early evening hours, aligning with residents' daily routines.

1898 & Co. projects the following outcomes for the three scenarios:

Table 4-21: Cooking, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 330 Induction: 1,347	Conventional: 142 Induction: 227	Conventional: 77 Induction: 133
Daily kWh	5,843	1,383	782
Peak kW	917	217	123

Table 4-22: Cooking, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Conventional: 413 Induction: 3,487	Conventional: 240 Induction: 1,734	Conventional: 142 Induction: 878
Daily kWh	13,099	6,674	3,470
Peak kW	2,055	1,047	544

4.5 Commercial Electrification

Los Alamos County is home to 960 commercial properties serving various purposes, from agriculture to aviation. These buildings vary significantly, with some as small as 500 square feet and others exceeding 50,000 square feet. Despite their diverse uses and sizes, all these buildings share a common requirement: an HVAC system to regulate interior temperatures and ensure a consistent supply of hot water.

4.5.1 Space heating

1898 & Co. projects that all commercial properties will employ central heat pumps, with larger properties utilizing multiple units. For expansive buildings exceeding 5,000 square feet, specialized heat pump technologies designed for large facilities will be implemented. This emerging sector within the HVAC industry offers numerous promising solutions. 1898 & Co. anticipates that commercial central heat pumps will be most active during the morning, activating around 5:00 am and reaching their peak use by 9:00 am This schedule would keep buildings warm when employees or customers arrive, with energy use leveling off once the building is occupied. At the end of the workday, the heat pumps will transition to an idle mode, consuming energy at a reduced rate until the next business day begins.

1898 & Co. projects the following outcomes for the three scenarios:

Table 4-23: Commercial Space Heating, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	388	63	37
Daily kWh	50,555	9,266	6,030
Peak kW	4,681	858	558

Table 4-24: Commercial Space Heating, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	968	482	244
Daily kWh	126,223	70,687	39,762
Peak kW	11,687	6,545	3,682

4.5.2 Water heating

1898 & Co. assumes that all commercial properties will use a conventional electric storage water heater and that larger properties will use specialized technologies designed for large facilities. It was also assumed that these water heaters will follow the same pattern as the commercial space heaters, activating around 5:00 am, peaking around 9:00 am, and then holding a steady state for the rest of the business day. At the end of the day, the water heaters will enter an idle mode that draws a low amount of energy until the next day.

1898 & Co. projects the following outcomes for the three scenarios:

Table 4-25: Commercial Water Heating, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	694	318	219
Daily kWh	34,069	17,213	12,979
Peak kW	3,155	1,594	1,202

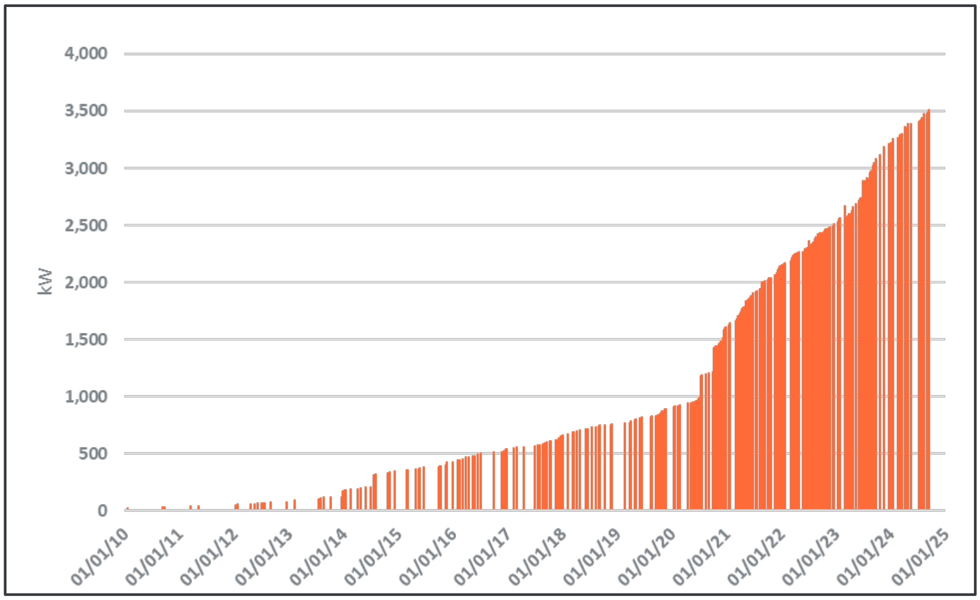
Table 4-26: Commercial Water Heating, 2055

`	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	741	484	279
Daily kWh	36,417	26,561	16,731
Peak kW	3,372	2,459	1,549

4.6 Solar PV & Batteries

As of January 1, 2025, Los Alamos County has 516 solar-generation customers, including 481 residential and 35 commercial properties. Residential customers constitute 5.5% of all homes in the county, while commercial customers represent 3.6% of all commercial buildings. The most common solar PV system sizes range from 4 to 7 kW, with the LACDPU typically restricting residential installations to no more than 10 kW.

Figure 4-3: Connected PV Generation



70% of solar PV systems were installed since 2020, indicating that early adopters are driving the technology toward mainstream acceptance. However, peak solar production does not necessarily align with peak energy usage. As previously discussed, winter peak energy usage occurs around 5:00 am to 6:00 am, depending on the severity of the cold. Energy consumption also decreases rapidly as residents unplug their vehicles, turn off heat pumps, and leave their homes. Meanwhile, as the sun rises, solar PV begins generating energy. 1898 & Co. found that the misalignment in timing of solar PV generation and electrification load effectively mitigates much of the increased grid demand from electrification during daytime hours.

Although most residential products are 15 kWh or smaller, battery energy storage systems (BESS) could support electrification. When paired with solar panels, these systems reduce net grid exports during daylight hours until the BESS is fully charged. At the end of the day, when residents return home, plug in electric vehicles, and begin evening activities, the batteries typically discharge completely within three to four hours. While batteries influence the rate at which grid demand increases, their impact may be short-lived assuming a 4hr system.

BESS have gained popularity with customers served by utilities where economic benefit can be gained through suitable time-of-use rate structures, though they generally lag solar installations.[27] Despite their relatively high cost, BESS can become economical when the utility rate structure incentivizes storing solar energy for consumption during peak hours. The federal government provides a residential clean energy tax credit, but neither New Mexico nor Los Alamos County offers additional incentives. LACDPU compensates PV solar customers with excess generation at the average wholesale cost, based on a rolling average over the previous 12 months.

1898 & Co. forecasts the following outcomes for the three scenarios in residential and commercial applications on a clear day in January. Overcast weather conditions will reduce the potential output of the solar PV systems. Negative numbers represent the direction of energy flow, specifically indicating the export of solar generation to the grid or a BESS. It is assumed that BESS are recharged by solar systems, thereby offsetting the power that would otherwise be exported to the grid.

Table 4-27: Residential Solar & Battery, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Solar: 699 Battery: 308	Solar: 482 Battery: 192	Solar: 234 Battery: 118
Max Daily kWh	Solar: (21,981) Battery: 2,413	Solar: (15,227) Battery: 1,508	Solar: (7,332) Battery: 927
Peak kW	Solar: (3,385) Battery: 302	Solar: (2,345) Battery: 189	Solar: (1,129) Battery: 116

Table 4-28: Residential Solar & Battery, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Solar: 2,608 Battery: 1,810	Solar: 1,691 Battery: 894	Solar: 602 Battery: 439
Max Daily kWh	Solar: (79,634) Battery: 14,192	Solar: (51,927) Battery: 7,011	Solar: (19,043) Battery: 3,444
Peak kW	Solar: (12,263) Battery: 1,774	Solar: (7,996) Battery: 876	Solar: (2,932) Battery: 430

[27] Sharda, S., Garikapati, V. M., Goulias, K., Reyna, J. L., Sun, B., Spurlock, C. A., & Needell, Z. (n.d.). *Is the Adoption of Electric Vehicles (EVs) and Solar Photovoltaics (PVs) Interdependent or Independent?* https://docs.nrel.gov/docs/fy23osti/84543.pdf

Table 4-29: Commercial Solar & Battery, 2040

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Solar: 201 Battery: 18	Solar: 88 Battery: 8	Solar: 42 Battery: 0
Max Daily kWh	Solar: (16,154) Battery: 308	Solar: (6,947) Battery: 146	Solar: (3,417) Battery: 0
Peak kW	Solar: (2,488) Battery: 38	Solar: (1,070) Battery: 18	Solar: (526) Battery: 0

Table 4-30: Commercial Solar & Battery, 2055

	Scenario 1	Scenario 2	Scenario 3
New Equipment Quantity	Solar: 445 Battery: 48	Solar: 201 Battery: 18	Solar: 88 Battery: 8
Max Daily kWh	Solar: (36,224) Battery: 935	Solar: (16,154) Battery: 308	Solar: (6,947) Battery: 146
Peak kW	Solar: (5,578) Battery: 117	Solar: (2,488) Battery: 38	Solar: (1,070) Battery: 18

4.7 Electrification Forecast Results

In all scenarios, LACDPU is expected to experience a substantial rise in electricity usage. In the most conservative projection, Scenario 3, the peak load is anticipated to increase by at least 3.7 MW by 2040 and 13.1 MW by 2055, representing a 60% increase over the current peak demand of the LAC electric system. Conversely, in the most aggressive projection, Scenario 1, the peak load is projected to rise by 20.6 MW in 2040 and 43.5 MW by 2055, equating to a 200% increase compared to the current peak demand of the LAC electric system.

Scenarios 1 and 3 are designed as boundary conditions and are unlikely to occur exactly as described. Scenario 1 would require federal, state, and local governments to significantly promote zero-emission technologies while discouraging fossil fuel use wherever feasible over the next thirty years. Conversely, Scenario 3 represents limited influence from government regulations and reflects new technologies' natural adoption rate over the next thirty years.

A more probable outcome lies between these two bookends, reflecting evolving policy goals from federal and state governments over the next thirty years. Scenario 2 forecasts an increase in peak load by 7.4 MW in 2040 and 27.1 MW in 2055, a 120% rise compared to the current peak demand of the LAC electric system. This scenario is not exactly equidistant between the boundary scenarios because residents of Los Alamos County display a strong interest in electric vehicles, heat pumps, and solar, making these technologies likely to be adopted even if political support fluctuates.

Table 4-31: Total Additional Electrification Peak Load

Scenarios	2040 Additional Peak Load (MW)	2055 Additional Peak Load (MW)
Scenario 1	20.6	43.6
Scenario 2	7.4	27.1
Scenario 3	3.7	13.1

To help understand how each electrification technology contributes to grid impact, 1898 & Co. created daily profiles based on the peak kW for each scenario. The daily profiles shown in the figures below help illustrate the difference in the use of each technology and how load can be shifted to help flatten the overall peak demand on the system. A cold winter day was chosen as the peak time for evaluation, as electric heat contributes significantly to winter demand, and the COP of heat pumps decreases in cold weather. Additionally, EVs consume more energy in cold weather and will need to charge more in the wintertime. Lastly, if demand response controls are in place for EV charging, in the summer, peak demand from EV charging can be shifted into the late evening or early morning.

4.7.1 Scenario 1

The 24-hour daily profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown in Figure 4-4 and Figure 4-5.

Figure 4-4: Scenario 1, 2040

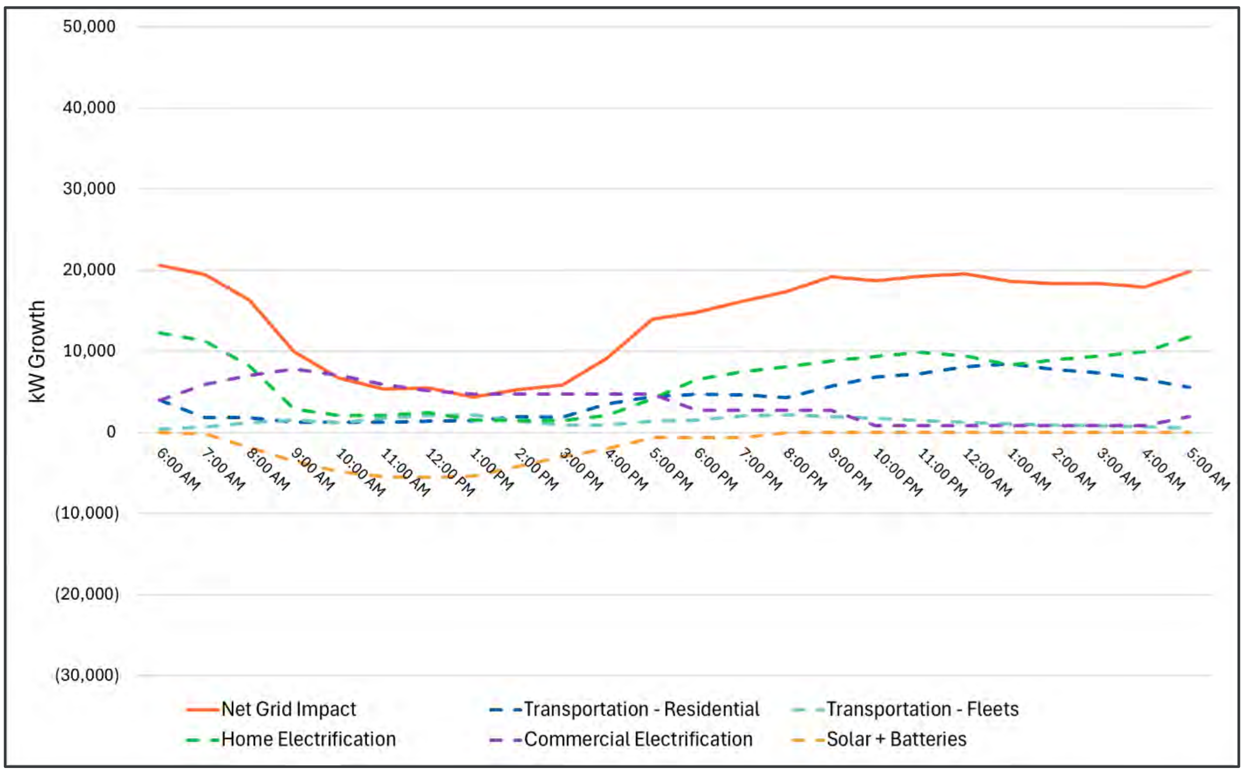
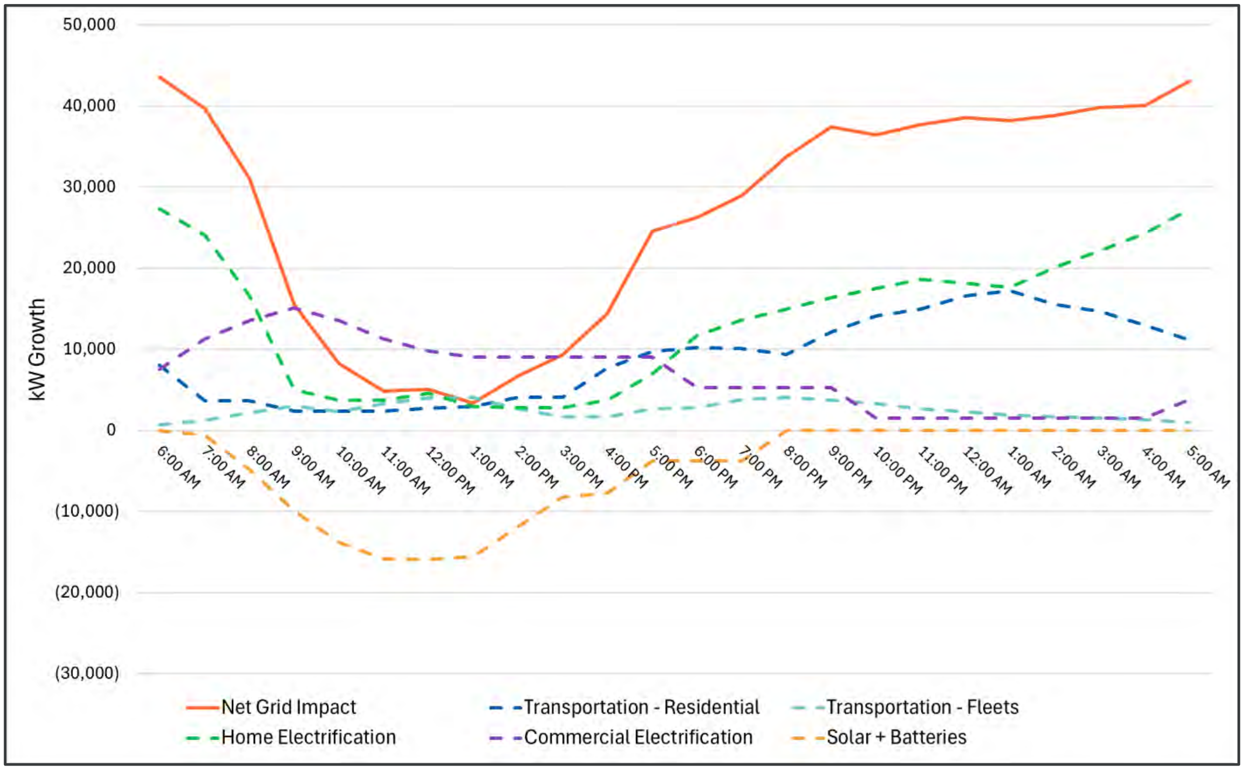


Figure 4-5: Scenario 1, 2055



In 2040, the daily peak demand of 20.6 MW occurs at 6:00 am, driven primarily by home electrification, particularly space heating, alongside approximately equal demand from residential EV charging and commercial electrification. The grid demand decreases rapidly after 7:00 am as both home electrification and residential EV charging reduce, coinciding with an increase in solar generation. The daily minimum demand of 4.4 MW is observed at 1:00 pm when the daytime charging of electric school buses subsides, although solar generation remains substantial. From 3:00 pm onwards, as solar generation diminishes, there is a noticeable increase in demand due to home electrification, residential EV charging, and commercial fleet EV charging.

By 2055, the daily peak will continue to occur at 6:00 am at 43.6 MW, roughly twice what was observed in 2040. The daily minimum demand of 3.3 MW is observed at 1:00 pm, reflecting the growth in solar PV after 2040. The influence of 20% of homes equipped with battery energy storage systems is visible but brief, lasting approximately four hours between 4 pm and 8 pm.

4.7.2 Scenario 2

The 24-hour daily profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown in Figure 4-6 and Figure 4-7.

Figure 4-6: Scenario 2, 2040

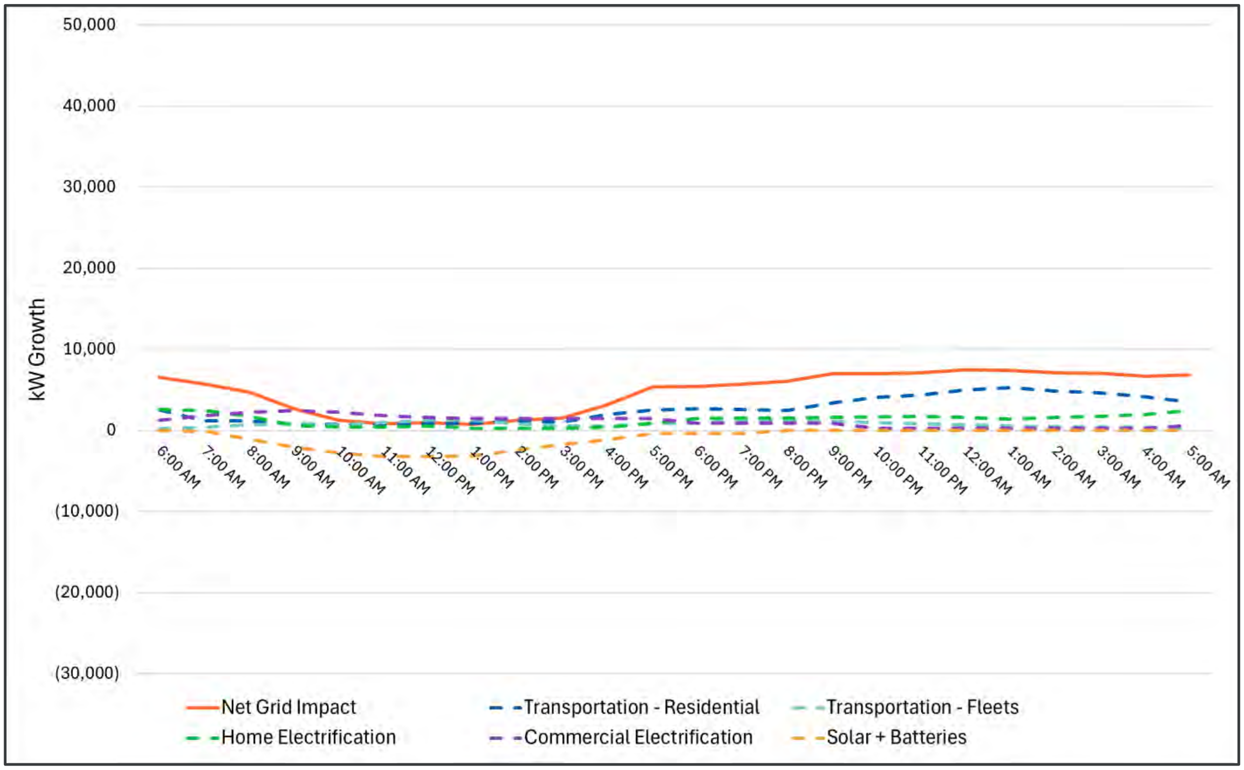
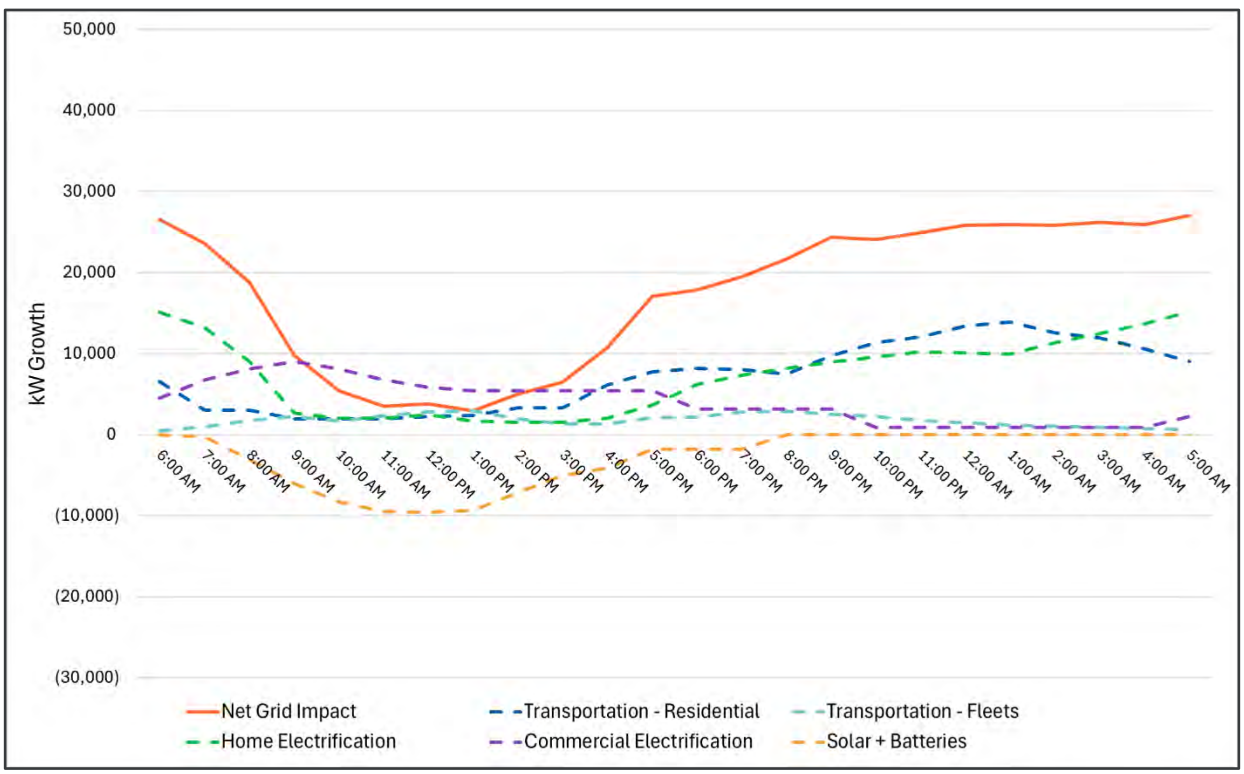


Figure 4-7: Scenario 2, 2055



In 2040, the daily peak demand of 7.4 MW occurs at 12:00 am, primarily due to residential EV charging. Unlike Scenario 1, all-electric space heating is not as widely adopted, resulting in a less pronounced impact on the grid and not influencing the daily peak during high heating demand periods. Residential EV charging continues to dominate demand throughout the night until 7:00 am, when commercial electrification and solar generation begin to rise. The daily minimum demand of 0.7 MW is recorded at 1:00 pm as the daytime charging of electric school buses decreases, despite substantial solar generation. After 3 pm, residential EV charging demand steadily increases as solar generation diminishes.

By 2055, the daily peak demand shifts to 27.1 MW at 5:00 am, driven by home electrification, particularly space heating. While residential EV charging still peaks at 1:00 am, the demand for space heating surpasses the demand for EV charging in the early morning hours. The daily minimum demand of 2.9 MW still occurs at 1:00 pm. The pattern and magnitude of demand are like the 2040 forecast in Scenario 1.

4.7.3 Scenario 3

The 24-hour daily profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown in Figure 4-8 and Figure 4-9.

Figure 4-8: Scenario 3, 2040

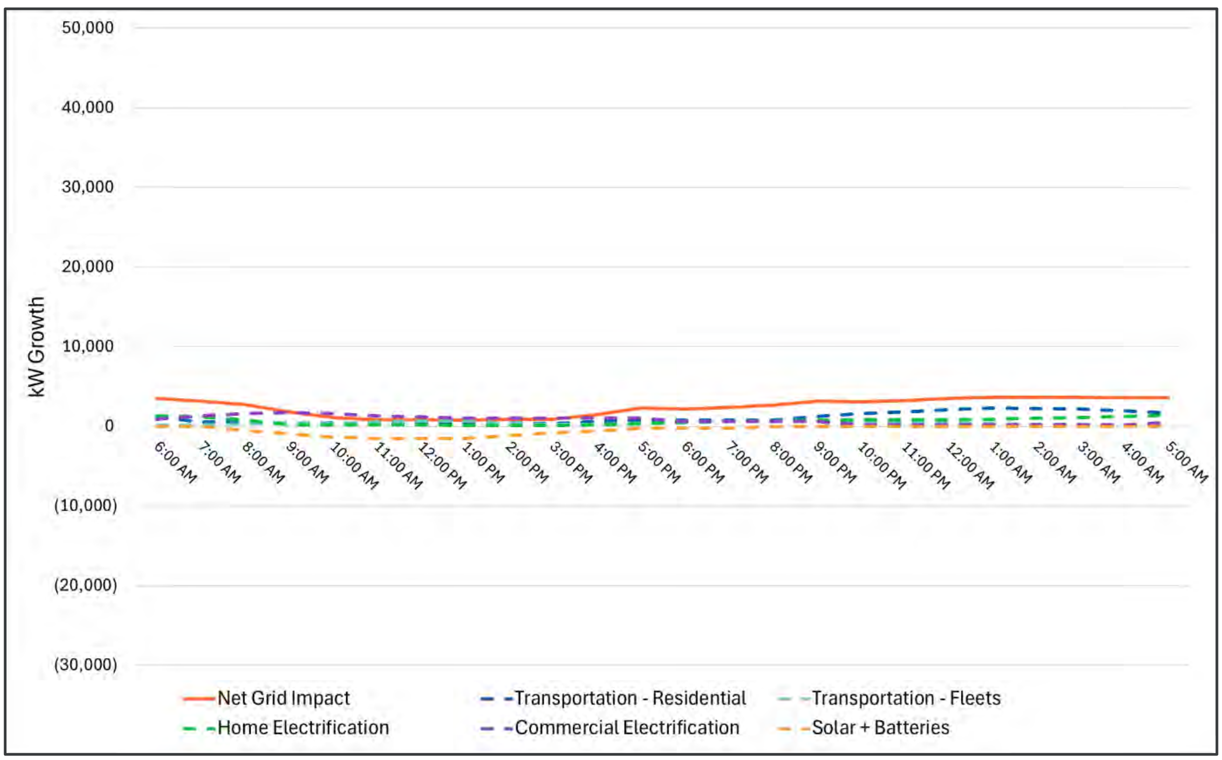
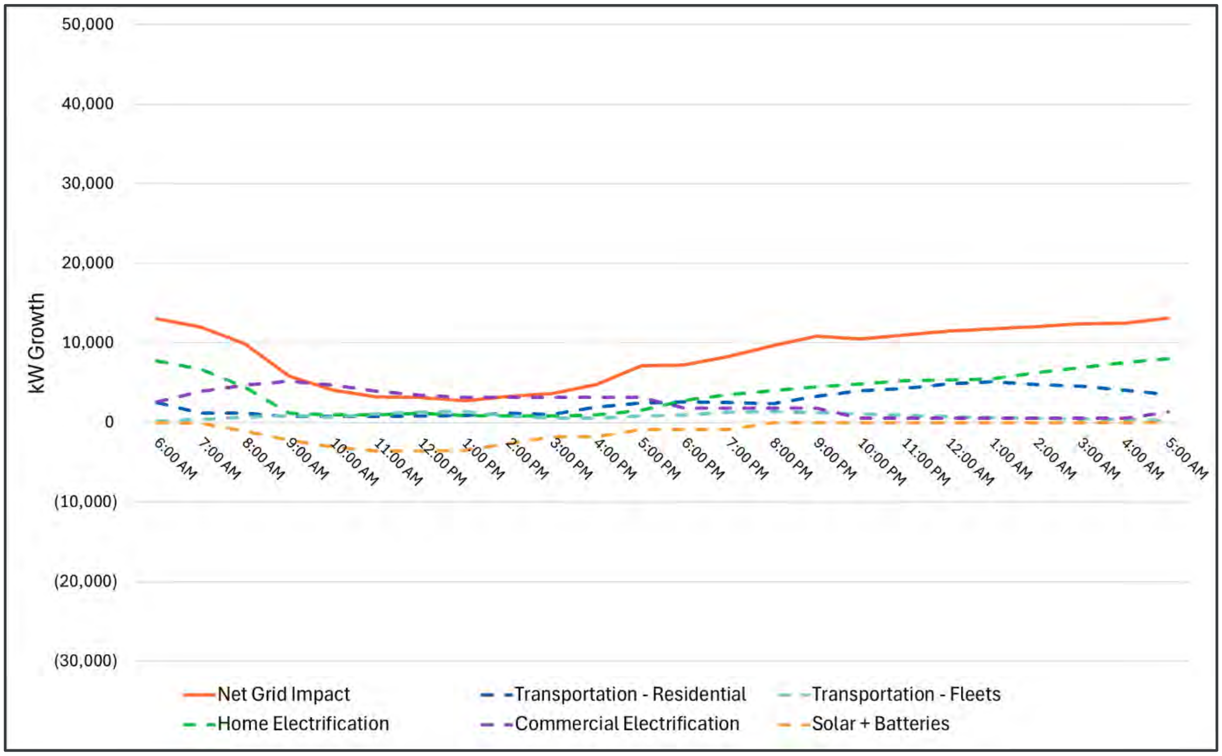


Figure 4-9: Scenario 3, 2055



In 2040, the daily peak demand of 3.7 MW occurs at 3:00 am due to residential EV charging. Similar to Scenario 2, all-electric space heating does not shape peak demand like in Scenario 1. Residential EV charging dominates most of the demand throughout the night until 7:00 am, when commercial electrification and solar generation increase. The daily minimum demand of 0.7 MW is observed at 1 pm when the daytime charging of electric school buses subsides.

In 2055, the daily peak demand of 13.1 MW shifts to 6:00 am due to home electrification, primarily space heating. Residential EV charging peaks at 1:00 am, but space heating overtakes that demand in the early morning. The daily minimum demand of 2.7 MW occurs at 1:00 pm.

