Los Alamos County
30 Years Electrification Forecast

Board of Public Utilities
July 16th 2025

Outline

- Electrification Impact Study
  - Electrification Load Growth Overview
  - Summary of Impact Analysis
  - Financial Impact
- Electrification Financial Analysis
  - Incremental Revenue Growth and Capital Projects
  - Rules and Regulations
- Staffing Review

Electrification Grid Impact Study

Electrification Impact Scenarios

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

The electrification load forecast was updated with the following changes

- The counts of heavy duty vehicles was decreased after reviewing Experian registration data again and discussions with the BPU about RVs in the heavy duty vehicle class.
- The customer PV adoption rate in Scenario 1 was decreased from 50% to 35%
- The population of homes with furnaces was reviewed and updated after reviewing additional data sources and feedback received from the BPU.

Major Capital Projects – Substation Upgrades

Substation projects are recommended to support anticipated electrification growth.

1. **Eastgate Substation**
   - 2-14 MVA transformers, 2-22.4 MVA transformers, or 2-33.7 MVA transformers depending on the electrification scenario.

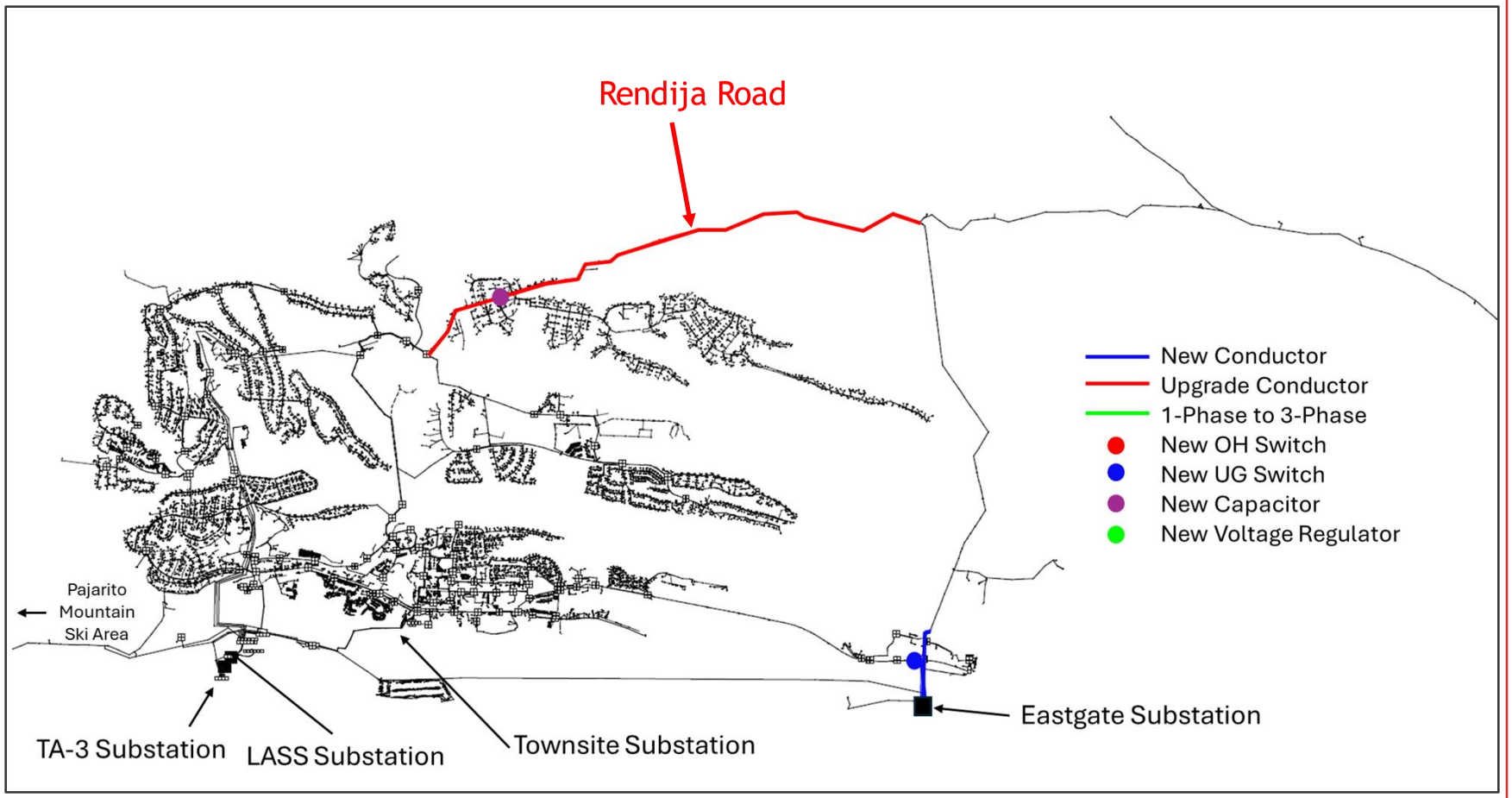
2. **White Rock Substation Upgrade**
   - Replace the transformers only or rebuild the whole substation with 2-14 MVA transformers or 2-22.4 MVA transformers depending on the electrification scenario.

The timing, staging, and full scope of these projects is dependent on growth trends experienced in the County.

Los Alamos - Overhead Conductor Upgrade

Upgrade approximately 3 miles of conductor to 477 ACSR to create a strong tie path from the Eastgate Substation to the north region of the service territory for normal load service and contingency support.

This upgrade was common across all electrification scenarios with the Eastgate Substation constructed.

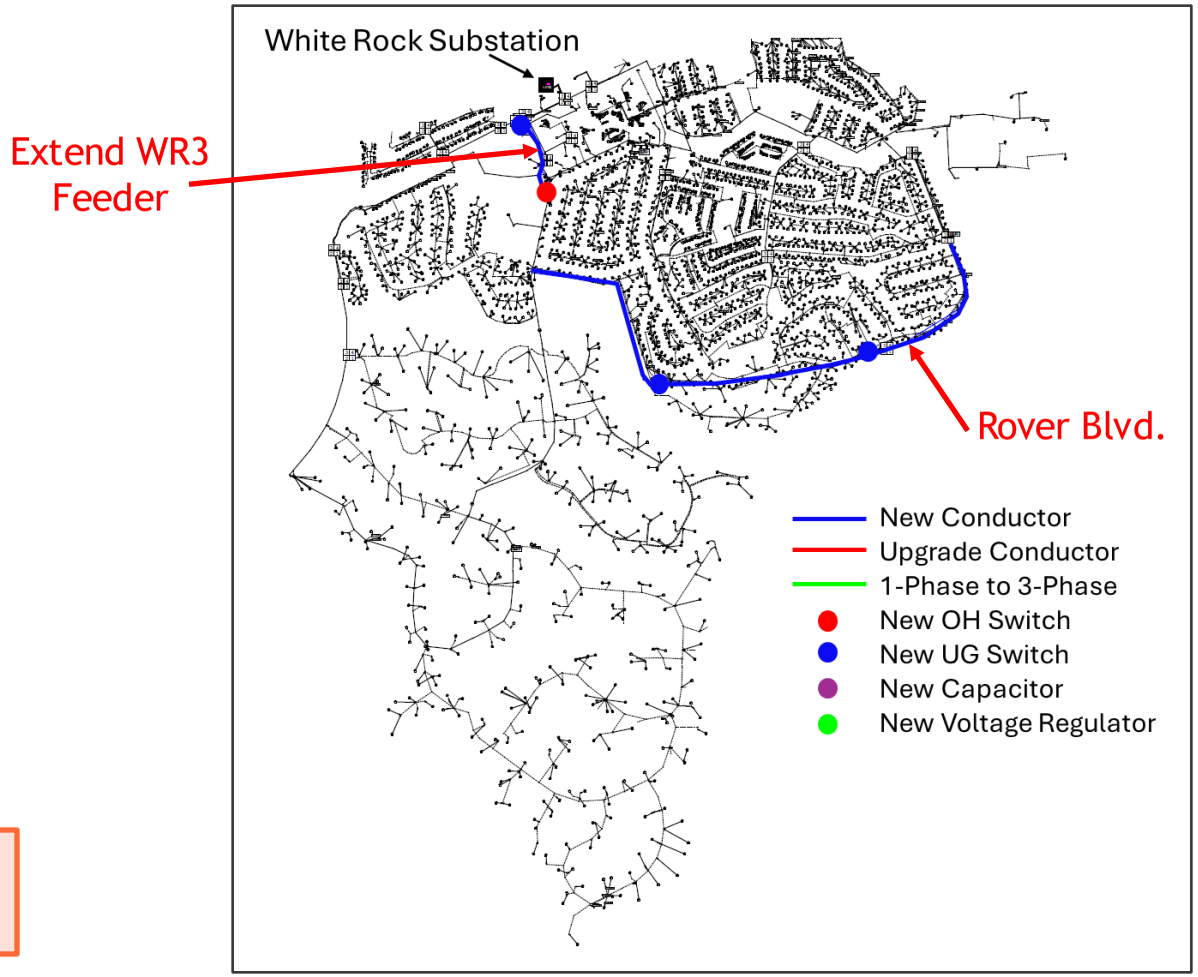


White Rock - Underground Loop Construction

- Build approximately 2 miles of 500 MCM CU cable to create another strong tie point within the White Rock system.

- Reconfigure the area to add more load to White Rock Feeder 3 to evenly distribute load and improve power flow results.

This upgrade was common across all electrification scenarios.



Grid Upgrades Financial Impact

Investment Categories

- **System Improvements** – upgrades performed to serve forecasted electrification load growth. These upgrades were necessary to maintain both normal load service and provide capacity for contingency scenarios.

- **Asset Replacement** – replacement of existing system assets due to age and deterioration. Estimates of necessary replacements are provided for each electrification scenario based on the data provided by LACDPU. The County may not be required to replace the magnitude of assets presented in this study if actual asset life exceeds the anticipated asset life recommendations from the LACDPU.

Cost estimates are provided separately for these two investment categories in the report and the following slides.

Financial Impact Summary

Scenario	2040 Model Year			2055 Model Year - Incremental Costs			Total Scenario Cost
	System Improvement Costs	Asset Replacement Costs	Total Financial Impact	System Improvement Costs	Asset Replacement Costs	Total Financial Impact	