5.0 Electric Distribution System Impact Analysis

The electrification forecasts shown in Section 4.0 were applied to the WindMil power flow model to understand the impact on the existing system. Real power demand, measured in kW, and the reactive power demand, measured in kVA, are considered in power flow simulations. The combination of real and reactive power is called apparent power, measured in kVAR. The equation for apparent power equation is shown below:

$$S = P + jQ$$

Where:

- **S:** Apparent power in units of kilovolt Amperes (kVA)
- **P:** Real power in units of kilowatts (kW)
- **Q:** Reactive power in units of kilovolt-Ampere Reactive (kVAR)

Table 5-1 shows the existing LACDPU modeled load and the increase in the electrification load modeled for three forecast scenarios. A 95% power factor was assumed for this study to estimate the reactive power demand from this electrification load growth. Six total power flow scenarios were evaluated to identify necessary capital projects, such as substation transformer upgrades, new substation transformers, new distribution feeders, and conductor upgrades. These upgrades were incorporated into the power flow model to mitigate planning criteria violations.

Table 5-1: Electrification Scenarios Forecasted System Load

Scenario	LACDPU Existing System Load kVA	2040 Total Forecasted LACDPU System Load kVA	2055 Total Forecasted LACDPU System Load kVA
Scenario 1	21,716	43,400	67,611
Scenario 2	21,716	29,505	50,242
Scenario 3	21,716	25,611	35,505

5.1 Electrification Impact Analysis Methodology

The following steps were applied to the WindMil power flow model to perform the electrification impact analysis.

- Electrification forecast load was added to the existing system peak power flow model.
- Electrification forecast load was applied to the power flow model with a 95% power factor.
- Electrification forecast load was applied evenly throughout the power flow model. Existing loads were scaled until the total system demand matched the system demand forecast for each scenario.
- Existing solar PV generation was turned off. The system peak is anticipated to occur in the late evening/early morning hours for all forecast scenarios when customer generation will not produce.

- Once the electrification load growth was applied to the model, there were challenges with non-convergence in the model for the power flow simulation. This is typical in power flow software when modeling large increases in load. Secondary service transformers were removed from the model to resolve nonconvergence issues with the power flow simulations. Service transformers will be impacted by electrification, but the power flow model is intended to focus on the primary system impacts of electrification. The asset replacement estimate considers the impact to secondary service transformer from electrification. LACDPU can perform additional analysis with customer meter data to identify service transformers that are at risk of overloading.

Once the electrification forecast load was added to the power flow model, several analyses were performed to understand the impact of electrification and the system improvements necessary to maintain service to all customers in each scenario.

- **Normal Configuration Analysis** - After applying the electrification forecast load, planning criteria violations were identified. The system power flow model was reconfigured to resolve these violations by adding new substation sources, distribution feeders, conductor upgrades, and new equipment. Power flow results were recorded to confirm that all planning criteria were maintained after applying system improvements. The new configuration of the system influences power flow results as losses can be impacted by changes in power flow and new equipment can change reactive power flow on the feeder. The total apparent power modeled in each scenario is slightly different than the total apparent power recorded for each scenario in Table 5-1.
- **Contingency Configuration Review** - The most impactful substation and primary feeder contingency scenarios were evaluated to determine whether the system would maintain service to all customers. Feeder outage considerations were also made to determine whether certain loops or mainline tie paths should be upgraded.
- **Asset Replacement Estimate** – LACDPU is anticipated to need to maintain a rate of asset replacement primarily due to age, deterioration, and increasing customer energy consumption over the 30-year study horizon. For each scenario, the asset replacement estimates document the magnitude of assets that should be considered for future system operating budgets.
- **Financial Impact Summary** – The financial impact of each scenario was determined using the system improvement projects and asset replacement estimates, along with representative costs documented in Section 2.0.

5.2 2055 Scenario 1 Electrification Impact

2055 Scenario 1 added 45,895 kVA to the LACDPU system power flow model. Table 5-2 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-2: 2055 Scenario 1 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	32,126	49,937
White Rock	3,905	13,768	17,673
Total	21,716	45,895	67,611

5.2.1 Study Area Configuration

Figure 5-1 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 33.7 MVA transformers and two four-feeder switchgear with a main tie breaker between the two switchgears. Six new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

Figure 5-1: 2055 Scenario 1 Los Alamos Townsite System Configuration

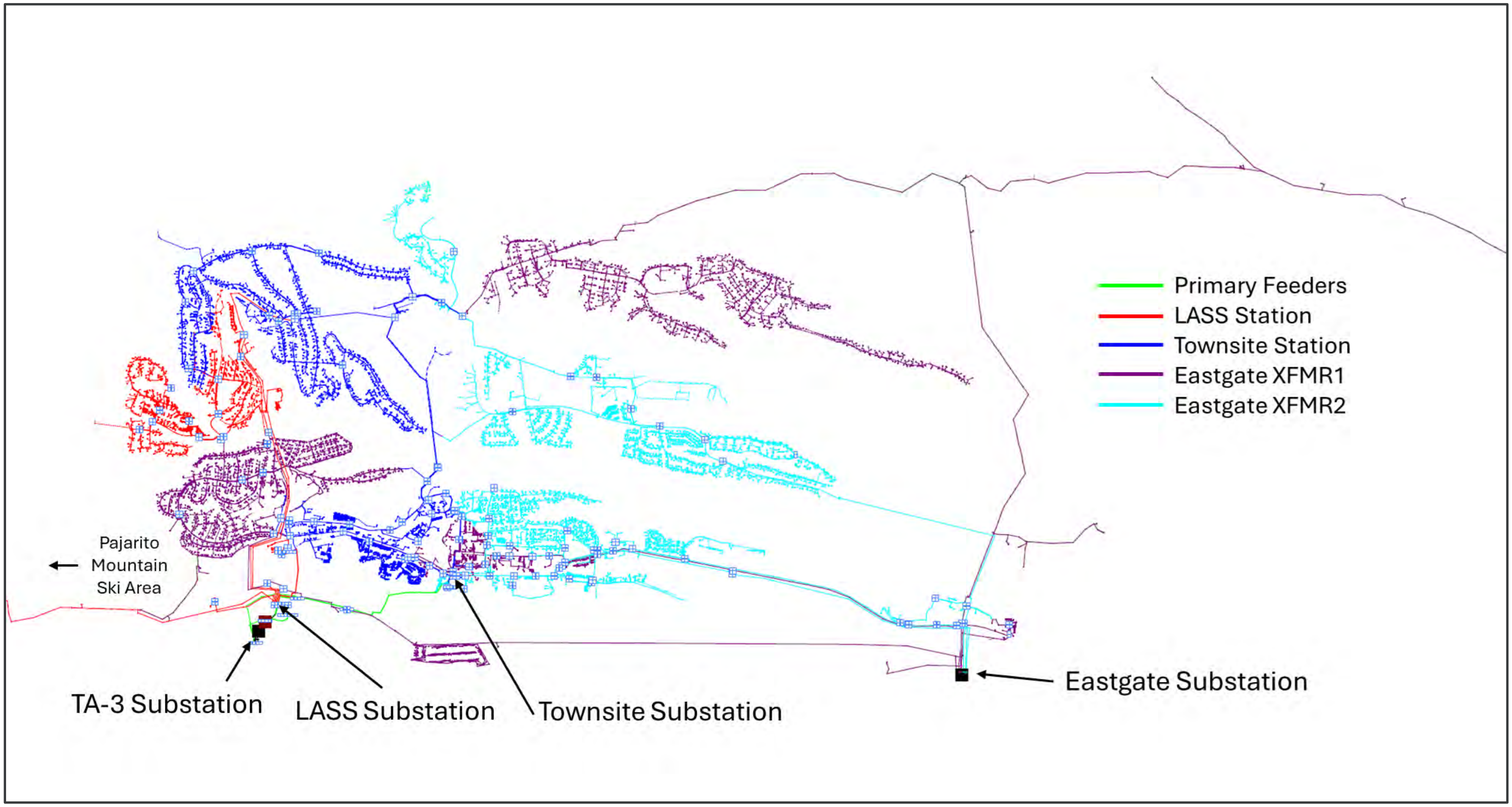
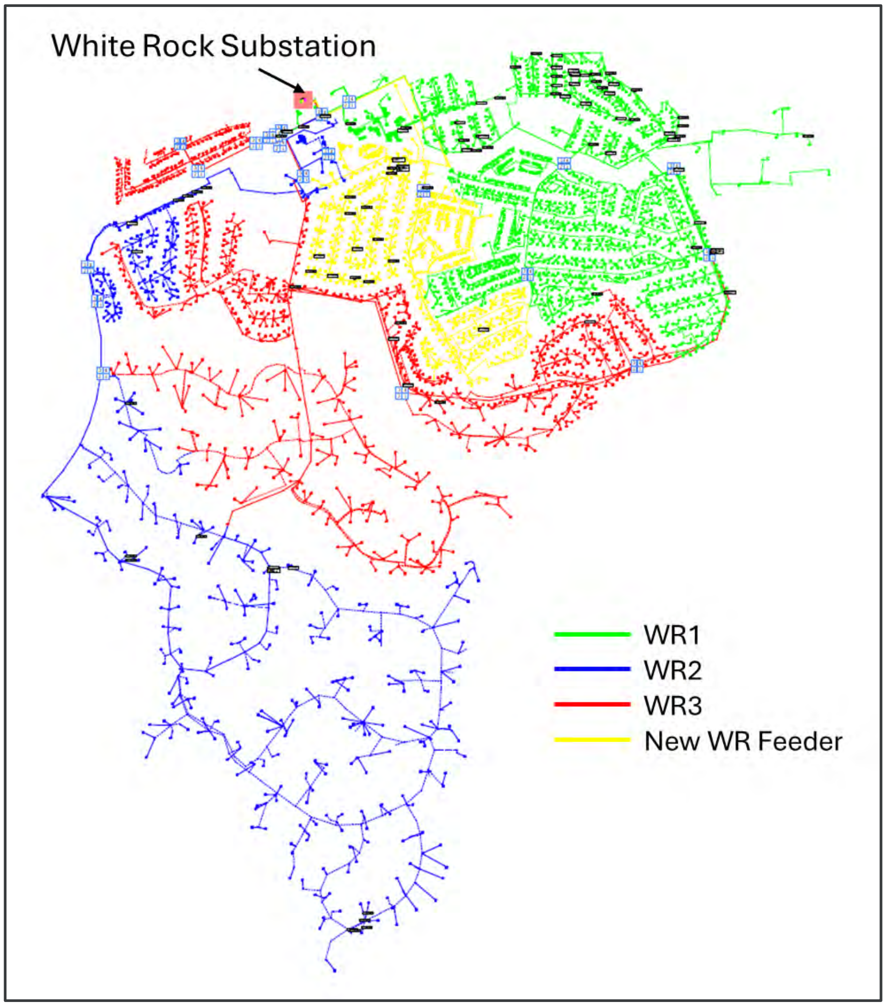


Figure 5-2 shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 22.4 MVA and accompanied by two four-feeder switchgear and a main tiebreaker between the switchgears. One new distribution feeder was constructed from the White Rock Substation to spread the load within the system evenly.

Figure 5-2: 2055 Scenario 1 White Rock System Configuration



5.2.2 Conductor and Equipment Buildout

Figure 5-3 shows the conductor buildout and new equipment used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-3 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required voltage regulators for two long overhead feeders. Voltage regulators were placed to raise voltage after confirming that voltage could not be maintained after upgrading the main line conductor and installing capacitor banks. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area, except for one new capacitor bank.

Figure 5-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and Equipment Buildout

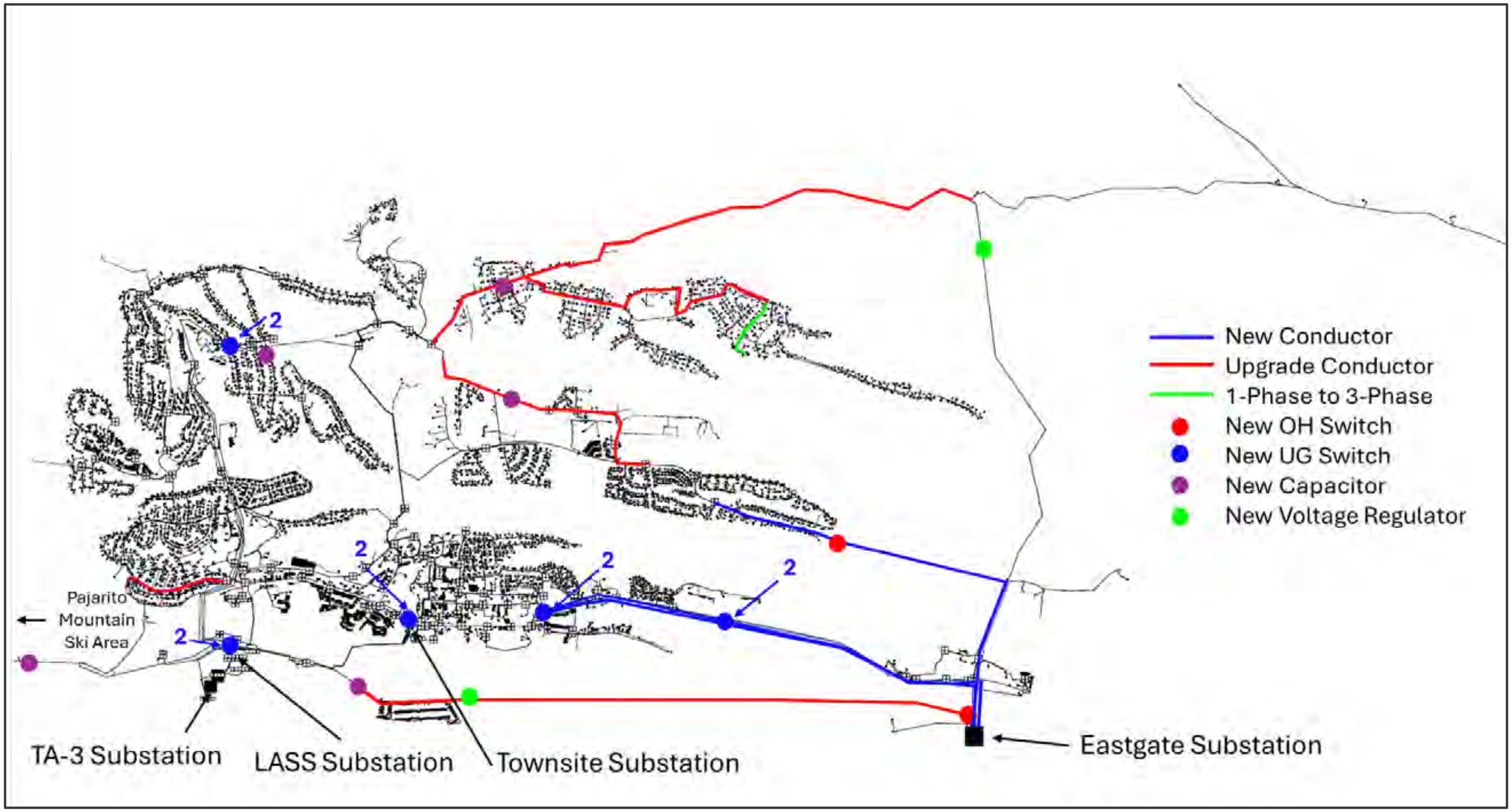


Table 5-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	7.9
4/0 CU Cable (miles)	0
477 ACSR Conductor (miles)	7.8
4/0 ACSR Conductor (miles)	1.9
UG Switch (PME)	11
OH Switch	2
Capacitor Bank	5
Voltage Regulator	2

Figure 5-4 shows the conductor buildout and new equipment used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-4 shows the quantities of conductors and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 5-4: 2055 Scenario 1 White Rock System Conductor and Equipment Buildout

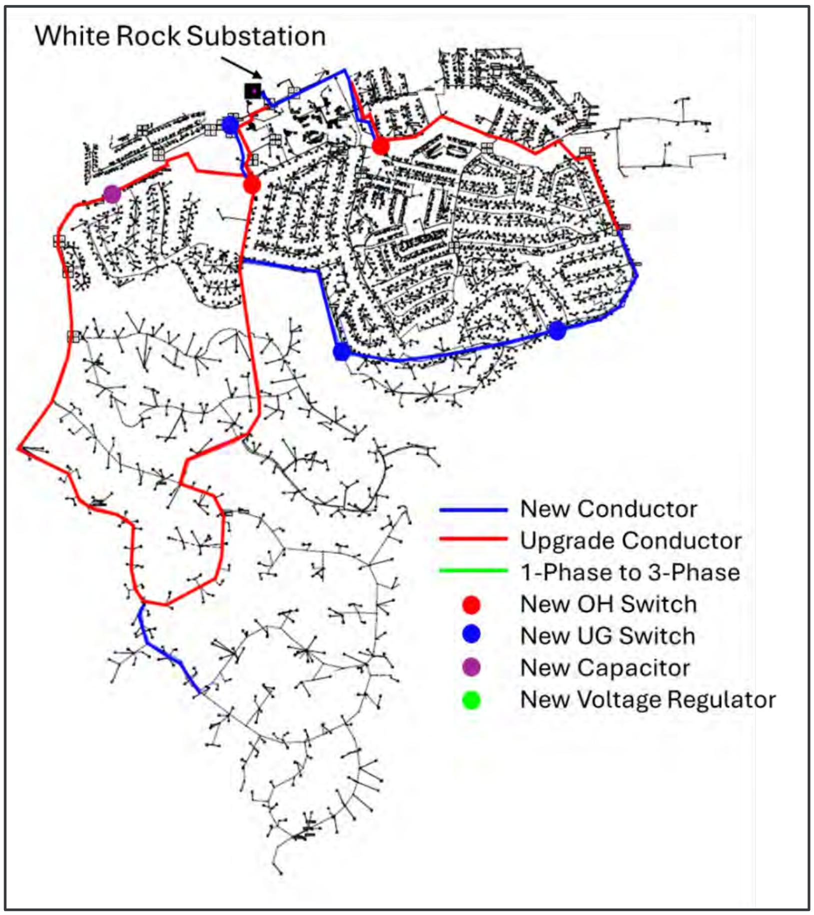


Table 5-4: 2055 Scenario 1 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	4.4
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	3.7
4/0 ACSR Conductor (miles)	0.1
UG Switch (PME)	3
OH Switch	2
Capacitor Bank	1
Voltage Regulator	0

5.2.3 Normal Configuration Power Flow Analysis

Table 5-5 shows the power flow results of the Los Alamos Townsite system. In this new configuration, all planning criteria were maintained.

Table 5-5: 2055 Scenario 1 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	3,554	1,340	3,805	211	122.5
	14**	-	-	-	-	-
	15	2,013	768	2,155	116	118.7
	16	2,158	-449	2,227	123	121.5
	17**	-	-	-	-	-
	18	212	59	220	9	124.5
	Substation	**8,049**	**1,916**	**8,278**	**-**	**-**
LASS	13T**	-	-	-	-	-
	NS6	4,010	820	4,093	172	124.3
	15T	2,804	1,099	3,013	153	121.2
	NSM6*	-	-	-	-	-
	16T**	-	-	-	-	-
	NS3	1,956	292	1,978	83	124.7
	NS18**	-	-	-	-	-
	18	1,602	-340	1,639	71	122.7
	Substation	**10,460**	**2,071**	**10,672**	**-**	**-**
Eastgate	11	5,441	438	5,461	240	122.6
	12	5,895	2,108	6,262	295	119.5
	13	5,960	1,427	6,140	290	119.6
	Transformer 1	**17,299**	**3,974**	**17,754**	**-**	**-**
	21	7,268	2,662	7,742	353	119.8
	21	3,875	-570	3,920	179	124.2
	23	2,160	755	2,289	107	123.1
	Transformer 2	**13,305**	**2,848**	**13,607**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are helpful for contingency restoration.

Table 5-6 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-6: 2055 Scenario 1 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	5,446	1,465	5,640	271	121.6
	WR2	3,484	-151	3,491	181	120.2
	WR3	5,552	1,124	5,665	290	121.9
	New WR Feeder	2,728	879	2,866	141	121.8
	Substation	17,215	3,320	17,537	-	-

5.2.4 Contingency Configuration Review

Table 5-7 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also assessed to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear units must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-7: 2055 Scenario 1 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	13,103	18,950	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	5,997	18,950	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	6,022	8,457	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	2,435	8,457	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	7,081	10,643	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	3,562	10,643	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	17,754	31,345	33,700	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	13,608	31,345	33,700	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-8 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-8: 2055 Scenario 1 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	17,537	17,537	22,400	No	No	With both substation transformers rated at 22,400 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie.

5.2.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 1, based on the present age of existing assets (Section 3.1), considering a 30-year time horizon, many of the LACDPU system assets may need to be replaced. Table 5-9 shows the estimated asset replacements over the 30 years for the Los Alamos Townsite system. This asset replacement estimate did not include conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis.

Table 5-9: 2055 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	25
Underground Cable Replacements (miles)	95%	46
Mainline Switches	100%	137
Three-Phase Service Transformers	80%	147
Single-Phase Service Transformers	90%	842
Secondary Services	90%	5,724

Table 5-10 shows the estimated asset replacements over the 30 years for the White Rock system's 2055 Scenario 1. The power flow analysis upgraded many conductors and cables, thereby reducing the quantity required for asset replacement.

Table 5-10: 2055 Scenario 1 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	6
Underground Cable Replacements (miles)	90%	6
Mainline Switches	100%	23
Three-Phase Service Transformers	80%	29
Single-Phase Service Transformers	90%	372
Secondary Services	90%	2,352

5.2.6 Financial Impact Summary

Table 5-11 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the improvement projects to serve electrification growth.

Table 5-11: 2055 Scenario 1 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$42.5M	$177.1M	$219.7M
White Rock	$25.2M	$37.3M	$62.5M
Total	$67.8M	$214.4M	$282.1M

5.3 2040 Scenario 1 Electrification Impact

2040 Scenario 1 added 21,684 kVA to the LACDPU system power flow model. Table 5-12 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-12: 2040 Scenario 1 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	15,179	32,990
White Rock	3,905	6,505	10,410
Total	21,716	21,684	43,400

5.3.1 Study Area Configuration

Figure 5-5 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgear with a main tie breaker between the two switchgears. In 2055 Scenario 1, two 33.7 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for the 2040 Scenario 1, two 33.7 MVA transformers were installed at the Eastgate Substation, knowing the potential load serving needs of the future 2055 Scenario 1. However, only four new distribution feeders were constructed in the planning model to bring new capacity west towards the load centers, given the forecasted load in 2040. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

Figure 5-5: 2040 Scenario 1 Los Alamos Townsite System Configuration

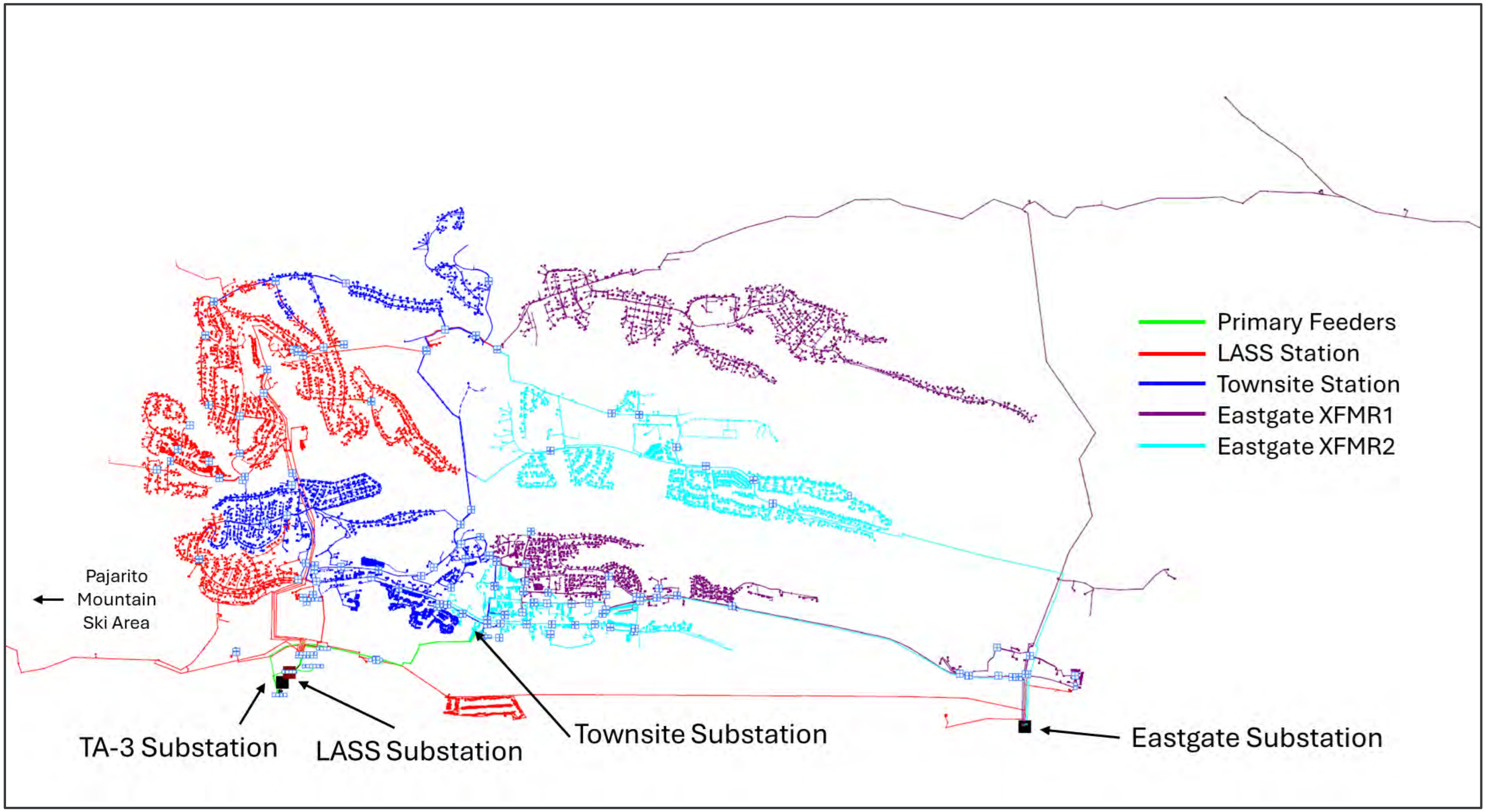
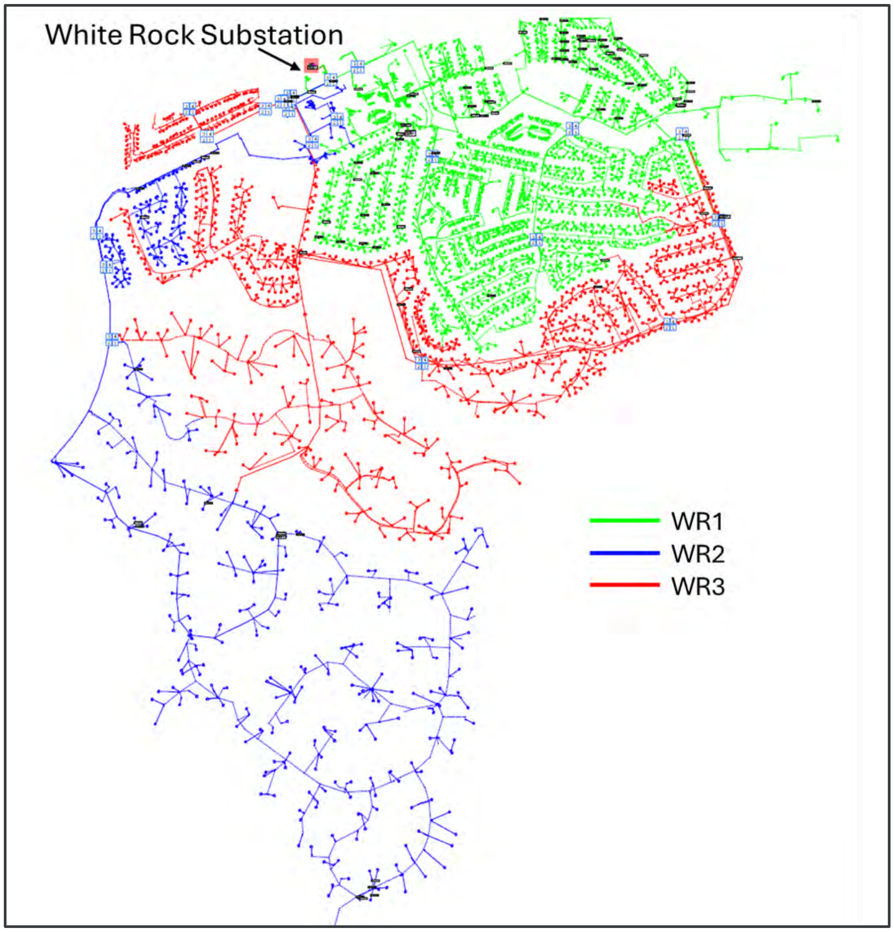


Figure 5-6 shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecast electrification growth in this scenario, both substation transformers must be upgraded to 22.4 MVA and accompanied by two four-feeder switchgears and a main tiebreaker between the two switchgears. For 2040 Scenario 1, a smaller transformer size could be feasible, but it is assumed that LACDPU would construct the substation transformer sized for the full buildout in 2055. No new distribution feeders are required, given the load forecast in this scenario for 2040.

Figure 5-6: 2040 Scenario 1 White Rock System Configuration



5.3.2 Conductor and Equipment Buildout

Figure 5-7 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-13 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required the use of voltage regulators for two long overhead feeders. Voltage regulators were not required in this scenario because the feeder load was lower than modeled in the 2055 scenario. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area, except for one new capacitor bank.