Scenario 1	$53.7M	$119.8M	$173.4M	$14.1M	$94.6M	$108.7M	$282.1M
Scenario 2	$38.1M	$125.3M	$163.4M	$15.1M	$86.1M	$101.3M	$264.6M
Scenario 3	$27.6M	$125.3M	$152.9M	$8.3M	$82.9M	$91.2M	$244.1M

- Asset replacement costs are anticipated to be more significant than the system improvement cost.

- System improvements have a similar financial impact as major substation upgrades were necessary for all electrification forecast scenarios.

Scenario 1 Financial Impact

2040 Model Year

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

- Eastgate Substation 2-33.7 MVA transformers
  - Four new feeders from the Eastgate Substation
- White Rock Substation upgrade to 2-22.4 MVA transformers

2055 Model Year

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

- Eastgate Substation 2-33.7 MVA transformers
  - Six new feeders from the Eastgate Substation
- White Rock Substation upgrade to 2-22.4 MVA transformers
  - One new feeder from the White Rock Substation

Scenario 2 Financial Impact

2040 Model Year

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

- Eastgate Substation 2-22.4 MVA transformers
  - Two new feeders from the Eastgate Substation
- White Rock Substation upgrade to 2-14 MVA transformers

2055 Model Year

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

- Eastgate Substation 2-22.4 MVA transformers
  - Four new feeders from the Eastgate Substation
- White Rock Substation upgrade to 2-14 MVA transformers

Scenario 3 Financial Impact

2040 Model Year

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

- Eastgate Substation 2-14 MVA transformers
  - Two new feeders from the Eastgate Substation
- Only Upgrade White Rock Substation transformer 1 to a 10 MVA unit. Transformer 2 is appropriately sized for this scenario.

2055 Model Year

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

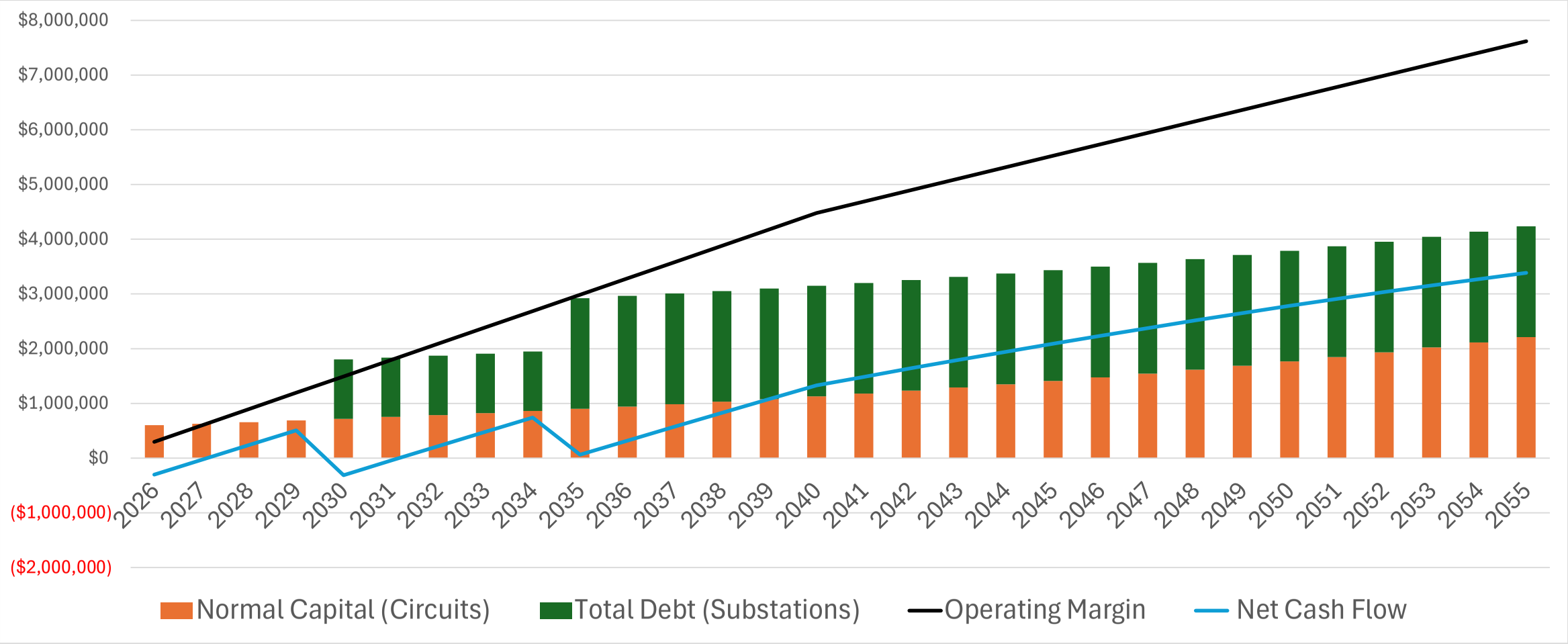
- Eastgate Substation 2-14 MVA transformers
  - Three new feeders from the Eastgate Substation
- Upgrade both White Rock Substation transformers to 10 MVA units.