Figure 5-7: 2040 Scenario 1 Los Alamos Townsite System Configuration

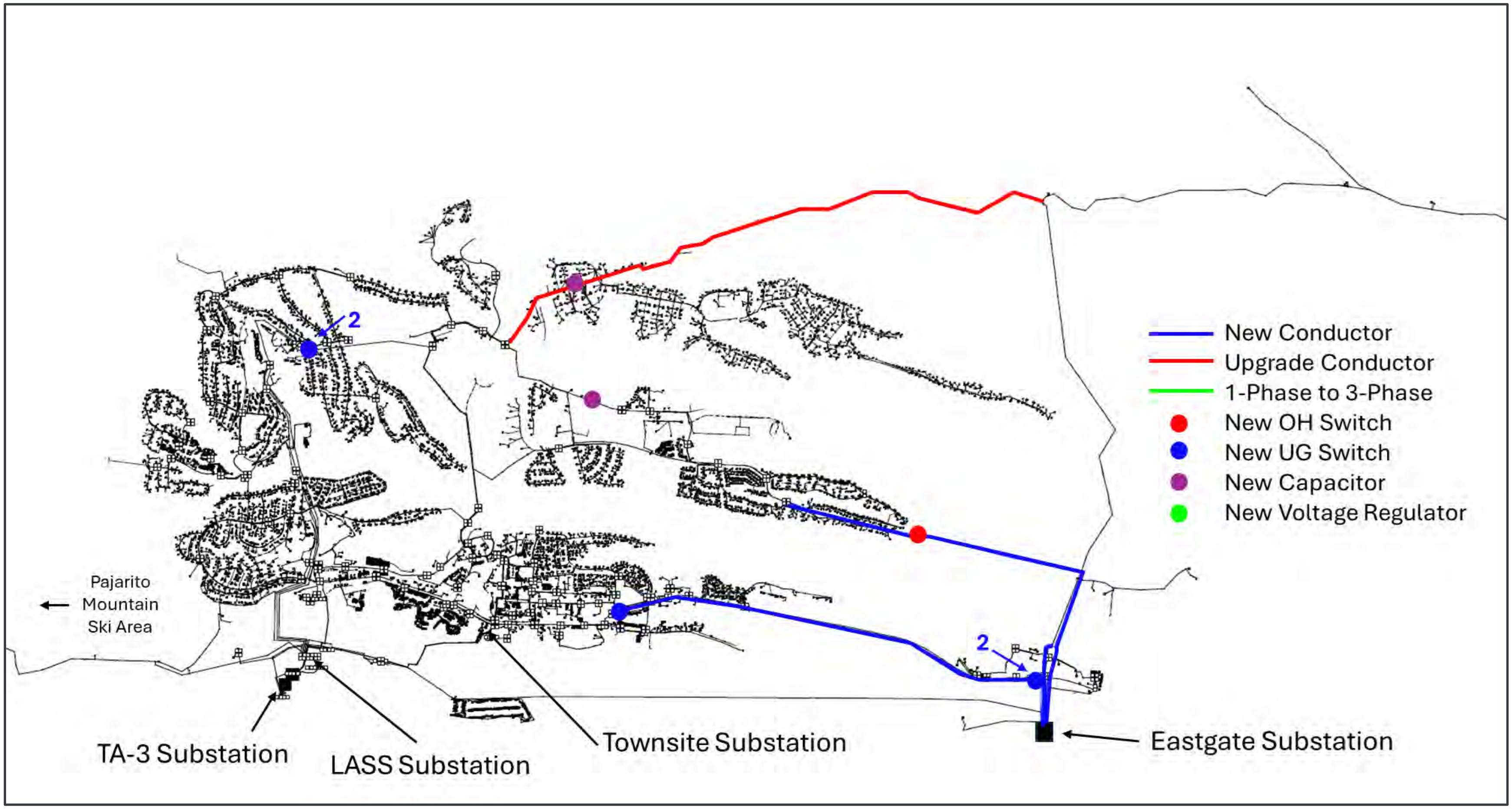


Table 5-13: 2040 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	4.4
4/0 CU Cable (miles)	0
477 ACSR Conductor (miles)	4.2
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	5
OH Switch	1
Capacitor Bank	2
Voltage Regulator	0

Figure 5-8 shows the conductor buildout and new equipment used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-14 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 5-8: 2040 Scenario 1 White Rock System Conductor and Equipment Buildout

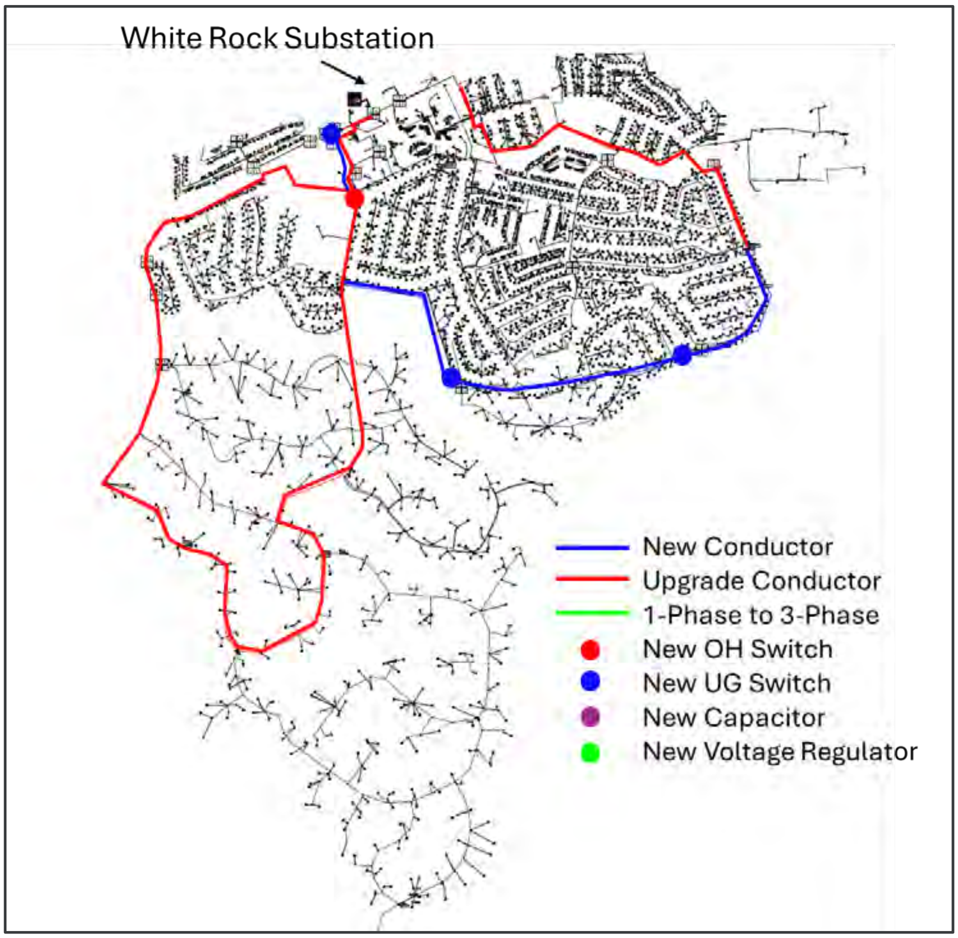


Table 5-14: 2040 Scenario 1 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	3.5
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	3.7
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	1
Capacitor Bank	0
Voltage Regulator	0

5.3.3 Normal Configuration Power Flow Analysis

Table 5-15 shows the power flow results of the Los Alamos Townsite system. In this new configuration, all planning criteria were maintained.

Table 5-15: 2040 Scenario 1 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	2,326	26	2,330	126	122.2
	14**	-	-	-	-	-
	15	3,002	830	3,114	139	121.7
	16	40	-35	63	4	124.9
	17**	-	-	-	-	-
	18	141	35	145	6	124.9
	Substation	**5,587**	**869**	**5,660**	**-**	**-**
LASS	13T	1,094	306	1,137	56	124.5
	NS6	2,628	853	2,763	116	124.5
	15T	2,559	688	2,651	159	121.4
	NSM6*	-	-	-	-	-
	16T	1,372	322	1,410	82	122.8
	NS3	1,283	410	1,347	57	124.7
	NS18	633	197	663	29	124.0
	18	1,044	292	1,084	48	122.4
	Substation	**10,750**	**3,363**	**11,283**	**-**	**-**
Eastgate	11	3,559	61	3,565	172	120.8
	12	4,721	1,404	4,926	224	121.8
	Transformer 1	**8,281**	**1,465**	**8,410**	**-**	**-**
	21	5,265	1,629	5,512	238	121.9
	22	2,518	-581	2,588	118	123.9
	Transformer 2	**7,785**	**1,046**	**7,856**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are helpful for contingency restoration efforts.

Table 5-16 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-16: 2040 Scenario 1 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	4,801	1,193	4,948	239	123.0
	WR2	2,051	634	2,147	129	121.2
	WR3	3,267	329	3,285	168	123.9
	Substation	10,121	2,156	10,355	-	-

5.3.4 Contingency Configuration Analysis

Table 5-17 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also assessed to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear units must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-17: 2040 Scenario 1 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	11,985	16,943	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	4,690	16,943	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	5,435	5,622	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	187	5,622	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	6,550	11,053	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	4,503	11,053	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	8,410	16,266	33,700	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	7,856	16,266	33,700	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-18 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-18: 2040 Scenario 1 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	10,355	10,355	22,400	No	No	With both substation transformers rated at 22,400 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie.

5.3.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 1, based on the present age of existing assets (Section 3.1), considering 15 years, many of the LACDPU system assets may need to be replaced. Table 5-19 shows the estimated asset replacements over the 15 years for the Los Alamos Townsite system. This asset replacement estimate did not include conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis.

Table 5-19: 2040 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	30%	7
Underground Cable Replacements (miles)	65%	32
Mainline Switches	90%	123
Three-Phase Service Transformers	25%	46
Single-Phase Service Transformers	35%	327
Secondary Services	30%	1,908

Table 5-20 shows the estimated asset replacements over the 15 years for the White Rock system’s 2040 Scenario 1. The power flow analysis upgraded many conductors and cables, reducing the quantity required for asset replacement.

Table 5-20: 2040 Scenario 1 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	95%	6
Underground Cable Replacements (miles)	50%	3
Mainline Switches	70%	16
Three-Phase Service Transformers	40%	14
Single-Phase Service Transformers	50%	207
Secondary Services	40%	1,045

5.3.6 Financial Impact Summary

Table 5-21 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the system improvement projects to serve electrification growth.

Table 5-21: 2040 Scenario 1 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$30.7M	$100.9M	$131.7M
White Rock	$22.9M	$18.8M	$41.8M
Total	$53.7M	$119.8M	$173.4M

5.4 2055 Scenario 2 Electrification Impact

2055 Scenario 2 added 28,526 kVA to the LACDPU system power flow model. Table 5-22 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-22: 2055 Scenario 2 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	19,968	37,779
White Rock	3,905	8,558	12,463
Total	21,716	28,526	50,242

5.4.1 Study Area Configuration

Figure 5-9 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 22.4 MVA transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. Four new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

Figure 5-9: 2055 Scenario 2 Los Alamos Townsite System Configuration

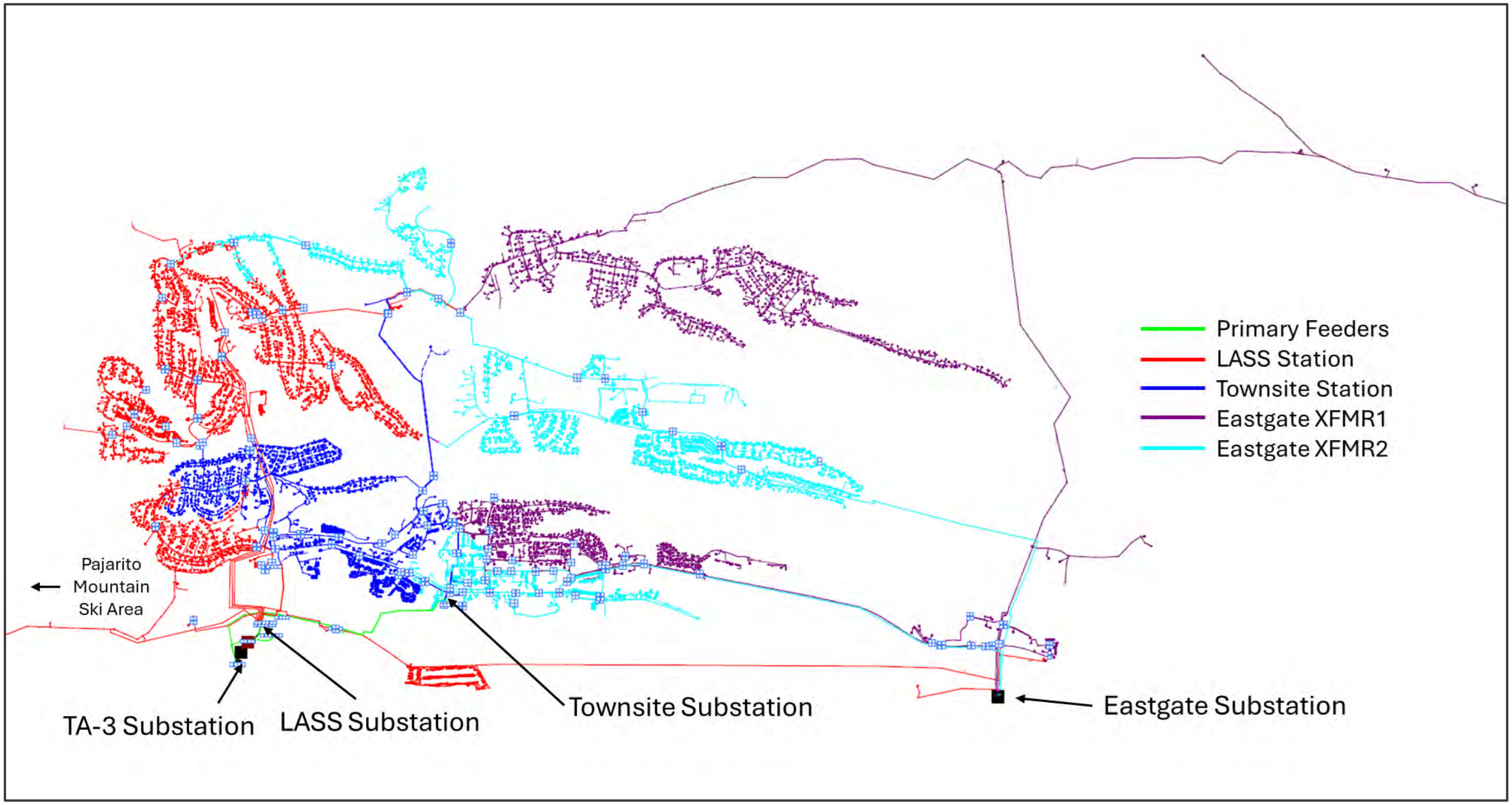
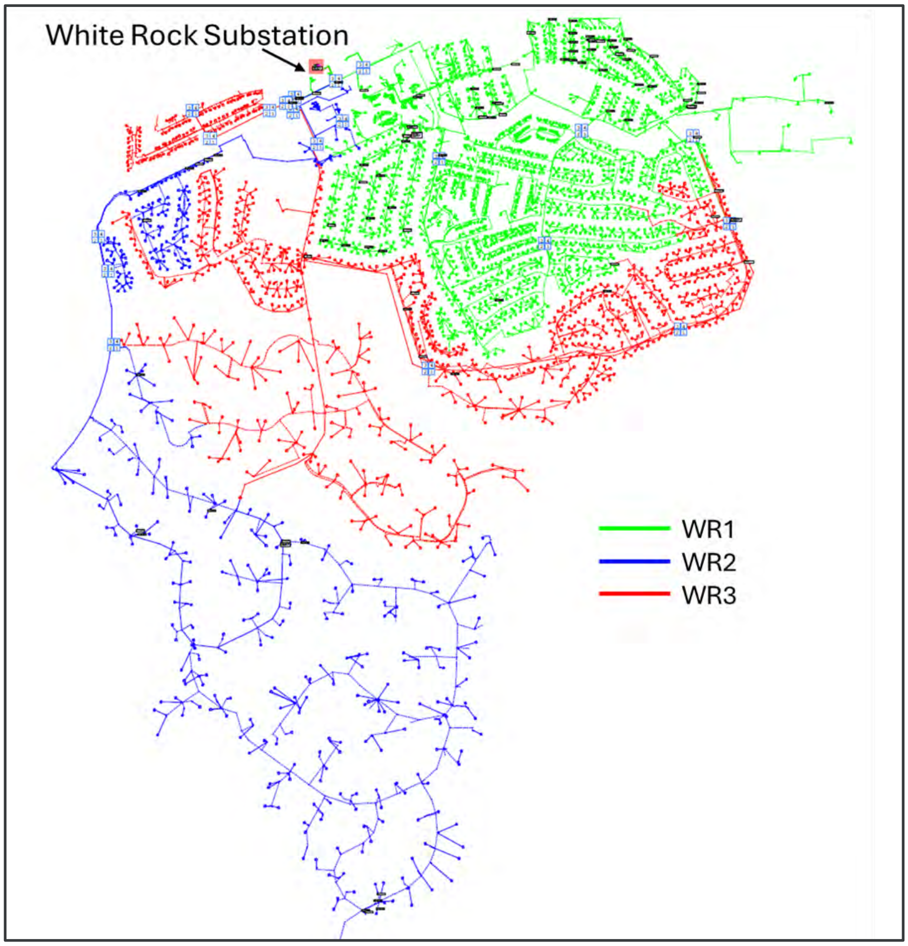


Figure 5-10 shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 14 MVA and accompanied by two four-feeder switchgears and a main tiebreaker between the two switchgears. No new distribution feeders were constructed for this scenario, but WR3 was extended to serve more load in the center of the White Rock system.

Figure 5-10: 2055 Scenario 2 White Rock System Configuration



5.4.2 Conductor and Equipment Buildout

Figure 5-11 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-23 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required the use of voltage regulators for the one long overhead feeder that serves the northern portion of the area. This voltage regulator was placed to raise the voltage after confirming that the voltage could not be maintained after upgrading the main line conductor and installing capacitor banks. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

Figure 5-11: 2055 Scenario 2 Los Alamos Townsite System Conductor and Equipment Buildout

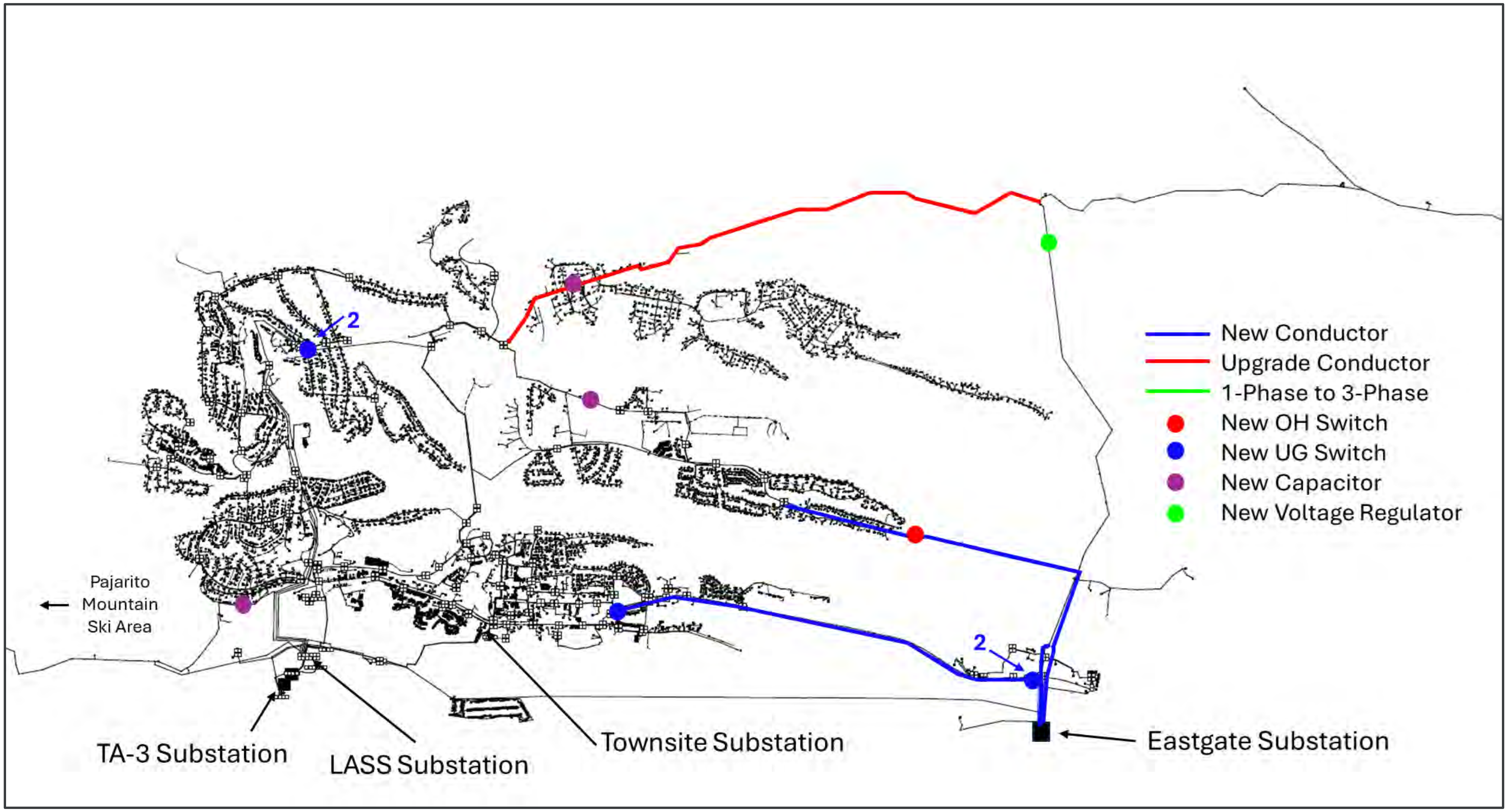


Table 5-23: 2055 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	4.4
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	4.2
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	5
OH Switch	1
Capacitor Bank	3
Voltage Regulator	1

Figure 5-12 shows the conductor buildout and new equipment used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-24 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 5-12: 2055 Scenario 2 White Rock System Conductor and Equipment

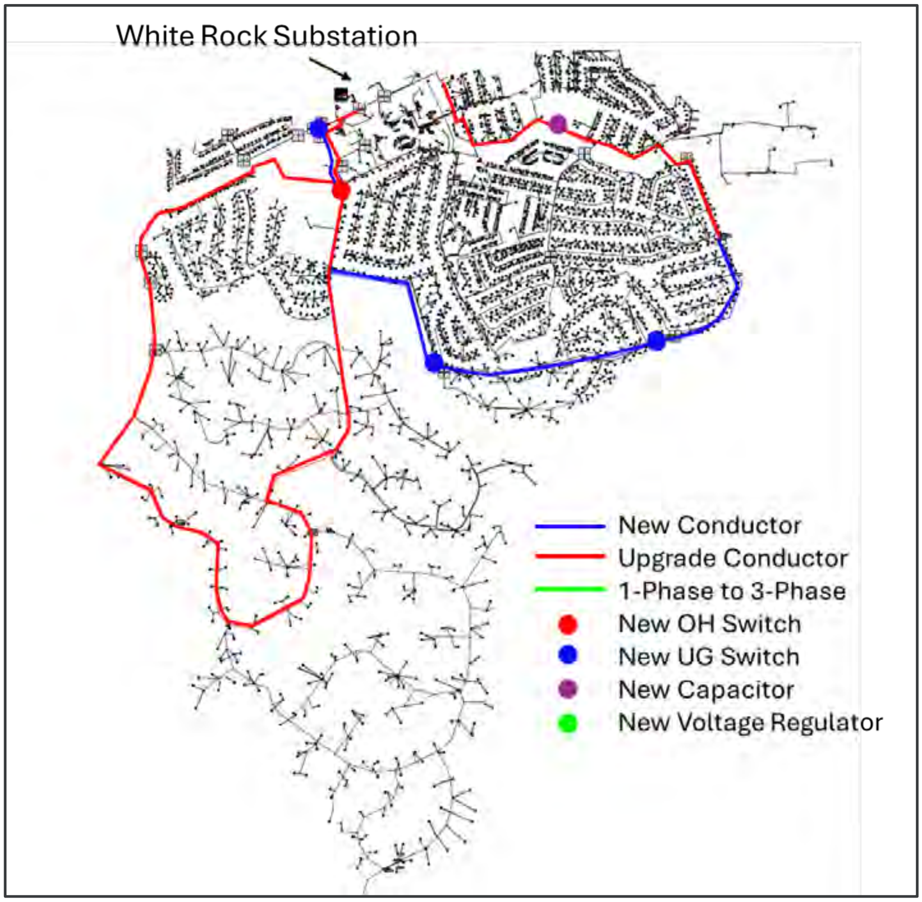


Table 5-24: 2055 Scenario 2 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	3.5
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	3.7
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	1
Capacitor Bank	1
Voltage Regulator	0

5.4.3 Normal Configuration Power Flow Analysis

Table 5-25 shows the power flow results of the Los Alamos Townsite system. In this new configuration, all planning criteria were maintained.

Table 5-25: 2055 Scenario 2 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	2,647	134	2,655	144	122.3
	14**	-	-	-	-	-
	15	2,359	707	2,463	112	121.6
	16	45	-33	67	5	124.8
	17**	-	-	-	-	-
	18	158	41	163	7	124.9
	Substation	**5,283**	**843**	**5,353**	**-**	**-**
LASS	13T	1,247	-930	1,565	71	124.8
	NS6	2,992	974	3,146	132	124.5
	15T	2,919	816	3,032	184	122.7
	NSM6*	-	-	-	-	-
	16T	1,563	387	1,611	94	122.5
	NS3	1,460	469	1,534	65	124.6
	NS18	720	227	755	42	124.4
	18	1,190	344	1,239	55	122.0
	Substation	**12,261**	**2,662**	**12,571**	**-**	**-**
Eastgate	11	4,058	280	4,074	198	122.0
	12	5,383	1,637	5,626	256	121.3
	Transformer 1	**9,442**	**1,917**	**9,635**	**-**	**-**
	21	6,008	1,897	6,300	262	121.3
	22	3,945	-130	3,948	168	123.0
	Transformer 2	**9,954**	**1,766**	**10,110**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are helpful for contingency restoration efforts.

Table 5-26 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-26: 2055 Scenario 2 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	5,840	269	5,848	262	122.3
	WR2	2,496	792	2,619	158	120.4
	WR3	3,974	572	4,016	205	123.6
	Substation	12,316	1,628	12,430	-	-

5.4.4 Contingency Configuration Analysis

Table 5-27 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also assessed to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear units must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-27: 2055 Scenario 2 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	12,329	17,677	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	5,348	17,677	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	5,113	5,322	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	209	5,322	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	7,216	12,355	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	5,139	12,355	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	9635	19,745	22,400	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	10,110	19,745	22,400	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-28 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-28: 2055 Scenario 2 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	12,430	12,430	14,000	No	No	With both substation transformers rated at 14,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie.

5.4.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 2, based on the present age of existing assets (Section 3.1), considering 30 years, many of the LACDPU system assets may need to be replaced. Table 5-29 shows the estimated asset replacements over the 30 years for the Los Alamos Townsite system. This asset replacement estimate did not include conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis.

Table 5-29: 2055 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	30
Underground Cable Replacements (miles)	95%	47
Mainline Switches	100%	137
Three-Phase Service Transformers	70%	129
Single-Phase Service Transformers	80%	748
Secondary Services	80%	5,088

Table 5-30 shows the estimated asset replacements over the 30 years for the White Rock system's 2055 Scenario 2. The power flow analysis upgraded many conductors and cables, reducing the quantity required for asset replacement.

Table 5-30: 2055 Scenario 2 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	6
Underground Cable Replacements (miles)	90%	6
Mainline Switches	100%	23
Three-Phase Service Transformers	70%	25
Single-Phase Service Transformers	80%	330
Secondary Services	80%	2,090

5.4.6 Financial Impact Summary

Table 5-31 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the system improvement projects to serve electrification growth.

Table 5-31: 2055 Scenario 2 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$30.2M	$176.4M	$206.6M
White Rock	$23.1M	$35.0M	$58.0M
Total	$53.2M	$211.4M	$264.6M

5.5 2040 Scenario 2 Electrification Impact

2040 Scenario 2 added 7,789 kVA to the LACDPU system power flow model. Table 5-32 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-32: 2040 Scenario 2 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	5,453	23,264
White Rock	3,905	2,337	6,242
Total	21,716	7,789	29,505

5.5.1 Study Area Configuration

Figure 5-13 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. In 2055 Scenario 2, two 22.4 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for this 2040 scenario, two 22.4 MVA transformers were installed at the Eastgate Substation, knowing the potential load serving need of the future 2055 scenario. However, only two new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers, given the forecasted load in 2040. Some of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Some of the Townsite Substation load was transferred to Eastgate Substation.

Figure 5-13: 2040 Scenario 2 Los Alamos Townsite System Configuration

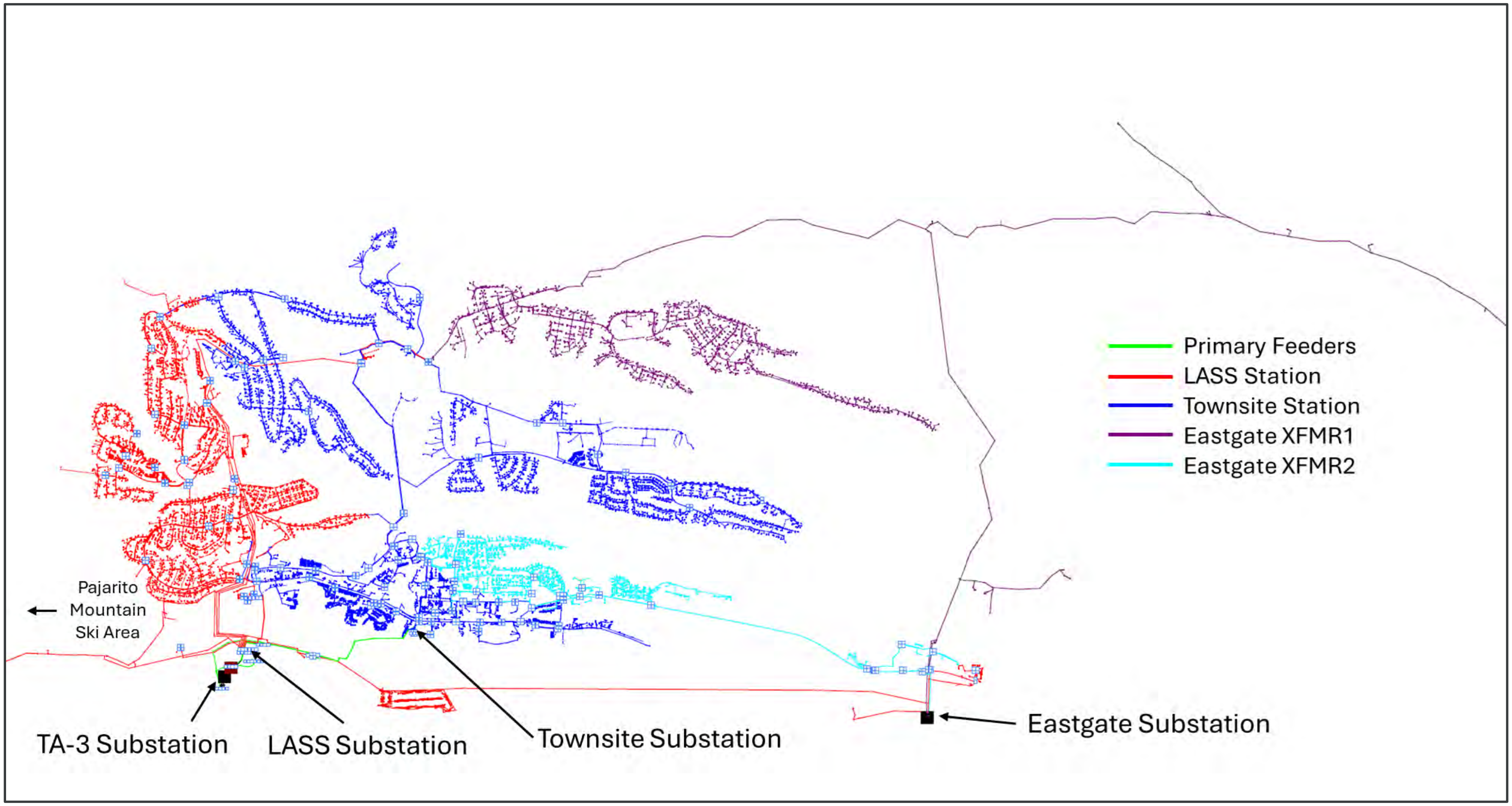
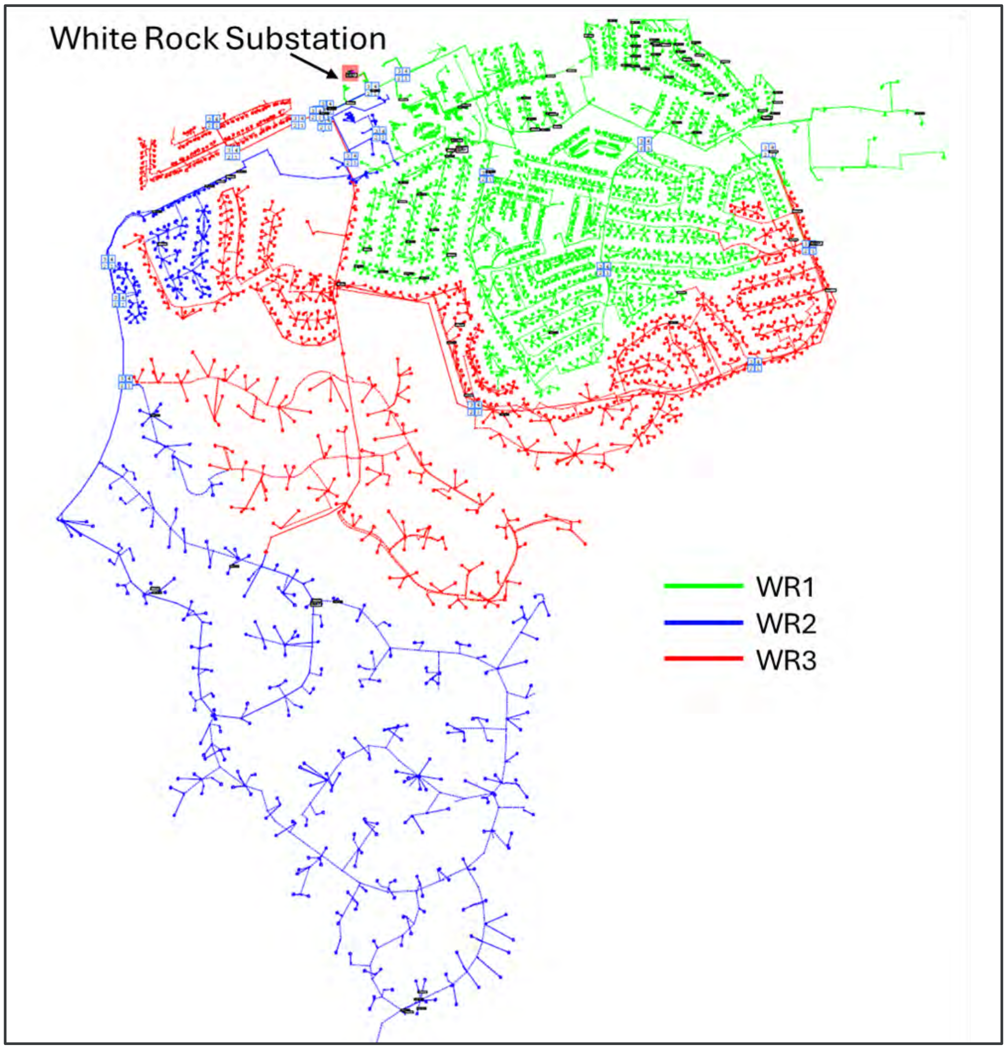


Figure 5-14 shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, White Rock Transformer 1 must be upgraded to 14 MVA to accommodate the 2040 and the 2055 forecasted loads. No new distribution feeders were constructed for this scenario, but WR3 was extended to serve more load in the center of the White Rock system.

Figure 5-14: 2040 Scenario 2 White Rock System Configuration



5.5.2 Conductor and Equipment Buildout

Figure 5-15 shows the conductor buildout and new equipment used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-33 shows the quantities of conductors and equipment used in this scenario. One new underground switch was utilized to connect the new distribution feeders to the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

Figure 5-15: 2040 Scenario 2 Los Alamos Townsite System Conductor and Equipment Buildout

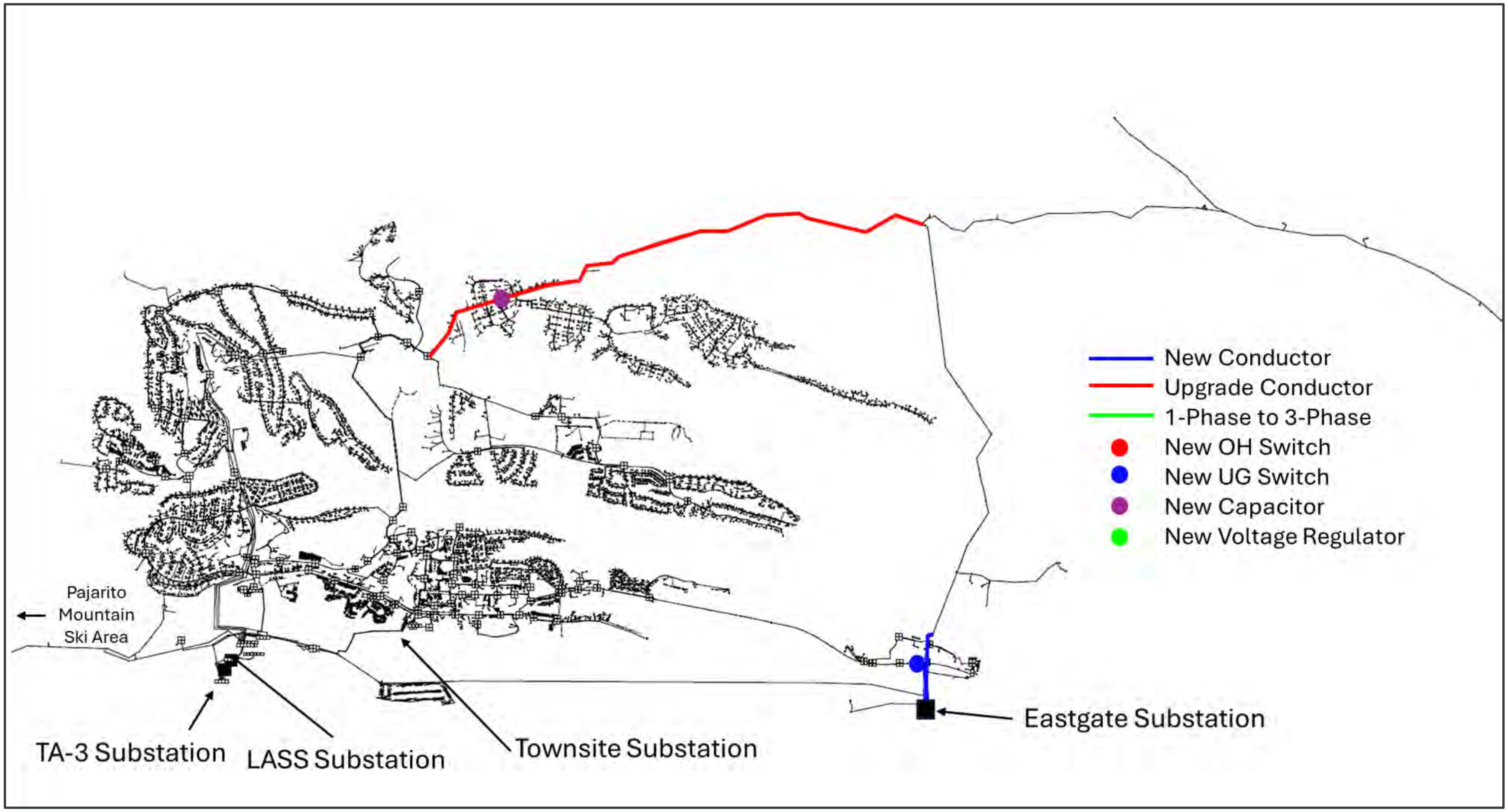


Table 5-33: 2040 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	0.8
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	3
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	1
OH Switch	0
Capacitor Bank	1
Voltage Regulator	0

Figure 5-16 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-34 shows the quantities of conductor and equipment used in this scenario.

Figure 5-16: 2040 Scenario 2 White Rock System Conductor and Equipment

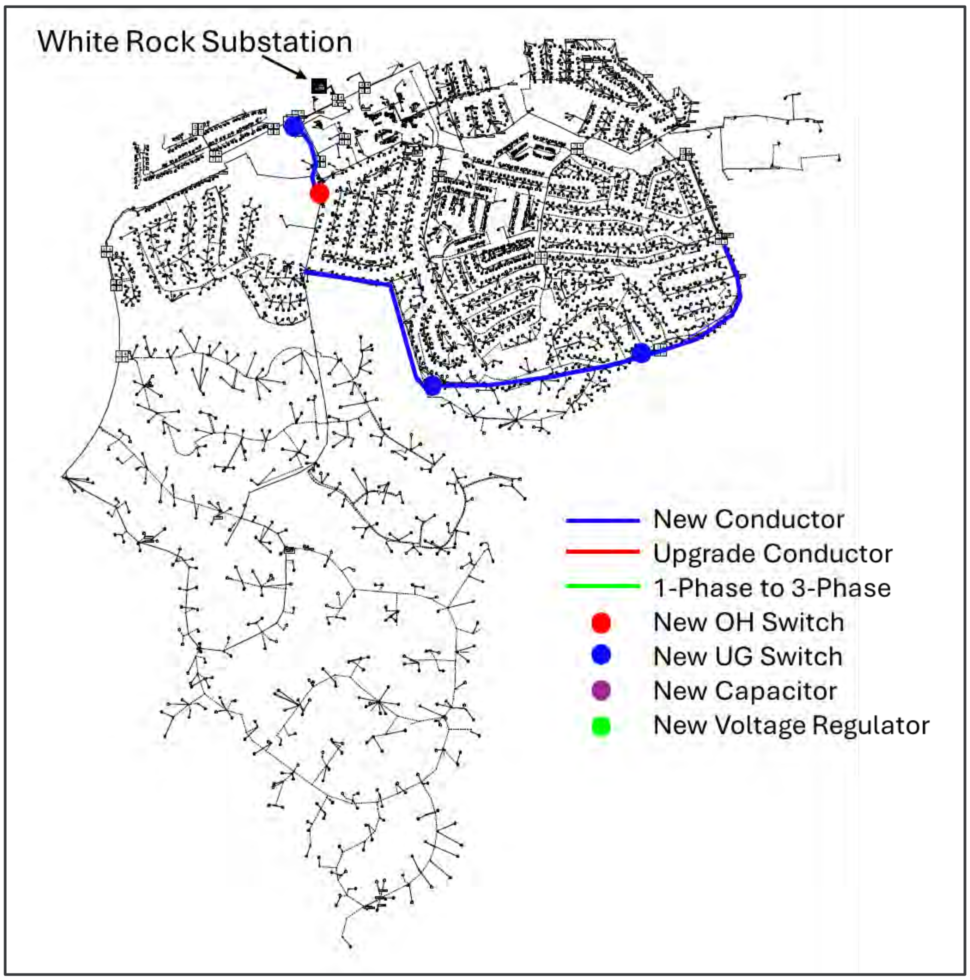


Table 5-34: 2040 Scenario 2 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	1.9
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	0
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	1
Capacitor Bank	0
Voltage Regulator	0

5.5.3 Normal Configuration Power Flow Analysis

Table 5-35 shows the power flow results of the Los Alamos Townsite system. In this new configuration, all planning criteria were maintained.

Table 5-35: 2040 Scenario 2 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	1,564	-235	1,589	85	123.7
	14**	-	-	-	-	-
	15	1,582	353	1,622	82	122.5
	16	1,723	433	1,778	95	120.7
	17	3,477	1,029	3,627	158	123.8
	18	94	20	96	4	123.8
	Substation	**8,558**	**1,934**	**8,779**	**-**	**-**
LASS	13T	2,237	632	2,325	108	123.5
	NS6	1,768	568	1,857	78	124.6
	15T	1,715	394	1,760	105	122.6
	NSM6*	-	-	-	-	-
	16T**	-	-	-	-	-
	NS3	864	272	906	38	124.8
	NS18	615	176	640	33	124.1
	18	699	170	720	32	123.2
	Substation	**7,993**	**2,295**	**8,328**	**-**	**-**
Eastgate	11	3,103	-222	3,117	143	121.8
	Transformer 1	**3,103**	**-222**	**3,117**	**-**	**-**
	21	3,163	864	3,279	142	122.9
	Transformer 2	**3,163**	**864**	**3,279**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are helpful for contingency restoration efforts.

Table 5-36 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained. White Rock Transformer 2, rated at 7,500 kVA, can serve this forecasted load, however the demand is approaching the rating of this transformer.

Table 5-36: 2040 Scenario 2 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	2,622	449	2,660	123	123.9
	WR2	1,247	364	1,299	64	122.5
	WR3	2,265	-37	2,269	113	124.9
	Substation	6,135	777	6,187	-	-

5.5.4 Contingency Configuration Analysis

Table 5-37 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also assessed to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear units must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-37: 2040 Scenario 2 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	9,099	17,107	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	7,773	17,107	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	3,160	8,687	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	5,527	8,687	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	5,939	8,185	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	2,246	8,185	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	3,160	6,625	22,400	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	3,465	6,625	22,400	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-38 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 5-38: 2040 Scenario 2 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	6,187	6,187	14,000	No	No	With Transformer 1 upgraded to 14,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie.

5.5.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 2, based on the present age of existing assets (Section 3.1), considering 15 years, many of the LACDPU system assets may need to be replaced. Table 5-39 shows the estimated asset replacements over the 15 years for the Los Alamos Townsite system. This asset replacement estimate did not include conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis.

Table 5-39: 2040 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	30%	7
Underground Cable Replacements (miles)	65%	32
Mainline Switches	90%	123
Three-Phase Service Transformers	25%	46
Single-Phase Service Transformers	35%	327
Secondary Services	30%	1,908

Table 5-40 shows the estimated asset replacements over the 15 years for the White Rock system's 2040 Scenario 2.

Table 5-40: 2040 Scenario 2 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	95%	10
Underground Cable Replacements (miles)	50%	4
Mainline Switches	70%	16
Three-Phase Service Transformers	40%	14
Single-Phase Service Transformers	50%	207
Secondary Services	40%	1,045

5.5.6 Financial Impact Summary

Table 5-41 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the system improvement projects to serve electrification growth.

Table 5-41: 2040 Scenario 2 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$20.8M	$100.9M	$121.7M
White Rock	$17.3M	$24.4M	$41.7M
Total	$38.1M	$125.3M	$163.4M

5.6 2055 Scenario 3 Electrification Impact

2055 Scenario 3 added 13,789 kVA to the LACDPU system power flow model. Table 5-42 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-42: 2055 Scenario 3 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	9,653	27,464
White Rock	3,905	4,137	8,042
Total	21,716	13,789	35,505

Figure 5-17 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 14 MVA transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. Three new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. Most of the electrification load growth must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

Figure 5-17: 2055 Scenario 3 Los Alamos Townsite System Configuration

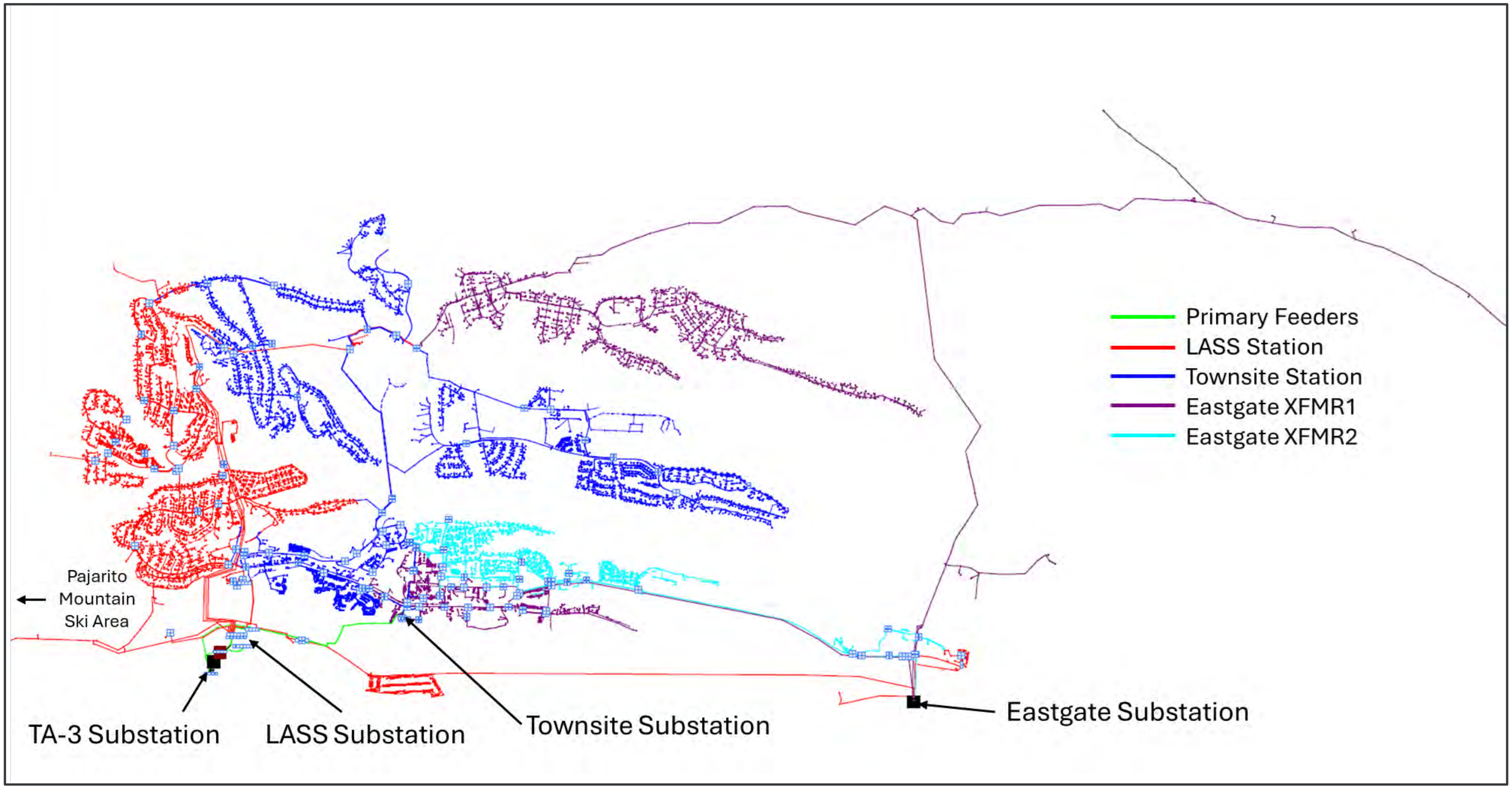
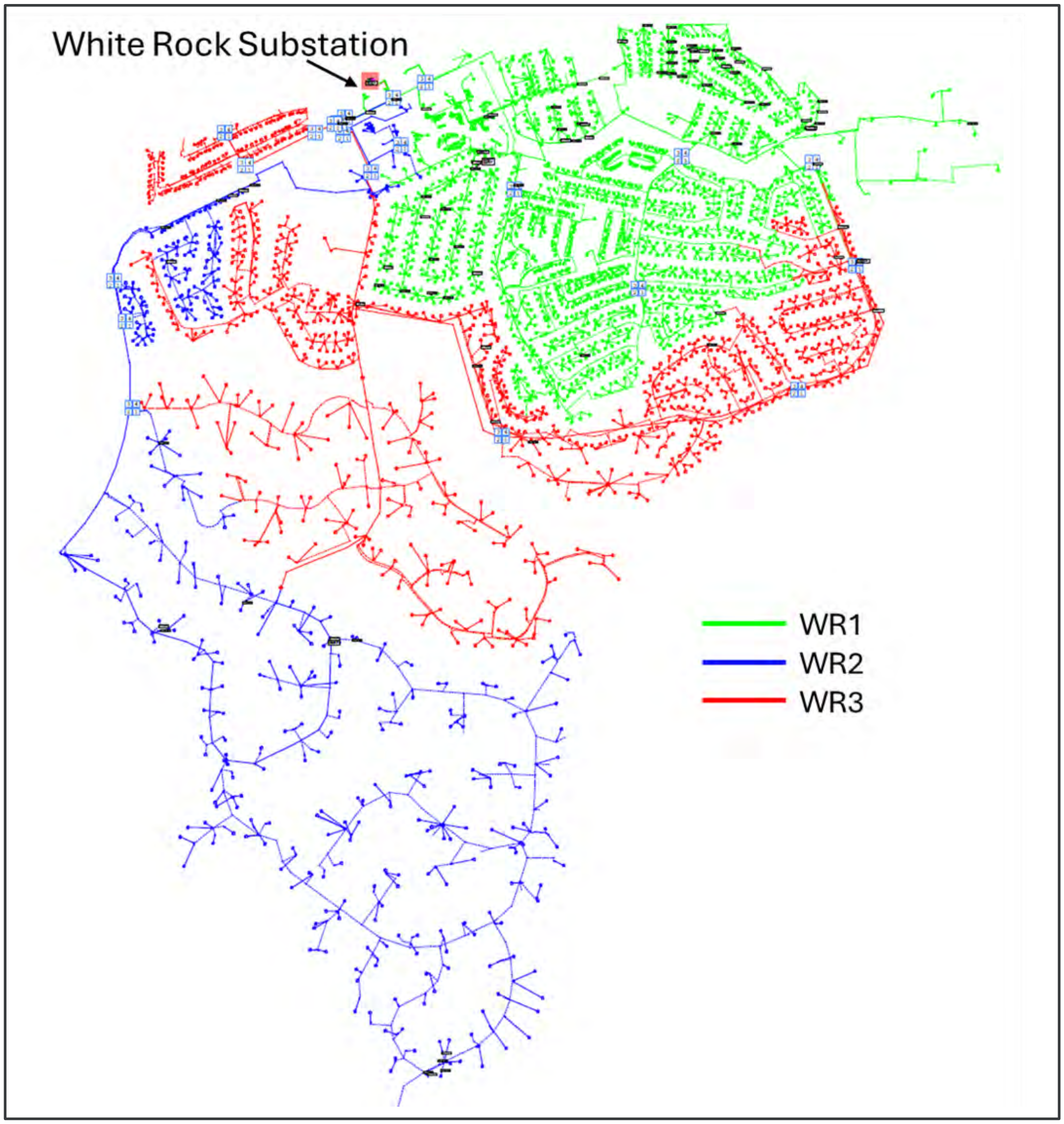


Figure shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 10 MVA and accompanied by two four-feeder switchgear and a main tiebreaker between the two switchgears.

Figure 5-18: 2055 Scenario 3 White Rock System Configuration



5.6.1 Conductor and Equipment Buildout

Figure 5-19 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-43 shows the quantities of conductor and equipment used in this scenario. No voltage regulators were required in this scenario. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

Figure 5-19: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout

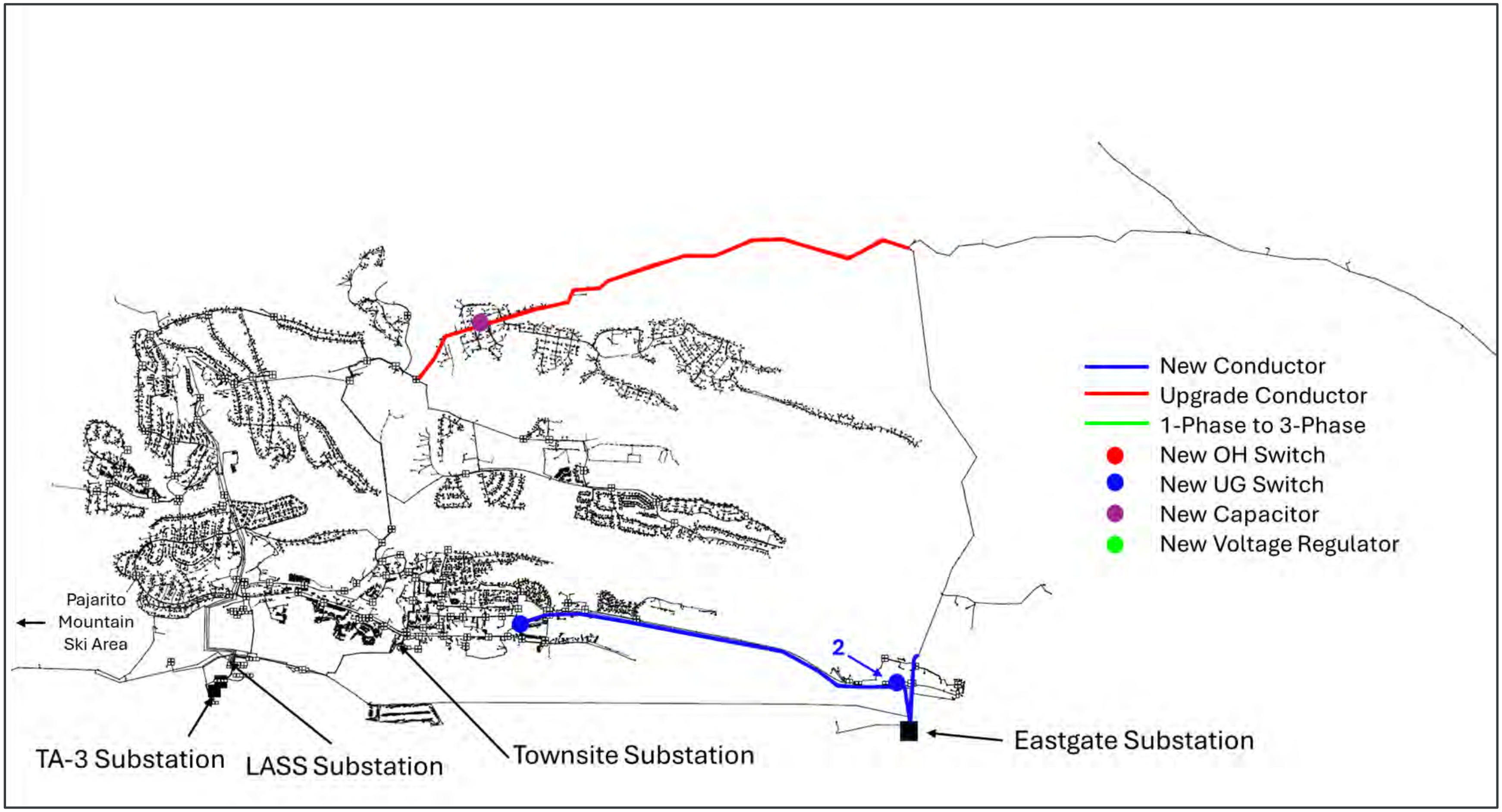


Table 5-43: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	3.2
4/0 CU Cable (miles)	0
477 ACSR Conductor (miles)	3
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	0
Capacitor Bank	1
Voltage Regulator	0

Figure 5-20 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-44 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system were not upgraded in this scenario. However, extending the underground mainline created a strong tie point for White Rock Feeder 1 and Feeder 3.

Figure 5-20: 2055 Scenario 3 White Rock System Conductor and Equipment Buildout

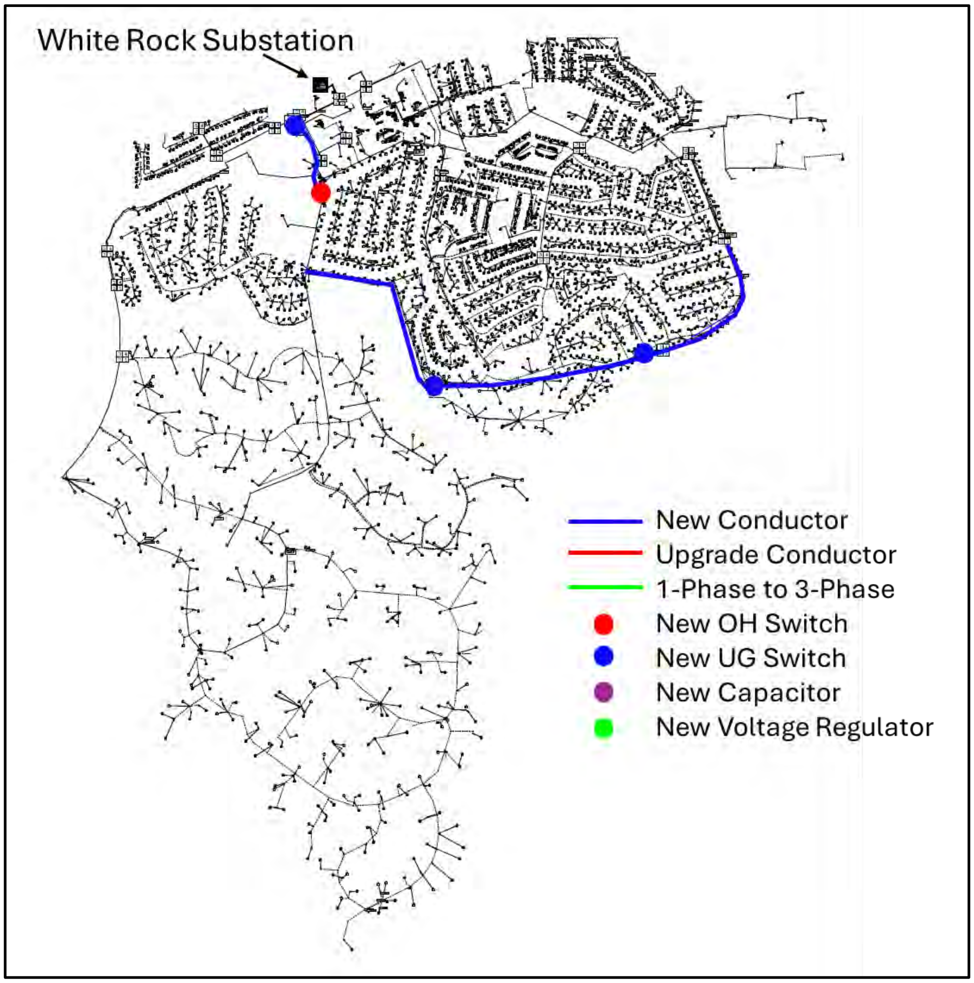


Table 5-44: 2055 Scenario 3 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	1.9
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	0
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	1
Capacitor Bank	0
Voltage Regulator	0

5.6.2 Normal Configuration Power Flow Analysis

Table 5-45 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-45: 2055 Scenario 3 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	1,849	-138	1,860	100	123.4
	14**	-	-	-	-	-
	15	1,873	455	1,927	98	122.0
	16	2,041	543	2,113	113	120.7
	17**	-	-	-	-	-
	18	111	25	114	5	124.5
	Substation	**5,953**	**1,006**	**6,042**	**-**	**-**
LASS	13T	2,646	773	2,757	128	123.2
	NS6	2,090	675	2,196	92	124.5
	15T	2,030	503	2,092	125	122.1
	NSM6*	-	-	-	-	-
	16T**	-	-	-	-	-
	NS3	1,021	324	1,071	45	124.8
	NS18	728	214	758	40	123.9
	18	828	215	856	37	123.0
	Substation	**9,460**	**2,868**	**9,904**	**-**	**-**
Eastgate	11	3,311	-126	3,320	154	120.9
	12	4,196	1,263	4,382	189	121.7
	Transformer 1	**7,507**	**1,137**	**7,594**	**-**	**-**
	21	3,745	1,063	3,893	177	122.5
	Transformer 2	**3,889**	**1,113**	**4,046**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are useful for contingency restoration efforts.

Table 5-46 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-46: 2055 Scenario 3 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	3,339	696	3,411	157	123.1
	WR2	1,591	483	1,662	82	120.5
	WR3	2,883	188	2,891	145	123.5
	Substation	7,815	1,376	7,939	-	-

5.6.3 Contingency Configuration Review

Table 5-47 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders.

Table 5-47: 2055 Scenario 3 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	10,795	15,946	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	4,888	15,946	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	3,751	5,973	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	2,222	5,973	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	7,044	9,710	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	2,666	9,710	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	7,594	11,640	14,000	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	4,046	11,640	14,000	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-48 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized.

Table 5-48: 2055 Scenario 3 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	7,940	7,940	10,000	No	No	With both substation transformers rated at 10,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie.

5.6.4 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 3, based on the present age of existing assets (Section 3.1), considering a 30-year period, many of the LACDPU system assets may need to be replaced. Table 5-49 shows the estimated asset replacements over the 30-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 5-49: 2055 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	30
Underground Cable Replacements (miles)	95%	47
Mainline Switches	100%	137
Three-Phase Service Transformers	60%	110
Single-Phase Service Transformers	70%	655
Secondary Services	70%	4,452

Table 5-50 shows the estimated asset replacements over the 30-year period for the White Rock system's 2055 Scenario 3. This scenario required fewer upgrades to improve distribution feeder capacity than the higher scenarios. The quantity of conductor and cable replacements is greater in this scenario as a result.

Table 5-50: 2055 Scenario 3 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	100%	10
Underground Cable Replacements (miles)	90%	8
Mainline Switches	100%	23
Three-Phase Service Transformers	60%	22
Single-Phase Service Transformers	70%	289
Secondary Services	70%	1,829

5.6.5 Financial Impact Summary

Table 5-51 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the system improvement projects needed to serve electrification growth.

Table 5-51: 2055 Scenario 3 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$26.1M	$170.0M	$196.1M
White Rock	$9.8M	$38.2M	$48.0M
Total	$35.9M	$208.2M	$244.1M

5.7 2040 Scenario 3 Electrification Impact

2040 Scenario 3 added 3,895 kVA to the LACDPU system power flow model. Table 5-52 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 5-52: 2040 Scenario 3 Modeled Load

System	Existing System Load kVA	Forecasted Electrification Load kVA	Total Forecasted System Load kVA
Los Alamos Townsite	17,811	2,726	20,537
White Rock	3,905	1,168	5,073
Total	21,716	3,895	25,611

Figure 5-21 shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. In 2055 Scenario 3, two 14 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for this 2040 scenario, two 14 MVA transformers were modeled at the Eastgate Substation, knowing the potential load serving need of the future 2055 scenario. However, only two new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers, given the forecasted load in 2040. Some of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Some of the Townsite Substation load was transferred to Eastgate Substation.