Financial Analysis

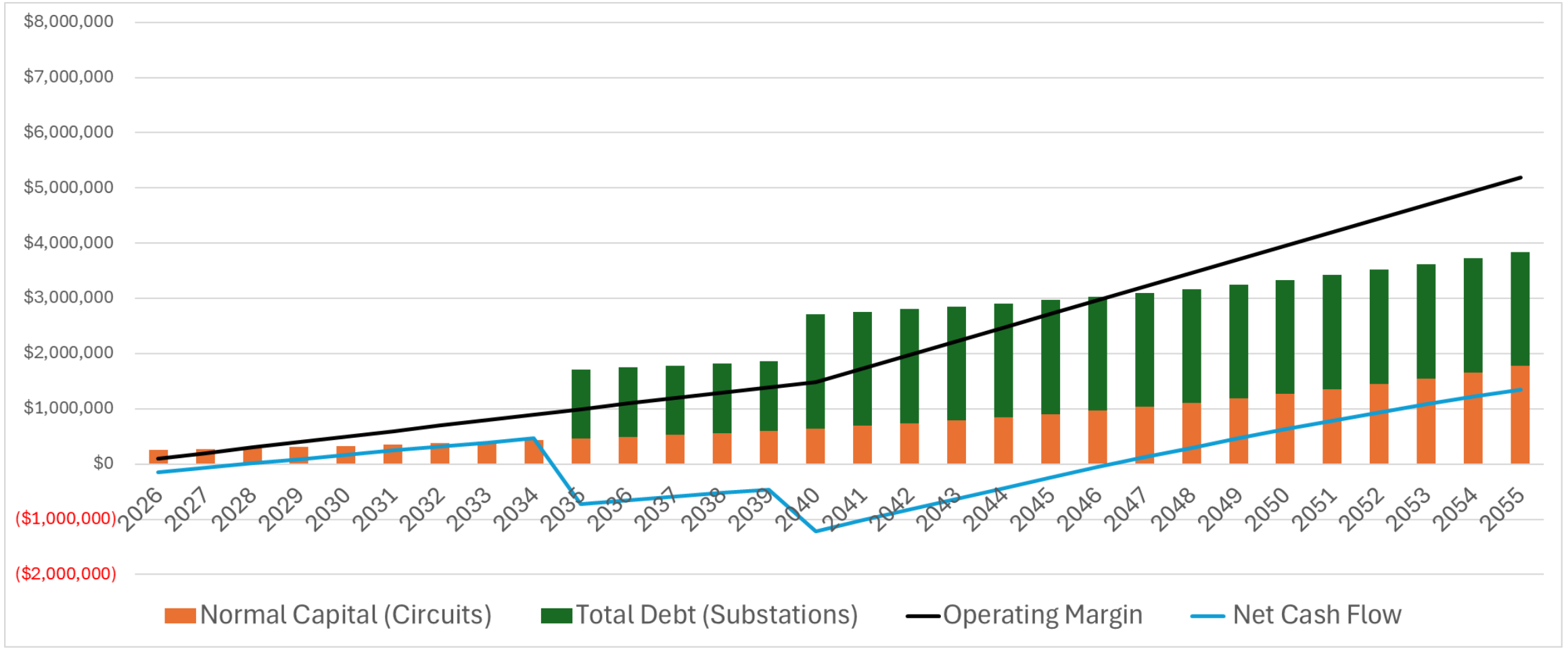
Financial Forecast Analysis

- Prepared incremental financial forecast models for all 3 scenarios
- Estimated incremental annual electric revenues and operating margins
- Projections assume TOU rates and EV and EH demand response in place
- Projected major capital and routine capital by year (system improvement costs only)
- Major substation projects are debt financed over 30 years at 4.5%
- Developed incremental cash flow analyses to determine viability
- Key question: Can incremental electric sales fund system expansion?

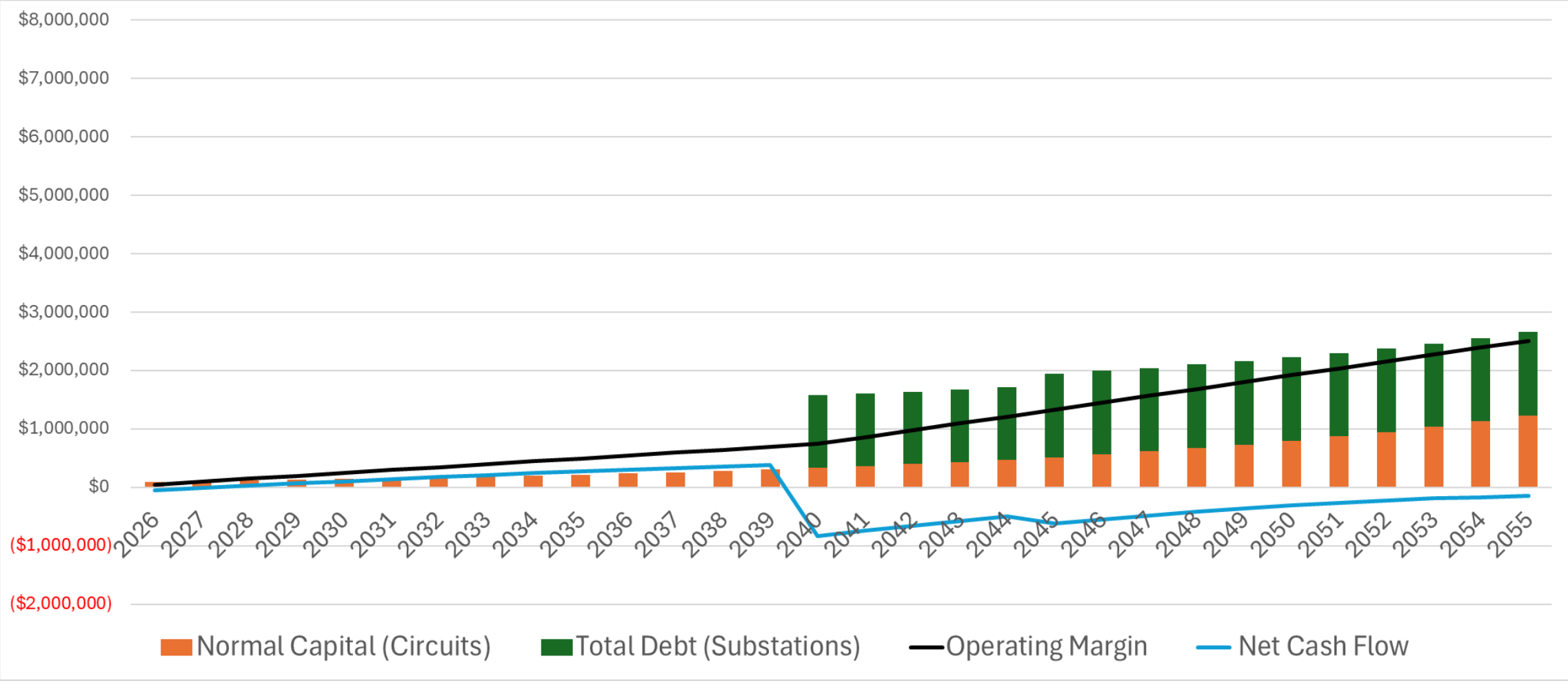
Financial Forecast Analysis - Scenario 1



Financial Forecast Analysis - Scenario 2



Financial Forecast Analysis - Scenario 3



Financial Forecast Analysis - Conclusions

- Scenarios 1 and 2 electric sales and associated margins should be able to support incremental capital and debt service.
- Scenario 3 will require rate increases to support incremental debt service if major substation projects are built too early.
- Financial projections do not guarantee viability but provide an indication of potential assuming electric sales are realized and margins are maintained.

Rules and Regulations

Line Extension Policy and Customer Credits

- Electric Heat (EH), Electric Water Heating (EWH) and Electric Vehicles (EVs) all increase sales and support higher utility CIAC (or connection fee discounts).
- Utility's can justify providing upfront credits (or discounts) to customers who install electric appliances that generate more energy sales.
- DPU policy requires a $1,400 connection fee. Fees are typically based on future benefits, incremental costs, and embedded system costs.
- Other utilities (i.e. PNM) charge a lower connection fee to customers who install electric heat, water heating, and EV's. The credit ranges from $500-$1500.