Figure 5-21: 2040 Scenario 3 Los Alamos Townsite System Configuration

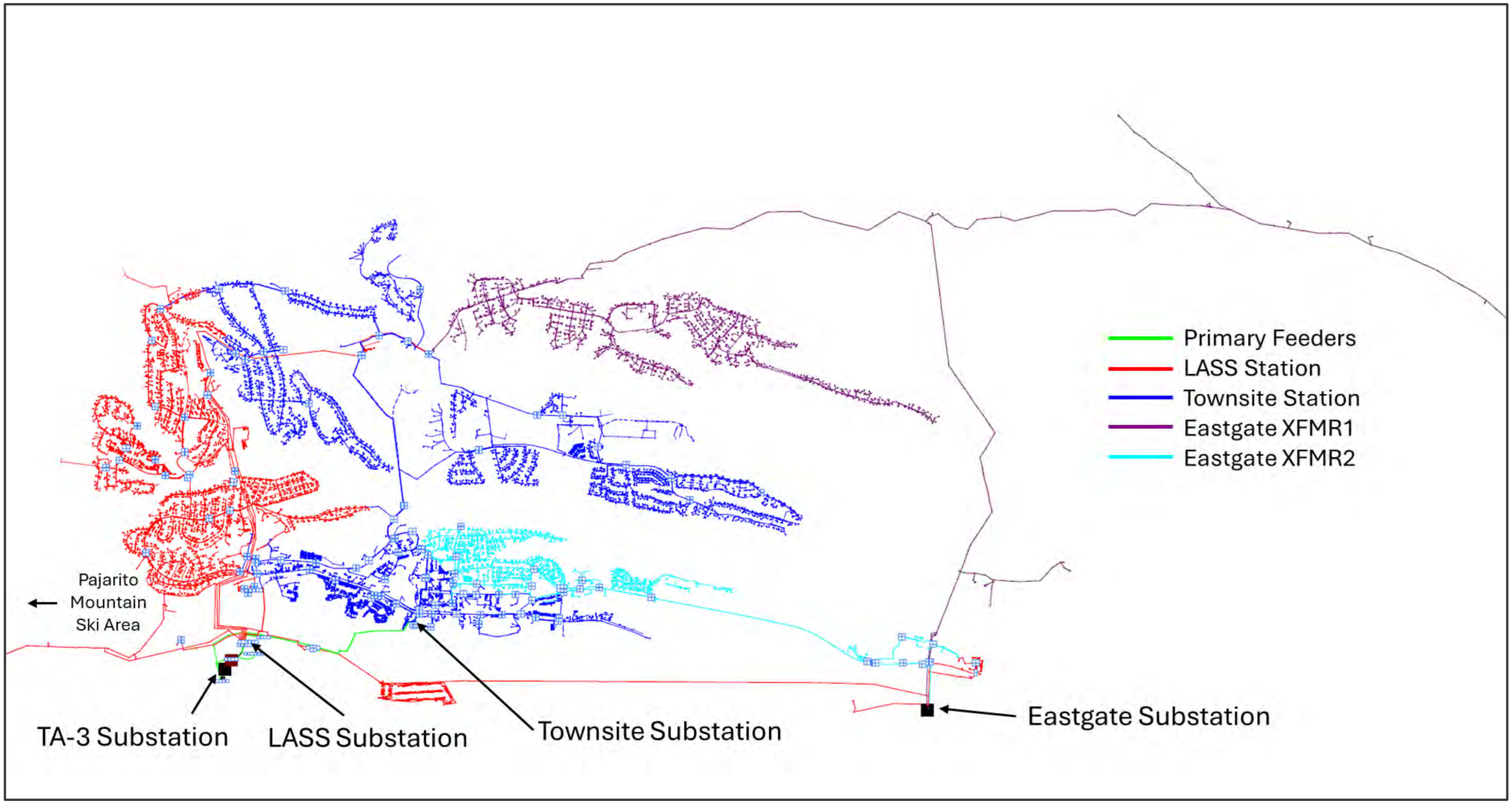
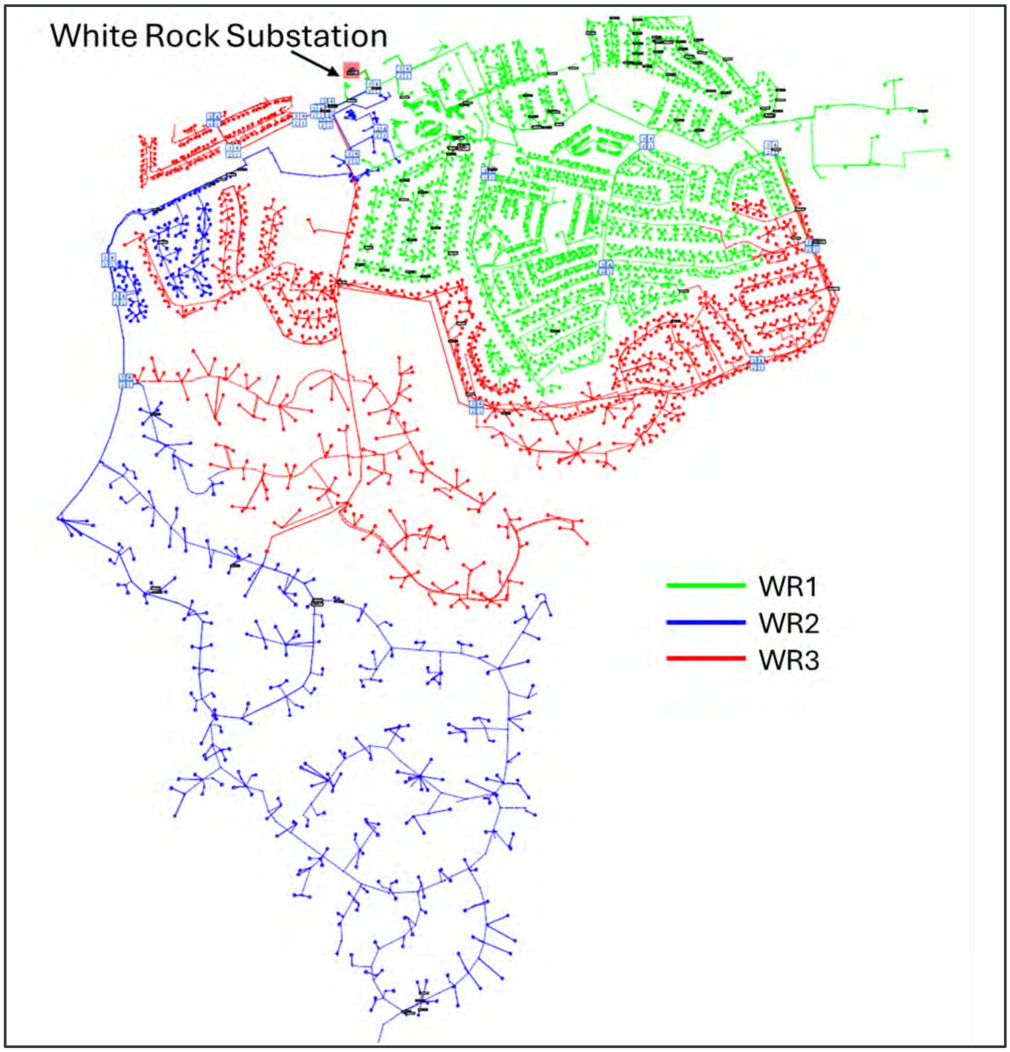


Figure 5-22 shows the proposed configuration for the White Rock system, colored by the distribution feeder. White Rock Transformer 2, with a rating of 7.5 MVA, is sized appropriately to serve the White Rock system load in the 2040 Scenario 3. However, for successful contingency support in this area, White Rock Transformer 1 must be upgraded to 10 MVA. 10 MVA is the appropriate size to serve forecasted load growth in the low scenario through 2055.

Figure 5-22: 2040 Scenario 3 White Rock System Configuration



5.7.1 Conductor and Equipment Buildout

Figure 5-23 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 5-53 shows the quantities of conductor and equipment used in this scenario. No voltage regulators were required in this scenario. One new underground switch was utilized to connect a new distribution feeder into the existing underground portion of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

Figure 5-23: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout

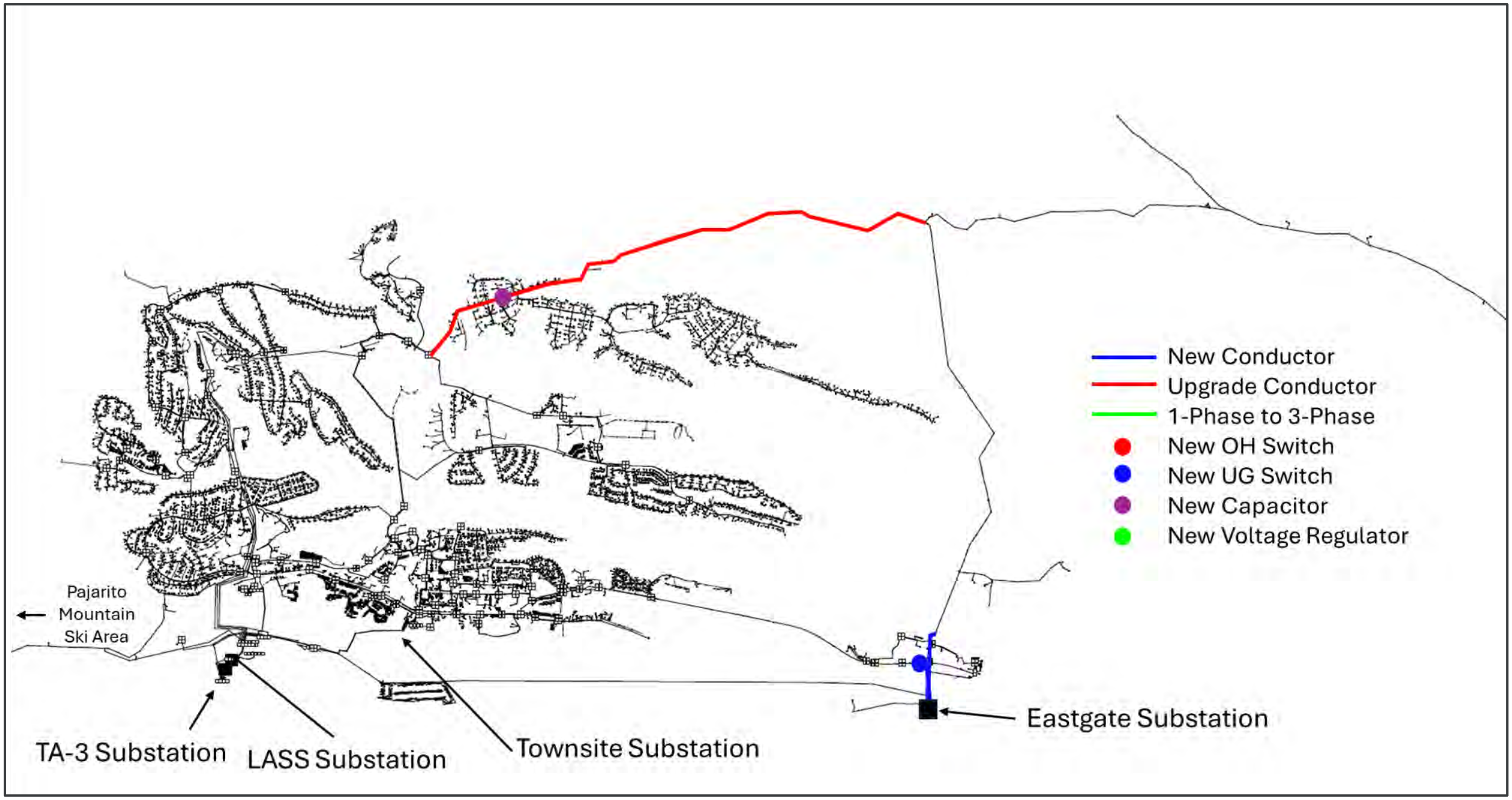


Table 5-53: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	0.8
4/0 CU Cable (miles)	0
477 ACSR Conductor (miles)	3
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	1
OH Switch	0
Capacitor Bank	1
Voltage Regulator	0

Figure 5-24 shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 5-54 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system were not upgraded in this scenario. However, extending the underground mainline created a strong tie point for White Rock Feeder 1 and Feeder 3.

Figure 5-24: 2040 Scenario 3 White Rock System Conductor and Equipment Buildout

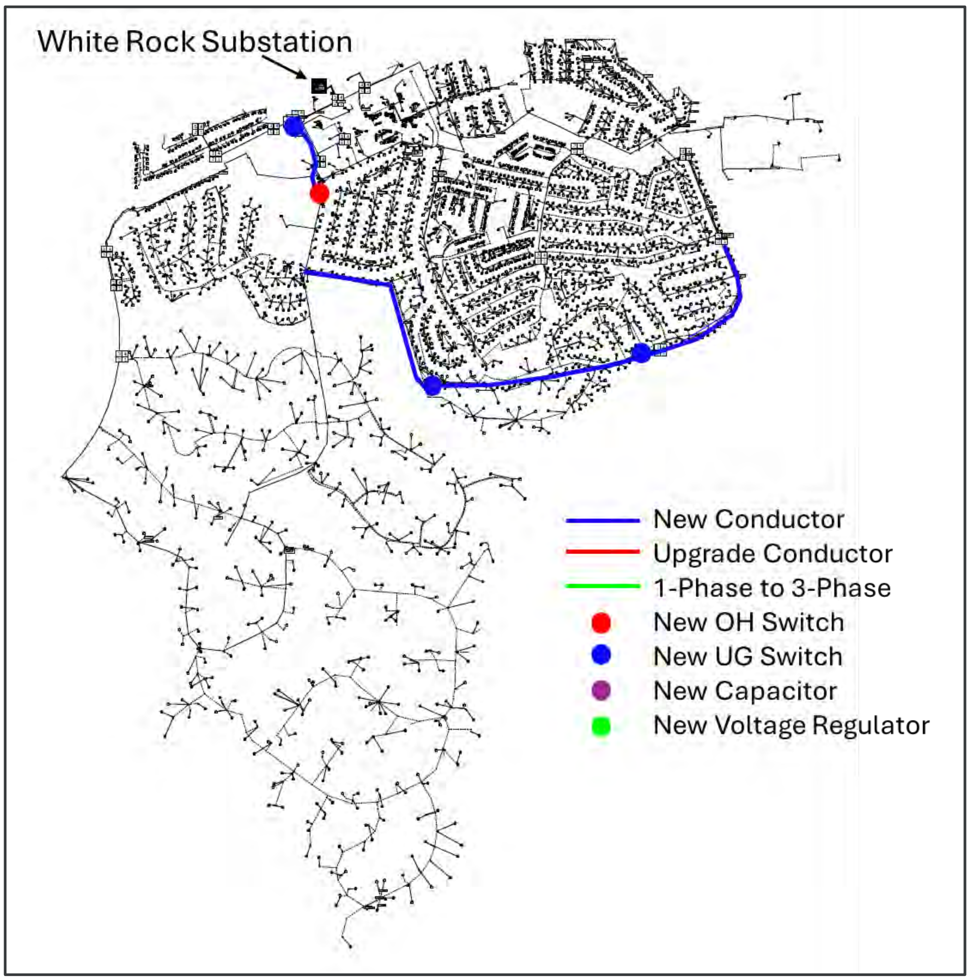


Table 5-54: 2040 Scenario 3 White Rock System Conductor and Equipment Quantities

Conductor/ Equipment	Quantity
500 MCM CU Cable (miles)	1.9
4/0 CU Cable (miles)	0
Installed 477 ACSR Conductor (miles)	0
4/0 ACSR Conductor (miles)	0
UG Switch (PME)	3
OH Switch	1
Capacitor Bank	0
Voltage Regulator	0

5.7.2 Normal Configuration Power Flow Analysis

Table 5-55 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-55: 2040 Scenario 3 Los Alamos System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
Townsite	13	1,380	-297	1,419	75	123.9
	14**	-	-	-	-	-
	15	1,394	288	1,424	72	122.9
	16	1,517	362	1,561	84	121.2
	17	3,067	894	3,195	139	123.9
	18	83	16	84	4	124.0
	Substation	**7,540**	**1,502**	**7,692**	**-**	**-**
LASS	13T	1,971	542	2,045	95	123.7
	NS6	1,560	499	1,638	69	124.6
	15T	1,1,511	324	1,546	92	122.9
	NSM6*	-	-	-	-	-
	16T**	-	-	-	-	-
	NS3	762	238	798	34	124.8
	NS18	543	152	563	29	124.2
	18T	617	141	633	28	123.6
	Substation	**7,044**	**1,933**	**7,314**	**-**	**-**
Eastgate	11	2,808	-328	2,832	129	122.5
	Transformer 1	**2,808**	**-328**	**2,832**	**-**	**-**
	21	2,787	735	2882	131	123.1
	Transformer 2	**2,787**	**735**	**2,882**	**-**	**-**

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration but are useful for contingency restoration efforts.

Table 5-56 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 5-56: 2040 Scenario 3 White Rock System Power Flow Results

Station	Distribution Feeder	kW	kVAR	kVA	Max Amps	Min Voltage
White Rock	WR1	2,178	304	2,199	102	123.6
	WR2	1,035	292	1,076	53	122.0
	WR3	1,883	-154	1,893	94	123.9
	Substation	5,096	442	5,119	-	-

5.7.3 Contingency Configuration Review

Table 5-57 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgears must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders.

Table 5-57: 2040 Scenario 3 Los Alamos Townsite System Contingency Review

Scenario	Customer Load to Restore kVA	Total Applicable Customer Load kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of TA-3 XFMR 1	8,006	14,837	20,000	No	No	Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency.
Loss of TA-3 XFMR 2	6,831	14,837	20,000	No	No	Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency.
Loss of TC1	2,783	7,640	14,100	No	No	Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of TC2	4,857	7,640	16,000	No	No	Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency.
Loss of LC1	5,223	7,197	14,100	No	No	Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency.
Loss of LC2	1,974	7,197	14,100	No	No	Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency.
Loss of Eastgate XFMR 1	2,882	5,714	14,000	No	No	Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer.
Loss of Eastgate XFMR 2	2,832	5,714	14,000	No	No	Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer.

Table 5-58 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained by utilizing feeders 16 and 17 to restore customers through White Rock Transformer 1.

Table 5-58: 2040 Scenario 3 White Rock System Contingency Review

Scenario	Total Applicable Customer Load kVA	Customer Load to Restore kVA	Remaining Applicable Capacity kVA	Loading Violations?	Voltage Violations?	Comments
Loss of XFMR 2	5,210	5,210	10,000	No	No	With White Rock Transformer 1 upgraded to 10,000 kVA and White Rock Transformer 2 already rated at 7,500 kVA, there is sufficient capacity to restore all customers for loss of either transformer.

5.7.4 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 3, based on the present age of existing assets (Section 3.1), considering a 15-year period, many of the LACDPU system assets may need to be replaced. Table 5-59 shows the estimated asset replacements over the 15-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 5-59: 2040 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	30%	7
Underground Cable Replacements (miles)	65%	32
Mainline Switches	90%	123
Three-Phase Service Transformers	25%	46
Single-Phase Service Transformers	35%	327
Secondary Services	30%	1,908

Table 5-60 shows the estimated asset replacements over the 30-year period for the White Rock system's 2040 Scenario 3. This scenario required fewer upgrades to improve distribution feeder capacity than the higher scenarios. The quantity of conductor and cable replacements is greater in this scenario as a result.

Table 5-60: 2040 Scenario 3 White Rock System Asset Replacement Estimate

Conductor/ Equipment	% of Assets Replaced	Quantity
Overhead Conductor Replacements (miles)	95%	10
Underground Cable Replacements (miles)	50%	4
Mainline Switches	70%	16
Three-Phase Service Transformers	40%	14
Single-Phase Service Transformers	50%	207
Secondary Services	40%	1,045

5.7.5 Financial Impact Summary

Table 5-61 shows the estimated cost in millions of dollars for performing all system improvements and replacing aging infrastructure. Asset replacement is anticipated to require significantly more funds than the system improvement projects needed to serve electrification growth.

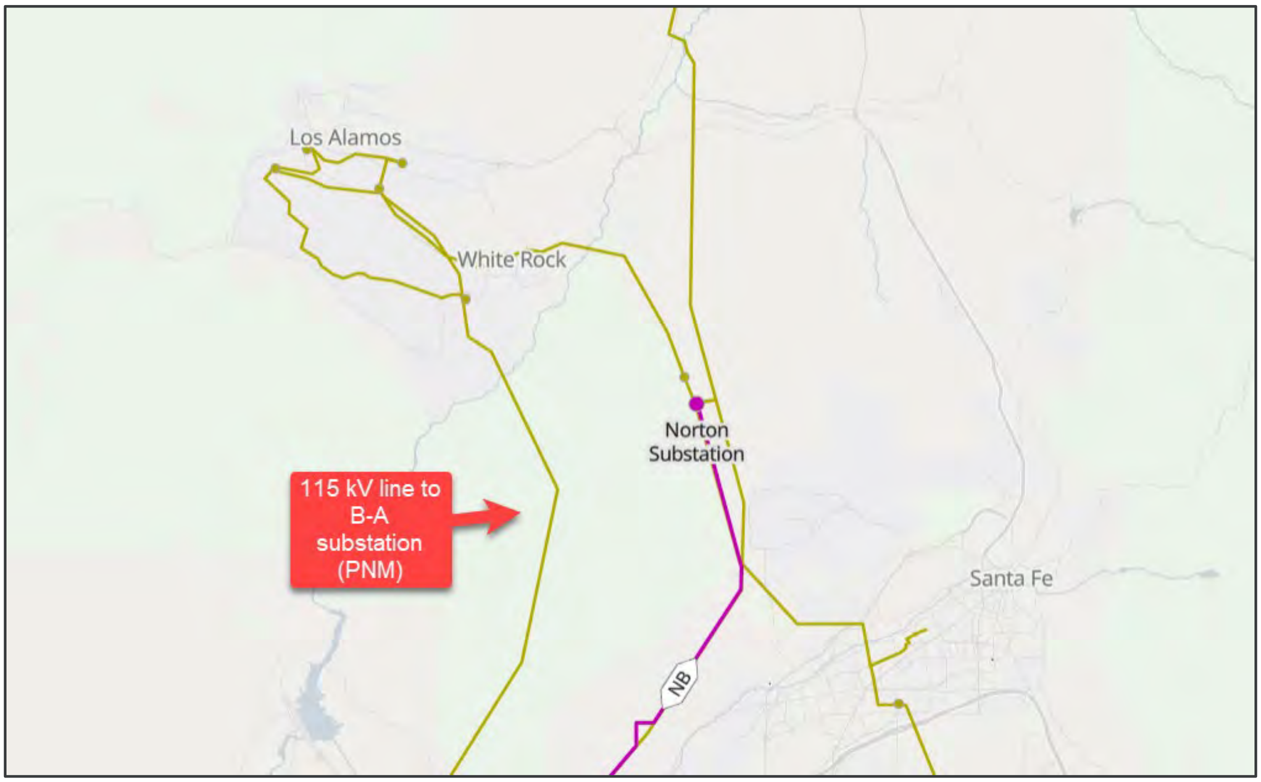
Table 5-61: 2040 Scenario 3 Financial Impact

System	System Improvement Costs	Asset Replacement Costs	Total Financial Impact
Los Alamos Townsite	$20.4M	$100.9M	$121.3M
White Rock	$7.2M	$24.4M	$31.6M
Total	$27.6M	$125.3M	$152.9M

6.0 Transmission Source Requirements

Los Alamos County including the Los Alamos National Laboratory (LANL) receives its electricity from the Public Service Company of New Mexico (PNM) transmission system, which serves much of the state of New Mexico[28]. This system uses a network of transmission lines and substations to deliver power from various generation sources to Los Alamos County and LANL. Power generation occurs where it's most efficient and cost-effective, often hundreds of miles from consumers. The County and LANL's power needs are met by regionally produced energy; the only constraint is transmission capacity. Two transmission lines, the B-A and Norton Lines, serve Los Alamos County[29]. Additionally, the county has a 1 MW solar facility, and LANL operates a 20-27 MW combustion gas turbine generator.

Figure 6-1: Transmission system of Los Alamos County[30]



[28] Powering Los Alamos National Laboratory - https://www.energy.gov/sites/default/files/2024-09/LANL%20EPCU%20Factsheet_final.pdf

[29] Los Alamos National Laboratory Electrical Power Capacity Upgrade Project - https://www.energy.gov/sites/default/files/2023-11/draft-ea-2199-epcu-project-2023-11_0.pdf

[30] Open infrastructure maps - https://openinframap.org/#12.96/35.8387/-106.26342

The existing configuration of TA3 and White rock substations are fed from 115kV lines from PNM. White Rock substations are fed from PNM's Norton substation and TA3 substation is fed from PNM's B-A substation. There is a high dependency on the PNM transmission system as demonstrated from an outage that occurred in October of 2024. The four-hour outage affected White Rock and LANL due to issues with the Norton transmission line. The outage was resolved after PNM re-energized the line.

The 115kV Transmission line from Norton substation to White Rock is constructed with 397.5MCM ACSR conductor that is typically rated to carry between 100 to 130 MVA of power. The 115kV Transmission line from B-A substation to LANL's STA substation consists of primarily ACSR conductor which is also typically rated to carry between 100 to 130 MVA of power.

As outlined in Table 5-1, Scenario 1 projects the 2040 total forecasted LACDPU system load to be around 43.4 MVA which is roughly double the existing system load. Similarly, the 2055 total forecasted LACDPU system load is estimated to be 67.6 MVA which is roughly triple the existing system load. While the new Eastgate Substation will improve the reliability of the distribution system and provide options for redirecting the power, the transmission system will not benefit from the Eastgate substation as it will still depend on the power delivered from PNM transmission lines.

This electrification study did not include transmission power flow analysis needed to study specific impacts and requirements of the transmission system. However, the increased electrification load forecasted in this study indicates that an additional transmission line into Los Alamos County may be needed. An additional transmission line will improve reliability, especially during an outage on one of the existing lines.

Due to the lack of power flow information with regards to the existing PNM transmission lines, it is not prudent to comment on the measured impacts on the transmission system due to additional LACDPU forecasted electrification load. Due to this reason, in this study 1898 & Co. qualitatively believes that an additional transmission line into the LACDPU may be required.

6.1 Reconductoring Transmission Lines

While an additional transmission source into the Los Alamos County would be the preferred solution to improve reliability, an alternative solution would also be to reconductor one or both 115kV transmission lines from PNM's Norton and B-A substations. While reconductoring one of the lines will improve the system under normal conditions, the loss of the reconductored line would result in all the power flow to Los Alamos being redirected to the other line. Therefore, it would be important to reconductor both 115kV transmission lines to support the projected load growth in the LACDPU area.

7.0 Finance and Regulations

The electrification of Los Alamos will generate significant increases in additional sales and revenues for the electric utility. The increased levels of load will also require increased levels of infrastructure investment in order to serve electrified homes, businesses, and vehicles. Many of the technology additions and their respective loads included in this study's forecast anticipate that future innovative rates, utility programs, and policies are put into place that will efficiently help move the utility system towards electrification. The scope of this section is to provide a general strategy for funding future infrastructure investments and to provide guidance on changes that Los Alamos should consider regarding its existing rates, policies, and regulations.

7.1 Load Estimates and Revenue Projections

1898 & Co. anticipate large levels of incremental revenue resulting from the electrification of the community. Energy sales forecasts were prepared using high, medium, and low load electrification forecasts. For example, using estimates from the "large" load in Scenario 1, 1898 & Co. estimates an additional 117,000,000 kWh per year of additional load and $17M per year (2025$) of additional revenue would be generated due to electrification in 2055. This increased revenue would increase gradually over the forecast period. This revenue would be used to not only pay for the increased future power supply costs but also the increased capital investment in the distribution system over time. The estimated level of incremental revenues, power cost, and operating margins available to support distribution system investment by year are provided in the figures below for the three scenarios. All values presented are in 2025 dollars.

Figure 7-1: Scenario 1 High Growth Electrification Incremental Operating Margins

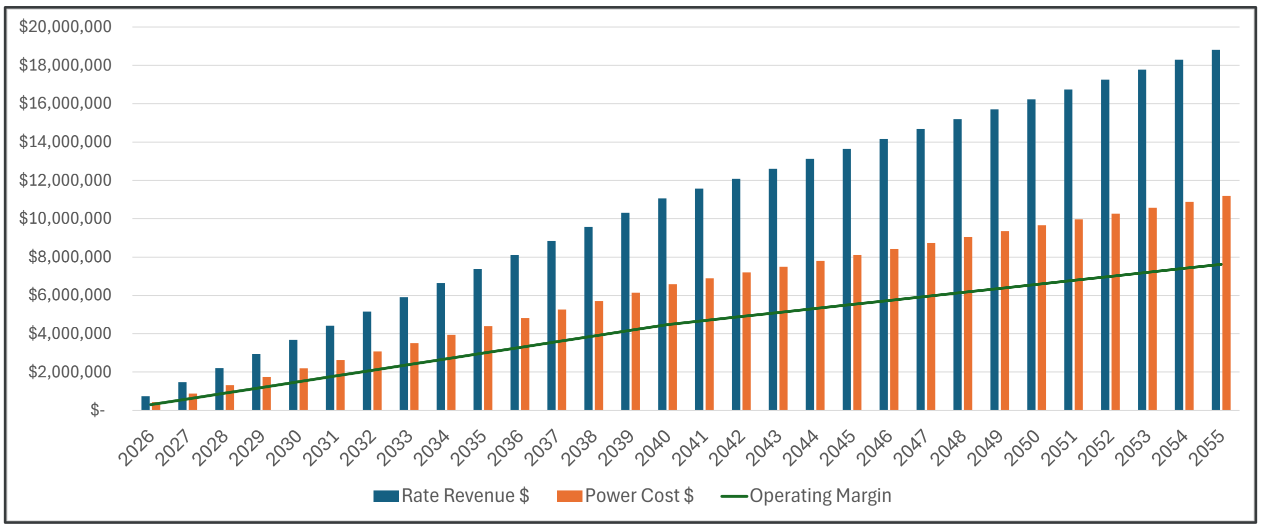


Figure 7-2: Scenario 2 Medium Growth Electrification Incremental Operating Margins

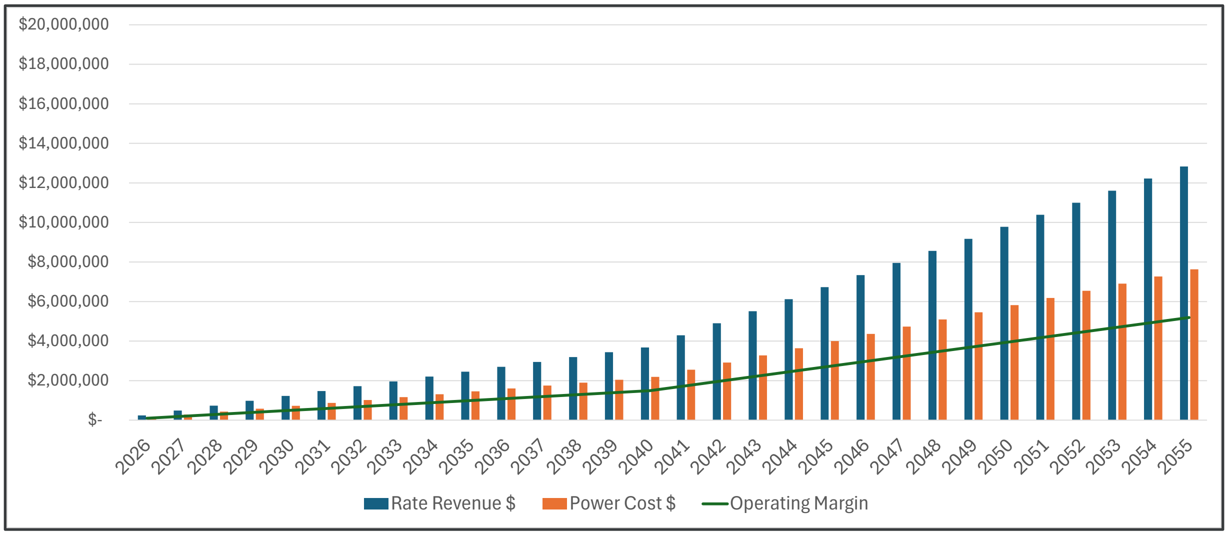
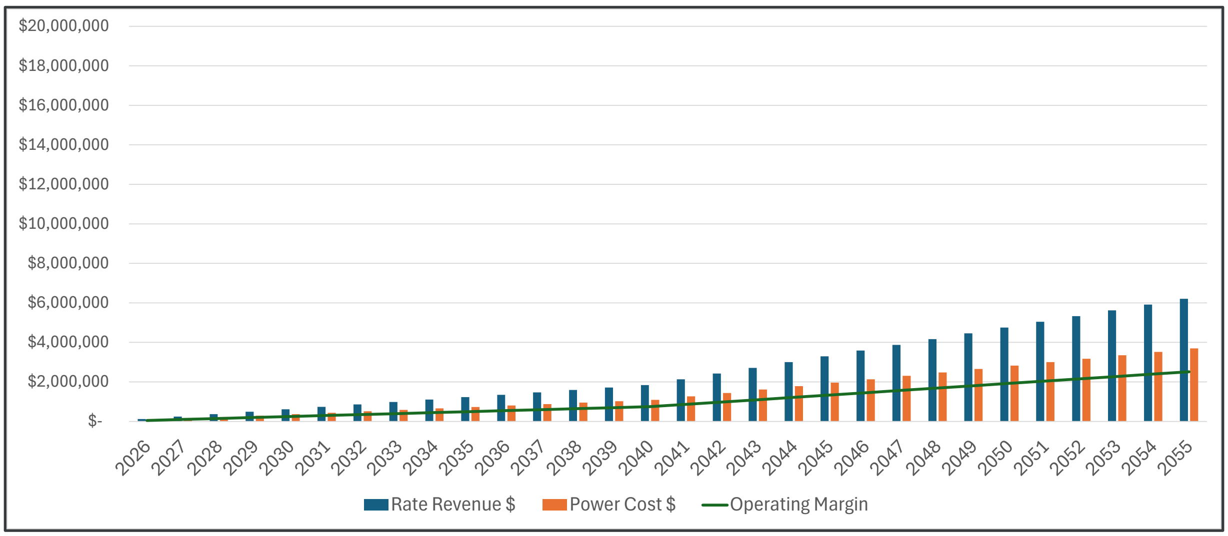


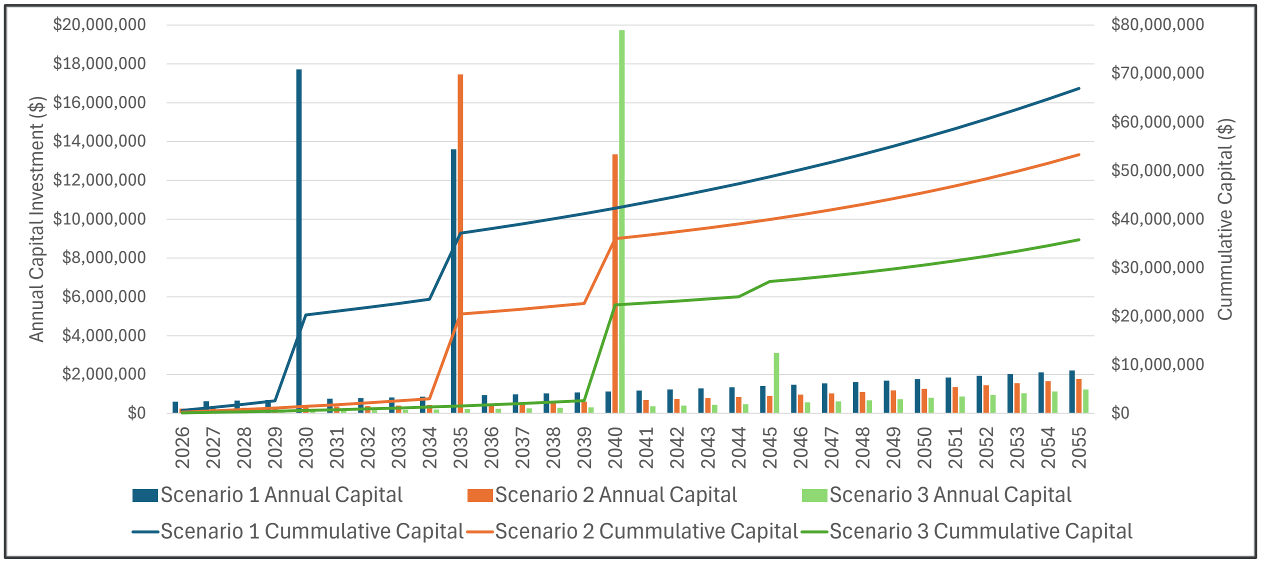
Figure 7-3: Scenario 3 Low Growth Electrification Incremental Operating Margins



7.2 Capital Investment Plan

Based on the projections prepared within this study, the utility will need to make upgrades to its system to support the anticipated levels of load growth from electrification. Scenarios were prepared using high (Scenario 1), medium (Scenario 2), and low (Scenario 3) load forecasts. These projects will include large one-time capital investments such as substations and various circuit upgrade projects over time. The level of capital will need to be planned carefully and will be implemented over time as system load increases. The level of incremental capital investment to support the growth of the utility will need to be refined over time; however, 1898 & Co. anticipates a multi-year phased plan for upgrades. Based on the electrical system analysis, 1898 & Co. anticipates that multiple upgrade projects will be required between 2025 and 2055 to support electrification. The figure below provides a rough order of magnitude of capital investment by year and cumulative capital investment (2025$).

Figure 7-4: Annual and Cumulative Capital Investment due to Electrification Load



7.3 Capital Funding Strategies

It is anticipated that the utility will be able to fund the incremental capital associated with system electrification with a combination of cash generated from rate revenues and new bonds. Scenarios were prepared using high, medium, and low load electrification forecasts. For the purposes of this analysis, the routine system circuit upgrade projects identified are assumed to funded with operating margins from increased electric sales while large new projects, such as new substations, would be funded by long term municipal debt over 30 years at 4.5 percent. The incremental financial projections included the funds from debt along with the incremental debt service on future projects as presented in the following section.

7.4 Financial Forecast Projections

LACDPU will be able to fund most of the investments needed to support electrification with incremental electric rate revenues. The utility will need to purchase incremental power supply to support load growth which is beyond the scope of this section of the report. This analysis assumes that LACDPU will be able to continue to secure power at a cost similar to its current level in 2025$ and that the incremental operating margins generated from electric sales will be available for funding incremental electrical system investments and future debt service on bonds. A projection of the incremental operating margins, normal capital, and incremental debt service from future bonds is provided in the following figures. Based on the projected level of incremental operating margins, capital investment timing, and debt issuance assumptions, the LACDPU should be able to fund electrification system expansion capital from increased electric rate revenues in the high load growth (Scenario 1) and medium load growth (Scenario 2) scenarios over the forecast period. The low load growth (Scenario 3) will be much more challenging to fund with growth-related capital due to the large substation cost required in 2040 to support this new load. Based on the analysis performed, it may be in the interest of the LACDPU to defer the construction of an additional substation if electrification growth is much lower than anticipated instead of implementing large rate increases to cover the increased substation project debt service.

Figure 7-5: Scenario 1 High Growth Electrification Incremental Cash Flow Analysis

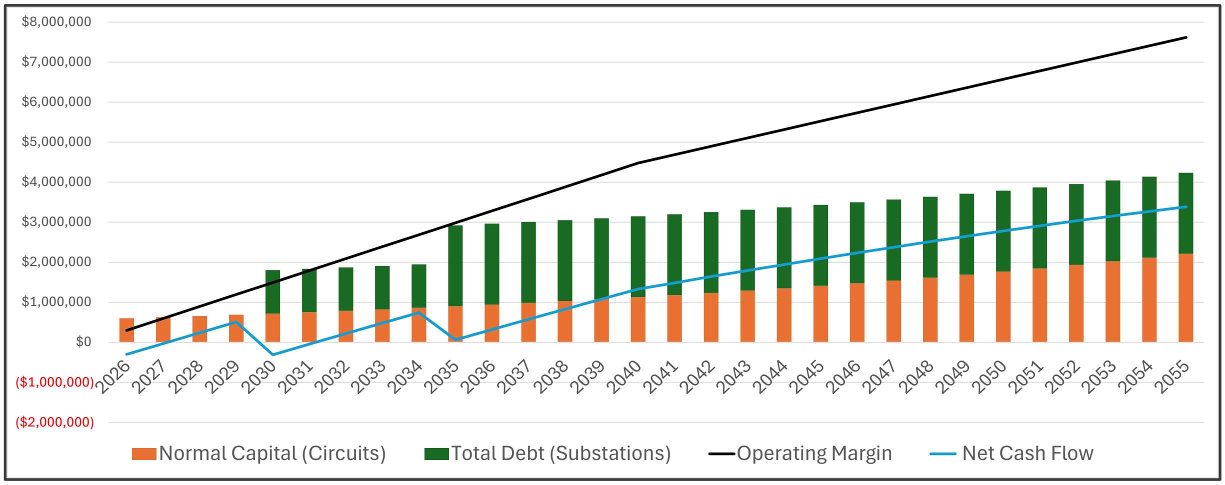


Figure 7-6: Scenario 2 Medium Growth Electrification Incremental Cash Flow Analysis

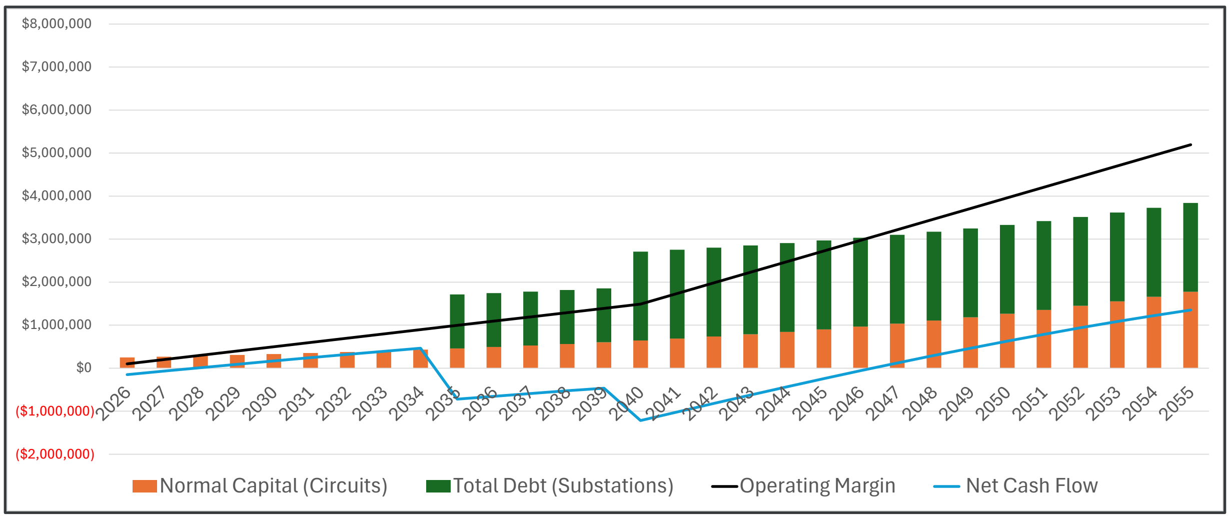
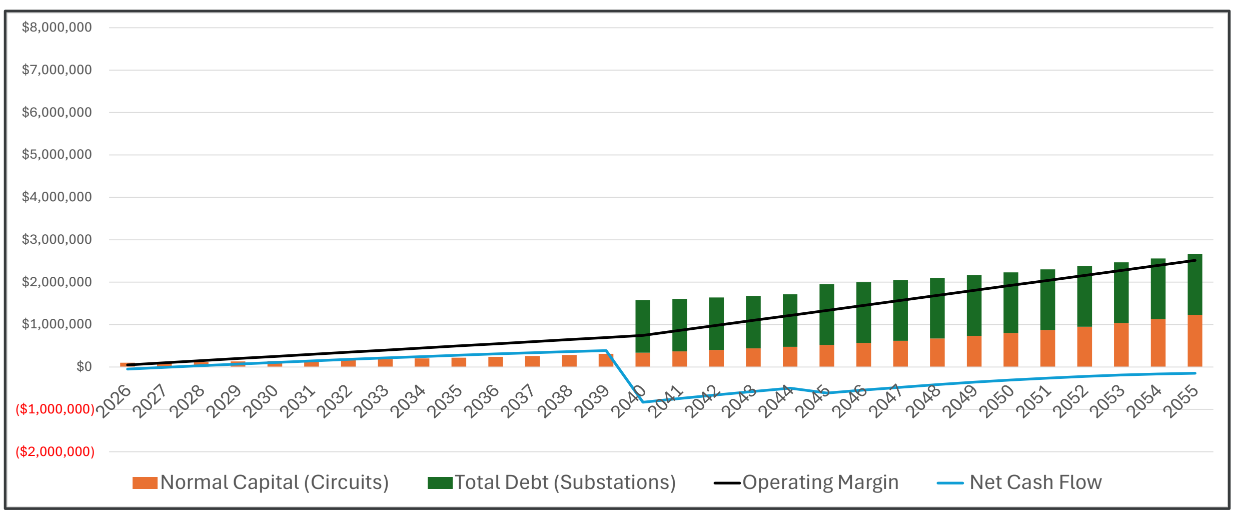


Figure 7-7: Scenario 3 Low Growth Electrification Incremental Cash Flow Analysis



7.5 Customer Programs and Policies

The LACDPU will need to make various changes and additions to its customer programs, rate offerings, and service offerings to support the electrification goals in an efficient manner. The electrification load projections anticipate that several of the programs listed below are adopted while others may need to be implemented for large levels of electrification to take hold within the community.

7.5.1 Line Extension Policy and Customer Adoption

Since electrification provides greater revenues and operating margins, utilities will typically charge lower customer connection fees or will alternatively provide a connection fee revenue credit. LACDPU currently has a $1,400 connection fee charged to customers when they connect to the system. Connection fees are quite common and are established based on an estimated level of energy sales (i.e. 10,000 kWh/year) and net revenues to be earned over time against the cost to install the service drop, transformer, meter, and supporting system infrastructure. However, if a customer's energy use increases by 5,000 kWh per year due to the addition of off-peak electric heating and off-peak EV charging the utility will earn an estimated incremental net revenue of $100 per year ($0.14/kWh - $0.12/kWh power supply x 5000 kWh/year). This increase would justify the utility providing a connection fee revenue credit for higher electric use customers assuming distribution upgrades are not immediately required. In this example the utility has now overcharged the original customer for the connection fee and should provide a revenue credit for the net margins gained due to the higher level of energy use. PNM, the regional investor-owned utility, includes revenue credit provisions in their residential customer line extension policy for customers with various types of appliances and heating systems to avoid over collecting fees from higher use electric customers. PNM customers that install electric heat will receive between $500 and $1500 more in revenue credits when compared to a gas heat customer depending on the size of the home's conditioned square footage. The increased net revenue is also considered when PNM derives its rebates for EV chargers and efficient electric heating.

7.5.2 Electric Vehicle Charging Revenue Credit Programs

Customers who purchase electric vehicles and primarily charge them at home will see a significant increase in their annual electricity usage. This higher consumption leads to increased net revenue for the utility. To encourage this behavior, many electric utilities offer upfront rebates or credits to incentivize the installation of home EV chargers. The customer credits or rebates are set at a level that is less than the net revenues received such that the utility's benefits are greater than the cost incurred to pay the rebate. This is widely implemented by cooperatives, investor-owned utilities, and municipal utilities.

7.5.3 Electric Heating Equipment Revenue Credit Programs

Switching from gas to electric heating increases a customer's annual electricity usage, which in turn leads to higher net revenues for the utility. To equitably support this transition, utilities often offer upfront rebates or credits, that help to offset the cost of new electric heating systems. The electrification scenarios assume a high-level adoption of electric heating which means that a payment to the customer can be reasonably justified. The LACDPU should consider implementing a credit for high efficiency heating equipment that is less than the incremental net revenues received. The benefits of increased net revenues will be greater than the net cost of providing the credit to the customer.

7.5.4 Electric Hot Water Equipment Revenue Credit Programs

Switching from gas to electric water heaters increases a customer's annual electricity usage, which in turn leads to higher net revenues for the utility. To equitably support this transition, utilities often offer upfront rebates or credits to offset the cost of new electric water heating systems. The electrification scenarios assume a high-level adoption of electric heating which means that a payment to the customer can be reasonably justified. The LACDPU should consider implementing a credit for high efficiency heating equipment that is less than the incremental net revenues received. The benefits of increased net revenues will be greater than the cost of providing the credit to the customer.

7.5.5 Electric Vehicle Rates and Load Control Program

A key assumption in the electrification scenarios is that EV charging will be managed to minimize its impact on system peak demand in Los Alamos. For electric utilities, generation capacity and transmission costs are largely driven by peak system demand. Distribution system upgrade requirements will also be closely tied to peak demand. If EV charging is not managed, either through time-of-use (TOU) rates or a load control program, a significant portion of charging is likely to occur during peak hours. This unmanaged load could substantially increase the system peak, leading to infrastructure upgrades and higher power costs, which would ultimately impact the rates of all customers.

EV TOU rates are designed specifically for EV charging and typically require the installation of a second meter dedicated to the EV charger. These rates are structured to reflect the varying cost of electricity throughout the day where charging during peak demand periods incurs higher rates, while off-peak and low demand periods offer lower rates. Many electric utilities implement either a two-tier TOU structure, or a three-tier structure that includes on-peak, off-peak, and super off-peak periods. These pricing models encourage EV owners to shift charging to times when electricity is less expensive and unlikely to affect the system peak, helping reduce strain on the grid and lower overall system costs. The current residential TOU rate proposed to come into effect no earlier than July of 2026, if designed properly, should be able provide similar results as a EV specific TOU rate.

EV direct load control programs are a common form of demand response, often referred to as residential EV managed charging. These programs involve the installation of a smart EV charger or require access to vehicle telematics. The vehicle charging can be remotely managed by the electric utility or a Distributed Energy Resource Management System (DERMS) provider via Wi-Fi. For managed charging systems that use vehicle telematics the customer can opt in to the program and set their driving schedule in the app. The system can then optimize the vehicle charging. Furthermore, with both smart charger and vehicle telematics systems the utility can call an event that stops EV charging to shed load when peak demands are high on the electric system. To encourage participation, utilities typically offer customers an upfront rebate for purchasing the compatible charger or provide an annual incentive for allowing their charger to be controlled during peak demand periods. These programs help utilities manage grid load more effectively while offering customers financial benefits in return. These load management programs are typically evaluated in combination with the changes to net revenues, power costs, utility costs, and utility incentives to ensure that the net benefits to participating and non-participating customers are positive.

7.5.6 Electric Heating Rates and Load Control Program

The electrification scenarios also assume TOU rates and some form of direct load control for electric heating is implemented to help reduce system peak demand as electricity use increases. Keeping peak demands lower will keep distribution infrastructure upgrade requirements lower which will in turn help keep purchased power costs lower. The newly proposed TOU rate, which includes a demand rate component, can help support peak demand management. Utility customers will have a direct incentive to manage their peak load due to electric heating if the TOU rate includes winter peak periods in the morning and evening.

Electric heating demand response programs can be implemented through either (1) a direct load control of the heating system or (2) by managing a smart thermostat. A residential electric heating direct load control program typically involves installing a load control device, most commonly a switch, between the electric heating system and the power source. This device allows the utility or a DERMS provider to remotely turn off or cycle the heating system during peak demand events. To encourage participation, utilities generally offer customers an annual bill credit and the utility will often pay for the switch.

Alternatively, utilities can manage electric heating by controlling a smart thermostat. In this approach, the utility or DERMS provider remotely adjusts the thermostat setting via a Wi-Fi connection during peak periods. This usually involves increasing or decreasing the temperature on the thermostat by three to four degrees, depending on the targeted peak, a few times a year. Customers who participate typically receive an annual bill credit as compensation and/or the utility will pay for the thermostat.

7.5.7 Electric Water Heating Rates and Load Control Program

The electrification scenarios also assume the implementation of direct load control for electric water heating to help reduce system peak demand. This program typically involves installing a load control device, most commonly a switch, between the electric water heater and its power source. This device allows the utility or a DERMS provider to remotely turn off or cycle the water heater during peak demand events. To encourage participation, utilities generally offer customers an annual bill credit and the utility will often pay for the load control switch.

7.5.8 Solar Net Energy Metering and Rates Policy

The current solar net energy metering policy credits customers for excess energy sent back to the LACDPU at the total blended wholesale cost of energy and capacity, currently around $0.070 / kWh, for any net excess energy produced during a month. While a more detailed analysis is needed, Los Alamos appears to be overcompensating customers for solar energy. This is because the Residential revenue lost at $0.14/kWh is much greater than LACDPU’s actual wholesale power supply energy cost reduction which can range from $0.025/kWh to $0.045/kWh depending on the time of day and season. Solar provides very little accredited capacity and therefore provides nearly zero power supply capacity cost reduction or distribution system cost reduction. In some cases, distributed solar PV generation causes distribution system upgrades. As solar adoption continues to grow across New Mexico, the total magnitude of overcompensation under the current policy is expected to increase without changes to LACDPU’s rate policy. With LACDPU’s new rate design incorporating TOU energy rates and a non-coincident peak demand rate, there is a very good opportunity to evolve this policy over time to one where the LACDPU can compensate customers with solar equitably while recovering revenues necessary to maintain its system and mitigating the impacts to customers who don’t install solar.

Once the demand rate is in place, the LACDPU should slowly increase the amount that is recovered through the demand charge to maintain revenues sufficient for maintaining the electric utility. The TOU energy portion will need to evolve such that the energy charges will recover the cost of power supply based on DPU’s hourly energy cost. In addition, to adjusting its rate design, the LACDPU should also revisit limits on the size of the solar systems that are allowed to be installed on a site such that generation is no greater than the last 12 months of the customer’s energy use.

7.5.9 Battery Energy Storage and Rates Policy

Currently, battery energy storage systems (BESS) are not permitted to discharge onto the LACDPU system; however, customers are allowed to install a BESS at their property and charge the BESS with excess solar production for later use during evening hours. While this is a reasonable and safe approach, we recommend LACDPU consider revisiting this policy and treat BESS like solar PV, as BESS can offer significant benefits to the electric utility, especially considering potential electrification growth. BESS benefits include supporting solar PV integration, reducing peak demand, providing ancillary services, and complementing future time-based or demand-based rate structures.

Solar energy production peaks during midday when sunlight is abundant, but this often does not align with the system peak demand, which typically occurs in the evening or early mornings. Pairing solar with battery storage allows excess solar energy to be stored and discharged later during peak periods, when electricity is most needed.

Like EV load control programs, utilities can implement BESS load control programs, enabling the utility or a DERMS provider to discharge customer batteries during peak demand or periods of high energy costs. In return, utilities typically offer customers either an upfront rebate for the battery purchase or an annual incentive for participation. In some cases, a BESS-controlled discharge may result in some level of net export to the system if not limited by control systems.

Residential batteries can also enhance grid reliability by providing ancillary services such as balancing supply and demand, maintaining voltage and frequency stability, and improving overall power quality. However, further evaluation of integrating batteries on the LACDPU distribution system is required to better understand the specific challenges and benefits of using residential BESS.

If residential rates evolve to include time-of-use or demand-based components, customers may find additional value in installing a battery. Under time-based rates, customers can perform energy arbitrage by charging the battery when electricity is inexpensive and discharging it when prices are high. With demand-based rates, batteries can help reduce a customer’s peak demand, lowering their bill while also reducing the utility’s generation, transmission, and distribution costs. The current policies of LACDPU would only allow the customer to see benefits from having a BESS by being able to reduce demand and on-peak energy charge if the customer is on the new proposed residential TOU rate.

7.6 Alternative Funding Opportunities

7.6.1 State Grants and Loans

Currently, there are no state grants or loan programs available to support electrification build-out efforts. However, Los Alamos should continue to monitor evolving state policies for future funding opportunities. While not directly tied to electric utilities, programs such as LIHEAP, the Energy Smart Weatherization Program, and the PNM Good Neighbor Fund may offer financial assistance to low-income customers seeking to electrify their homes.

7.6.2 Federal Grants and Loans

The Grid Resilience and Innovation Partnerships (GRIP) Program is funded by the Infrastructure Investment and Jobs Act (IIJA) with a total of $10.5 billion allocated to modernize and strengthen the electric grid. As of now, $7.6 billion has already been awarded. The LACDPU should evaluate the GRIP program and determine if the program may be suitable for the DPU to pursue. All funding from the GRIP Program is planned to be awarded by the end of 2026. There may be potential for additional rounds of funding in the future.

Potential Federal loans under the Energy Infrastructure Reinvestment (EIR) Program. The loans from the EIR Program are designed as loan guarantees for projects that reinvest in or repurpose existing energy infrastructure, reduce greenhouse gas emissions, or improve grid reliability and resilience. These loans are typically cheaper than commercial financing, which those savings can then be passed on to Los Alamos electric customers.

7.6.3 Customer Funded Grid Infrastructure

Except for residential service installations and net metering applications and inspections, all other electric service installations required to serve new load are based on the cost of the equipment necessary to provide that service. This approach aligns with standard practices across the electric utility industry. The LACDPU should continue following this policy while regularly reviewing its alignment with the line extension policies and rate design justifications to ensure there is no double counting and that the policy remains fair and equitable for all stakeholders.

7.6.4 Utility Alternative Clean Energy Funding Sources

Historically, LACDPU could not take direct advantage of various renewable tax investment credits or production tax credits that are available only to taxable entities. Under the Inflation Reduction Act (IRA), Los Alamos businesses, residents, and the LACDPU may now be eligible to receive direct payment of an Investment Tax Credit (ITC) for renewable energy resource projects such as wind, solar, and energy storage projects. The ITC provides a 30 percent tax credit upon completion of the project, based on the total project cost that is eligible. The ITC can be increased by an additional 10 percent if at least 40 percent of the system's manufactured components are produced in the United States, and if 100 percent of the steel and iron used are domestically sourced. Under the passing of the One Big Beautiful Bill Act on July 4, 2025, construction on wind and solar must begin before July 4, 2026, and placed in service by December 31, 2027, to qualify. Energy storage ITC is not affected by this bill.

7.6.5 Customer Alternative Clean Energy Funding Sources

Prior to July 4, 2025 the federal tax code provided tax credits and incentives for clean energy investments to homes. Under the One Big Beautiful Bill Act signed into law on July 4, 2025, the Energy Efficient Home Improvement Credit and Residential Clean Energy Property Credit will expire for systems installed after December 31, 2025.

8.0 LACDPU Staffing Requirements

The Los Alamos Department of Public Utilities (LACDPU) is at a critical inflection point. This study forecasts unprecedented growth, driven by the electrification of the county's transportation and building sectors. The most aggressive scenario projects a threefold increase in system load by 2055.

This level of growth and technical evolution presents a challenge to the existing organizational structure. Successfully managing this transition requires not just investment in physical infrastructure but a strategic investment in people, processes, and organizational design.

An analysis of the department's current "Experience and Operations" reveals a highly capable, technically proficient, and lean team. However, this team's structure, where a small group of engineers manage the full spectrum of responsibilities from long-range planning to the direct daily supervision of field crews, is not scalable to meet the coming challenge.

This report outlines a high-level strategic transition plan to evolve the Electric Distribution Department from its current state into a future-state organization designed for scalability, efficiency, and resilience. The core recommendation is to restructure the department into three distinct, functionally aligned groups:

- **Engineering & Planning**
- **Project Management Office (PMO)**
- **Operations**

This evolution will be supported by a multi-phase transition plan and a series of recommended follow-up analyses to ensure success. Adopting this structure will enable LACDPU to successfully deliver on its critical mission to provide safe, reliable power to the community through this period of transformation.

8.1 Current State Analysis: A Capable but Overextended Team

The current Electric Distribution Department operates as a highly effective and tightly integrated unit characterized by a generalist approach. Key personnel hold a wide array of responsibilities.

8.1.1 Key Current State Observations

Staffing and Structure: The department is anchored by a core team of five engineering personnel who oversee a twelve-person operations team that is comprised of three supervisors, seven linemen, and two engineers' associates. This flat structure has fostered deep system knowledge within the engineering team, which is directly involved in nearly every aspect of the utility's functioning.

Division of Responsibilities: There is significant overlap between strategic and tactical duties. The engineering team's responsibilities include not only traditional design and analysis but also direct operational control. Duties include:

- Direct supervision of the electric distribution department and responsibility to develop work schedules for the line crews.
- Direct all aspects of Electric Utility Projects, including development of the project plan, design drawings, budget, schedule, execution, and closeout.
- The team must manage the ongoing procurement requirements to sustain operations, capital projects and system maintenance while working with supervisors to define ready stock requirements and maintain stock levels.

8.1.2 Inherent Risks

This lean model is agile and has clearly been successful in managing a complex system to date. However, it presents fundamental risks when faced with exponential growth:

- This generalist model cannot effectively scale to manage a utility that serves the electrification demand forecast.
- Critical system knowledge and project oversight are concentrated in a few individuals. The departure of even one key person could create a significant operational gap.
- The constant pressure of daily operational issues, such as outage response and customer complaints, inevitably distracts from the long-range strategic planning required for the system's transformation.

While this structure has clearly been effective in the past, it concentrates an immense amount of responsibility onto a few key individuals. This creates significant risk and will become a bottleneck when faced with a potential increase in system load and the associated increase in capital improvements.

8.2 Recommended Future State: A Scalable, Functionally Aligned Organization

To successfully prepare for the future, the department must transform into a more specialized organization with greater depth. The core of the new organization is the separation of duties into three primary departments, which are functionally aligned, a structure common among larger peer utilities.

1. **Engineering & Planning:** This department will become fully dedicated to long-term planning and system design. It sheds all direct supervision of field crews and daily project execution. Its sole focus is on high-level engineering tasks such as performing the ongoing power flow and contingency analyses; maintaining and updating models; developing and enforcing material and construction standards; and creating the master plans for system upgrades.
2. **Project Management Office (PMO):** The PMO is a department responsible for project execution. Taking the designs from the Engineering department, the PMO manages all capital projects through their lifecycle. This includes managing budgets and schedules, overseeing contractors, handling required procurement, and serving as the primary coordinator between engineering, operations, contractors, and other stakeholders. This proposed PMO could span across all the utility functions at LACDPU (water, gas, and electric) but would require additional analysis since the scope of this project was focused on the electric department.
3. **Operations:** This department owns the "grid in the field." This group is responsible for the safe and efficient execution of all physical work. This includes the planning, scheduling, direct supervision of all field personnel (linemen, technicians, etc.), and the construction of internally executed capital projects. In addition, the department performs all preventive and corrective maintenance on the system and leads all outage response efforts. This places a dedicated focus on grid reliability, productivity, and workforce safety.

This new focused departmental structure creates clear lines of responsibility and allows for specialization and scalability.

8.2.1 Engineering & Planning Department

This department would be the utility's strategic and technical core with the following responsibilities.

- **System Planning:** Long-range planning, load forecasting, DER/hosting capacity analysis, and maintaining and managing the system models.
- **System Protection:** Overseeing protection schemes, performing coordination studies, and defining settings for all system protection equipment.
- **Standards:** Developing and maintaining construction and material standards. Creating design packages and drawings, specifications, and compatible units for capital projects. This is crucial for improving supply chain efficiency, ensuring safety, and simplifying maintenance.
- **Asset Management:** Owning the overall strategy for condition assessment and preventive maintenance, using data to determine what needs to be done and when.

8.2.2 Project Management Office (PMO)

This new department would be formalized to manage the execution of the capital plan with the following responsibilities.

- **Oversight:** The core function would be to standardize project execution, budget and schedule management across all projects, allowing uniform reporting to leadership.
- **Capital Project Execution:** Taking the design packages from the Engineering department and managing them through construction and closeout. This includes managing budgets, schedules, and overseeing contractors.
- **Procurement & Materials Management:** Responsible for managing the logistics for capital projects, ensuring materials are defined, ordered, and staged efficiently.
- **Cross-Departmental Coordination:** Acting as the central point of coordination for large projects that impact other county departments, stakeholders, and the public.