"Utility Benefits (NPV Net Margins) / Utility Costs (Incentives + NPV Costs) > 1"

Electric Vehicle - Rates and Demand Response

- EV Time of Use Rates –
  - Implement time-based demand rate or energy rate for customers to use for beneficial off-peak EV charging.
  - TOU rates should be directly marketed to EV customers and will enhance efficient use of the electric system.
  - Design rates to promote shifting and provide benefits>cost.

- EV Demand Response Program -
  - As an alternative, EV chargers or other EV load control devices (switches) can be part of a demand response program.
  - Demand response programs can help to shed load during peak times and can also be used to enhance efficient use of the electric system.
  - DPU should develop a program that provides incentives that yield benefits>costs.

Electric Heating – Rates and Demand Response

- Electric Heating Rates –
  - Implement time-based demand rate or energy rate for customers to use for beneficial off-peak electric heating.
  - EH rates (declining block, demand rates, lower winter rates) can provide an attractive rate for electric heating.
  - EH customers cost less to serve on a$/kWh basis. DPU should evaluate this in the next cost of service study.

- Electric Heating Demand Response Program -
  - As an alternative, EH load control devices (switches) can be part of a demand response program.
  - Demand response programs can help to shed loads during peak times and can also be used to enhance efficient use of the electric system.
  - DPU should develop a program that provides control incentives that yield benefits>costs.

Solar & Battery – Rates and Demand Response

- Solar PV Rates and Policy –
  - Continue implementation of time-based demand rate ($/kW-month) or energy rate for customers for equitable system cost recovery and increase over time.
  - Reduce net excess compensation rate to match avoided cost of energy supply.

- Battery Energy Storage Rates and Policy -
  - Enable BESS or solar+BESS customers to use TOU demand rates or TOU energy rates to realize benefits of BESS.
  - Consider evaluating DR programs that provide a demand response credit or paid incentive for BESS load control.

Alternative Funding Sources

- Federal Grants and Loans
  - GRIP Grants
- Customer Funded Grid Infrastructure
  - Commercial Pays Extensions
- Direct Payment Federal Tax Credits
  - Utility Battery Storage ITC
- Customer Equipment Tax Credits
  - Expiring soon as of July 4, 2025

Staffing Review

Staffing Review

	Current	Foundational Years	Build Capacity & Specialization	Mature Organization
Total	17	19	23	25
Change		+2	+4	+2

- **Current State:**
  - A lean, highly-skilled engineering team (5 FTEs) manages all functions, including system design, project management, and direct supervision of the operations crews (12 FTEs). This agile but non-scalable model concentrates significant operational duties onto a few key individuals.
- **Organizational Recommendation:**
  - Restructure into three functionally aligned departments to enable scalability and specialization:
    - Engineering & Planning
    - Project Management Office (PMO)
    - Operations
- **Phased Transition Plan:**
  - Phase 1 Foundational Setup – Hire a PM Lead and a Field Operations Manager to establish new leadership and separate daily operations from the Engineering department.
  - Phase 2 Building Capacity – Recruit specialized engineers and technicians.
  - Phase 3 Achieve Maturity – Establish advanced functions like a Business Analysis unit to leverage data to optimize performance, assets, and spending.

Our recommendations for increased capacity should be viewed as purpose- or function-based. Existing, skilled personnel across the breadth of LACDPU can be repurposed to fulfill the new roles envisioned.

Electrification Study Recommendations

Actionable Recommendations

- 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 City 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.

Recommendations for 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.

- 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).

- Perform a holistic review of all LACDPU departments. Electrification will most impact the Electric Distribution Department, but it is anticipated that there is an opportunity for repurposing staff from departments that forecast a decline in workload. Additionally, other departments such as customer service and geographic information systems (GIS) may forecast an increase in workload resulting from electrification.