8.2.3 Operations Department

This department would be responsible for the physical construction (for internally executed projects), maintenance, and real-time operation of the distribution system. It would directly oversee line crews and other field personnel, freeing the Engineering department from these duties.

- **Workforce Management:** Directly managing the line crews, including developing work schedules, assigning daily tasks, and ensuring all safety procedures are followed.
- **Construction & Maintenance:** Executing the construction of capital projects planned by the PMO for internal execution and performing all preventive and corrective maintenance identified by the Engineering department's asset management plan.
- **Outage Response:** Responding to all system outages, performing switching, and managing restoration efforts safely and efficiently.
- **Metering & Field Services:** Performing all field work related to metering, including commercial meter testing, AMI installations and maintenance, inspections, and responding to customer complaints.

8.2.4 Other Organizational Impacts

While the core of the transformation will occur within the Electric Distribution department's new structure, the scale of change necessitates a corresponding evolution in other departments. The successful operation of a modern grid relies on a seamless partnership between field operations, technology, and customer-facing teams.

8.2.4.1 IT/OT Convergence

This study makes it clear that the future utility is a digital utility. The proliferation of smart field devices, sensors, and control systems requires a fundamental rethinking of how technology is managed. The traditional separation between corporate Information Technology (IT) and grid-based Operational Technology (OT) will no longer be effective.

We strongly recommend additional analysis around creating a unified IT/OT department to break down these silos between IT and OT. An integrated structure is essential for managing the complex data flows from the grid and for developing a holistic cybersecurity strategy that protects both customer data and critical infrastructure. This converged department would have responsibility for the utility's entire technology stack, ensuring that as new systems are deployed, they are secured and effectively integrated.

8.2.4.2 Customer Programs & Services: Managing the New Customer Relationship

In an electrified future, a utility’s relationship with the customer will fundamentally change. Customers will evolve from passive energy consumers into active participants in the grid through the adoption of electric vehicles, rooftop solar, battery storage, and smart appliances like digital thermostats. This requires a customer service department equipped to manage this new, complex relationship.

Currently, customer service functions largely revolve around billing inquiries and outage reporting. This study; however, envisions a future with sophisticated customer programs, including managed EV charging, time-of-use (TOU) rates, and direct load control for heating and water heating. These programs are essential for managing system peaks and minimizing infrastructure costs. Managing them requires a proactive approach to customer engagement, education, and support.

LACDPU must evolve the customer service function into a more comprehensive "Customer Programs & Services" department. This goes beyond just answering calls; it involves actively managing the customer relationship and the programs they participate in. This new department requires specialized staff with responsibilities for:

- **Program Management & Marketing:** Designing, marketing, and administering the new electrification programs to encourage customer adoption.
- **Public Outreach & Education:** Developing clear communication materials to educate customers on the benefits and workings of complex new rates and technologies.
- **Specialized Support:** Training representatives to handle complex technical questions about EV charger installation, solar PV policies, and troubleshooting smart home devices.

8.3 Transition and Phasing Plan

This section outlines a phased approach to stand up and grow capability across the functions outlined above, ensuring minimal disruption while maximizing long-term benefits.

A critical consideration in this transition is the staffing and resource model. While the establishment of this new functional alignment may suggest an increase in staffing, it's essential to clarify that this does not necessarily equate to an exclusive reliance on new hires. Instead, our recommendations for increased capacity should be viewed as purpose or function based. This means that existing, skilled personnel across the breadth of LACDPU can be repurposed to fulfill the new roles envisioned.

For example, a highly capable engineer currently embedded within one of the utility departments could be trained and repurposed to serve as a dedicated Project Manager within the PMO, leveraging their deep technical knowledge for broader project oversight. Similarly, if a particular utility function, such as the gas department, anticipates a future decrease in project demand or operational workload, personnel from that area could be strategically repurposed. This approach capitalizes on existing institutional knowledge, fosters internal career development, and optimizes LACDPU's overall human capital.

8.3.1 Phase 1: Foundational Setup

The objective for Phase 1 is to establish leadership and frameworks for the new structure. The following key actions should be considered.

- **Hire a PMO Lead:** The first critical hire is a senior Project Manager or PMO Lead. Their initial mandate will be to establish a standardized project management methodology and immediately control the budget, schedule, risk, and contractor management for ongoing projects.
- **Appoint a Field Operations Manager:** Formally separate daily operations from engineering by appointing a Field Operations Manager or Superintendent to take over direct supervision of the electric distribution department and manage crew scheduling and work assignments.
- **Initiate Key Analyses:** Begin the follow-up work detailed in Section 8.4 below for additional recommended analysis, starting with a comprehensive skills assessment and a competitive salary survey to inform the next phase of hiring.

Table 8-1 outlines the existing staff and additional staff as part of the foundation of this phased approach.

Table 8-1: Phase 1 - Foundational Setup

Foundational Years	Existing personnel	New Hires - Phase 1	Total
Engineering & Planning	**2 x Professional Engineer (PE)** **2 x Bachelor of Science Electrical Engineer (BSEE, Power)** **1 x Engineer's Associate**		**5**
Project Management Office		**1 x Project Manager (PM)** • **8-10 years experience managing construction projects in the utility industry**	**1**
Operations	**3 x Line Supervisors** **7 x Line Crew** **2 x Engineer's Associates**	**1 x Field Operations Manager** • **10+ years managing line crews for an electric utility**	**13**
Total	**17**	**2**	**19**

8.3.2 Phase 2: Building Capacity & Specialization

The objective for Phase 2 is to hire specialized roles and develop the workforce. The following key actions should be considered.

- **Expand the PMO:** Hire additional project managers to handle the growing portfolio of capital projects.
- **Hire Specialized Engineers:** Recruit for specialized roles within the Engineering department, such as a dedicated System Planner focused on modeling, a Protection & Control Engineer focused on grid reliability, a Standards Engineer, and an Asset Management professional.

Table 8-2 shows the staff from phase 1 along with the additional team members added as part of the phase 2 rollout.

Table 8-2: Phase 2 - Building Capacity and Specialization

Build Capacity & Specialization	Phase 1	New Hires - Phase 2	Total
Engineering & Planning	2 x PE 2 x BSEE (Power) 1 x Engineer's Associate	2 x PE (Specialization for each of the 4 functions) • System Planning • System Protection • Standards • Asset Management 1 x Engineer's Associate	8
Project Management Office	1 x PM	1 x PM • Portfolio split (ex. undergrounding vs large capital)	2
Operations	1 x Field Operations Manager 3 x Line Supervisors 7 x Line Crew 2 x Engineer's Associates		13
Total	19	4	23

8.3.3 Phase 3: Mature Organization

The objective for Phase 3 is to achieve the full future-state organizational model and focus on optimization and leveraging data to drive strategic decisions. The following key actions should be considered.

Establish a formal Business Analysis Function: This function within the Engineering and Planning Department would process the vast amount of data now being collected by the IT/OT systems. It would track, analyze, and provide data-driven recommendations to improve the entire organization's performance.

- Support Operations by tracking Key Performance Indicators (KPIs) like Outage time, First-time fix rate, and number of truck rolls, to identify underperforming circuits or inefficient processes and provide the Field Operations Manager with actionable intelligence.
- Support the PMO by performing variance analysis and reporting on capital projects, enabling better financial controls and more accurate future estimates.
- Support Engineering & Asset Management by analyzing equipment failure data to help refine planned asset lifecycles, potentially deferring significant capital costs by optimizing replacement schedules.

Focus on Continuous Improvement: With robust data analysis in place, all departments can shift to a cycle of continuous improvement, using performance metrics to refine processes, enhance reliability, and manage costs effectively.

Table 8-3 outlines the team created in phase 2 and adds additional team member as part of phase 3.

Table 8-3: Phase 3 - Mature Organization

Mature Organization	Phase 2	New Hires - Phase 3	Total
Engineering & Planning	4 x PE 2 x BSEE (Power) 2 x Engineer's Associate	1 x Lead Planning & Performance Analyst 1 x Data Analyst	10
Project Management Office	2 x PM		2
Operations	1 x Field Ops Manager 3 x Line Supervisors 7 x Line Crew 2 x Engineer's Associates		13
Total	23	2	25

As summarized in Table 8-4, this three-phase transition plan provides a deliberate and manageable roadmap for evolving the Electric Distribution department. This strategic approach ensures that investments in personnel and organizational structure are made proactively and are directly aligned with the escalating demands of the electrification forecast. By methodically establishing foundational leadership and project controls in Phase 1, building essential specialized capacity in Phase 2, and achieving data-driven maturity with advanced analytical functions in Phase 3, the department can scale its capabilities in lockstep with its challenges. Following this roadmap will successfully transform the department from the lean, agile team of today into the robust, specialized, and resilient organization required to power the community's future.

Table 8-4: Summary Transition and Phasing Plan

	Current	Foundational Years	Build Capacity & Specialization	Mature Organization
Engineering & Planning	17	5	8	10
Project Management Office		1	2	2
Operations		13	13	13
Total	17	19	23	25
Change		+2	+4 +6 from current	+2 +8 from current

8.4 Recommended Additional Analysis

Successfully navigating this organizational transition requires further detailed analysis beyond the scope of this initial report. We recommend LACDPU conduct the following essential studies:

8.4.1 Organizational Assessment for Cross-Departmental Synergies through a PMO

The PMO organization recommended in the preceding section should span electric, water, and natural gas functions to foster cross-departmental synergies. A similar organizational assessment across those domains could identify:

- **Integrated Project Portfolios:** How could the departments prioritize and manage a diverse portfolio of projects encompassing electrical grid upgrades, water treatment plant modernizations, and gas pipeline replacements?
- **Shared Resources and Expertise:** How could the departments optimize the use of shared resources, such as project managers, engineers, heavy equipment, and specialized crews, across different utility projects?
- **Standardized Methodologies:** How could the departments consolidate project management methodologies, tools, and processes across electric, water, and gas services?
- **Data and Information Sharing:** How could the departments facilitate effective data exchange and collaborative decision-making?

The findings from this broader organization assessment would directly inform the design and implementation of LACDPU's PMO more broadly than only within the electrical department.

The PMO, in this context, would act as the catalyst and enabler for these cross-departmental synergies. By providing a common framework for project management, standardizing processes, and promoting a culture of collaboration, the PMO would break down traditional silos between electric, water, and gas departments. It would facilitate shared learning from past projects, optimize resource allocation across the entire utility enterprise, and ensure that all projects align with the LACDPU's overarching strategic goals. Ultimately, the PMO would transform individual departmental efforts into a cohesive, efficient, and strategically aligned project delivery engine for the benefit of all Los Alamos County customers.

8.4.2 Industry Benchmarking:

A common industry practice for workforce planning is to benchmark staffing levels using metrics like full-time equivalents (FTEs) per 1,000 customers. However, for the unique growth scenario facing Los Alamos, relying solely on this metric can be misleading. The primary driver of future demand is not an increase in the number of customers, but the intensification of energy use per customer due to electrification. A single household that adds electric vehicles and heat pumps can double or triple its load, placing significantly more demand on the distribution infrastructure and requiring more complex customer service interactions without changing the overall customer count.

Therefore, a more sophisticated benchmarking approach is required. While Los Alamos may not grow significantly beyond its current customer base, the future complexity and load density of its system will more closely resemble that of a larger utility. For this reason, we recommend benchmarking against public power utilities in the 20,000-50,000-customer range. This peer group provides a more accurate proxy for the organizational structures and staffing ratios required to manage a technologically advanced, high-density distribution grid.

To further refine the analysis, we also recommend incorporating asset-based benchmarks, such as FTEs per $100 Million in Distribution Assets. As LACDPU's asset base grows, this metric will provide a valuable, non-customer-based view of the staffing required for maintenance and operations.

This dual approach, using a larger customer peer group to proxy for complexity and an asset-based metric to account for the growing infrastructure, will provide a much more robust and defensible foundation for your future workforce planning.

8.4.3 Comprehensive Skills and Training Needs Assessment:

A formal gap analysis should be performed to map the specific skills of the current workforce against the detailed requirements of the future-state roles. This will identify who can be up-skilled through training versus what skills must be acquired through new hires. This assessment should result in a multi-year training and development roadmap for the entire department.

8.4.4 Market Compensation & Salary Survey:

The utility sector faces a highly competitive labor market for skilled technical talent. To attract and retain the qualified PEs, PMPs, and specialized technicians needed to execute the electrification plan, LACDPU must offer competitive compensation. A formal salary survey benchmarked against other public power utilities in the region is critical to ensure the success of your hiring and retention efforts.

8.4.5 Formal Change Management Plan:

An organizational transition of this magnitude can create uncertainty and resistance among staff. A formal change management plan is crucial. This plan must include strategies for effective sponsorship and decision-making from leadership and a communication strategy to ensure all employees understand the vision, the reasons for the change, and their role in the future organization.

8.4.6 Holistic Review of All Departments:

This report has focused exclusively on the Electric Distribution Department, which will experience the most immediate impact. However, the projected growth will place significant strain on all other parts of the LACDPU. Similar deep-dive analyses are required for:

- **Customer Service & Billing:** As mentioned in Section 8.2.4.2, this team will need to be trained and potentially expanded to manage complex new programs and explain new rates for EVs and solar to customers.
- **Procurement & Supply Chain:** Current processes must be evaluated to ensure LACDPU can handle the scale and complexity of procuring major, long-lead-time equipment like substation transformers and managing a much larger inventory of materials.
- **Finance, HR, and Information Technology:** These support functions will also need to scale their processes and staffing to support a much larger and more complex organization.
- **Gas and Water Utilities:**
  - The Gas Utility faces a strategic challenge, as the electrification plan is fundamentally a "de-gasification" plan aimed at eliminating natural gas in buildings. A comprehensive review is needed to create a long-term strategic plan for the Gas department, which will likely involve managing a decline in revenue, planning for the safe decommissioning of infrastructure, and developing a workforce transition plan for its employees.
  - The Water Utility relies on the electric grid to power its critical infrastructure, including water wells and pumping facilities. These modernization updates to the electric system must be closely coordinated with the Water department to ensure the reliability of these essential services is maintained throughout the transition.
- **Geographic Information Systems (GIS) Department:** The GIS team is the keeper of the utility's foundational asset map. The capital plan outlined in this study will result in tens of thousands of asset changes over the next 30 years. Every new conductor, transformer, switch, and service must be meticulously and accurately updated in the ArcGIS system. In the future, the accuracy of this GIS data becomes even more critical, as it is the bedrock upon which advanced systems like Outage Management (OMS) and an Advanced Distribution Management System (ADMS) are built. A review is needed to ensure the GIS department has the staffing, tools, and processes to handle this dramatically increased workload and the heightened importance of its data integrity.

9.0 Conclusion

Los Alamos County is expected to experience a significant increase in electricity demand due to building and transportation electrification. 1898 & Co. reviewed many parts of the LACDPU system and performed several analyses to understand the grid impacts of electrification. The LACDPU must invest in the electric system to maintain safe and reliable customer service.

9.1 Existing System Review

The LACDPU is planning to energize the Los Alamos Switching Station (LASS) this summer. Energizing the LASS substation will improve reliability and utility metrics but will not increase substation capacity to serve new load growth. The study showed that substation capacity is a system limitation and must be corrected through system improvement projects to support electrification load growth.

The LACDPU is concerned about asset health. 1898 & Co. reviewed the County's recent asset condition assessment, which showed that by 2055, most critical system assets will be beyond their expected service life and may require replacement to maintain safe and reliable customer service. Present operations and maintenance budgets are not sufficient to replace assets at the appropriate rate. A significant asset replacement effort may be required for the LACDPU.

1898 & Co. reviewed the hosting capacity for all distribution feeders in the LACDPU system. All distribution feeders showed some remaining hosting capacity, but the maximum amount was observed near the substation. Locations on distribution feeders further from the substation source presented lower amounts of hosting capacity. The LACDPU should consider implementing Volt-VAR control for new solar PV customers, which will help to regulate voltage on the distribution feeders and mitigate the potential high voltage impacts from solar PV generation. Protection system improvements should be the next focus to increase hosting capacity. Reverse power flow resulting from solar PV generators can negatively impact protective devices. Upgrades are required for protective devices to mitigate the negative impacts of reverse power flow.

9.2 Electrification Forecast

1898 & Co. evaluated the potential impacts of three future scenarios for Los Alamos County:

- **Scenario 1** aligns with the County's Climate Action Plan, incorporating considerable transportation and building electrification efforts.
- **Scenario 2** reflects historical trends within the County and considers existing statewide regulations.
- **Scenario 3** follows historical statewide trends but assumes minimal new state or federal regulations regarding transportation and building electrification.

Across all scenarios, LACDPU is projected to experience significant increases in electric grid demand by 2040—even under minimal electrification conditions.

Table 9-1: Additional Electrification Peak Load by 2040

Scenarios	2040 Additional Peak Load (MW)	Time of Day
Scenario 1	20.6	6:00 am
Scenario 2	7.4	12:00 am
Scenario 3	3.7	3:00 am

By 2055, grid demand intensifies across all scenarios as adoption of electric vehicles and heat pumps continues to grow:

Table 9-2: Additional Electrification Peak Load by 2055

Scenarios	2055 Additional Peak Load (MW)	Time of Day
Scenario 1	43.6	6:00 am
Scenario 2	27.1	5:00 am
Scenario 3	13.1	6:00 am

In all cases, the primary drivers of peak demand are transportation electrification and electric space heating—both of which exert pressure on the grid during nighttime hours. In contrast, sectors such as commercial electrification tend to align more closely with daytime solar generation, thus having a more tempered impact on peak load.

Scenarios 1 and 3 represent bounding cases—defining the upper and lower limits of external regulatory influence and zero-emission technology adoption. A more likely outcome lies between these extremes. Scenario 2 demonstrates how strong local interest in electric vehicles, heat pumps, and distributed solar could still elevate grid demand significantly—potentially surpassing the midpoint between Scenarios 1 and 3.

9.3 Electric Distribution System Impact

The electrification forecast load was applied to the WindMil power flow model to understand the impact on the existing system. Six total power flow scenarios were evaluated to identify necessary capital projects, such as substation transformer upgrades, new substation transformers, new distribution feeders, and conductor upgrades. These upgrades were incorporated into the power flow model to mitigate planning criteria violations.

The existing system assessment showed that substation capacity is limited. Once the electrification forecast load was added to the power flow model, substation projects were required to successfully serve all customer loads. A new Eastgate Substation will support load growth within the town of Los Alamos. This substation will require two power transformers to provide adequate contingency capacity for the town. The size of these transformers and the associated number of new distribution feeders required will vary depending on the electrification load growth that the LACDPU experiences. Approximately one mile of transmission line extension will be required to serve the Eastgate Substation. Further analysis will be required on the transmission system to identify if any line upgrades will be required to serve the forecasted electrification load growth.

Upgrades will also be necessary for the White Rock Substation to serve forecasted electrification load growth. At a minimum, the two existing power transformers must be upgraded to provide the necessary contingency capacity for White Rock. The required size of these transformers and whether the whole substation must be rebuilt will depend on the electrification load growth that the LACDPU experiences. The power flow analysis also identified several feeder upgrades that were common among the various scenarios studied.

Asset replacement estimates were provided for each electrification scenario. The scope and cost of asset replacement are anticipated to exceed the system improvements required to serve the forecasted electrification load growth. 1898 & Co. recommends the LACDPU develop a holistic and comprehensive asset replacement plan that incorporates a more detailed review of asset health and ranking of projects based on cost vs benefit analysis.

9.4 Financial Impact

Varying levels of electrification will cause different outcomes related to how recovery of system upgrade costs can be achieved through incremental revenue collected from the sale of electricity. Under the high and medium electrification scenarios incremental revenue from electrification can pay for the necessary system improvement capital projects. However, under the low electrification scenarios the utility will not generate enough revenue to cover major system upgrade costs, and the utility will need to increase electric rates to fund the identified capital projects at the time intervals developed.

In addition to the incremental capital required to support growth, LACDPU will need to make modifications to its electric rates and rules. More specifically, LACDPU will need to implement rates and demand response programs that provide customers with financial benefits from levelizing their incremental electric load from electric vehicles and electric heating. LACDPU should also consider evaluating its line extension policy and customer connection fees to consider the benefits and costs of having customers that use more electricity as outlined within this report.

1898 & Co. recommends further financial analysis to identify how to pay for the replacement of existing aging assets across the system. This repair and replacement of aging assets will need to be systematically executed over many years and will likely require increased rate revenues to support it.

9.5 Staffing Impact

The LACDPU staffing levels will fluctuate over the next 30 years in response to electrification. This study focused on the impacts to the Electric Distribution Department. This department operates as a highly effective and tightly integrated unit characterized by a generalist approach where key personnel hold a wide array of responsibilities. To successfully prepare for the future, the Electric Distribution Department must transform into a more specialized organization with greater depth. The core of the new organization is the separation of duties into three primary areas, Engineering and Planning, Project Management Office, and Operations, which are functionally aligned, a structure common among larger peer utilities.

Other organizational impacts should also be considered in the future. The proliferation of smart field devices, sensors, and control systems requires a fundamental rethinking of how technology is managed. The traditional separation between corporate Information Technology (IT) and grid-based Operational Technology (OT) will no longer be effective.

In an electrified future, a utility's relationship with the customer will fundamentally change. Customers will evolve from passive energy consumers into active participants in the grid through the adoption of electric vehicles, rooftop solar, battery storage, and smart thermostats. This requires a customer service department equipped to manage this new, complex relationship.

The establishment of this new functional alignment does not necessarily equate to an exclusive reliance on new hires. The LACDPU should look to repurpose skilled personnel across the breadth of the organization to fulfill the new roles envisioned and then look to new hires as necessary. 1898 & Co. also recommends a more holistic review of all LACDPU departments to understand the potential opportunities for synergies and also the opportunities to repurpose and train existing staff.

9.6 Recommendations

This study included many analyses that enabled 1898 & Co. to understand the state of the LACDPU system and the challenges that it faces. Action is required for the LACDPU to prepare for electrification. 1898 & Co. has identified the following recommendations based on the analyses and reviews documented in this electrification study:

- Work with MilSoft, to improve the power flow model fidelity by maintaining a direct connection between WindMil and the GIS system. This will enable more agile power flow studies and investigations into the performance of the LACDPU electrical system.
    - Regularly perform studies to identify system impacts when electrification occurs and recommend the appropriate system improvements.
- Implement Volt-VAR control for new solar PV customers to mitigate potential voltage violations that can result from distributed generation.
- Construct the Eastgate Substation to provide necessary substation capacity for the Town of Los Alamos. The timing and scope of this new substation will depend on the load growth experienced by the LACDPU.
- Upgrade the White Rock Substation to provide necessary substation capacity for the Town of White Rock. The timing and scope of this substation upgrade will depend on the load growth experienced by the LACDPU.
- Investigate demand-side management programs related to water heating, space heating/cooling, and managed EV charging programs. Increased customer service support may be required as the LACDPU implements new programs and works to educate customers on electrification and energy efficiency.

This study also identified several areas where the LACDPU should further investigate and perform additional analysis:

- Develop a holistic asset replacement plan that aligns with the system's needs and the appropriate O&M budgets. This may require a full financial study to determine rate impacts in the near term.
- Analyze all LACDPU departments to identify workforce transition plans and cross-functional roles for a holistic staffing plan that considers electrification.
- Perform a new Integrated Resource Plan (IRP) or consider completing "IRP-lite" modeling between the full IRP analyses to determine the optimal resource selection based on actual market conditions and after resource procurement by the Los Alamos Power Pool.
- Perform an organizational assessment for cross-departmental synergies through a Project Management Office (PMO).

APPENDIX A – Hosting Capacity Analysis Results

10.0 Appendix A- Hosting Capacity Analysis Results

Substation: White Rock
Feeder: WR1

Legend	Greater than (kW)	Less than (kW)
Orange	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

Maximum Hosting Capacity	**915 kW**
Criteria Violation	**Reverse Flow**

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	398	130	419	56
Phase B	433	142	456	61
Phase C	306	100	322	43
Total	**1,137**	**372**	**1,197**	**-**

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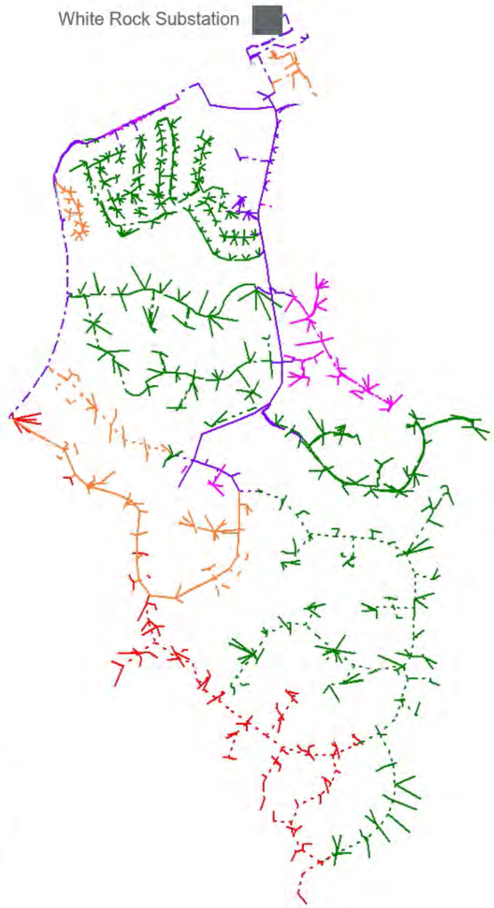
Substation: White Rock
Feeder: WR2



Legend

Greater than (kW)	Less than (kW)
0	25
25	100
100	200
200	300
300	500
500	1,000
1,000	2,000
2,000	5,000

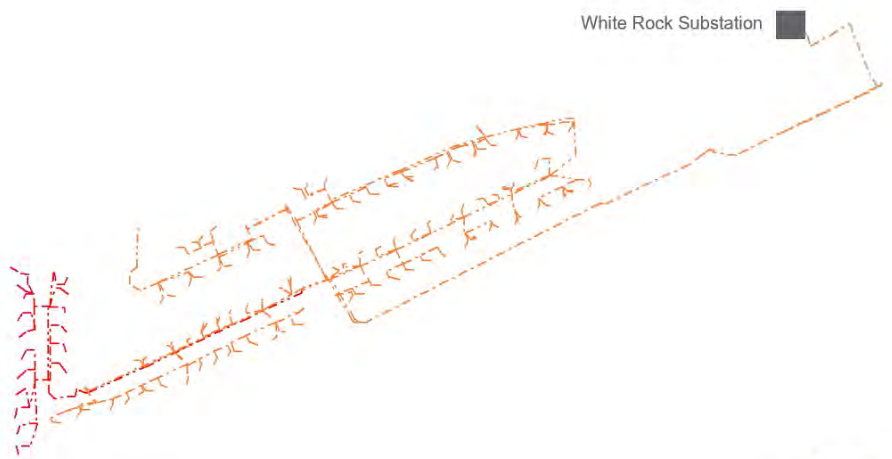
Maximum Hosting Capacity	383 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	256	103	276	38
Phase B	128	61	142	20
Phase C	157	71	172	24
Total	**541**	**235**	**590**	**-**

Substation: White Rock
Feeder: WR3

Legend		
	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

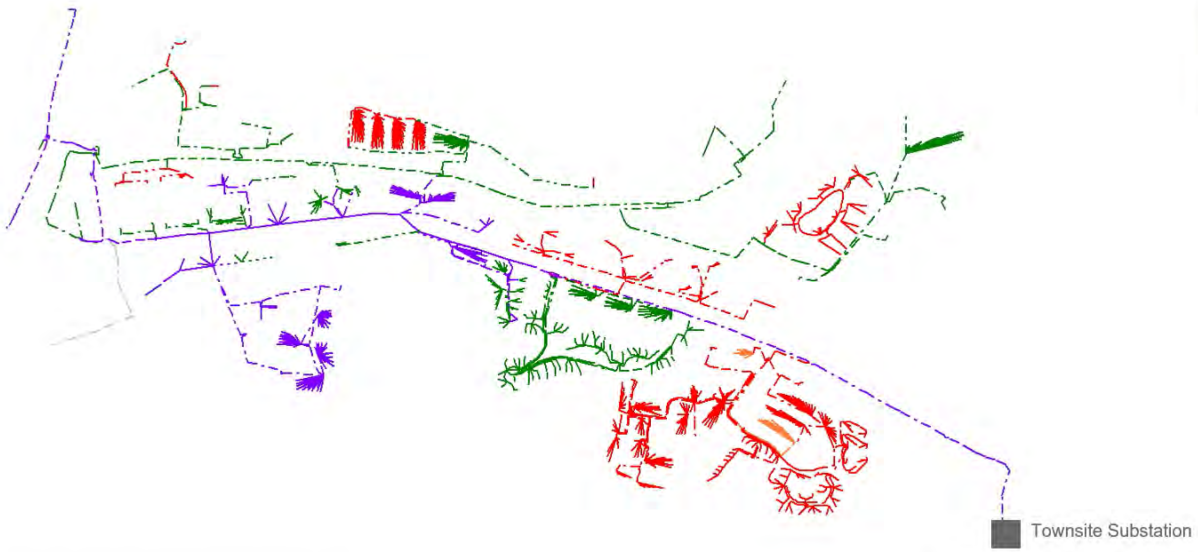


Maximum Hosting Capacity	35 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	1	1	1	0
Phase B	1	11	1	0
Phase C	36	12	38	5
Total	**38**	**24**	**40**	**-**

Substation: Townsite
Feeder: Feeder 13



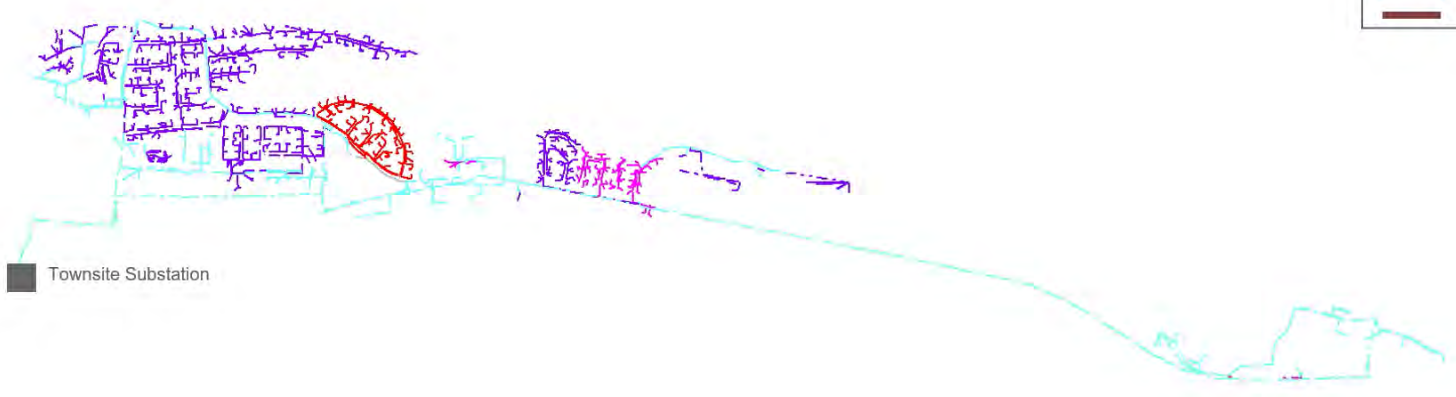
Legend	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

Maximum Hosting Capacity	461 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	183	-47	189	24
Phase B	154	-126	199	25
Phase C	162	-99	190	24
Total	**499**	**-272**	**578**	**-**

Substation: Townsite
Feeder: Feeder 14



Legend	Greater than (kW)	Less than (kW)
(yellow)	0	25
(red)	25	100
(green)	100	200
(magenta)	200	300
(purple)	300	500
(cyan)	500	1,000
(blue)	1,000	2,000
(brown)	2,000	5,000

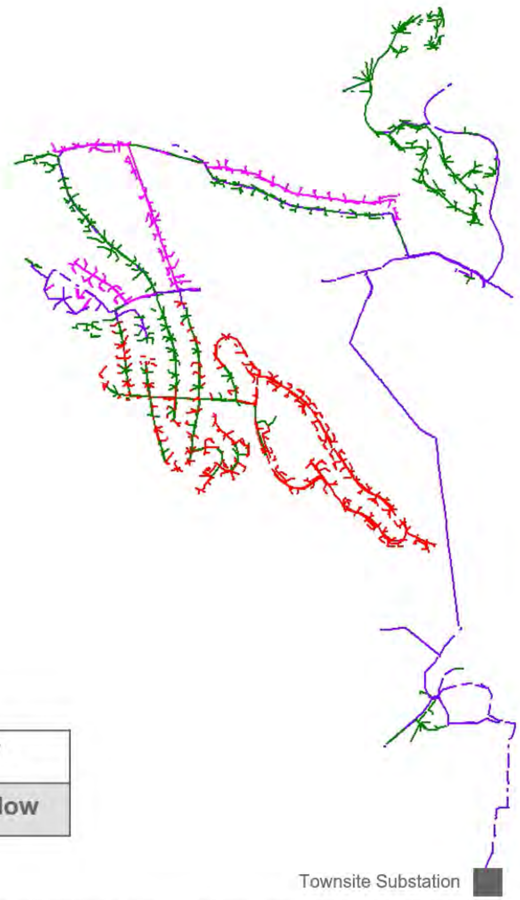
Maximum Hosting Capacity	**929 kW**
Criteria Violation	**Reverse Flow**

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	310	90	323	41
Phase B	337	110	355	45
Phase C	333	97	347	44
Total	**980**	**297**	**1,025**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: Townsite
Feeder: Feeder 15



Legend	Greater than (kW)	Less than (kW)
	0	25
	25	100
	100	200
	200	300
	300	500
	500	1,000
	1,000	2,000
	2,000	5,000

Maximum Hosting Capacity	435 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	164	51	171	22
Phase B	218	68	229	29
Phase C	145	33	148	19
Total	**527**	**152**	**548**	**-**

Substation: Townsite
Feeder: Feeder 16

Legend

	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Light blue	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

Maximum Hosting Capacity	425 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	141	21	143	18
Phase B	151	37	156	20
Phase C	270	71	280	35
Total	**562**	**129**	**579**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: Townsite
Feeder: Feeder 17

Legend	Greater than (kW)	Less than (kW)
(yellow)	0	25
(red)	25	100
(green)	100	200
(magenta)	200	300
(purple)	300	500
(cyan)	500	1,000
(blue)	1,000	2,000
(brown)	2,000	5,000

Maximum Hosting Capacity	**1,309 kW**
Criteria Violation	**Reverse Flow**

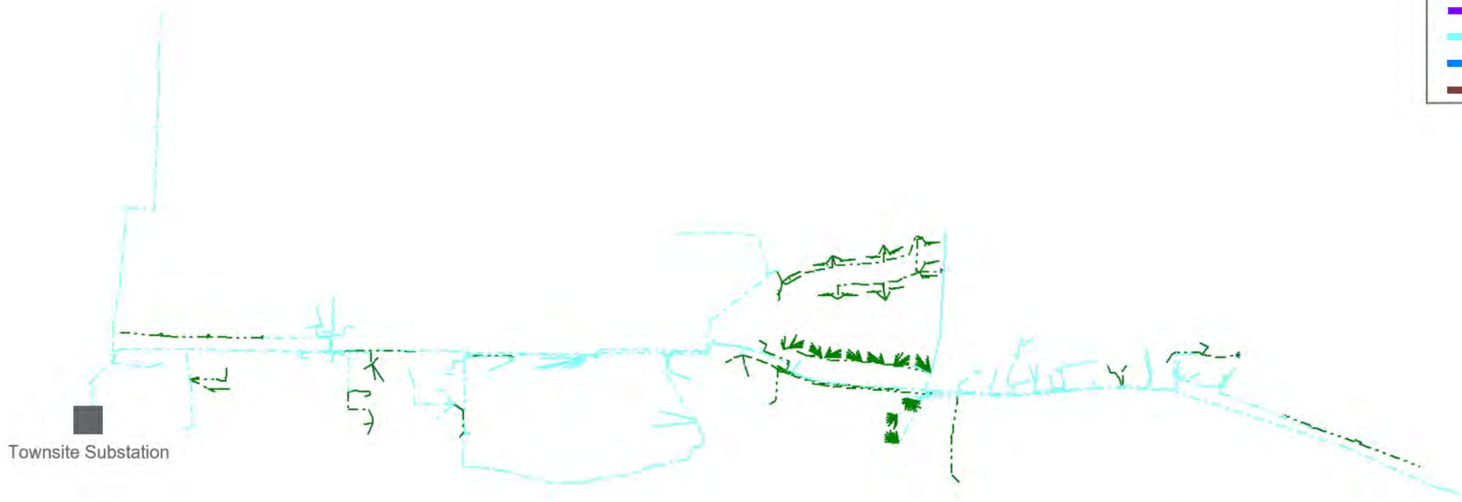
Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	436	95	436	56
Phase B	478	157	503	64
Phase C	449	146	472	60
Total	**1,363**	**398**	**1,411**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: Townsite
Feeder: Feeder 18

Legend	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000



Maximum Hosting Capacity	534 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	178	53	186	23
Phase B	199	59	207	26
Phase C	182	56	190	24
Total	**559**	**168**	**583**	**-**

1898 & Co. PART OF BURNS & McDONNELL

Substation: LASS
Feeder: Feeder 13T

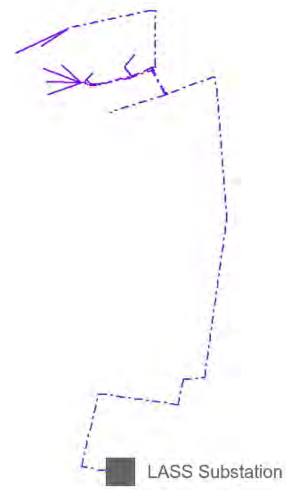
Legend	
Greater than (kW)	Less than (kW)
0	25
25	100
100	200
200	300
300	500
500	1,000
1,000	2,000
2,000	5,000

Maximum Hosting Capacity	**625 kW**
Criteria Violation	**Reverse Flow**

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	209	136	249	31
Phase B	236	202	311	39
Phase C	234	173	291	37
Total	**679**	**511**	**851**	**-**

Substation: LASS
Feeder: Feeder NS6



Legend	Greater than (kW)	Less than (kW)
yellow	0	25
red	25	100
green	100	200
magenta	200	300
purple	300	500
cyan	500	1,000
blue	1,000	2,000
brown	2,000	5,000

Maximum Hosting Capacity	375 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	125	26	128	16
Phase B	125	26	128	16
Phase C	125	26	128	16
Total	**375**	**78**	**384**	**-**

Substation: LASS
Feeder: Feeder 15T

Legend	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

Maximum Hosting Capacity	408 kW
Criteria Violation	Reverse Flow

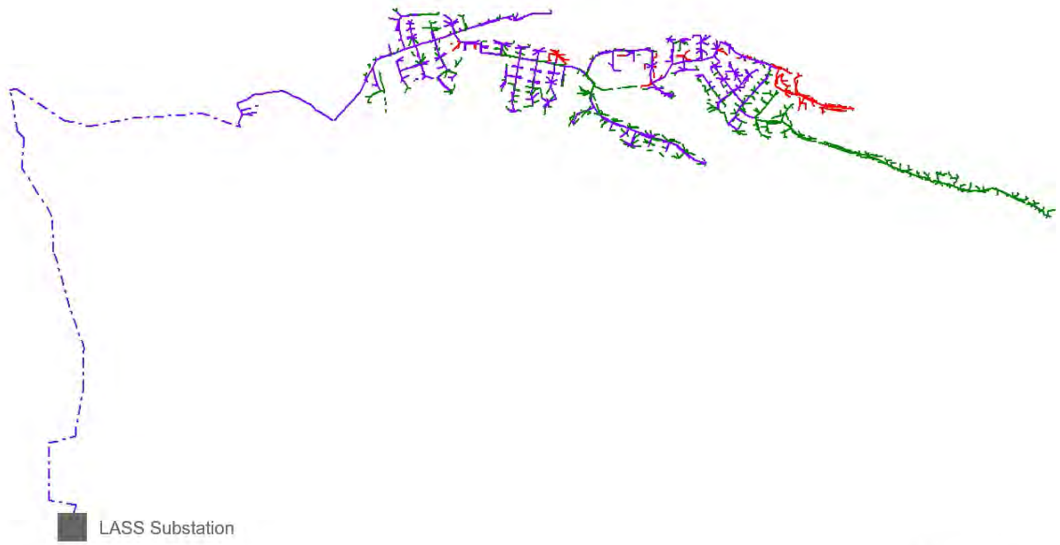
Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	136	29	139	19
Phase B	153	31	156	22
Phase C	250	84	264	37
Total	**539**	**144**	**559**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: LASS
Feeder: Feeder 16T

Legend	Greater than (kW)	Less than (kW)
	0	25
	25	100
	100	200
	200	300
	300	500
	500	1,000
	1,000	2,000
	2,000	5,000



Maximum Hosting Capacity	334 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	255	109	277	35
Phase B	196	31	211	27
Phase C	112	2	124	16
Total	**563**	**142**	**612**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: LASS
Feeder: Feeder NS3

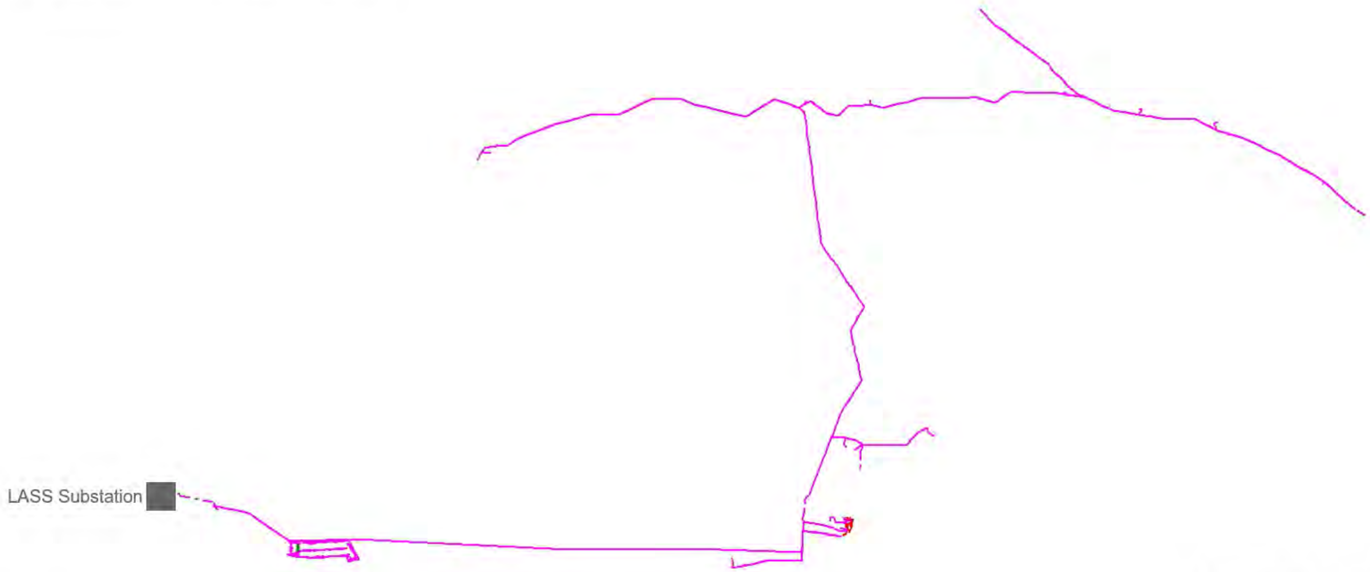
Legend	Greater than (kW)	Less than (kW)
	0	25
	25	100
	100	200
	200	300
	300	500
	500	1,000
	1,000	2,000
	2,000	5,000

Maximum Hosting Capacity	180 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	60	18	63	8
Phase B	60	18	63	8
Phase C	60	18	63	8
Total	**180**	**54**	**189**	**-**

Substation: LASS
Feeder: Feeder NS18



Legend	Greater than (kW)	Less than (kW)
	0	25
	25	100
	100	200
	200	300
	300	500
	500	1,000
	1,000	2,000
	2,000	5,000

Maximum Hosting Capacity	205 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	69	23	73	9
Phase B	83	29	88	11
Phase C	91	31	96	12
Total	**243**	**83**	**257**	**-**

1898 & CO. PART OF BURNS & McDONNELL

Substation: LASS
Feeder: Feeder NS18

Legend	Greater than (kW)	Less than (kW)
Yellow	0	25
Red	25	100
Green	100	200
Magenta	200	300
Purple	300	500
Cyan	500	1,000
Blue	1,000	2,000
Brown	2,000	5,000

Maximum Hosting Capacity	285 kW
Criteria Violation	Reverse Flow

Minimum Daylight Feeder Load

	kW	kVAR	kVA	Amps
Phase A	108	6	125	16
Phase B	100	68	121	15
Phase C	96	65	115	15
Total	**304**	**139**	**361**	**-**

APPENDIX B – Grid Modernization Strategies

11.0 Appendix B – Grid Modernization Strategies

11.1 BESS within the Electric System

BESS resources are versatile and can provide many different services for electric systems. A single BESS cannot necessarily offer all services at once. The size, location, operating agreement, and other factors will limit the services that can be provided to the electric grid. The common use cases for BESS on the utility system are listed below:

- **Energy Arbitrage:** Charge the battery during low customer demand and high renewable generation output and discharge it during high customer demand and low renewable generation output.
- **Firm Capacity/Peaking Capacity**: Installed capacity that can reliably operate during high-risk hours.
- **Ancillary Services:** The battery can support the operation of the electric system through frequency and/or voltage support. A BESS resource's quick operating time can make it suitable for ancillary services over other generation sources.
- **Capital Project Deferral:** The battery can supply energy during peak demand and defer and/or replace the need for traditional wire upgrades. It can also store excess renewable energy that might require traditional wire upgrades to mitigate equipment overloads.
- **Microgrid/Reliability Improvements**: The battery can be used to island the distribution system during outages or storm events.

11.1.1 Transmission Scale BESS

Transmission-scale BESS are becoming increasingly popular for utilities throughout North America. Typical sizes of these installations are 50+ MW output with 2 to 4 hours of storage. Table compares the benefits and challenges of a transmission-scale BESS.

Table -1: Transmission Scale BESS

Benefits	Challenges
More Economical – large installations will be cheaper to construct on a unit cost basis.	Limited Distribution System Improvement – reduced opportunity to defer distribution system investments or provide ancillary service to distribution feeders.
Simpler Control – a single resource to control and manage. Helpful in managing system-level power flow and maintaining demand charges and upstream impacts.	Siting/Construction - Given the geography of Los Alamos, finding adequate sites for installing a transmission-scale resource may be difficult.
More Impactful Grid Services – a larger BESS could provide services beyond the LACDPU system and potentially become an additional revenue stream for the county.	

A transmission scale resource would likely require cooperation with the neighboring Pueblo communities and/or the Los Alamos National Lab. A new transmission line serving Los Alamos could be necessary to enable the interconnection of a larger resource owned by LACDPU. LACDPU could pursue joint ownership of a larger transmission-scale resource or construct a site with other parties. Land for a larger project like this will be a significant challenge. If LACDPU can develop a larger-scale BESS project, there could be opportunities to generate revenue by providing grid services to the surrounding utilities.

11.1.2 Distribution Level BESS

Distribution-scale BESS is a newer development for utilities throughout North America. Typically, the size of the distribution BESS resources has made them cost-prohibitive solutions. However, the costs of materials and installations are decreasing, resulting in more BESS being connected to the distribution system. Typical sizes of these installations are 2 to 10 MW with 2 to 4 hours of storage. Table -2 compares the benefits and challenges of a distribution-scale BESS.

Table -2: Distribution Scale BESS

Benefits	Challenges
Siting/Construction – Given the geography of Los Alamos, finding suitable locations to construct a distribution-scale BESS should be easier.	Less Economical – smaller installations will be more expensive to construct on a unit cost basis.
System and Feeder Benefits – a BESS on the distribution system can provide system benefits at a smaller scale. It can also be used to manage local power flow and to provide local ancillary services.	Limited Use Cases – where a distribution BESS is located may influence the types of services it can provide. A single distribution BESS will not be able to provide all services simultaneously.
Microgrid Potential – locating a BESS closer to load centers can simplify the design and operation of a microgrid.	Public Opposition – safety and environmental impacts could be challenging with the distribution BESS located closer to homes and businesses.

Distribution scale BESS is likely the right size for the LACDPU system, considering the amount of power served and the area's geography. Further study will be required to identify a suitable location, size, storage capacity, onsite generation needs, system impacts and other factors. Initial discussions focused on constructing a distribution-scale BESS on county-owned land in the canyons and near the distribution system. As the system evolves, LACDPU will need to consider what use cases are most desired for each BESS project, as that will influence the viable locations and system impacts from operating the BESS.

11.1.3 Residential Level BESS

Residential-scale BESS is growing in popularity among utility customers. New programs are being developed at various utilities to leverage the assets owned and maintained by their customers. Typical sizes of these installations are 3 to 10 kW with 2 to 6 hours of storage. Aggregating these resources across a distribution feeder/distribution system can result in large amounts of energy storage. This concept of aggregating customer resources is often called “Virtual Power Plants”. Table -3 compares the benefits and challenges of a distribution-scale BESS.

Table -3: Residential Scale BESS

Benefits	Challenges
Environmental Impact - no land will be required to construct a larger BESS site. Given the geography of Los Alamos, this may be the most feasible option.	Complexity – aggregating the control of customer-owned BESS may be challenging. Customers may not be willing to give LACDPU control of their assets.
Local Improvement - System loss will be lower as the resource is closer to the load, therefore, power quality can be managed more successfully.	Insufficient Energy Storage – not all customers will invest in a BESS. If adoption is low, the number and types of services these customer-owned BESS can provide to the distribution system will be reduced.
Microgrid Potential - if customers own enough BESS, there could be potential for dynamic microgrid operation.	Cost - LACDPU may need to offer higher compensation to customers participating in a residential BESS program. The structure of the LACDPU municipal utility may prohibit incentives/rebates for residential BESS.

It will likely be some time before enough BESS are deployed within the LACDPU system to create a feasible virtual power plant. LACDPU could implement new rate structures and financial incentives for customers to use their BESS resources to reduce the strain on the grid by shifting load to opportune times. During the discussion with the LACDPU project team, a virtual power plant program could be considered in the future, but it will likely not be a sought-after solution in the near term.

11.1.4 Mobile BESS

Mobile BESS is a recent development in the energy storage industry. Utilities are beginning to utilize mobile BESS to limit outages during planned capital work on the system. Other use cases include providing capacity to a distribution feeder during storm restoration efforts or to support temporary loads. Typical sizes of these installations are Between 250 to 1,000 kW with 1 to 2 hours of storage. Recent quotes from mobile BESS vendors are in the range of $1M to $2M or more depending on the configuration desired. Table -4 compares the benefits and challenges of mobile BESS.

Table -4: Residential Scale BESS

Benefits	Challenges
Versatile – ability to move system to areas in need of power. This resource can be used for a variety of reasons over the life span of the asset.	High Cost – a mobile BESS will have the highest cost for energy storage compared to permanently installed solutions.
Temporary – being mobile, this resource can be parked in areas unsuitable for a permanent installation.	Logistics - LACDPU would need to have trained staff to transport this equipment or contract out this service. The geography of Los Alamos may make it challenging to find suitable locations for connecting a mobile BESS in the areas in need.
Quiet Operation – Deploying mobile BESS instead of a diesel generator would be viewed more positively by customers.	Return on Investment – The LACDPU system is not as dynamic as larger utilities, as a result the effort required to own and operate this equipment may make ownership burdensome.

Opportunities to use a mobile BESS in the LACDPU system were discussed for the water wells and fleet vehicle charging. A mobile BESS would allow LACDPU to quickly deploy energy storage areas that are capacity constrained. It could also be used temporarily to serve loads until a permanent BESS can be constructed.

11.1.5 Ownership and Operation of BESS

If LACDPU determines a desirable use case for BESS within their system, additional consideration must be made related to the ownership model of this new resource. Table -5 shows the benefits of both models for BESS within the utility system.

Table -5: BESS Ownership and Operation Considerations

Own and Operate	Contract with BESS Operators
Control – ownership will provide the most flexibility when controlling this resource. If LACDPU wants to change the use case of the BESS over time, it can.	Capital Cost – reduced capital investment in constructing these resources.
Knowledge/Experience – LACDPU engineers will gain more exposure to this resource and may identify new dispatch methods when operating the system.	Liability – reduced concern of having staff on hand to operate this resource. A simpler forecast of the cost of using this resource.

11.2 Fault Location, Isolation, and Service Restoration (FLISR)

FLISR is a term used in the electric utility industry to describe an automated method of isolating faults and restoring service to customers. When a fault occurs, protective relays detect an abnormal condition in the distribution system and open a circuit breaker or recloser to isolate the faulty equipment. These actions can be automated by investing in new reclosers and other protective devices on the distribution feeders that are capable of communication. With communication in place, system operators can manually control these devices, or more advanced systems can be developed that perform real-time calculations to identify optimal network configurations. Investing in new protective device technology can also provide opportunities for improved data and telemetry, load shed capabilities, improved reliability, and reduced operation and maintenance costs. Figure -1 shows an image of a distribution recloser that can be configured with remote control capability.

Figure -1: Distribution Line Recloser

During discussions with the LACDPU project team, fault restoration efforts were reviewed, and several determinations were made specific to the service territory. The LACDPU service territory is compact compared to many utilities that are implementing FLISR schemes. Utilities that experience the most significant benefit from FLISR schemes have high exposure to overhead faults, inclement weather, and long response times when outages occur. The LACDPU system benefits from greater emphasis on underground construction and short response times when an outage does occur.

Installing new reclosers in areas of greater overhead exposure could benefit the LACDPU system by reducing outage impacts. However, implementing a complete FLISR scheme in the LACDPU system would require investment in new equipment and software to configure, which could be costly for such a small utility. Although the value of FLISR for LACDPU may be low today, as the distribution system grows due to electrification, this method may become more valuable to the county. If LACDPU chooses to install new reclosers and protective devices, they should verify the equipment's remote control and communications capabilities, to enable FLISR to be implemented in the future.

11.3 Distribution System Microgrid

Distribution system microgrids are becoming a popular option among electric utilities. Microgrids are often constructed to improve reliability but can also provide other benefits like improved efficiency and increased operability. The industry term for when a microgrid separates from the electric grid is called islanding. Microgrids can be contained within a single building or can be as large as a college campus or city sector. The size of the microgrid and its use case will influence many of its design parameters.

The project team discussed several considerations when designing a microgrid related to the size, use case, customer participation, and factors unique to the LACDPU system. This discussion is summarized below.

- **Loads and Customers in the Microgrid:** Typically, there is a community focus on the customers participating in a microgrid. The LACDPU project team identified that a downtown microgrid, including the police station, grocery stores, and community center, would be desirable. Additionally, a microgrid focused on the sewer plant and water well sites would be beneficial, as this infrastructure serves the community.
- **Duration of Microgrid Island:** The duration that a microgrid must sustain an island will significantly impact the required generation and energy storage. Pairing solar PV with battery storage can help sustain longer microgrid islands. However, it was discussed with the LACDPU project team that limited land is available for large-scale solar PV systems within the LACDPU system. For LACDPU, a microgrid will likely need to be paired with natural gas generation to sustain an island for an extended time. A detailed future study will help define the design parameters for the sustained island's length and the microgrid's generation requirements.
- **Customer Load Shed Potential:** Load shed is a technique employed in many microgrids to extend the operation of an island if the power or energy demands of customers cannot be met. Load shed strategies are typically more viable in industrial applications where parallel processes can be energized/de-energized. Upon discussion with the LACDPU project team, the LACDPU system primarily serves residential and commercial customers. If the microgrid is focused on community buildings and/or residential customers, there would be limited potential for load shedding. The microgrid must be designed to serve the total load of customers participating in the microgrid.
- **Size of Microgrid:** The physical size of the microgrid and the number of customers participating will impact several design parameters. When a microgrid is operated in an islanded mode, the fault current supplied by the utility system is significantly reduced, which can affect existing protection schemes. LACDPU may need to upgrade existing protective devices or implement group settings to prevent the safety of the system from being compromised during islanded operation.
- **Cybersecurity Risks:** LACDPU does not presently have remote operability of its system. A microgrid will require telemetry and remote operation of utility equipment. As new equipment and technology are included in a microgrid, there is an increased risk of cybersecurity attacks. LACDPU should work with vendors to discuss how they mitigate cybersecurity risks as new technologies are adopted on the LACDPU system.

A fully functioning microgrid will likely be a long-term option for the LACDPU system. The considerations listed above can help guide LACDPU towards developing a microgrid in the future. As new technologies are deployed on the system, LACDPU engineers should verify the compatibility of new equipment with microgrid controllers. Siting generation sources closer to customer loads is of critical importance for the development of a microgrid in the future as it will help improve the resilience and efficiency of the LACDPU electric system. LACDPU should further investigate the feasibility of generation within its service territory. Due to the geography and climate of Los Alamos, natural gas generation may be a solution, as land to develop PV systems is limited.

11.4 Modular Substations

Several utilities have deployed modular substations when the construction of a traditional substation is cost-prohibitive or undesirable to customers. Traditional substations utilize large power transformers to convert transmission voltage to distribution voltage for delivering power to homes and businesses. Traditional substations can vary in size from 0.25 acres to 4+ acres. Energized components such as the power transformer, switchgear, and bus work are contained within a fence to protect the public and substation equipment from damage. Generally, two or more distribution feeders are routed from a traditional substation to serve homes and businesses. Figure -2 shows an image of a traditional substation in the White Rock community.

Figure -2: White Rock Substation

Modular substations perform the same function as traditional substations but are constructed to be smaller, use dead front equipment, which is safe to touch, do not require a fence or large barriers, and are faster to construct. However, a single modular substation is not capable of delivering the same power as a traditional substation. Consequently, it could take multiple modular substations, distributed across a geographic area, to provide the necessary capacity that a single conventional substation can provide. Figure -3 shows an image of a modular substation from Manitoba Hydro, an electric utility in Canada[31].

Figure -3: Modular Substation Example from Manitoba Hydro

Table shows a summary of the discussion with the LACDPU project team regarding the potential use of modular substations within the county. If LACDPU desires to pursue modular substations, additional feasibility analysis must be performed, and design considerations must be made.

Table -6: Modular Vs Traditional Substation Considerations

Consideration	Modular Substation	Traditional Substation
Construction	Preassembled equipment, shorter construction times, and shorter lead times	On-site construction and assembly, longer construction times, longer lead times, and future expansion can be challenging.
Operations and Maintenance	Quick replacement, hot stick operable, reduced copper theft potential, similar life expectancy to traditional substation assets, and more locations to maintain	More rigorous maintenance schedules, expensive components, fewer locations to maintain
Safety	Dead front components, tamper resistant, grounding to IEEE 80	Physical security equipment required (fencing, locks, etc.), exposed bus work, and more stringent safety training
Environmental	Less visual impact, low impact from oil spills, reduced EMF exposure	Large footprint, large transmission structures, more public visibility, perceived environmental impact

[31] Manitoba Hydro modular substation example - https://www.mhi.ca/products/hvpt

11.5 Volt-VAR Optimization

Utilities use capacitor banks, shunt inductors, and voltage regulators to regulate voltage within the distribution system. As DER penetration increases on the distribution system, voltage compliance can become more challenging and require adjustments to typical operating procedures. The LACDPU system is primarily made up of residential and commercial customers. These customers typically have a high power factor, which results in more efficient system operation. Because the LACDPU system serves a small quantity large motors and industrial customers, a small number of capacitor banks are located on the LACDPU system. The geography of the LACDPU system also results in relatively short distribution feeders that can successfully maintain customer service voltage. Historically, LACDPU has maintained compliance with voltage criteria without applying Volt-VAR optimization.

As DER penetration increases on the LACDPU system, there is potential for voltage rise when customer generation is high. This is further exacerbated when customer generation is high and local customer demand is low in the spring and fall seasons. Utilities across the country are adjusting their interconnection agreements to require new solar PV customers to adopt Volt-VAR inverter control to assist in regulating voltage on the distribution feeder. PNM implemented such a requirement in 2024[32]. PV customers on the LACDPU system presently operate at unity power factor to maximize generator output and customer return on investment. 1898 & Co. recommends that LACDPU update its interconnection agreement to incorporate dynamic voltage control, such as the Volt-VAR inverter control outlined in the PNM TIIR document. By requiring this control scheme from new solar PV customer equipment, the LACDPU system will benefit from improved voltage regulation that will help mitigate potential high-voltage violations for customers.

Even with dynamic voltage control enabled for new PV customers, the LACDPU system may require additional voltage regulating equipment to maintain compliance with ANSI C84.1. Static compensators are a technology that is gaining traction with distribution utilities. A static compensator uses power electronics to absorb and produce reactive power on a distribution feeder to regulate voltage. Static compensators can react quickly and improve the system's efficiency by producing and absorbing reactive power closer to the area of need. There is no need for static compensators in the near term for the LACDPU system. However, if LACDPU is experiencing sustained high voltage within a specific area, a static compensator may be a solution that can be used in the future. Alternatively, lowering the substation voltage setpoint is another solution if solar PV penetration results in high voltage throughout the system. If the substation voltage setpoint is lowered, it must be confirmed that low voltage does not result during peak load times.

Conservation Voltage Reduction (CVR) is a method related to Volt-VAR optimization and energy efficiency. CVR is a strategy LACDPU could pursue to reduce peak demand as better voltage regulation is implemented on the system. To successfully implement CVR, additional equipment like capacitor banks, voltage regulators, or even static compensators could be required on the LACDPU system. No near-term action for CVR is recommended for LACDPU, but this may be a future option for the County to make incremental improvements to the system's peak demand.

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[32] PNM TIIR Requirements - https://www.pnm.com/documents/28767612/28777474/PNM+Technical+Interconnection+and+Interoperability+Requirements+%28Feb+1%2C+2024%29.pdf/bc34f992-67c7-43b5-eda5-3ff014d97c04?t=1704474064849

11.6 Demand Response Programs

Customer load varies throughout each day, week, month, and season. Electric utilities nationwide have implemented demand response programs to influence how customer load impacts the electric distribution system. During times of high customer demand, the utility can operate a demand response program to shed customer load and improve the electric system's reliability. Common demand response programs focus on a residential home's most significant energy sources, such as space heating, cooling and water heating. Typically, utilities will interface with smart thermostats or other controllers of these electric loads to influence the grid impact. Often, customers can be credited for opting into a demand response program or provided with other monetary incentives for participation.

Another method of reducing peak customer demand on the electric system is to use various rate structures. Time of use rates can be implemented to encourage customers to shift their electricity usage outside the hours where peak demand occurs. Customers who can adjust their demand are then charged reduced rates for energy consumption during off-peak times. In addition to time of use rates, demand charges can be implemented to encourage customers to limit their peak demand impact on the grid. A demand charge would add a fee to customers' bill based on the monthly maximum power consumed. Customers who can minimize their maximum power consumption will reduce the demand charge component of their electric bill. Customers who reduce their maximum power consumption help to mitigate the electric grid impacts from their energy consumption.

Electric vehicle adoption is growing and represents a new type of load for many customers who drive internal combustion engine vehicles. EVs can consume large amounts of energy from the grid, but these loads can be flexible. As EV adoption rates increase, there may be new opportunities for LACDPU to implement managed EV charging programs and rate structures to spread out EV charging and limit the impact on the electric grid. These managed EV charging programs would require input from drivers, such as the typical daily drive distances and the time the vehicle must be charged. The program would be administered to spread EV charging load while meeting customers' needs to have their vehicles charged and ready for use at the appropriate time each day. LACDPU should look for opportunities to implement a managed EV charging program when EV adoption rates increase and solutions from vendors become more mature. Figure -4 shows an image of electric vehicle supply equipment (EVSE).

Figure -4: Electric Vehicle Supply Equipment

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